

Appendix B:
July 21, 2016 Board Hearing Comment Letters

Comments received during in written materials during the Board Hearing,
July 21, 2016



OG-B-1-M2

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July 18, 2016

Clerk of the Board
 California Air Resources Board
 1001 Eye Street
 Sacramento, California 95814

Subj: Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear California Air Resources Board (CARB):

These comments address California Environmental Protection Agency's efforts to minimize greenhouse gas emissions and volatile organic compounds (VOCs) for oil & natural gas facilities in a technically feasible and cost-effective manner.

CARB states:

The proposed regulation will reduce...emissions by over fifty percent. The proposal is also expected to reduce both volatile organic compounds (VOC) and toxic air contaminant (TAC) emissions and provide an essentially neutral nitrous oxide (NO_x) impact statewide.

B-1-1

If operators capture leak data at specified intervals—not continuously—the regulation suggests this will be sufficient for establishing compressors' emissions' footprints.

M-Squared Products & Services, Inc. manufactures the packing leak detector (PLD[®]), a technology offering inexpensive and accurate emissions' measurements with universal applicability. PLDs are an effective solution for large, reciprocating compressors' methane emission standards in addition to leak detection and repair (LDAR) for other large compressor components and smaller compressors.

Significantly, PLDs operate effectively with and can be retrofitted to any reciprocating compressor capacity.

In reciprocating compressors, emissions result from several possible functional failures. Until the PLD, emissions detection was less a precise science and largely anecdotal.

The evolution of Optical Gas Imaging (OGI) increases operator awareness of leakage, but doesn't provide volume or causal information. Additionally, OGI observations are static. PLDs operate continuously and isolate failure causal factors.

M-Squared Products & Services, Inc.

Features and benefits of a properly installed PLD

- First, real-time baseline indicator of packing gland and packing health. Determines whether packing material is appropriate, leaking, failing, installed correctly, the piston rod is too smooth or assembly is over-lubricated
- Visually indicates packing gland leaks
- Measures leak rates
- Calibrated for varying rates and different gases
- PLD outlets can be redirected for low-pressure gas applications until packing is serviced or replaced

Additionally, transducer-equipped PLDs

- Provide local and remote monitoring
- Coupled to V570 Programmable Logic Control (PLC) panels enable alarm and shutdown capabilities

PLDs are cost-effective tools which can help the California Environmental Protection Agency achieve emissions baselines for used or new compressors.

Of CARB's stated *objectives and benefits of the proposed regulatory action*, PLDs would find appropriate applications for provisions 2, 3, 4 and 7.

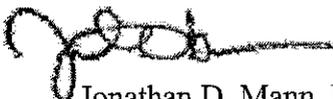
┌ B-1-2

PLDs are the first, unique tools that provide real-time baselines helping operators assess the health & effectiveness of compressor packing. As operators install PLDs broadly, they will enjoy the following direct & indirect benefits:

- Cost effective alternative to determining packing life cycle
- Linear vs. random maintenance
- Capturing profit instead of lost production (when integrated with vapor recovery technologies)
- Flexibility (local & remote data monitoring & alarms)
- Compliance (the ultimate goal of emission regulations)

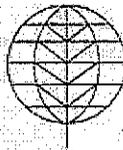
We appreciate the opportunity to contribute to this regulatory forum and would be delighted to provide Packing Leak Detector product and technical information.

Sincerely,



Jonathan D. Mann, President
M-Square Products & Services, Inc.

®Registered in the U.S. Patent and Trademark Office



EARTHWORKS

OG-B-2-Earthworks

16-7-2

Bruce Baizel

**California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10
Climate Change, Article 4
Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and
Natural Gas Facilities**

July 21, 2016

Thank you for the opportunity to comment on the California Air Resources Board (CARB) Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Please accept these comments on behalf of Earthworks, a national nonprofit organization dedicated to protecting communities and the environment from the impacts of mineral and energy development while seeking sustainable solutions.

General Comments

Overall, these proposals represent an important step forward in controlling methane emissions from oil and gas facilities. We especially appreciate CARB's leadership in proposing standards simultaneously for both new and existing sources. Other essential components include robust programs for Leak Detection and Repair (LDAR) as well as inspections and replacements.

B-2-1

CARB should make some improvements to this proposal to ease public participation in the regulatory process, especially with respect to the LDAR program as described below.

In addition, CARB should maintain a consistent standard for inspection frequency. Under this proposal, failing to discover leaks can form the basis for less frequent inspections. This approach is flawed for two reasons. First, the absence of a leak reveals nothing about the probability of a future leak. Second, reducing inspections for failure to discover emissions may inadvertently encourage shoddy inspection work. Operators may find it easier not to find leaks rather than repair them. This approach also sets a poor regulatory precedent.

B-2-2

In general, Earthworks supports the implementation of LDAR requirements (95669) to the listed 95668 facilities.

Specific Comments

95668(i) Natural Gas Underground Storage Facility Monitoring Requirements

Earthworks applauds CARB's proposal for special monitoring requirements for underground storage.

B-2-3

To begin, we support CARB's decision to assume LDAR implementation from the

Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR). By 2018, CARB wants the ability to remotely access readings from the continuous monitoring of ambient air from underground natural gas storage facilities. This data will greatly benefit the public.

B-2-3
Cont.

We also suggest CARB augment this remote access monitoring system with a simple function allowing the public to upload monitoring data of our own.¹ As discussed below, a cooperative LDAR approach involving industry, government, and the public will most efficiently reduce emissions, save money, and ease compliance.

B-2-4

In addition, we support CARB's proposal (95668 (i)(c)(6)) to require operators to maintain and make available records of their monitoring system to CARB upon request. We urge CARB to similarly require operators to make those records also available to the public.

B-2-5

95669. Leak Detection and Repair.

The Optical Gas Imaging (OGI) from the leak at the Aliso Canyon facility helped bring to the national spotlight the dangers associated with methane emissions. The infrared plumes also highlighted the contributions citizen science can bring to the enforcement of this rule. Ultimately, regulations mean nothing without proper enforcement mechanisms like an effective LDAR program.

In particular, CARB should encourage voluntary third party verification of the LDAR testing required under this section. This approach will both ease the compliance burden on operators and the oversight burden on CARB. Faster leak identification saves operators money, conserves the resource, and results in fewer fines and penalties. Regulators and the public, in turn, achieve better public health, safety, compliance and climate benefits.

B-2-6

As part of the LDAR program, third party verification will comply with the same requirements placed upon operators pursuant to 95669(g)(2) and (g)(2)(a). These certified OGI Thermographers will also conform to the applicable recordkeeping and reporting provisions of 95671 and 95672.

To ease both compliance and implementation, CARB should create a single publicly accessible and searchable web based portal. This platform will first assist the regulated community by allowing electronic submission of recordkeeping and inspection reports. It will also benefit the public from online streaming of the continuous monitoring data CARB will receive under 95668(i)(1)(A). Finally, this system ought to accommodate citizen complaints- especially a function allowing persons to upload OGI footage directly to CARB for 95669 purposes.

B-2-7

Nothing in this above approach should be construed to replace or supersede the inspection, recordkeeping, and reporting requirements detailed under this proposed regulation.

95669(b)(1) Earthworks encourages CARB to collaborate with local air districts on implementing an LDAR program that standardizes inspections, monitoring, recordkeeping, and reporting. Accordingly, local air districts should maintain the flexibility to impose additional LDAR requirements. In no circumstance should some districts have weaker LDAR requirements than CARB.

B-2-8

95669(b)(4) Earthworks looks forward to the upcoming rulemaking CARB is developing in conjunction with the Public Utility Commission to regulate methane emissions from oil and gas pipelines. Pipelines can be a significant source of methane emissions and operators should have similar LDAR obligations for all components of pipeline systems.

B-2-9

95669(g)(1) Earthworks supports regular inspections of all 95668 components. However, we oppose CARB's proposal to reduce the frequency of inspections simply because the operator finds no leaks or only low-level leaks. This approach provides a disincentive to find and repair leaks, by rewarding operators for not detecting them. Furthermore, past leak performance is not indicative of future performance. If anything, older components should receive greater scrutiny.

B-2-10

95669(g)(2) Earthworks supports CARB's proposal to encourage operators to employ OGI instruments. In particular, we appreciate that CARB provides that only a certified Thermographer may operate the equipment and proscribes specific timeframes for verification of the camera readings.

B-2-11

95671 Record Keeping Requirements.

95671(a)(9 and 10) Earthworks supports CARB's proposal to require operators to maintain records of LDAR inspections for at least 5 years. We also urge CARB to require operators to make these records available to the public upon request; CARB should create a publicly accessible and searchable web based platform where operators must submit these records.

B-2-12

95672 Reporting Requirements.

95672(a)(8-12) Earthworks supports CARB's proposals to require operators to report leaks within specified timeframes and to report the results of inspections conducted pursuant to section 95669. Similarly, Earthworks urges CARB to require operators to make these reports available to the public upon request; and create a publicly accessible and searchable web based platform where operators must submit these records.

B-2-13

Conclusion

CARB achieves important public health, safety and climate benefits from this rule. As with all rules, enforcement is key. CARB should not take a "step-down" approach to enforcement, but instead encourage voluntary third party LDAR verification.

B-2-14

Sunlight also aids enforcement. CARB already proposes remote access monitoring, recordkeeping, reporting, and a robust LDAR program. Allowing a role for citizen science in this rule's implementation will achieve benefits for all stakeholders.

B-2-15

¹ We envision here an opportunity to allow the public to submit citizen complaints with OGI video compliant with 95668(i)(B) that can trigger the 95669 inspection and repairs.

**Chevron Cahn Plant
Lost Hills, CA**



EARTHWORKS

FLIR

**Murphy Oil Field
Los Angeles, CA**



EARTHWORKS

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W. James Wagoner
Air Pollution Control Officer

Robert McLaughlin
Asst. Air Pollution Control Officer

July 20, 2016

Elizabeth Scheehle, Chief
Oil and Gas and GHG Mitigation Branch
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Agenda Item 16-7-2: Comments on Proposed Regulation of Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear Ms. Scheehle:

Thank you for the opportunity to provide comments on the Proposed Regulation of Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Staff from the Butte County Air Quality Management District have been involved with the CAPCOA/ARB working group over the past several months collaborating with ARB staff as the regulation has been developed. We appreciate ARB establishing the working group and seeking input from the air districts early in the process of developing this important measure. Having said that, we have the following comments which should be considered. These are areas which our staff brought forward in the working group meetings.

Idle wells: The regulation is unclear on the requirements for wells not currently in service. Districts have heard terminology describing wells as "idle", "abandoned", "plugged", "dry", "inactive", etc. but the Proposed Regulation and ISOR do not include definitions for these terms and is unclear to what extent wells not currently in service for any reason are to be regulated. The regulation and ISOR limits discussions of "idle" to intermittent bleed pneumatic devices and does not clarify if the control, monitoring and reporting requirement apply to "idle" wells; however, we believe that there are as many or more wells not currently in service than in service that may be subject to this regulation and require district or ARB oversight but are not included in the cost estimates prepared for this ISOR. Regulating wells currently not in service will be a significant challenge for districts, ARB and the regulated community.

B-3-1

Record keeping: Section 95668(i) relating to Natural Gas Underground Storage Facility Monitoring Requirements was a recent inclusion to the proposed regulation. In this section requirement monitoring for these facilities, Section 95668(i)(1)(C) 6 requires facilities with continuous monitoring to keep records but Section 95668(i)(1)(B) does not require facilities opting for daily screening to keep records of this monitoring. We recommend record keeping be required regardless of the type of monitoring system chosen. If the requirements in 95668(i)(1)(C) 6 are supposed to also apply to 95668(i)(1)(B), this is not clear in the regulation or ISOR.

B-3-2

In general, organization of bifurcated compliance methods, requirements, and standards in the proposed rule are problematic. For example, in Section 95668(g), owners and operators with liquid unloading "shall do one of the following:" and below are listed three compliance options and one record keeping requirement. All four elements of the rule are on the same outline level indicating only one of the four is required; however, we believe it the intent of the ARB as clarified in the ISOR which indicates owners or operators must choose a compliance and then records kept of the option. Similar organizational issues exist within many subsections of the proposed regulation and the ISOR does help clarify the intent on some of these sections. We recommend organizing the regulation so that interpretation of the requirements is not an unnecessary issue.

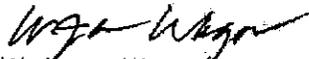
B-3-2
Cont.

Enforcement and permitting: While ARB states in the ISOR that districts may elect to implement and enforce the regulation, Section 95673(b)(1) requires regulated entities to apply to the local district to have conditions added to district permits ensuring compliance with this (sub)article upon the district issuing a new or renewed permit. Based on this language, district participation is not optional. If district participation is optional, it is not evident how permits will be issued if a district does not implement the regulation. Permitting authorities and the implementation needs to be clarified.

B-3-3

Thank you again for the opportunity to comment. We look forward to working with ARB staff on the final regulation. If there are any questions regarding these comments, please contact David Lusk of my staff or me.

Sincerely,



W. James Wagoner
Air Pollution Control Officer

Willie Rivera
16-7-2



California Independent Petroleum Association
1001 K Street, 6th Floor
Sacramento, CA 95814
Phone: (916) 447-1177
Fax: (916) 447-1144

**Comments of the California Independent Petroleum Association
on the Proposed Greenhouse Gas Emission Standards for
Crude Oil and Natural Gas Facilities (May 31, 2016 version)**

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

July 21, 2016

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bcsubform.php?listname=oilandgas2016&comm_period=A

The California Independent Petroleum Association (CIPA) appreciates this opportunity to officially comment on the proposed new regulation to control methane from oil and gas operations here in California. The Proposed Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities is an entirely new regulation under California's continued push to reduce greenhouse gases (GHGs) and Short-Lived Climate Pollutants (SLCP). This regulation is designed to specifically address a single pollutant (methane) within a single industrial category (Oil and Gas Production) and within a single state, therefore this opportunity to fully address remaining technical issues and evaluate its impacts on that single industry is critical.

The mission of CIPA is to promote greater understanding and awareness of the unique nature of California's independent oil and natural gas producer and the market place in which he or she operates; highlight the economic contributions made by California independents to local, state and national economies; foster the efficient utilization of California's petroleum resources; promote a balanced approach to resource development and environmental protection and improve business conditions for members of our industry.

Over the past year CIPA has actively been working with Air Resources Board (ARB or Board) staff on informal versions of this regulation. Through multiple conversations and comment submittals, CIPA has conveyed concerns about the scope, standards and implementation of this regulation. We would like to recognize the effort ARB staff has made to improve the regulation and work with industry stakeholders. *This version is much improved, but it cannot yet be considered complete.* There are remaining technical, clarity and implementation issues that must be addressed in a subsequent 15-day amendment package. CIPA has not provided an exhaustive list of detailed changes, but rather highlighted the remaining issues that staff and stakeholders need to continue working together to resolve. Those categories of potential changes are the focus of this comment letter.

B-4-1

CIPA's remaining areas of concern are summarized below followed up with additional details:

- Implementation and enforcement
- Consistency with MRR
- Standards and exemptions
- Vapor recovery requirements, including the late addition of "Gauge" tanks

B-4-1
Cont.

Implementation and Enforcement

CIPA understands ARB's desire to have this regulation implemented and enforced at the local level, and believes that doing so may be the most efficient use of resources. But not all local Air Districts (districts) have the resources or desire to take on this responsibility. To date, CIPA has not seen any district MOUs to fully understand what these would look like, who would be the primary enforcement body, and how ARB would handle oversight of the districts. As it is anticipated that more than one local air district will enter into an MOU with ARB, these agreements should be finalized and made public prior to the effective date of the regulation. Knowing who your regulatory lead is, is just as important as the standards themselves.

B-4-2

Historically, air quality regulations have been segregated into either "CARB enforced" or "local enforced". This clear delineation has been well established. A regulated party should only have to answer to one regulatory body for a single regulatory regime. This regulation subjects CIPA members to potential violation at both the State and local level for the same potential offense. This is a significant concern.

B-4-3

Additionally, there are a variety of dates, and response times contained within the regulation that are shorter than those of the existing local district rules. This inconsistency is problematic and should be reconciled to be consistent with the longer timeframes already in use today.

B-4-4

CIPA strongly recommends that prior to final regulatory adoption, these pending implementation and enforcement issues are resolved in the public domain, including the elimination of possible double jeopardy and adoption of any local district MOUs.

B-4-5

MRR Consistency

In reviewing the proposed Regulation, CIPA members have noted several inconsistencies between it and the Mandatory Reporting Regulation (MRR). This may cause uncertainty, confusion, and inconsistency in interpreting the regulation, in defining record keeping and reporting practices, and in agency and public use of the data collected under these regulations. Because definitions are critical to the implementation of the rule and are key to enforcement and compliance efforts it is of paramount importance to ensure they are as tightly written as possible. The definitions of "component" and "facility" are only two examples. CIPA believes these issues can and should be addressed in a subsequent 15-day amendment package, and looks forward to working with staff.

B-4-6

CIPA recommends ARB continue to work with stakeholders and then use a 15-day amendment package to revisit and clarify as needed prior to the final adoption of the rule.

B-4-7

Standards and Exemptions

This regulation is entirely new, but it is also layered with a variety of difference sections each with their own set of standards and exemptions. CIPA has noted that several of these provisions, and exemptions, are either not feasible (timelines for certain required action) or do not take into account the reality of California's oil production system (exemptions based

B-4-8

on an inappropriate “one size fits all” oil/water ratio criteria) and should be revisited in a 15-day amendment package prior to final adoption.

B-4-8
Cont.

An example of a specific technical issue is the requirement to change to dry seals. A number of wet seal compressors cannot be converted to dry seals due to the size of the dry seal cartridge. Also, when using dry seals in the oil fields, they require a gas scrubber and treatment equipment to achieve for their supply system as they need clean dry gas, as well as, additional equipment to ensure the high pressure supply to the dry seal at start up and low flow operations to prevent premature seal failure.

B-4-9

It was also brought to CIPA’s attention that a late staff proposal would eliminate the option to “step down” Leak Detection and Repair frequency from quarterly to annual. This is a significant change which comes with a increase in costs to stakeholders. CIPA is concerned that the costs and impacts of such a change have not be analyzed including that such a change creates local and state testing requirements that are not in sync.

B-4-10

CIPA recommends ARB continue to work with stakeholders on these issues and then use a 15-day amendment package to revisit and clarify as needed prior to the final adoption of the rule.

B-4-11

Vapor Recovery Requirements

The regulation envisions additional vapor control and/or flaring of collected methane emissions, including from heavy oil tanks. However, the ability to permit new flares in California’s non-attainment air districts is still a major question. In fact, some districts have stated that they do not want additional flaring to occur under this regulation. Because increased flaring and/or new flares would not be allowed without air district permitting, CIPA is concerned that new flares may not be a reasonable method of compliance.

B-4-12

CIPA also notes that the inclusion of gauge tanks in this version of the regulation comes without prior stakeholder discussion or notice. This addition is a significant concern as it changes the initial point of regulation under the rule, requiring owners or operators to extend the reach of vapor control, which for a variety of reasons may not be practicable. Prior versions of the regulation did not contain such provisions. CIPA is concerned with the implications of such an addition, including costs and lack of transparency or analysis in the process. There are also significant concerns about the effectiveness of such a requirement due to the intermittent nature of their operations.

B-4-13

CIPA recommends that because the stakeholder process was bypassed, including a robust feasibility and cost analysis, that the newly inserted gauge tank provisions be removed. CIPA recommends that prior to final adoption, ARB demonstrate that there are viable compliance options associated with new vapor recovery requirements.

B-4-14

CIPA has consistently advocated for a fair, cost-effective, and implementable regulation. And while this version is much improved, CIPA respectfully submits these summary comments in an effort to constructively assist ARB in taking the next step to a final adoption that addresses these remaining technical and implementation concerns. The version presented to the Board at the July 21, 2016, hearing cannot be the final version of the rule.

B-4-15

We are ready to continue the dialogue that is needed to bring this process to a successful conclusion. This additional dialogue should result in a subsequent 15-day amendment process. Thank you for your attention to this important matter. Any questions or follow-up comments can be directed to rock@cipa.org.

Sincerely,

A handwritten signature in black ink, appearing to read 'Rock Zierman', with a stylized flourish at the end.

Rock Zierman
CEO

317305163.1

**Testimony on CARB's Proposed Rulemaking for
"PROPOSED REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS FOR
CRUDE OIL AND NATURAL GAS FACILITIES"**

Jaclyn Schroeder
Moms Clean Air Force
July 21, 2016
Sacramento, California

Hello my name is Jaclyn Schroeder, and thank you for taking the time to hear my story.

When I was first invited to come today, I almost quickly declined because it is extremely hard to leave three young children at home. But that's exactly the reason I decided to come because I AM A MOTHER FIRST.

Being a mother first is being a voice for my children. Being a mother first is making sure I provide a HEALTHY and happy environment for my children. I am a mother first by speaking up for my children's health.

Thank you for taking this important step in addressing methane pollution from oil and gas operations and I urge you to move forward with your proposal, while considering TWO important changes:

- 1) Remove the "step-down" provision which would allow operators to shift to less rigorous monitoring requirements, this would create a perverse incentive to avoid finding and reporting leaks, and less of a reason to avoid fixing them quickly. B-5-1
- 2) The current proposal pushes the implementation timeline by a year (from Jan 2017 to Jan 2018). Our families cannot afford to wait until 2018. B-5-2

I currently own a home in Porter Ranch, California where I live with my husband and three children (a 5 year old and twin 2 year olds).

My family, community and I understand the direct impacts of methane pollution especially the exposure to co-pollutants that leak alongside methane pollution from oil and gas development.

I am a local native of the San Fernando Valley. I grew up in Porter Ranch and decided to raise my family in Porter Ranch. However, never did I realized that we lived on top of one of the LARGEST gas storage reserves in the United States, THAT WAS NOT MONITORED PROPERLY and what that could mean to the health of my family.

October 23, 2015, in Porter Ranch, the largest methane gas leak in US history was reported. Ironically, a month earlier, my daughter, Emma (22 months), was sent home from Kaiser with an at home nebulizer (breathing treatment). She began showing signs of asthma, and continued to show signs of asthma over the next few months.

October 31st, Halloween. Unbeknownst to us at time, the leak had been reported a week earlier. My children that evening were sniffing, complaining of headaches and fatigue. There was an odd odor in the air, like rotten eggs. My kids barely lasted 30 minutes trick or treating.

November 5, 2015 we took our daughters to Kaiser again because they were having trouble breathing. Just days later my daughter Grace developed bad eczema on her cheeks.

December 10th, my girls were BACK at Kaiser and diagnosed with asthma with acute exacerbation.

These are the real impacts of oil and gas development and the hazards that can come for the co-pollutants leaked alongside methane pollution. Our most vulnerable are the little lungs and developing bodies of our children.

My twins needed breathing treatments at home, and my son began getting sick (often missing school because of persistent coughing and runny nose). It was time to move. Within days of relocating, the symptoms my kids were experiencing began to fade. My kids were healthy.

The leak was "capped" on February 18 and we moved back. However, within days of returning, the symptoms began to reappear. February 25 my girls needed at home breathing treatments. February 26 my daughter Grace broke out with another eczema rash. All three of my kids were "sick" CONTINUALLY within the month of moving home.

As mothers, we must account for the unaccountable and prepare for the unknown. The health impacts of co-pollutants emitted alongside methane pollution from oil and gas development are real. I urge you to strengthen this proposed rule. Our children's health and safety depends on it.

B-5-3

Thank you for your time.

Before Gas Leak

September 12, 2015
Before game were canceled

September 29, 2015
Enjoying our front porch

October 5, 2015
"Fresh" rain outside

October 3, 2015
Family Hike in Aliso Canyon Park

October 5, 2015
Holleigh Bernson Park
play before the oily residue

October 10, 2015
A walk with neighbors Wood Fire

October 5, 2015
Holleigh Bernson Park
play before the oily residue

After Gas Leak

Nov 5, 2015
Emma
having
trouble
breathing

December 9, 2015 breathing
treatment needed

December 10, 2015. Twins diagnosed
with Asthma

Nov 14, 2015 Eczema and
SICK on birthday

Nov 14, 2015 Eczema on
the birthday girl's
cheeky

February 15, 2016 living away from
Porter Ranch and HEALTHY

Back home Feb 25, 2016
Emma needed breathing
treatment

Back home March 18, 2016
Grace needed breathing
treatment

Back home Feb 26, 2016 Grace
developed eczema again

Back home March 29, 2016
Grace sick again

Back home March 31, 2016 Ian
fatigued and "tummy hurts"

Back home Feb 25, 2016 Grace
needed breathing treatment

Loni Russell
16-7-2

**Testimony on CARB’s Proposed Rulemaking for
“PROPOSED REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS FOR
CRUDE OIL AND NATURAL GAS FACILITIES”**

Loni Russell, Deputy Field Manager, Western States

Moms Clean Air Force

July 21, 2016
Sacramento, California

I am Loni Russell, I am here today as a concerned citizen, a daughter and an aunt. I am a member and community organizer for Moms Clean Air Force California, a community of over 80,000 California parents fighting for clean air. On behalf of our members, I want to thank you for the opportunity to testify today.

I thank you for taking this important step in addressing methane pollution from oil and gas operations and respectfully urge you to move forward with your proposal, while considering two important changes:

- 1) The current proposal includes a “step-down” provision which would allow operators to shift to less rigorous monitoring requirements if it fails to find leaks over a specified number of inspections, this would create a perverse incentive to avoid finding and reporting leaks, and less of a reason to avoid fixing them quickly. | B-6-1
- 2) The current proposal pushes the implementation timeline by a year (from Jan 2017 to Jan 2018). Our communities cannot afford to wait until 2018 for the public health benefits. | B-6-2

The scientific record and public health co-benefits demonstrate that cutting methane pollution would provide strong public health protections for Californians and most importantly for our children. | B-6-3

I am no stranger to poor air quality growing up in the San Fernando Valley of Los Angeles, where my family still resides. Many of my relatives suffer from asthma.

Nearly 1 in every 10 schoolchildren in the US has asthma. Asthma being the number one health issue that causes kids to miss school.

Co-pollutants that leak along with methane lead to ozone formation, or smog, which is damaging to health. Numerous studies have found elevated smog in regions with oil and gas development, largely due to emissions of volatile organic compounds (VOC) and nitrogen oxides from these activities. | B-6-4

Standards that reduce methane emissions from oil and gas development will simultaneously reduce emissions and formation of health-damaging air pollutants, including VOC, hazardous air pollutants (HAP), particulate matter (PM2.5), and ozone. | B-6-5

Reducing all of these would reduce the exposure of nearby communities to these pollutants and the subsequent risk of health effects, including respiratory morbidity and premature death.

B-6-5
Cont.

A large body of scientific research indicates that oil and gas development is associated with adverse health impacts. Empirical studies have found evidence for the following:

- 1) Higher reported health symptoms per person among residents who live close to gas wells
- 2) Greater prevalence of adverse birth outcomes, including congenital heart defects, neural tube defects, and low birth weight for infants born to mothers who live in high densities of natural gas development compared to no natural gas development

B-6-6

Children, pregnant women, and the elderly - are most susceptible to experiencing negative health impacts from oil and gas pollution.

Let's keep our most vulnerable safe with a strong standard that helps millions of children breathe easier.

Thank you for this opportunity to testify.

HOW OIL AND GAS OPERATIONS IMPACT YOUR BABY'S HEALTH

Lori Russel 16-7-2

Air pollutants associated with oil and gas

operations are known to cause serious health

impacts in pregnant women, babies, and

children – as well as other adults.

DID YOU KNOW?

- Children's lungs continue to develop after birth.
- Children breathe faster and spend more time outside than adults.
- Other organs like their brains and reproductive systems are also still developing after birth.
- That makes children particularly vulnerable to air pollution.
- Pregnant women also need clean air.
- If the air you breathe is polluted, that can lead to health problems for your baby.
- Companies are not required to monitor or disclose dangerous air pollution, and government air monitors may not be sited close to natural gas activity.
- As a result, it's hard to find out whether you are breathing these pollutants in your community.

LOW BIRTH WEIGHT

A Pennsylvania study found that living near natural gas wells was associated with having lower birth weight babies. Low birth weight babies are at increased risk of early death, infections, and learning disabilities.

PRETERM BIRTH

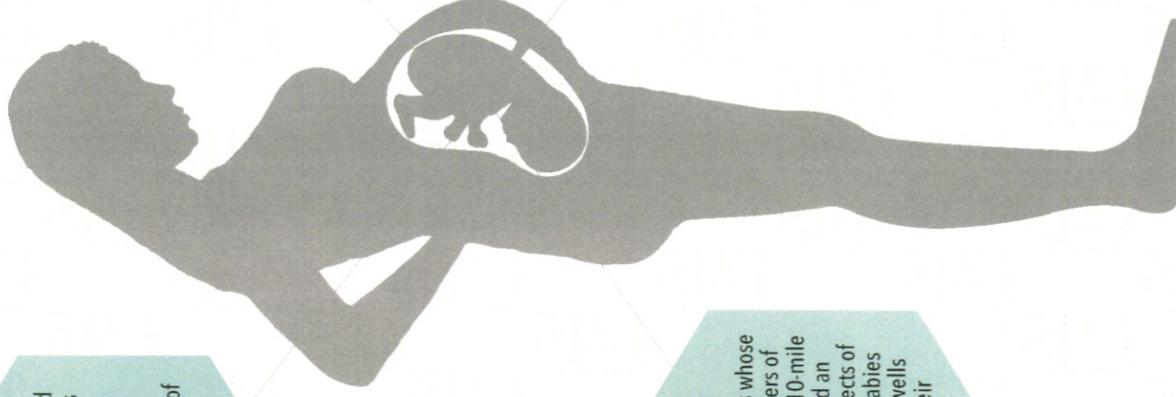
In a Pennsylvania study, babies whose mothers lived close to natural gas wells were more likely to be born preterm (before 37 weeks gestation), compared to babies whose mothers lived farther away from gas wells.

CONGENITAL HEART DEFECTS

In a Colorado study, babies whose mothers had large numbers of natural gas wells within a 10-mile radius of their home had an increased risk of birth defects of the heart, compared to babies whose mothers had no wells within 10 miles of their home.

HIGH-RISK PREGNANCY

Pregnancies in Pennsylvania among mothers who lived close to natural gas operations were more likely to be labeled "high-risk," a designation that can include high blood pressure or excessive weight gain during pregnancy.



MOMS
clean air
FORCE
FIGHTING FOR
OUR KIDS' HEALTH

WHAT IS HAPPENING TO BABIES IN OIL AND GAS REGIONS?

Preliminary studies have found that living near pollution emitted from oil and gas operations may be harmful to your baby's health.



HOW CAN I PROTECT MY BABY?

Because the oil and gas industry does not monitor or disclose air pollution, you should document your family's health by writing down your observations. If you notice health problems, contact your local health department and your state environmental agency. Visit your doctor regularly, and discuss these issues with her.

| AIR POLLUTANT | OIL AND GAS SOURCE | HEALTH IMPACTS |
|---------------------------|--|---|
| BENZENE | Occurs naturally in oil and gas; leaks during routine operations of natural gas wells, pipelines, compressor stations; also released by diesel-powered equipment. | Leukemia, asthma attacks, lung infections, low birth weight, headaches, vomiting, dizziness. |
| DIESEL EMISSIONS | Emitted from generators and trucks associated with oil and gas development. Pumps and compressor stations are often powered by diesel engines. | Asthma attacks, cancer, lung infections, heart disease, premature death. |
| FORMALDEHYDE | Emitted by compressor stations; created in the atmosphere when oil and gas pollutants, such as benzene, combine with heat and sunlight. | Asthma attacks, cancer. |
| METHANE | The main component of natural gas. Leaks at every point along the natural gas life cycle. Sometimes is vented deliberately into the air. | A powerful greenhouse gas that contributes to climate change. Health impacts of climate change include heat illness, asthma attacks, vector-borne infection, and disruptions to the global food supply. |
| PARTICLE POLLUTION | Emitted from generators and trucks used in oil and gas development. Pumps and compressor stations are often powered by diesel engines. Also caused by heavy truck traffic. | Infant death, asthma attacks, low birth weight, heart attacks, stroke, cancer, premature death. |
| SILICA DUST | Sand is used in the process of hydraulic fracturing, or fracking. As sand is transported to well pads and poured into well shafts, silica dust can get into the air. | Cancer, silicosis. |
| SMOG (GROUND LEVEL OZONE) | Created when oil and gas pollutants, such as benzene, combine with heat and sunlight in the air. | Asthma attacks, lung infections, impaired lung development. |

Join other families in your community to demand protections from pollution.

www.momsleanairforce.org

MOM'S
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OUR KIDS' HEALTH

**Testimony on CARB's Proposed Rulemaking for
"PROPOSED REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS FOR
CRUDE OIL AND NATURAL GAS FACILITIES"**

Jennifer Moeller, Los Angeles Field Organizer, CA

Moms Clean Air Force

July 21, 2016

Sacramento, California

Good Morning, my name is Jennifer Moeller and I come before you today as a mother and concerned citizen. Thank you in advance for allowing me a few brief minutes to tell my story.

I am the mother of three beautiful children five and under. My son Mason is 5.5, Madison 2.5 and Miles 9 months old. I can remember October 2015 like it was yesterday, it was two weeks after I had given birth to our third child, Miles, I returned home from a much needed outdoors walk when I noticed a letter taped to my front door, on Southern California Gas Company letterhead, notifying me of the biggest gas leak known to date. Naturally, I panicked, was horrified and stricken with more questions than I could fathom. Baffled and looking for answers, I immediately relocated our family to a distant city away from our current, dangerous and hazardous living environment. Prioritizing my family's health was of utmost importance and this momma bear was not taking any chances of jeopardizing my children's health or potential to developing future illnesses.

Because of this catastrophe, I urge you to address high levels of methane pollutions and efforts to controlling oil and gas operations by considering the following options:

1. Fixed frequency inspections: remove incentives to shift to loose annual inspections. A substantial portion of methane emissions across the supply chain come from leaks. That's why a leak detection and repair (LDAR) program that requires operators to regularly find and fix leaks is a straightforward, cost-effective way to reduce oil and gas methane emissions. CARB's proposed rule initially requires quarterly monitoring of facilities, but allows for a step-down to annual depending on whether operators find leaks. A program that allows operators to meet less rigorous inspection requirements creates a disincentive to find and report leaks and sets a bad precedent for other programs.

B-7-1

2. The implementation timetable needs to be faster. Recent amendments pushed back the implementation of the rule by a year – California communities need reductions sooner than that.

B-7-2

Did you know, that children's lungs continue to develop after birth? Children breathe faster and spend more time outside than adults. That children are especially more vulnerable to air pollution, and organs much like a child's brain and reproductive system still continue to develop post birth? You can see why my sense of urgency to immediately relocate my family to safer and cleaner breathing grounds was nothing less but my main priority when high levels of methane

along with other cancer causing chemicals such as benzene were being emitted into the air due to a lack of regularly regulated aging infrastructure in a oil/gas storage facility.

Living in a dense and overly populated city such as Los Angeles where driving vehicles is a commonality, smog and air pollution is already a heavy and weighted ongoing issue, let alone allowing for the release of high levels of methane into the air.

Lets work together to make a difference, for us, for our children.

Thank you allowing me to share my story with you.

**Testimony on CARB's Proposed Rulemaking for
"PROPOSED REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS
FOR CRUDE OIL AND NATURAL GAS FACILITIES"**

Jason Hector

July 21, 2016
Sacramento, California

It is an honor and pleasure to speak before the CA Air Resources Board and I want to thank the ARB for proposing comprehensive regulation of fugitive emissions especially in light of Aliso Canyon. My name is Jason Hector and I have been a longtime resident of Porter Ranch, husband, father of an amazingly bright 3 ½ year old daughter and have taken care of my elderly grandmother for the last decade all in Porter Ranch. My daughter, when I would watch the webcast of the Porter Ranch Community Advisory Committee she would point at my computer and say "Is that the Gas Leak Meeting?"

I urge you to move forward with your proposal, while considering two important changes:

Removing the "step-down" provision which would allow operators to shift to less rigorous monitoring requirements, this would create a perverse incentive to avoid finding and reporting leaks, and less of a reason to avoid fixing them quickly.

B-8-1

The proposal pushes the implementation timeline by a year (from Jan 2017 to Jan 2018). Our families and communities cannot wait until 2018.

B-8-2

My family and my community understand the direct impacts of pollution from these facilities and the impacts of the co-pollutants that leak alongside oil and gas development.

Increasingly, scientific research indicates that oil and gas development is associated with adverse health impacts. During the massive gas blowout, I personally experienced severe headaches, nosebleeds, blood in my phlem, lethargy, sick feeling, and extreme allergy like symptoms.

My daughter had difficulty breathing and other sickness symptoms for a long time even after we relocated. My first severe symptoms started after being outside and exposed to the methane blowout for several hours. I suffered from a severe headache and my wife felt very dizzy. After speaking with public health officials, we left our home and checked into a hotel. My 98 year old grandmother was relocated as well. Unfortunately, when we would return to work or pick up clothes or mail, we would get sick again.

I remember just before our vacation, I started having the worst allergy-type symptoms like extreme thirst, non-stop runny nose, uncontrollable sneezing and headache.

I am very concerned about the health effects of the children who live, go to school and play near oil and gas facilities like Aliso Canyon. I support the ARB standards because they help reduce methane emissions from oil and gas facilities and formation of health damaging air pollutants, including volatile organice compounds, and other hazardous air pollutants. An example are the children attending attending the two schools in Porter Ranch. We still don't know all the chemicals that we may have been exposed to since that information has been deemed confidential or proprietary. Once moving back, oily residue was found in our park and since we have not returned out of fear of unknown. I am very concerned about how this might impact our groundwater aquifer.

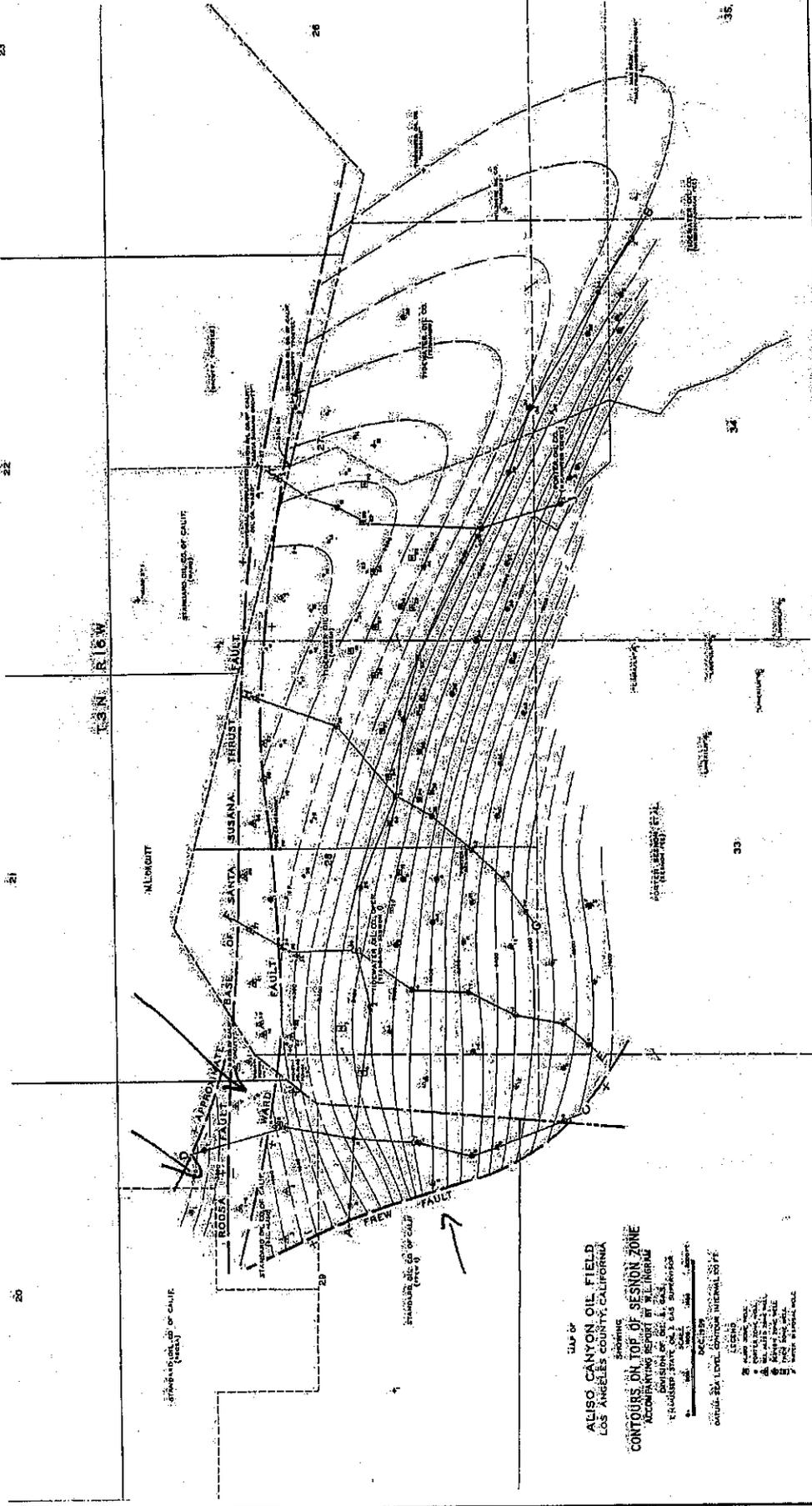
B-8-3

(over)

I am also very concerned about the concept of storing gas underground. There is not a steel SCUBA tank underground to ensure containment of the very high pressure reservoir. Also, how can we confirm if there are leaks coming up from the reservoir. We are talking about geologic formations here and Aliso Canyon sits on a fault line. How can we be sure that the gas is not moving up from the reservoir through the ground and through the water before it reaches the surface?

B-8-4

I want to thank the ARB for continuing California's leadership on climate change and taking this important step to address methane pollution and the opportunity to testify. Let's make to not let this happen to California families again.



MAP OF
ALISO CANYON OIL FIELD
 LOS ANGELES COUNTY, CALIFORNIA

Showing
CONTOURS ON TOP OF SESNON ZONE
 According to Well Log 214 (Merrill)
 (Elevation in feet, sea level)

Legend:
 - Fault
 - Contour
 - Aliso Formation
 - Sesnon Zone
 - Base of Santa Susana Fault
 - Frew Fault
 - Santa Susana Thrust Fault

**Geologic Cross-Section
 Reference Map**
 Technical Report
 Aliso Canyon Gas Storage Facility
 Los Angeles County, California

Geosyntec
 consultants

Los Angeles April 2016

Figure
 A3

Note: Cross-Sections provided in Appendix B



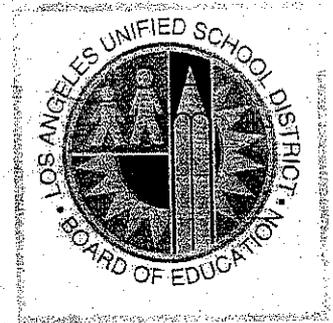
Castlebay Lane, Porter Ranch Schools to Relocate Due to Aliso Canyon Natural Gas Leak

S F E C

Schools will share space with two other campuses for second semester

LOS ANGELES (Nov. 17, 2015) - The Board of Education took action today to expedite the temporary relocation of Castlebay Lane Charter and Porter Ranch Community School, where teaching and learning have been disrupted by a natural-gas leak in nearby Aliso Canyon.

When classes resume after the winter break, the 770 students in grades K-5 who attend Castlebay Lane will be relocated to Sunny Brae Avenue Elementary in Winnetka. Porter Ranch Community School, which has 1,100 students in grades K-8, will relocate to Northridge Middle School. Portable classrooms and available space at the host-schools will be used to house the Castlebay Lane and Porter Ranch students, teachers and staff.



To minimize disruption, the relocation will be in effect for the rest of the 2015-16 school year. Details are being finalized, and parents will be notified as decisions are made.

The board's unanimous approval will allow the District to make alterations or improvements at the Sunny Brae and Northridge campuses over the three-week winter break, without having to go through the time-consuming competitive-bidding process.

"This has been a difficult decision because it will impact the lives of so many families," said school board member Scott Schmerelson, who represents the West San Fernando Valley. "I believe this is the right decision to protect the health of our students and employees and to stabilize the learning environment."

The leak was discovered Oct. 23 in a natural-gas well owned by the Southern California Gas Co. Initial efforts to cap the well were unsuccessful, and the company estimates it will take up to four months to stop the leak.

Since late October, parents, employees and residents at Castlebay and Porter Ranch have been raising concerns about the effects of the odorant that allows natural gas to be detected. To ensure that schools, students and faculty remained safe, the District installed air filters in every classroom, assigned additional nurses and began independent air-quality monitoring at the two campuses.

L.A. Unified also worked with parents that relocated away from the Porter Ranch area to enroll their children in other District schools, and offered an independent study program for families that opted to keep their students at home.

Despite these efforts, absenteeism and visits to the health office increased. As a result, the Los Angeles County Department of Public Health issued a directive on Wednesday, ordering Southern California Gas to work with the District in relocating Castlebay Lane and Porter Ranch

students.

The board resolution adopted Thursday authorizes the District's Office of General Counsel to initiate litigation, if necessary, to recover the cost of temporarily relocating the schools.

###

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Keep in touch with LAUSD

Email Address:

Name:

Parent Employee Student

© Los Angeles Unified School District
333 S Beaudry Ave., Los Angeles, CA 90017
Phone: (213) 241-1000

The Los Angeles Unified School District is committed to providing a working and learning environment free from discrimination, harassment, intimidation and bullying. For more information regarding nondiscrimination, please click here.

Google Translate ▼

AQMD Meeting Notes

Item 8 Leak detection protocol—Include five main components to supplement present inspections and meet proactive requirement of #8.

1. Fence Line real time monitoring system surrounding the perimeter of ALL facilities which have nearby homes, schools, etc nearby.
2. Fixed site ground monitors which can be checked in real time by ARB and online by residents. Locations should be the places where high levels of methane have been found before.
3. Fly over monitoring by ARB using current technology and drones to be used in coordination with NASA Jet Propulsion Labs with a pilot program to be implemented at Aliso Canyon.
<http://www.jpl.nasa.gov/news/news.php?feature=6192>
4. Li Cor vehicle with mobile methane monitoring must be used on a DAILY basis or 6 days a week and results posted online as soon as possible. This mobile monitoring helps keep the community informed and compliments nicely the LiCor mobile methane monitoring vehicle.
5. On site monitoring must include using BOTH the FLIR type camera as well as a TVA. Using one without the other means less of a chance of finding leaks. Also, the TVA is a valuable tool for quantifying the emissions rates.
6. The air monitoring should be with ARB in collaboration with NASA's Jet Propulsion Labs since they have a methane drone combined with the flyovers ARB has been doing to identify and estimate emissions.

With respect to the issue of confirming odor complaints due to "fleeting smells" which was a recurring theme and concern of the board...one idea is to create an application for cell phones. This "I smell something app" would be simple for residents to report odors and GPS locations could be sent in real time to appropriate agencies.

Secondly, I would request the help of local city and county fire/police/haz mat facilities near these natural gas storage sites to be equipped with sensitive detection equipment to aid in confirmation of symptoms, smells, etc. Fire and EMS have training in observing and reporting symptoms but more importantly the ability to respond very quickly, maybe in less than 5 minutes to help document the validity of the complaint.

Health Study—#14 Key requirements needed for a comprehensive symptom based study for impacted residents of Porter Ranch and neighboring communities:

1. Creation of a means for impacted residents to voluntarily submit pictures, logs and sworn statements of health impacts.
2. As requested by board member, testimony from an expert about the AQMD proposed National Academy of Sciences. The public and board should be presented with a summary of the details for public review and comment.
3. Study length to remain open for one decade given the sometimes long period for onset of certain types of cancers.

PORTER RANCH REAL-TIME COMMUNITY AIR MONITORING DATA

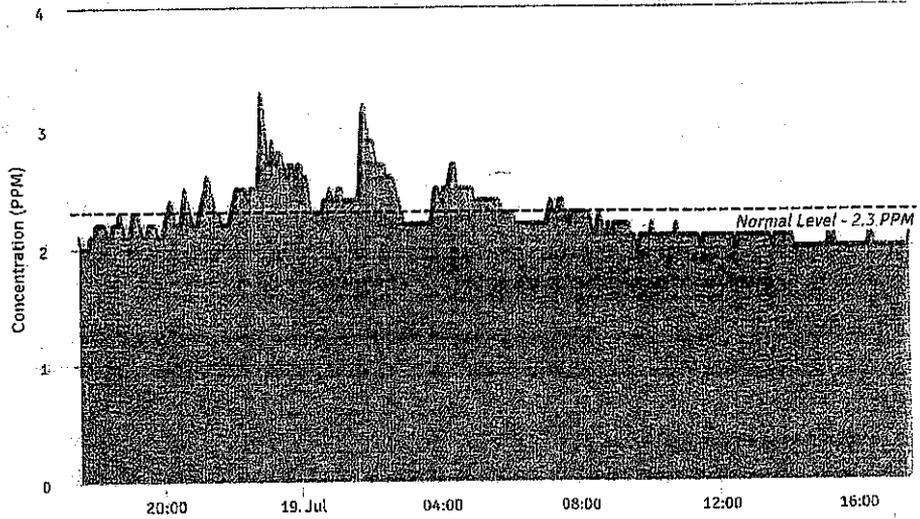
Message Board

06/04/2016 19:10 - We want to let you know we had to do some modification to the Porter Ranch Fence Line website. It turns out the air monitor we were using to detect Benzene, Toluene, and Xylene was a lot sicker than we originally thought. One of the electronic boards needed to operate the system burned out and it will take two months to get a replacement shipped to us. So to help keep the community up to date on what's going on, we're now taking the data from the benzene monitoring systems the Air District operates and are putting it on the website. The methane system continues to provide updated data every five minutes and nothing has changed with respect to that system.

Real-Time Air Monitoring Data

| | |
|--|----------------------|
| Methane | 2.1 PPM |
| Benzene Air District Site #5 | Non-Detect |
| Benzene Air District Site #7 | Offline |
| Weather Conditions | |
| Wind blowing from the WSW (248°) direction at the speed of 2 MPH | |
| Subscribe to Alert Notification List | |
| First Name: | <input type="text"/> |
| Last Name: | <input type="text"/> |
| Email: | <input type="text"/> |
| <input type="button" value="Submit"/> | |

24-Hour Plot for Methane



This website presents real-time air monitoring data at the fence line between the Aliso Canyon gas storage facility and the community of Porter Ranch. The systems are currently setup to monitor for methane, benzene, toluene, and xylene gases on a real-time basis. Information from the monitoring equipment is updated on the website every five minutes. The equipment is being supplied by [Argos Scientific](#), [Boreal Laser](#), and [WeatherUnderground](#). Special thanks is given to [Councilman Mitch Englander](#) for facilitating the installation of this equipment and the development of this real-time website for the community of Porter Ranch.

Ambient air quality data provided on this website is raw data at the time of collection and has not undergone Quality Assurance Checks. If you have a health emergency please contact local emergency agency.

Abbreviations

PPM - Parts per million
MPH - Miles per hour

This site is maintained and operated by [Argos Scientific](#) and is part of the [fenceline.org](#) network
[Contact Argos Scientific](#)

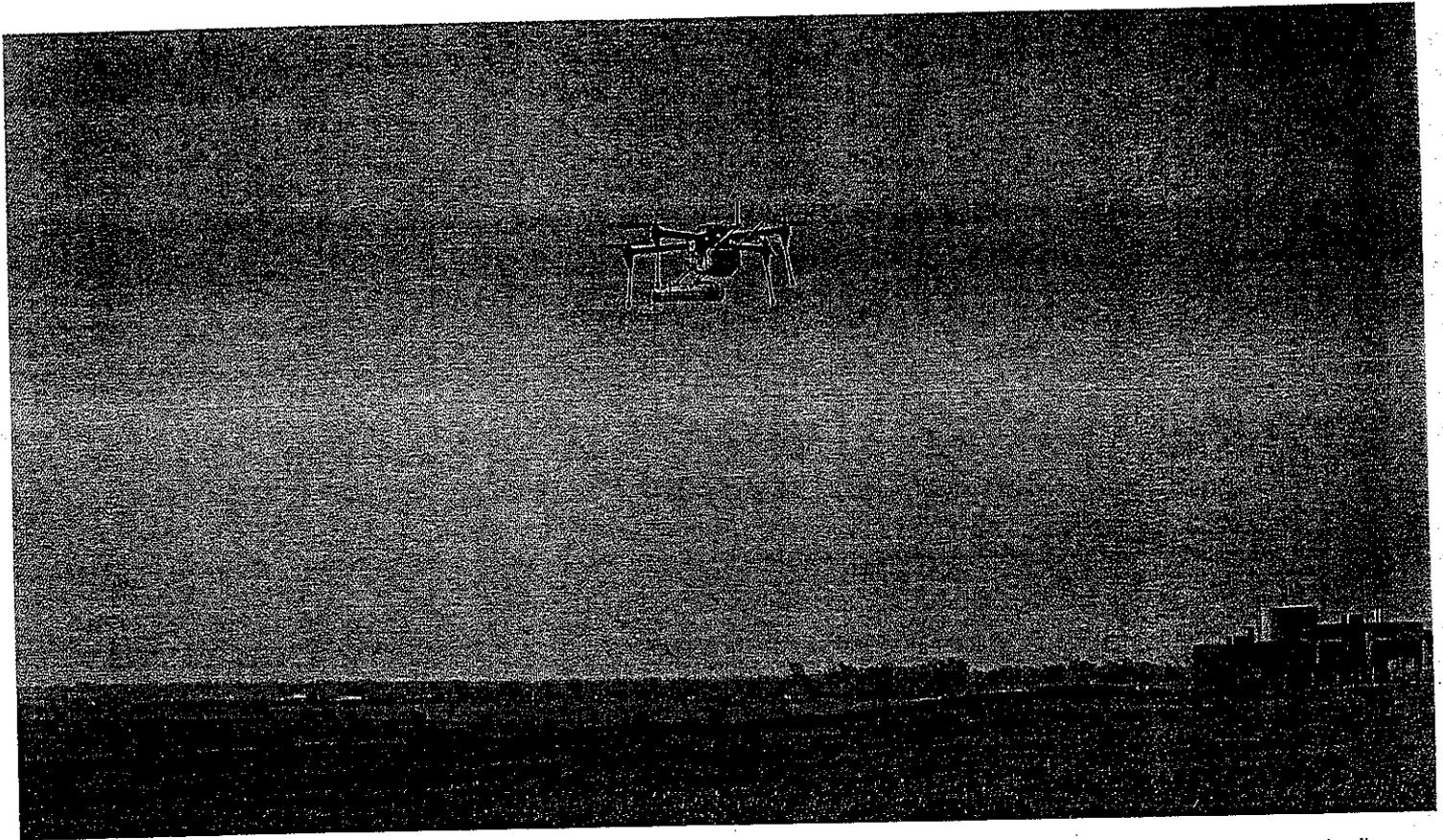
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NEWS | MARCH 28, 2016

Mini NASA Methane Sensor Makes Successful Flight Test



A JPL mini methane gas sensor is flight tested on a small unmanned aerial system (sUAS) under a project to improve energy pipeline industry safety. The sensor enables methane detection with higher sensitivity than previously available for the industry in hand-carried or sUAS-deployable instruments. Credit: University of California, Merced

[Larger image](#)

As part of a project to improve safety in the energy pipeline industry, researchers have successfully flight-tested a miniature methane gas sensor developed by NASA's Jet Propulsion Laboratory, Pasadena, California, on a Vertical Take-off and Landing small unmanned aerial system (sUAS). The sensor, similar to one developed by JPL for use on Mars, enables detection of methane with much higher sensitivity than previously available for the industry in hand-carried or sUAS-deployable instruments.

The tests were conducted in central California at the Merced Vernal Pools and Grassland Reserve, and were funded by Pipeline Research Council International (PRCI). The jointly conducted test of NASA's Open Path Laser Spectrometer (OPLS) sensor is the latest effort in a methane testing and demonstration program conducted on various platforms since

Popular

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[Curiosity Mars Rover Resumes Full Operations](#)

[NASA Sails Full-Speed Ahead in Solar System Exploration](#)

2014. The ability of the OPLS sensor to detect methane in parts per billion by volume could help the pipeline industry more accurately pinpoint small methane leaks.

Researchers from JPL and the Mechatronics, Embedded Systems and Automation (MESA) Lab at the University of California, Merced, conducted the flight tests in late February. They flew a small unmanned aerial system equipped with the OPLS sensor at various distances from methane-emitting gas sources. Tests were done in a controlled setting to test the accuracy and robustness of the system.

The advanced capabilities provided by sUASs, particularly enhanced vertical access, could extend the use of methane-inspection systems for detecting and locating methane gas sources.

Additional flight testing this year will feature a fixed-wing UAS, which can fly longer and farther. Those capabilities are necessary for monitoring natural-gas transmission pipeline systems, which are often hundreds of miles long and can be located in rural or remote areas.

This latest round of tests furthers the team's goal to develop sUASs to improve traditional inspection methods for natural-gas pipeline networks, which may enhance safety and improve location accuracy.

"These tests mark the latest chapter in the development of what we believe will eventually be a universal methane monitoring system for detecting fugitive natural-gas emissions and contributing to studies of climate change," said Lance Christensen, OPLS principal investigator at JPL.

NASA uses the vantage point of space to increase our understanding of our home planet, improve lives, and safeguard our future. NASA develops new ways to observe and study Earth's interconnected natural systems with long-term data records. The agency freely shares this unique knowledge and works with institutions around the world to gain new insights into how our planet is changing.

For more information about NASA's Earth science activities, visit:

<http://www.nasa.gov/earth>

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2016-088

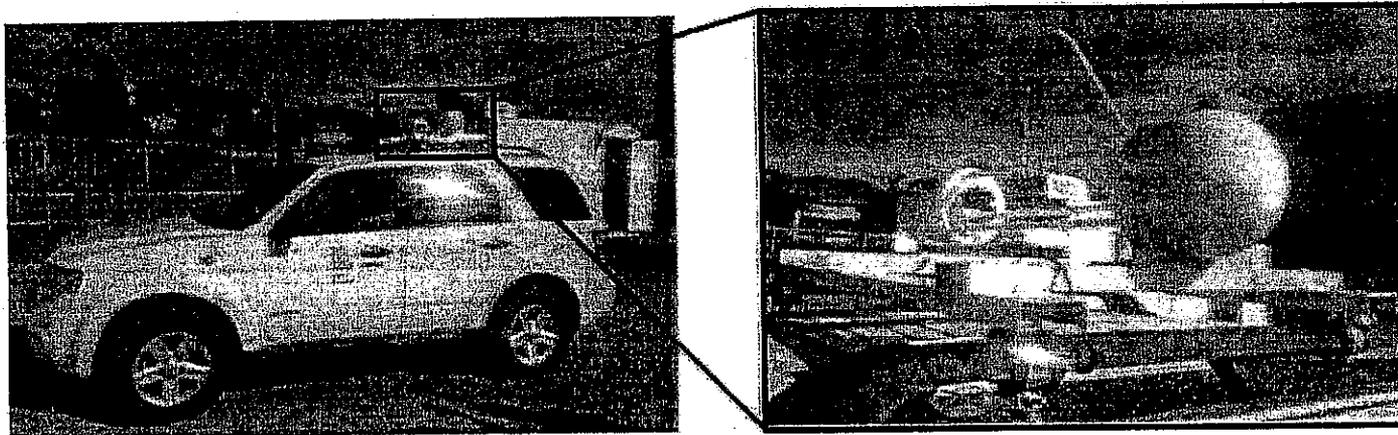
Site Manager: Jon Nelson

Webmasters: Tony Greicius, Martin Perez, Luis Espinoza

Mobile Methane Measurement Surveys

1

Beginning December 21, 2015, SCAQMD has been conducting mobile survey measurements in and around Porter Ranch to better characterize methane concentration levels and concentration gradients within the community and to support the fixed site methane monitoring efforts. For this purpose, a state-of-the-art methane analyzer (LI-COR 7700) and a Global Positioning System (GPS) were mounted on top of a hybrid vehicle and driven around Porter Ranch and other surrounding areas of the San Fernando Valley.

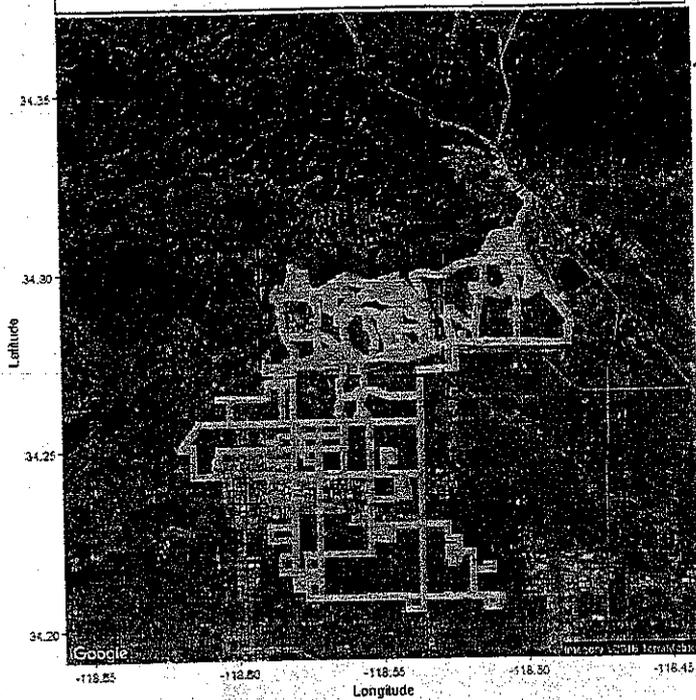


The LI-COR 7700 is an open-path instrument capable of measuring methane concentrations as low as single parts per billion (ppb) at rates as fast as 40 times per second with high accuracy and precision. This technology has previously been used and validated by the Environmental Defense Fund (EDF), Google Earth Outreach, and Colorado State University (CSU) for mapping methane plumes rising from leaking natural gas pipes below streets:

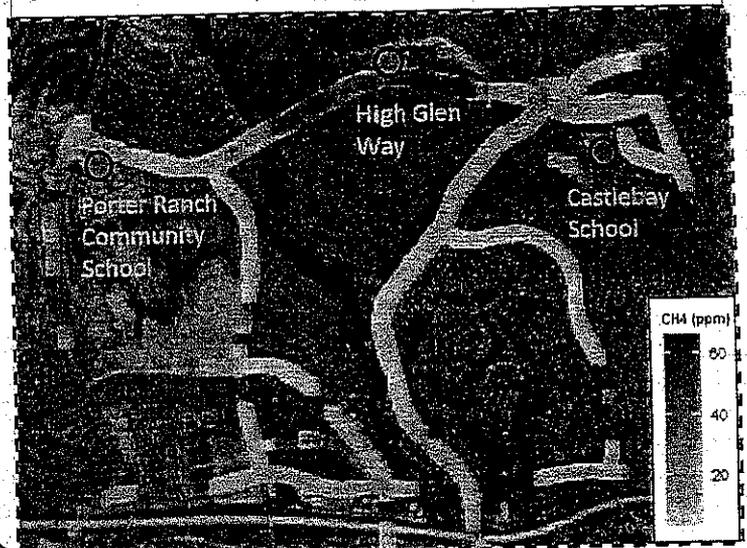
<https://www.edf.org/climate/methanemaps> (<https://www.edf.org/climate/methanemaps>)

Several routes in and around Porter Ranch and neighboring communities were selected for these surveys. Monitoring was conducted during different times of the day (e.g., morning, afternoon and evening) and under different meteorological conditions. As depicted in the map below, the highest methane concentrations measured thus far (up to 70 part per million [ppm]) were recorded at night in Sesnon Blvd, south of the Aliso Canyon Facility. These results support the placement of the SCAQMD fixed monitoring sites and the idea that the fixed SCAQMD sites will provide appropriate coverage for long term monitoring in Porter Ranch.

Area covered by mobile measurements
between 12/21/15 and 01/29/16



Map of the highest (12-70 ppm) methane
concentration measurements collected between
12/21/15 and 01/29/16



● Current SCAQMD measurement sites

Additional methane maps created using this mobile system can be found [here](#) (/docs/default-source/compliance/aliso-cyn/porter-ranch---all-maps-(070816)a466aaefc2b66f27bf6fff00004a91a9.pdf?sfvrsn=0).

Trending

[Lawn Equipment \(/home/programs/community/community-detail?title=lawn-equipment\)](/home/programs/community/community-detail?title=lawn-equipment)

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[Rules \(/home/regulations/rules\)](/home/regulations/rules)

[Lawn Mower Exchange Program \(/home/programs/community/lawnmower-registration\)](/home/programs/community/lawnmower-registration)

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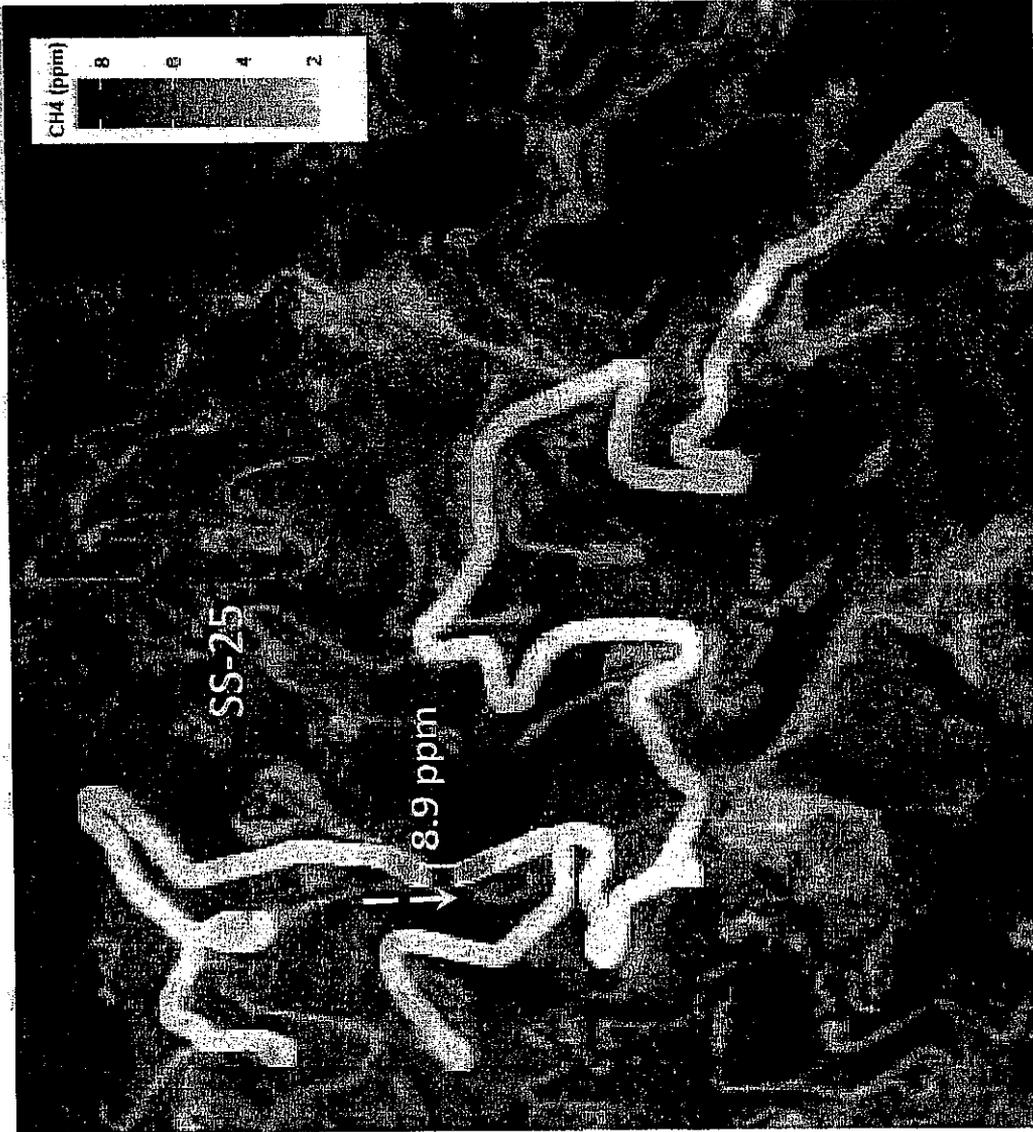
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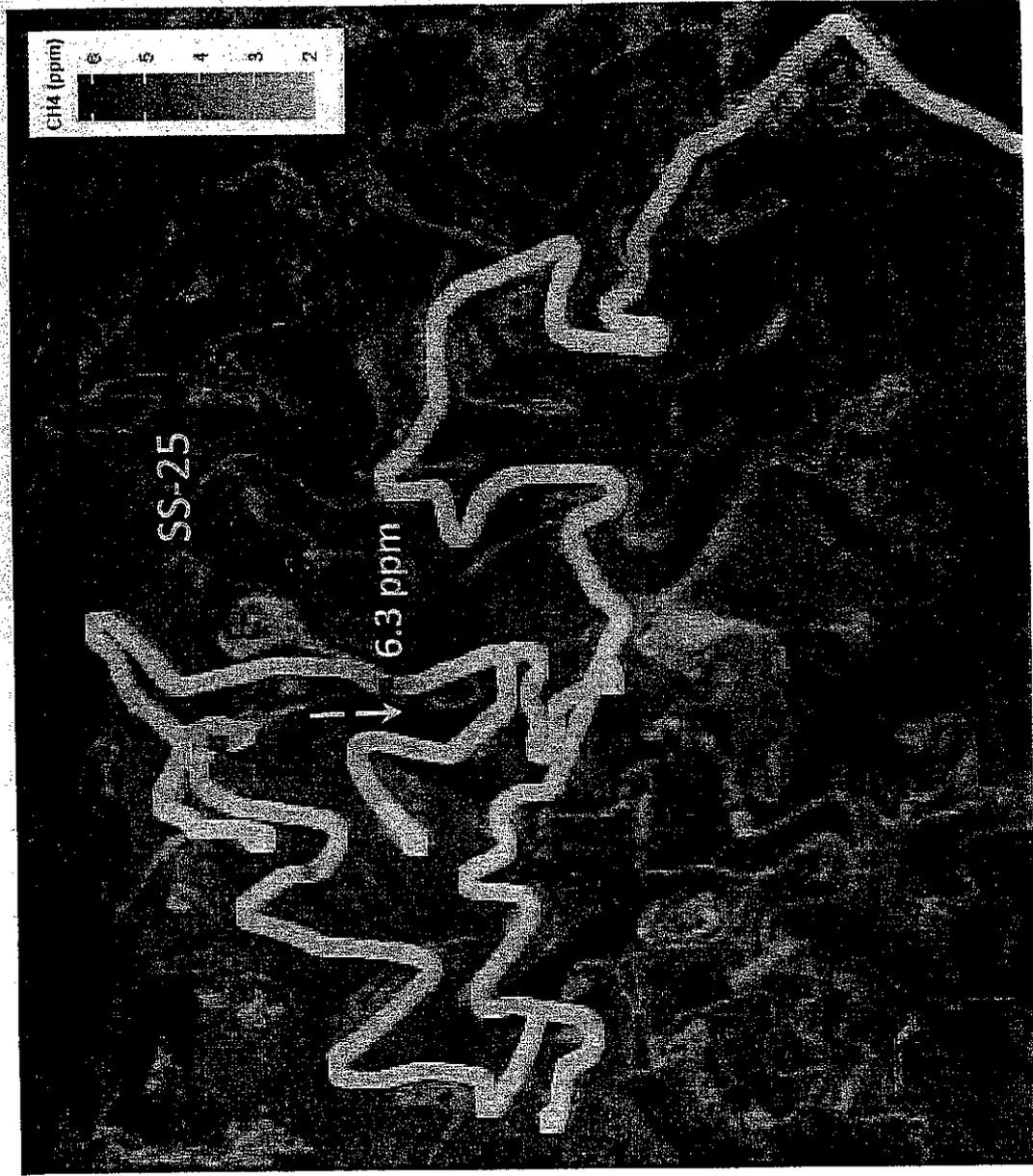
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Li Cor Mobile Methane Map

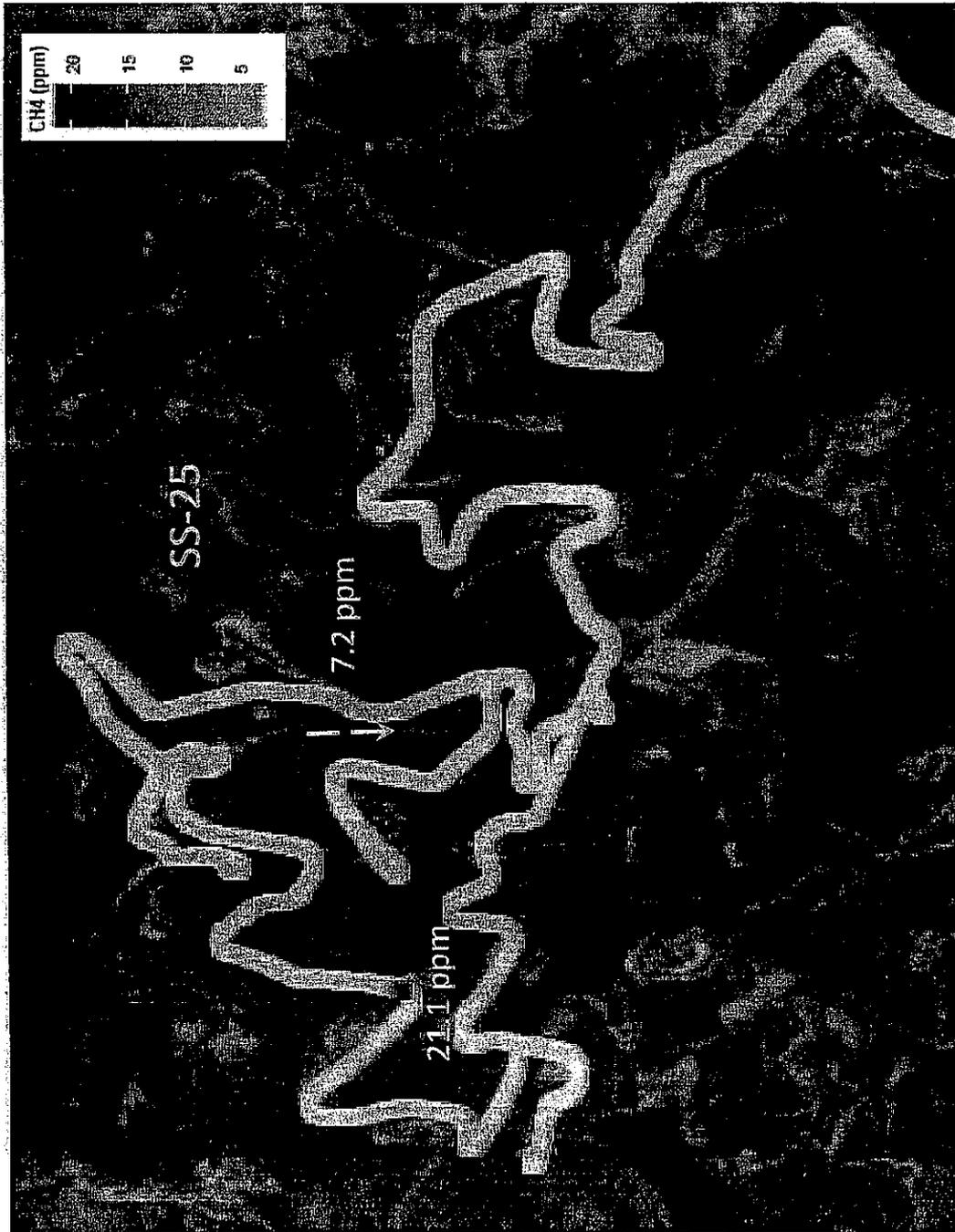
07/01/16 (09:02am - 09:52am)



07/05/16 (09:25am - 10:21am)



07/08/16 (08:49am - 09:41am)



July 18, 2016
California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

Dear Air Resources Board:

Thank you for accepting these comments submitted by Clean Air Task Force, Earthworks, Environmental Defense Fund, Natural Resources Defense Council and Sierra Club on Proposed Regulation Order 17 C.C.R. § 95665 et seq. (May 2016). We greatly appreciate the opportunity to comment on the California Air Resources Board's ("ARB") draft regulation for methane pollution from oil and gas facilities. These comments build upon recommendations that we submitted to ARB during its comprehensive stakeholder process and track closely recommendations that we made to ARB on the last draft, published February 19, 2016.¹

I. Introduction

We commend the ARB on proposing one of the strongest rules in the nation to curb the release of harmful emissions from oil and gas facilities. The draft regulation contains cost effective, technically feasible mechanisms that will achieve critically needed reductions in methane, a potent climate-altering pollutant, as well as important co-benefit reductions in volatile organic compounds (VOCs) and air toxics that pose serious threats to human health. ARB staff estimates the proposal will cut methane emissions from the over 51,500 oil and gas facilities in the state² by half³ while also removing 3,600 tons of VOCs and over 100 tons of air toxics from the atmosphere annually.⁴

Significant methane reductions are necessary for California to reach its goal of reducing greenhouse gas emissions to 1990 levels by 2020, as ARB acknowledges.⁵ As ARB's Staff Report explains, such reductions "can have an immediate beneficial impact on climate change" due to the relatively short atmospheric life of methane.⁶

Requiring oil and gas owners and operators to capture rather than vent or leak methane emissions is one of the most cost-effective and sensible ways to achieve deep and immediate reductions in GHG emissions. Natural gas is primarily methane, and as ARB's draft proposal demonstrates, in many instances operators can benefit from the natural gas recovered either by sending it to sales or utilizing it onsite. Indeed, ARB's analysis demonstrates the proposal to be

¹ Clean Air Task Force, *et al.*, "Methane comments to CARB" (February 19, 2016). (Ex. 1)

² ARB Staff Report: Initial Statement of Reasons, 6 (May 31, 2016), available at <http://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf>. (Ex. 2)

³ *Id.* at ES-2.

⁴ *Id.* at ES-4.

⁵ ARB, Proposed Short-Lived Climate Pollutant Reduction Strategy, 13 (April 2016), available at <http://www.arb.ca.gov/cc/shortlived/meetings/04112016/proposedstrategy.pdf>. (Ex. 3)

⁶ *Id.* at 2.

highly cost effective at \$15 per ton of CO₂e reduced, considering savings.⁷ Even without accounting for the savings operators can achieve by capturing methane, the draft rules are still highly cost effective at \$17 per ton of CO₂e reduced.⁸ These numbers reflect only the direct benefits that accrue from the removal of 1.5 million metric tons of CO₂e from the atmosphere annually. When one considers that the implementation of the various clean air measures contained in the proposal will remove additional tons of VOCs and air toxics annually, it is clear that this proposal represents a very cost effective pathway to achieve much-needed reductions in harmful oil and gas emissions.

Moreover, the state cannot rely on federal actions to achieve the greenhouse gas reductions required by legislative and gubernatorial mandates.⁹ US EPA rules adopted to date under the New Source Performance Standards program do not apply to existing oil and gas sources,¹⁰ and therefore will have no effect on the over 50,000 existing oil and gas wells in the state. While EPA has proposed requirements directed at reducing VOC emissions from a select number of onshore oil and gas facilities (control techniques guidelines, or CTGs),¹¹ these requirements are not final, and even once they become final, will have a limited effect on existing sources both in California and nationwide: the CTGs do not directly regulate methane, nor do they apply statewide (they only apply in parts of the state that are designated as moderate or above ozone nonattainment areas), and they do not apply to offshore facilities. Moreover, the proposed control techniques guidelines do not apply to many of the onshore facilities subject to the ARB proposal, including underground natural gas storage, transmission compressor stations, intermittent bleed pneumatic controllers or any facilities located in the storage and transmission segments. Accordingly, the proposed ARB rules are necessary to achieve critical reductions in methane, VOCs and air toxics that are left unaddressed by EPA requirements.

For all of the above reasons we urge ARB to adopt the Proposed Regulation Order, 17 C.C.R. § 95665 et seq. (May 2016). However, in so doing, we respectfully request ARB to strengthen the rule in a few key ways, the basis for which we discuss in the remainder of our comments:

- Leak detection and repair (LDAR)
 - Provide operators with flexibility to seek approval for utilizing alternative leak detection methods for making inspections provided such methods are at least as effective in reducing waste and emissions as Optical Gas Imaging (OGI)-based LDAR and that the approval process is transparent and open to public participation.

⁷ *Id.* at Table 14, 127.

⁸ *Id.*

⁹ Global Warming Solutions Act of 2006 (establishing statewide GHG emissions cap for 2020, based on 1990 emissions); *see also* ARB Senate Bill 605 (requiring ARB to develop a comprehensive plan to reduce emissions of short-lived climate pollutants); *see also* Short-Lived Climate Pollutant Reduction Strategy, ARB Pollutant Reduction Strategy (2016), *supra* note 5, discussing Governor Brown's announcement of a target for reducing GHG emissions to 40 percent below 1990 levels by 2030.

¹⁰ *See* 81 Fed. Reg. 35,824 (June 3, 2016).

¹¹ *See* 80 Fed. Reg. 56,577 (Sept. 18, 2015) (announcing availability of draft control techniques guidelines for VOCs from the oil and gas sector).

- Remove the provision in Section 95669 that allows operators to reduce the inspection frequency from quarterly to annual based on the percent or number of leaking components detected.
 - Require the repair of 500 ppm leaks detected during inspections.
- Underground natural gas storage
 - Expand daily screening or continuous monitoring provisions to include all wells in the field including but not limited to observation, monitoring, disposal, production and other wells.
 - Clarify that the monitoring requirements apply not only to active wells but also to idle and plugged and abandoned wells.
 - Clarify that the inspection requirements in Section 95668 are intended to apply in lieu of the inspection requirements in Section 95669.
- Pneumatic controllers and pumps
 - Phase out existing low-bleed continuous devices, and require quarterly testing of bleed rate during phase out period.
 - Prohibit or phase out the venting of emissions from intermittent-bleed pneumatic controllers; or, at a minimum, limit emissions from such devices to low bleed levels, and require operators to verify that emissions are at low-bleed levels via direct measurement.
 - Clarify that the pneumatic pump provision apply to glycol assist pumps, and ensure that methane emissions from these pumps are indeed controlled.
- Compressors
 - Expand the requirement to perform LDAR inspections to rod packing and seals on non-production reciprocating compressors.
 - Reduce the flow rate threshold from that triggers a repair or replacement of the rod packing or seals.
- Separator and tank systems
 - Tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems.
 - Require owners and operators of separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day to conduct periodic flash analysis testing.
- Liquids unloading
 - Revise definition of “liquids unloading” to remove “use of pressurized natural gas.”
 - Require operators to keep personnel onsite when conducting manual liquids unloading activities.
 - Require reporting of an enhanced list of key parameters and conditions when emissions are vented during liquids unloading.

In addition, while we commend ARB for recognizing the importance of accounting for the near term impacts of methane, we urge ARB to revise its assumptions to use the most recent IPCC AR5 20-year GWP for methane from fossil sources of 87. In supporting technical documentation and analyses for the rule, ARB assessed impacts and benefits of methane and

methane reductions using the IPCC AR4 20-year GWP of 72. Using the most updated information available will ensure that the results of analytics for the rule are as accurate and representative of methane impacts as possible.

II. Leak Detection and Repair

Frequent, comprehensive inspections of oil and gas facilities are a critical component of pollution prevention and mitigation. Direct measurement of emissions at a wide selection of oil and gas facilities across the country demonstrate that equipment malfunctions and poor maintenance can lead to significant pollution that is not represented in emission inventories. The direct measurement of scientific information demonstrates that oil and gas facilities are considerably leakier than industry reports, that operators do not and cannot predict when such failures will occur, and therefore, that frequent inspections with modern leak detection equipment are necessary to detect and promptly repair such leaks.

Fortunately, modern leak detection equipment exists to quickly and accurately find leaks. Moreover, frequent – namely, quarterly – inspections are highly cost-effective. Such inspections remove harmful pollution from the atmosphere, while also ensuring a safer and more efficient workplace.

1. Field Studies Using Direct Measurement and Recent Incidents in California Demonstrate the Need for Frequent Instrument-Based Inspections: Significant Emissions May Emanate from Individual Components and Operations

Up until recently, regulators have relied nearly exclusively on emission inventories in order to understand the magnitude of a particular pollution problem as well as the potential reductions associated with a proposed solution. Now, however, recent advances in science have added to our knowledge and understanding of emissions from oil and gas facilities. These studies demonstrate that emissions are systematically significant and, at a select number of facilities, actual emissions are magnitudes higher than emission inventories suggest. These studies strongly support at least quarterly inspections using modern leak detection technology to identify leaking equipment. In some instances, repairs can be made instantaneously with the turn of a wrench. A number of studies, as well as industry reports, note that the gas savings associated with fixing such leaks cover the costs associated with repairing them.

The first of these studies, conducted by an independent team of scientists at the University of Texas, found that emissions from equipment leaks, pneumatic controllers and chemical injection pumps were each 38 percent, 63 percent and 100 percent higher, respectively, than estimated in national inventories.¹² This study also found that 5 percent of the facilities were responsible for 27 percent of the emissions.¹³

¹² Allen, D.T., et al, (2013) “Measurements of methane emissions at natural gas production sites in the United States,” *Proc. Natl. Acad.* 2013, 110 (44), available at <http://www.pnas.org/content/110/44/17768.full>. (Ex. 4)

¹³ See Allen, D.T., et al, (2014), “Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers,” *Environ. Sci. Technol.*, 2015, 49 (1), pp. 633–640 (referencing 2013 Allen study), available at <http://pubs.acs.org/doi/abs/10.1021/es5040156>. (Ex. 5)

Two follow-up studies, focused specifically on emissions from pneumatic controllers and liquids unloading activities at wells, found similar results.¹⁴ Specifically, the studies found that 19 percent of the pneumatic devices accounted for 95 percent of the emissions from the devices tested, and about 20 percent of the wells with unloading emissions accounted for 65 to 83 percent of those emissions. The average methane emissions per pneumatic controller were 17 percent higher than the average emissions per pneumatic controller in EPA’s national greenhouse gas inventory.¹⁵

These findings were reiterated again in a series of direct measurement studies focusing on emissions from compressor stations in the gathering and processing segment and in the transmission and storage segment. The gathering and processing study found substantial venting from liquids storage tanks at approximately 20 percent of the sampled gathering facilities.¹⁶ Emission rates at these facilities were on average four times higher than rates observed at other facilities and, at some of these sites with substantial emissions, the authors found that company representatives made adjustments resulting in immediate reductions in emissions.

In the study on transmission and storage emissions, the two sites with very significant emissions were both due to leaks or venting at isolation valves.¹⁷ The study also found that leaks were a major source of emissions across sources, concluding that measured emissions are larger than would be estimated by the emission factors used in EPA’s reporting program.

A recent helicopter study of 8,220 well pads in seven basins confirms that leaks occur randomly and are not well correlated with characteristics of well pads, such as age, production type or well count.¹⁸ That study used statistical models to assess the relationship of detection to well pad parameters such as age, well count, gas and oil production. The study found a weak relationship between site characteristics and detected emissions. The study focused only on very high emitting sources, given the helicopter survey detection limit, which ranged from 35 to 105 metric tons per year of methane. The paper reports that emissions exceeding the high detection limits were found at 327 sites. 92 percent of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly and so could be expected to be addressed through a leak detection and repair program. While the study did not characterize the individually smaller but collectively significant leaks that fell below the detection limit, it nonetheless confirms that high-emitting leaks occur at a significant number of

¹⁴ Allen, D.T. *et al.*, “Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings,” *Environ. Sci. Technol.*, 2015, 49 (1), pp 641–648, available at <http://pubs.acs.org/doi/abs/10.1021/es504016r>. (Ex. 6)

¹⁵ Allen *et al.* (2015), *supra* note 13.

¹⁶ Mitchell, A.L., *et al.*, (2015) “Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants,” *Environ. Sci. Technol.*, 2015, 49 (5), pp 3219–3227, available at <http://pubs.acs.org/doi/abs/10.1021/es5052809>. (Ex. 7)

¹⁷ R. Subramanian, *et al.*, (2015) “Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol,” *Environ. Sci. Technol.*, available at <http://pubs.acs.org/doi/abs/10.1021/es5060258>. (Ex. 8)

¹⁸ Lyon, *et al.*, “Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites,” *Environ. Sci. Technol.*, 2016, 50 (9), pp 4877–4886, available at <http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705>. (Ex. 9)

production sites and that total emissions from such leaks are very likely underestimated in official inventories.

These studies demonstrate the importance of frequent inspections as well as the importance of comprehensive inspection requirements that apply to the full suite of components and equipment that can lead to leaks and unintentional venting. Specifically, certain components such as valves and connectors, may leak over time due to normal wear and tear. Other types of equipment, such as controlled storage tanks and pneumatic devices, may vent excess emissions when operating improperly. We commend ARB on drafting an LDAR provision that applies to both types of equipment. Under the proposal, operators must inspect controlled storage tanks, separators, vapor collection systems, circulation tanks, pneumatic devices and components such as valves and flanges on a quarterly basis using leak detection technologies. This is a critical aspect of the proposal as a comprehensive program coupled with frequent inspections is necessary to ensure operators detect all sources of unintentional leaks and venting.

The heterogeneous, unpredictable and ever-shifting nature of equipment leaks suggest that frequent leak detection and repair is essential to help identify and remediate leaks. We therefore support the finalization of a quarterly, comprehensive inspection requirement in the rule.

2. Leading States and EPA Require Quarterly Inspections

Currently, five major oil and natural gas producing states require quarterly monitoring at oil and gas facilities. In addition, EPA recently finalized a quarterly inspection requirement for compressor stations. These existing requirements demonstrate that ARB's proposed quarterly inspection requirement is both reasonable and necessary in order for California to remain one of the leaders with respect to oil and gas emissions mitigation.

EPA has finalized a quarterly inspection requirement to detect methane and VOC leaks at compressor stations.¹⁹ Per the NSPS, operators may conduct such inspections using either optical gas imaging equipment or Method 21. Components found to be leaking 500 ppm or greater with a Method 21 instrument must be repaired.²⁰

Colorado was the first state to promulgate comprehensive LDAR requirements aimed at reducing methane, as well as other pollutant emissions from a diverse suite of oil and gas facilities. Colorado's rules require operators to inspect for and repair hydrocarbon leaks, consisting of methane as well as other organic compounds, at three types of facilities: compressor stations, well sites and storage tank batteries. The rules require quarterly inspections at mid-sized facilities.²¹

¹⁹ 81 Fed. Reg. 35824, 35846 (June 3, 2016).

²⁰ *Id.*

²¹ 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Quarterly inspections are required at gathering sector compressor facilities with uncontrolled emissions between 12 and 50 tons of VOCs from equipment leaks and at well sites and tank batteries with uncontrolled emissions between 20 and 50 tons of VOCs from the largest condensate or oil storage tank onsite.

Colorado provides operators flexibility in determining what type of leak detection equipment to use and whether or not to quantify a leak. Operators may use either an IR camera, Method 21, or “other Division approved instrument based monitoring device or method.”²² To date, the Division has approved one additional device, the Rebellion photonics camera. If an operator chooses to quantify a leak, they must fix all leaks with a hydrocarbon concentration of 500 ppm from components located at new and existing well sites and new compressor stations.²³ At older, existing compressor stations, the leak threshold triggering repair is 2,000 ppm.²⁴

Pennsylvania, the second largest shale gas producing state, requires quarterly inspections of all onshore gas processing plants and compressor stations in the gathering and boosting sector.²⁵ Like Colorado, Pennsylvania requires operators to inspect for and repair methane leaks as well as VOC leaks. Pennsylvania requires that operators utilize either a forward looking infrared camera (“FLIR”) or “other leak detection monitoring devices approved by the Department”.²⁶ Pennsylvania has also announced an intent to adopt a quarterly inspection requirement at new and existing well sites.²⁷

Ohio also requires quarterly inspections for hydrocarbon, including methane, leaks at unconventional well sites.²⁸ Per the Ohio requirements, operators may use either a FLIR camera or a Method 21 compliant analyzer. When using a FLIR camera, a leak is defined as any visible emissions. When using an analyzer, a leak is defined using a 10,000 ppm threshold for all components except compressors and closed vent systems, which use a 500 ppm threshold. Ohio has also proposed to require quarterly inspections at other facilities, including compressor stations.²⁹

Wyoming requires quarterly instrument-based inspections at all new and modified well sites in its Upper Green River Basin with the potential to emit 4 tons of volatile organic compounds from fugitive components,³⁰ and has proposed to require the same for existing well

²² *Id.* at § XVII.A.2.

²³ *Id.* at § XVII.F.6.a,b.

²⁴ *Id.* at § XVII.F.6.a.

²⁵ Pa. Dep’t of Env’tl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5), Section G, http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf. (Ex. 10)

²⁶ *Id.*, Section H.

²⁷ Pennsylvania DEQ, Oil and Gas Technical Advisory Board Meeting, Concepts for Proposed General Permit for Well Pads and Proposed GP-5 Modifications (Mar. 31, 2016), <http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/TechnicalAdvisoryBoard/2016/March%2031/Oil%20and%20Gas%20Presentation%20-%20Methane%20Reduction%20Stds.pdf>. (Ex. 11)

²⁸ Ohio EPA, General Permit for High Volume Hydraulic Fracturing, Oil and Gas Well Site Production Operations, http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf. (Ex. 12)

²⁹ Ohio EPA, Draft Permits Available for Comment, *see* proposal for 18.1 Equipment/Pipeline Leaks, available at: <http://epa.ohio.gov/dapc/genpermit/permitsec.aspx>. (Ex. 13)

³⁰ Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Permitting Guidance (Sept. 2013), (WY Permitting Guidance) <http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf>. (Ex. 14)

sites and compressor stations in the Basin.³¹ Operators may use either Method 21 or an optical gas imaging instrument, or other approved instrument. Wyoming's rules and permit requirements are focused on reducing VOC and HAP emissions.

Utah requires quarterly instrument-based inspections at all new and modified well sites and tank batteries.³² Utah allows operators flexibility in determining which type of leak detection to use to conduct the inspections. Operators may use an IR camera, Method 21 or a tunable diode laser absorption spectroscopy. Utah requires operators of facilities that produce at least 25,000 barrels of crude oil and/or condensate to inspect on a quarterly basis. Operators of facilities that produce less than 25,000 barrels of crude oil and/or condensate must inspect annually. Utah requires that operators inspect components in hydrocarbon service, thereby requiring operators to detect and fix methane as well as VOC leaks.

3. Quarterly Inspections Are Highly Cost Effective

Quarterly instrument-based inspections can remove significant methane, HAPs and VOCs from the atmosphere for very low costs. When considering the value of natural gas that can be sold to end users instead of being leaked into the air quarterly inspections simply make economic sense, and even more so when considering the co-benefits associated with reducing VOCs and HAPs. This is supported by ARB's analysis, which estimates that the LDAR provision can be achieved for a cost of \$15 per ton of CO₂e reduced assuming savings and \$17 per ton of CO₂e reduced not assuming savings.³³ Data from ICF, other states, LDAR service providers and companies similarly demonstrate that quarterly inspections are cost-effective:

- **ICF.** ICF developed a complex model to investigate the distribution of LDAR cost profiles at well sites. The results of the model indicate that the cost for LDAR using third-party OGI contractors ranges between \$491–793 per facility, depending on facility size.³⁴ Further, the analysis found that quarterly LDAR is cost-effective at \$258/metric ton of methane avoided for an average facility in the modeled distribution.³⁵
- **ICF** is also in the process of compiling a model that assesses the costs and cost-effectiveness of inspections using Method 21. This model also investigates the distribution of LDAR costs at facilities of varying size and emissions profiles. In addition, the model estimates costs over a period of three years, rather than simply looking at inspection costs in year one of an inspection program. The preliminary results of this model indicate that the cost for using third-party Method 21 contractors to

³¹ Wyoming Department of Environmental Quality proposed changes to Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6, (UGRB proposal) available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>; WY Permitting Guidance, 22. (Ex. 15)

³² GAO DAQE-AN149250001-14, II.B.

³³ ARB Staff Report, *supra* note 2, at ES-4.

³⁴ ICF Leak Detection and Repair Cost-Effectiveness Analysis, December 4, 2015. (Ex. 16). Figures reflect survey and equipment costs per facility.

³⁵ *Id.* Cost is \$10.32/MT CO₂e for an average facility in the distribution model, using a GWP of 25 and gas price of \$3/Mcf.

perform quarterly inspections at production facilities is \$8.58 per metric ton of CO₂e reduced.³⁶

- Rebellion. In comments at an EPA public hearing on the proposed NSPS in Dallas, TX, Rebellion Photonics, the maker of a leak detection technology, noted that its services are available for \$250 per site.³⁷ Rebellion noted that this cost is “turn-key,” including data management services.
- Colorado. Colorado’s economic analysis of its LDAR requirements assumed an hourly contractor rate of \$134 (reflecting a 30 percent premium).³⁸ Assuming a per-site survey time of four hours, this hourly rate yields a total per-site survey cost of \$536.³⁹
- EPA. EPA determined compressor station quarterly inspections to be cost-effective, estimating that the agency’s requirements would result in the reduction of 16,500 short tons of CH₄, 3,897 tons of VOCs, and 143 tons of HAPs at 525 compressor stations by 2020 at total annualized costs, including revenue from saved gas, of \$9,780,000.⁴⁰ For gathering and boosting compressor stations, this equates to \$685 per short ton of CH₄ reduced and \$234 per short ton of VOC reduced. For compressor stations in the transmission and storage sectors, this equates to \$251 per short ton of CH₄ reduced and \$9,072 per short ton of VOC reduced.
- EDF also contacted a number of third-party service providers and equipment rental firms, which provided costs that support the reasonableness of EPA’s determination. In particular, a FLIR presentation includes information from survey providers suggesting well-pad rates ranging from \$300 - \$800.⁴¹
- Noble and Anadarko submitted comments in response to the Colorado LDAR rule, stating that “the leak detection and repair requirements using instrument-based monitoring is [sic] a reasonable and cost effective way to reduce fugitive emissions at well production sites.”⁴² Additionally, the companies compiled a cost analysis for LDAR

³⁶ Final results of the model and an accompanying report are forthcoming and will be submitted to ARB once final.

³⁷ Rebellion Photonics comments at the EPA hearing in Dallas, TX on September 23, 2015. (Ex. 17)

³⁸ Colorado Air Pollution Control Division, Final Economic Impact Analysis for Regulation Number 7, at 18.

Colorado assumed slight longer surveys, approximately 6.1 hours, yielding third party survey costs of approximately \$817. (Ex. 18)

³⁹ CDPHE Cost Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7. Table 14: Instrument Based Tank Inspections Based on Proposed Tiering. (Ex. 19)

⁴⁰ EPA Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Table 3-10, available at <https://www3.epa.gov/airquality/oilandgas/may2016/nsps-ria.pdf>. (Ex. 20)

⁴¹ FLIR, OGI Service Provider Survey, March 2016, at 2-3. The presentation notes additional charges for travel but also notes potential discounts for multiple well surveys. (Ex. 21)

⁴² Prehearing statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the matter of proposed revisions to Regulation Number 3, 6, and 7, available at

under the Colorado rule and found that, “Based on company-specific historic data and certain estimated values, Noble anticipates that LDAR monitoring at well production facilities would cost between approximately \$260 and \$430 per inspection...”⁴³

- According to a presentation delivered by Jonah Energy at the WCCA 2015 Spring Meeting, total LDAR program costs were about \$99 per inspection in the first year, decreasing to about \$29 per inspection in the fifth year.⁴⁴

4. *Incentivizing Innovation and Continuous Improvement in LDAR Technologies and Approaches*

Although frequent OGI and Method 21-based LDAR both offer feasible and highly cost-effective approaches to reducing leak emissions, advanced LDAR technologies – and protocols for using those technologies — are being swiftly developed and refined.

The methane leak detection technology landscape is highly dynamic, with innovation happening in real time, for example through ARPA-E's MONITOR project and EDF's Methane Detectors Challenge project in partnership with Shell, six other large producers and other stakeholders. It is crucial for new ARB rules to create space for innovative technologies, which may be able to deliver improved environmental performance at reduced cost. We strongly urge the agency to adopt a robust alternative compliance pathway that is minimally prescriptive and specifically creates an entry point for appropriately qualified/demonstrated methane selective and/or multiple hydrocarbon detecting approaches. Such an approach will help catalyze a race to the top in technology, reduce costs for the regulated community, and potentially boost environmental outcomes. We urge ARB to let operators choose from a list of approved devices, and to obtain approval from ARB for an equally effective device, rather than dictating technology in the rule. We note that ARB has proposed to allow operators of underground natural gas storage facilities to use screening instruments other than OGI or Method 21 to conduct inspections of wellheads and pipelines,⁴⁵ and that U.S. EPA included a pathway for operators to obtain approval to use innovative technologies to reduce fugitive emissions at well sites and compressor stations.⁴⁶

Accordingly, we encourage ARB to provide operators with flexibility to seek approval for alternative methods of complying with LDAR requirements, provided that these alternative

[http://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/PREHEARING%20STATEMENTS,%20EXHIBITS%20&%20ALTERNATIVE%20PROPOSALS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation%20\(Noble%20&%20Anadarko\)/Noble%20and%20Anadarko%20PHS.pdf](http://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/PREHEARING%20STATEMENTS,%20EXHIBITS%20&%20ALTERNATIVE%20PROPOSALS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation%20(Noble%20&%20Anadarko)/Noble%20and%20Anadarko%20PHS.pdf). (Ex. 22)

⁴³ Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the matter of proposed revisions to Regulation Number 3, 6 and 7; Page 7, available at

http://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/NOBLE_APC%20-%20REB.pdf. (Ex. 23)

⁴⁴ WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015 delivered by Paul Ulrich. (Ex. 24)

⁴⁵ Proposed 17 C.C.R. Section 95668(i)(1)(B).

⁴⁶ 81 Fed. Reg. 35824, 35861 (June 3, 2016).

compliance options are at least as effective in reducing waste and emissions as OGI-based LDAR, and that the approval process is transparent and open to public participation.

5. *ARB Should Remove the Frequency Adjustment Based on Percent or Number of Leaking Components*

Given the geographic and temporal unpredictability of leaking equipment discussed above, one of the most important aspects of an LDAR program is the frequency with which operators inspect facilities. ARB has proposed quarterly leak inspection surveys, with provisions to allow operators to reduce the frequency to annual inspections based on the percentage or number of leaking components found onsite. These provisions fall far short of what is necessary to protect public health and the environment, and lag behind what EPA, leading states and companies have already demonstrated in practice. Accordingly, we urge ARB to finalize a quarterly inspection requirement and to remove the provisions that allow operators to reduce inspection frequency to annual.

The proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. EPA investigations at petroleum refineries and other types of facilities demonstrate this to be so. A 2007 report by EPA found “significant widespread non-compliance with [LDAR] regulations” at petroleum refineries and other facilities.⁴⁷ EPA observed: “Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions.”⁴⁸ The report recommends that “[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time,” companies should monitor more frequently.⁴⁹

Furthermore, neither the percent nor number of leaking components is an accurate predictor of a facility’s emissions performance. At a conceptual level, if emissions from leaking components were homogeneously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large portion of emissions.

To estimate the extent to which the percent of leaking components correlates with a facility’s emissions performance, we empirically examined the effects of EPA’s proposed 1 and 3 percent thresholds using data from the City of Fort Worth Study Air Quality Study,⁵⁰ which includes both component level emissions information and site-level data. Figures 5 and 6 below show the results of this analysis. Figure 5 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below EPA’s proposed 1 percent threshold. Figure 6 aggregates site-level emissions at each of these

⁴⁷ EPA, “Leak Detection and Repair: A Best Practice Guide,” October 2007, at 1, *available at* <http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf>. (Ex. 25)

⁴⁸ *Id.* at 23.

⁴⁹ *Ibid.*

⁵⁰ Eastern Research Group, Inc. and Safe Environmental Consulting, LP, “City of Fort Worth Natural Gas Air Quality Study: Final Report,” July 13, 2011, *available at*: http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf. (Ex. 26)

thresholds. Sites with less than 1 percent leaking components constituted over half of total emissions and over half of all sites. Conversely, there were no high-emitting sites with greater than 3 percent of their components leaking, and sites above a 3 percent threshold accounted for a small percentage of total emissions.

Figure 1: Site Methane Emissions (lb per year) Versus Percent Leaking Components

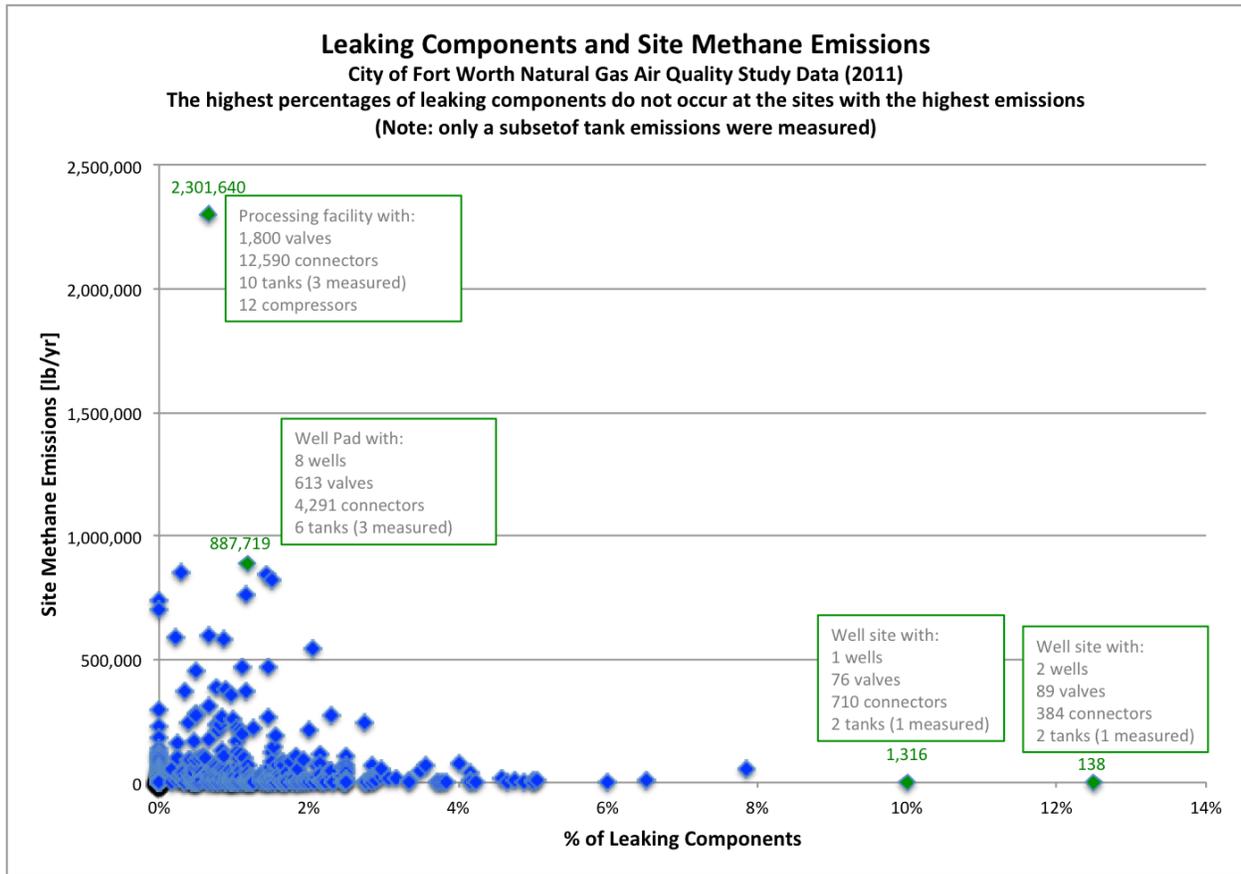
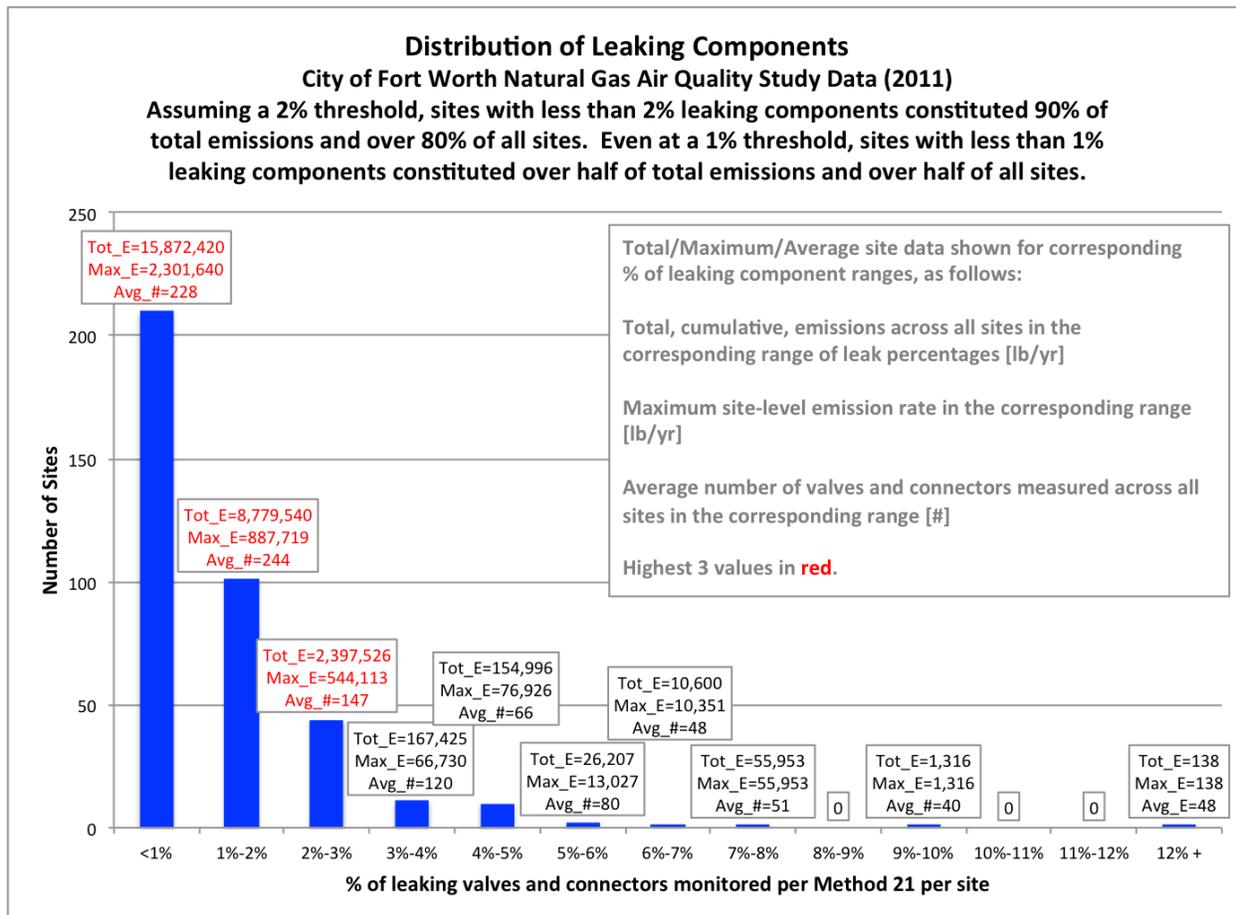


Figure 2: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



The number of leaking components is also a poor indicator of a facility’s emission performance. To test this, we empirically examined the effects of BLM’s proposed threshold using data from Allen, *et al.* (2013) and the Fort Worth Air Quality Study (2011),⁵¹ which include both component level emissions information and site-level data. Figures 3 and 4 below show the results of this analysis. Figure 3 shows the distribution of equipment leaks across the 150 production sites measured in the Allen, *et al.* (2013) study; sites with two or fewer leaks represented 70 percent of sites and constituted half of total methane emissions from leaks. Conversely, only 30 percent of sites had more than two leaks, representing only half of all emissions. In the Allen, *et al.* (2013) dataset, the site with the highest measured methane emissions from leaks had only two leaks but represented 18 percent of all emissions measured across all sites.⁵²

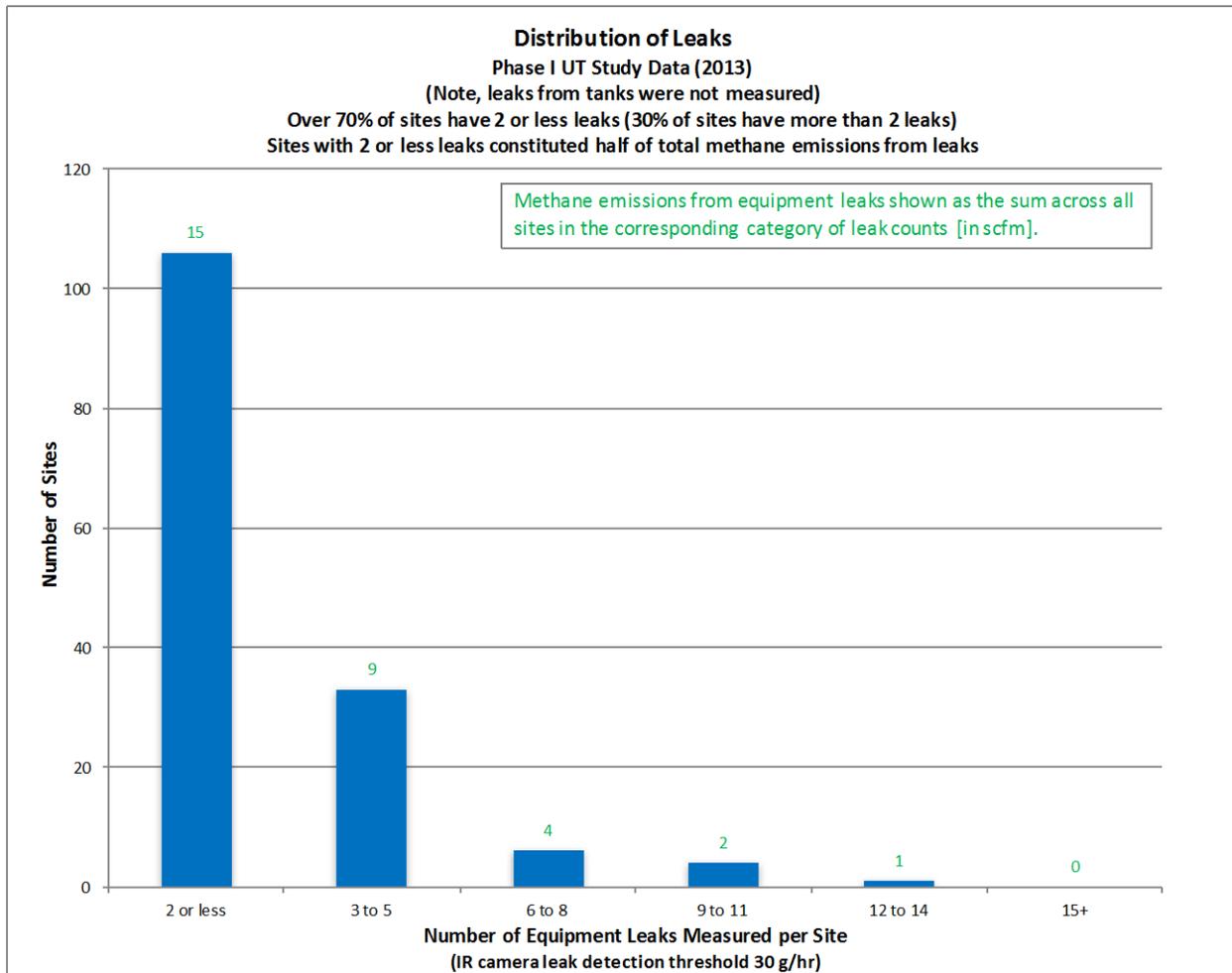
Figure 4 shows the distribution of leaks detected across the 388 sites measured in the Fort Worth Air Quality Study (2011); sites with two or fewer leaks represented 60 percent of sites and constituted 12 percent of total methane emissions from leaks. EPA reported in its Leaks White

⁵¹ *Id.*

⁵² One leaking separator vent was responsible for 5 scfm methane at this site.

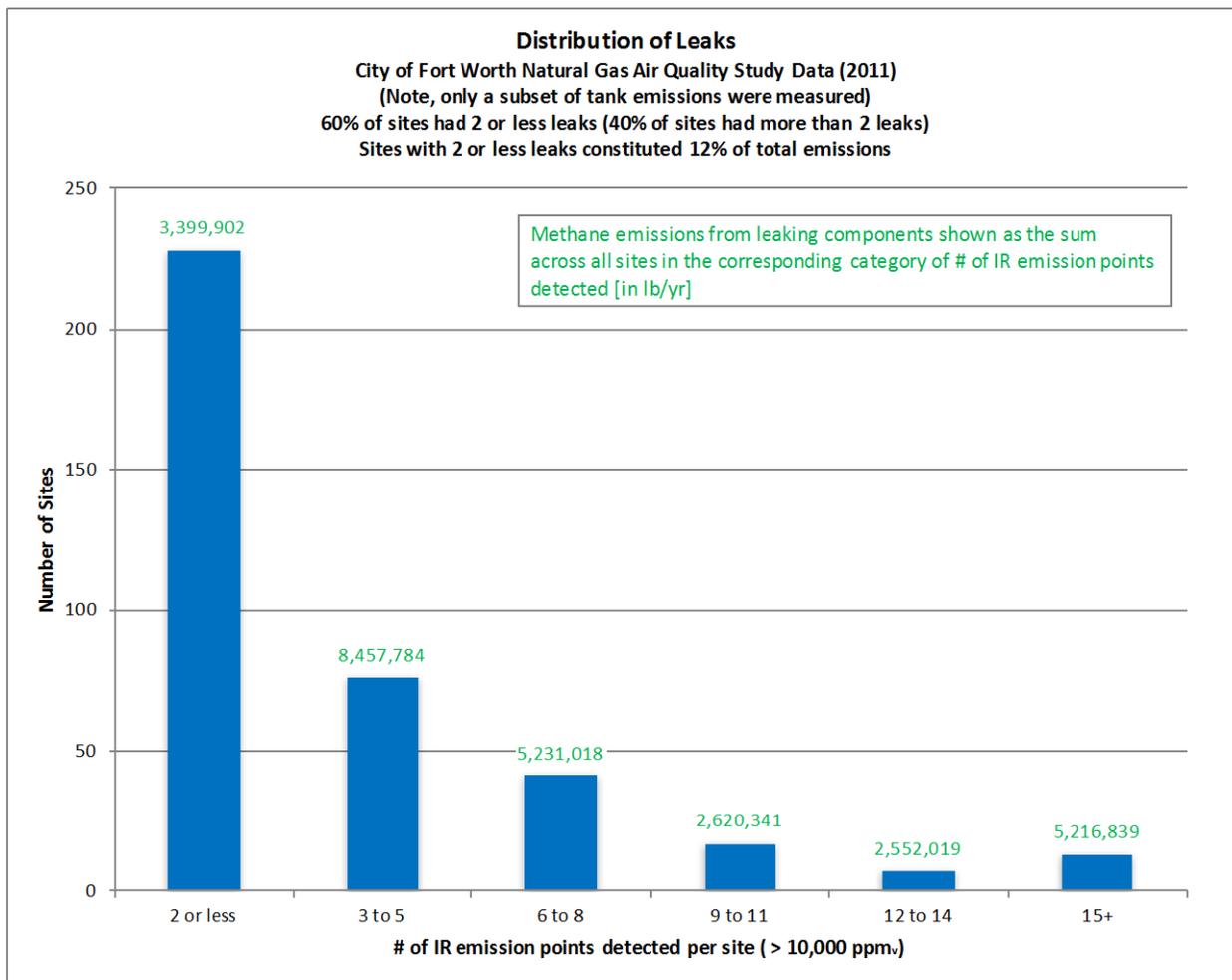
Paper that the well data provided in the Fort Worth report showed: “At least one leak was detected at 283 out of the 375 well pads monitored with an OGI technology with an average of 3.2 leaks detected per well pad; The TVA detected at least one leak greater than 500 ppm at 270 of 375 well pads that were monitored with an average of 2.0 leaks detected per well pad.”⁵³ These data indicate that significant emissions can occur at sites with few measured leaks.

Figure 3: Number of Sites versus Number of Equipment Leaks



⁵³ USEPA, “White Papers on Methane and VOC Emissions: Leaks,” available at <https://www3.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf>. (Ex. 27)

Figure 4: Number of Sites versus Number of Large Leaks



Other LDAR rules, and information submitted by stakeholders during such rulemakings, further underscore the need for ARB to finalize a flat quarterly inspection requirement.

EPA recently finalized inspection requirements for well sites and compressor stations. EPA’s final rules require operators to inspect compressor stations quarterly and well sites semi-annually. EPA removed a provision that appeared in the proposal that would have allowed operators to reduce the inspection frequency based on the percentage of leaking components identified during an inspection. As EPA noted, “most commenters opposed performance-based monitoring frequency” on the grounds that such an approach is “costly, time-consuming, and impose[s] a complex administrative burden for the industry and states.”⁵⁴

Colorado recently proposed, and ultimately adopted, a leak detection and repair requirement that requires operators inspect for leaks at all but the smallest sites on a continuous annual, quarterly, or monthly basis.⁵⁵ This proposal had the support of three large oil and gas

⁵⁴ 81 Fed. Reg. at 35857.

⁵⁵ 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014).

producers, Noble Energy, Anadarko Petroleum Corporation, and Encana. Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, “Encana’s experience shows leaks continued to be detected well into the established LDAR program.”⁵⁶ Viewed somewhat differently, Encana’s data suggests that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emissions reductions are still being realized in subsequent years of the LDAR program.”⁵⁷

Other information presented during the Colorado rulemaking further supports the need for frequent inspections over time. During the rulemaking, industry opponents of the Division’s proposal submitted data collected from their own LDAR monitoring experience. This data demonstrated an initial component leak rate frequency (before the first LDAR inspection) at new and modified gas processing plants of 1.7 percent.⁵⁸ The leak rate frequency falls to 0.4 percent after the first monitoring period and averages 0.3 percent over 12 consecutive calendar quarters. While it does support a decline after the first monitoring period, the data evidences a steady state of leak detection after that.

6. ARB Should Require All Leaks of 500 ppm be Repaired Upon Rule Implementation

The proposal sets the lowest leak threshold for the first year of the rule’s implementation at 10,000 ppm, and then lowers this to 1,000 in year two. A 10,000 ppm leak is a large leak, and we are not aware of any technical or other justification for allowing smaller leaks that can be detected to go unmitigated. Method 21 and OGI are both capable of detecting leaks smaller than 10,000 ppm. Moreover, other leading states with LDAR programs that contain quantitative leak thresholds such as Colorado and Pennsylvania require operators repair much smaller leaks of 500 ppm.⁵⁹ US EPA uses a leak threshold of 500 ppm for a number of LDAR requirements for new facilities under NSPS Subpart OOOO.⁶⁰ We therefore urge ARB to lower the initial leak threshold to 500 ppm to be consistent with these other states and to reflect what is technically feasible.

III. Underground Natural Gas Storage Facility Monitoring.

We applaud ARB on proposing rigorous monitoring provisions at underground natural gas storage facilities. The recent leaks at Aliso Canyon and McDonald Island demonstrate the unpredictable nature of leaks and the potential for such leaks to cause very significant harm to public health and the environment. The requirements that ARB has proposed will go a long way in ensuring that operators detect even small leaks immediately and repair them expeditiously.

⁵⁶ Rebuttal Statement of Encana Oil and Gas (USA) Inc., p. 10, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9. (Ex. 28)

⁵⁷ *Id.* at 10-11.

⁵⁸ Prehearing Statement of WPX Energy Rocky Mountain, LLC’S AND WPX Energy Production LLC, Ex. A, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9. (Ex. 29)

⁵⁹ 5 C.C.R. § 1001-9 XVII.F.6.b; Pa. Dep’t of Env’tl.

Prot., Air Quality Permit Exemptions, No. 275-2101-003, <http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf>. (Ex. 30)

⁶⁰ *See* 77 Fed. Reg. at 49490, 49498 (Aug. 16, 2016).

To address leaks from underground storage facilities, ARB has proposed a combination of ambient air monitoring and equipment monitoring. Specifically, operators must install a system capable of continuously monitoring the ambient air at the facility that can be accessed by ARB or local agencies.⁶¹ In addition, operators must perform either daily or continuous monitoring at wellheads, pipelines and the surrounding area within a 200 foot radius of the wellhead assembly.⁶² Operators must measure all leaks identified by the daily inspections or the continuous monitoring system in accordance with Method 21 (excluding the use of PID instruments) within 24 hours of detecting a leak, and repair all leaks measured above the thresholds specified in Section 95669 (the general LDAR provision) according to the timeframes specified in Section 95669.⁶³ Operators must notify ARB within 24 hours any time a leak is measured above the maximum leak threshold specified in Section 95669 or any time an air monitoring system detects levels of natural gas that exceed more than 10 percent of baseline conditions.⁶⁴ These provisions could be read as giving operators 24 hours from detection to measure a leak, and a subsequent 24 hours to report that measurement to ARB – in other words, two full days between detection and reporting. We therefore request that ARB clarify that operators must both measure any leak and report that measurement to ARB within 24 hours of detection, as we believe that this time frame is sufficient to accomplish both. The rule also requires operators to maintain records of leak measurements and submit an annual report containing leak measurement data.⁶⁵

The proposal contains a number of provisions that are critical to reducing the environmental, public health and safety threats of underground natural gas storage facilities. In particular, we strongly support the continuous ambient air monitoring combined with the daily or continuous equipment monitoring requirements. These provisions go beyond the requirements that currently apply to surface leak monitoring at natural gas storage facilities under emergency rules promulgated by the Division of Oil, Gas and Geothermal Resources (DOGGR) in response to the Aliso Canyon leak,⁶⁶ and also beyond new rules proposed by DOGGR. Indeed, per the DOGGR proposal, the ARB requirements will supersede the DOGGR surface leak monitoring requirements if ARB finalizes requirements that are at least as stringent, or more stringent, than DOGGR's rules.⁶⁷ The current draft meets this test.

We also support ARB's proposal to provide flexibility to operators in choosing what type of leak detection technologies to use in performing the daily equipment inspections.⁶⁸ As we

⁶¹ 17 C.C.R. Section 95668(1)(i)(A).

⁶² *Id.* at Section 95668(i)(1)(B),(C).

⁶³ *Id.* at Section 95668(i)(3),(4).

⁶⁴ *Id.* at Section 95668(i)(6).

⁶⁵ *Id.* at Section 95668(i)(7),(8).

⁶⁶ DOGGR, Emergency Regulations 14 C.C.R. Section 1726 et seq., available at <http://www.conservation.ca.gov/index/Documents/DOC%202016-0126-03E%20Gas%20Storage%20Requirements%20-%20Final%20Text%20of%20Emergency%20Regulations.pdf>. (Ex. 31)

⁶⁷ DOGGR, Discussion Draft 14 C.C.R. Section 1726.7(e), available at <http://www.conservation.ca.gov/dog/Documents/Public%20Discussion%20Draft%20Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf>. (Ex. 32)

⁶⁸ *See id.* at Section 95668(i)(1)(B)(providing that operators may use Method 21, OGI or “other screening instruments”).

note in our comments on the general LDAR provision in Section 95669, we believe it is imperative that regulations incent or, at a minimum, allow for the use of emerging technologies, provided that there is a rigorous and transparent process whereby ARB can ensure that such technologies are at least as effective in detecting leaks as the methods explicitly allowed for in the rule. Along these lines, we urge ARB to issue clear guidelines that lay out the criteria for approval of “other screening instruments”⁶⁹ and provide an opportunity for public comment on any application to use an alternate screening instrument.

We support ARB’s proposal to require either daily screening or continuous monitoring of each natural gas injection/withdrawal wellhead assembly, attached pipelines and the surrounding area within a 200 foot radius of the wellhead assembly for leaks of natural gas; however, we request that this be expanded to include not just injection/withdrawal wells, but all wells in the field including but not limited to observation, monitoring, disposal, production and other wells, as leaks can occur from any of these well types. We also request that ARB clarify that the monitoring requirements apply not only to active wells but also to idle and plugged and abandoned wells. Given the age and long operating histories of California’s underground gas storage fields, monitoring all wells—not just active wells—is critical to detecting and stopping leaks. The Montebello and Playa Del Rey underground gas storage fields, for example, have long, documented histories of leakage from plugged and abandoned wells.⁷⁰

Lastly, it appears from the proposal that the inspection requirements in Section 95668 are intended to apply in lieu of the inspection requirements in Section 95669. However, this is not explicitly stated in the proposal. We suggest ARB clarify this in the final rule.

IV. Pneumatic Controllers and Pumps

Pneumatic equipment – natural gas driven pneumatic controllers and pneumatic pumps – are the source of enormous amounts of methane pollution. US EPA estimates that, nationwide, pneumatic equipment emitted over 3,100,000 metric tons of methane in 2014 – or 32 percent of estimated methane emissions from all oil and natural gas sources. As we describe below, cost effective technologies can essentially eliminate these emissions. We commend ARB for proposing strong standards for pneumatic equipment, but as we describe below, the proposed standards would still allow significant emissions from these types of equipment, and as such, ARB must strengthen the proposal.

ARB’s proposal:

- Prohibits venting of natural gas from any newly installed⁷¹ continuous-bleed pneumatic controller, regardless of the nominal bleed rate for the controller, and requires that all older continuous-bleed pneumatic controllers emit less than six standard cubic feet per

⁶⁹ *Id.*

⁷⁰ Chilingar, G. V., & Endres, B. (2005). Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned. *Environmental Geology*, 47(2), 302-317. (Ex. 33)

⁷¹ ARB’s proposal would not allow venting from any continuous-bleed pneumatic controller installed after January 1, 2016.

hour (scfh), including provisions requiring operators to annually verify compliance with this limit with direct measurements of the rate of venting.

- Requires operators of intermittent-bleed pneumatic controllers to verify that these devices are not emitting natural gas between actuation as part of periodic leak-detection inspections.

- Prohibits venting of natural gas from pneumatic pumps.

No other state prohibits all venting from new continuous bleed devices or new and existing pumps located at the suite of facilities subject to this proposal, nor includes all pneumatic devices, including intermittent bleed devices, in leak detection and repair requirements. These provisions will go a long way towards reducing emissions from new continuous-bleed pneumatic devices and pumps, and improperly functioning intermittent and continuous-bleed devices and pumps. Joint commenters support these provisions.

Nevertheless, ARB's proposal will continue to allow significant pollution from pneumatic controllers. In particular, the proposal will allow "grandfathered" continuous-bleed controllers to operate indefinitely, provided that their emissions remain below six scfh. And, it will allow both new and existing intermittent-bleed controllers that vent to the atmosphere to continue operating - again, indefinitely. Allowing these polluting devices to remain in operation is not necessary because, as we detail below, cost effective technologies are available to eliminate, or at least greatly reduce, venting from pneumatic controllers. ARB must strengthen the proposal so that harmful methane emissions from pneumatic controllers do not continue unnecessarily.

1. Zero-Emitting Alternatives to Natural Gas-Driven Pneumatic Controllers are Available

A number of alternative technologies and approaches that can eliminate, or at least drastically reduce, venting of natural gas from pneumatic controllers are available and in-use today at oil and gas facilities in the United States and Canada. These technologies/approaches include:

- Using compressed "instrument air," instead of natural gas, to drive pneumatic controllers.
- Using electronic control systems and electric valve actuators, instead of pneumatic controller and valve actuators, for valve automation. As described below, this approach can be used both at sites where electricity is already available and at sites without power by installing solar powered systems.
- For some applications, pneumatic controllers are available that do not release gas to the atmosphere, but rather release gas to a pressurized gas line. These are typically referred to as "bleed-to-pressure" or "integral" controllers.
- Gas released from pneumatic controllers can be routed to vapor collection systems (VCSs) or fuel lines.

Clean Air Task Force recently commissioned Carbon Limits to examine these and other alternatives to traditional, venting pneumatic controllers. Carbon Limits examined these

technologies in detail, conducting numerous interviews with oil and gas producers who have utilized them and with suppliers of these systems. The first two technologies listed above, instrument air and electric systems, are inherently non-emitting technologies; Carbon Limits' research shows that these technologies are mature and proven, with successful installation at hundreds of sites in North America. Furthermore, Carbon Limits demonstrates that for almost any configuration of oil and gas facilities, at least one of these technologies is cost effective as a means of methane abatement as compared to unmitigated natural gas-drive pneumatic controllers.

Instrument Air. Compressed air can be used instead of natural gas to drive devices. EPA's 2012 OOOO NSPS standards require all pneumatic controllers at processing plants to be zero emitting,⁷² and EPA presumes that most operators will use compressed "instrument air" systems to comply with this regulation.⁷³ Instrument air is a "well-established mature solution" to run pneumatic control systems and is in wide use globally. In fact, in some countries with significant oil production, instrument air systems are more common than natural gas-driven pneumatic controllers.⁷⁴

Instrument air systems offer several advantages over natural-gas driven pneumatic controllers, in addition to reduced emissions of methane and other pollutants in natural gas:

- Increased revenue from sales of natural gas that would otherwise be vented by gas-driven controllers.
- For many sites, instrument air systems can be simpler and cheaper to maintain. For gas-driven controllers, maintenance costs are significant if the gas at the site is wet (condensation of heavier hydrocarbons interferes with pneumatic controller operations) or sour. These costs are avoided with instrument air. Instrument air is very reliable; in contrast some sites with low gas-to-oil ratios may need to purchase natural gas or propane from offsite in order to ensure that sufficient gas is always available to drive pneumatic systems. These costs are all avoided with instrument air systems.⁷⁵

For sites with 20 or more pneumatic devices, instrument air is a cost effective and feasible approach to eliminate emissions from all types of pneumatic controllers and pneumatic chemical injection pumps or heat trace pumps when electric power is available from the grid or from on-site generators. Oil and gas production in California occurs largely in areas with access to electric power. Many centralized production sites and compressor stations have numerous pneumatic devices. Retrofit of sites with instrument air is straightforward because operators can use existing pneumatic controllers and actuators with instrument air systems.

Electric Systems. Gas-driven pneumatic controllers can now readily be replaced with electric systems at sites with and without electricity already available. These systems include electric valve actuators, electronic controllers, control panels and wiring, and—for sites without

⁷² 40 C.F.R. § 60.5390(b)(1).

⁷³ See EPA, TSD for the Proposed NSPS Subpart OOOO, 5-22 (July 2011). (Ex. 34)

⁷⁴ Carbon Limits, "Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness" (2016) at 17. (Ex. 35)

⁷⁵ *Id.* at 18.

power available from the grid or from pre-installed on-site generators—solar panels and batteries.

These systems have become more mature and robust in recent years and are in use at hundreds of oil and natural gas production sites in the United States and Canada.⁷⁶ Operators report that these systems are reliable.⁷⁷ Like instrument air, these systems offer several advantages over natural-gas driven pneumatic controllers, in addition to reduced emissions of methane and other pollutants in natural gas, including:

- Increased revenue from sales of natural gas that would otherwise be vented by gas-driven controllers.
- Like instrument air, greater reliability and lower maintenance for sites with wet or sour gas, which degrades performance of gas-driven pneumatic controllers, or for sites where sufficient and steady supply of natural gas is not available.⁷⁸
- Easier and less expensive site level automation (for example, with Supervisory Control and Data Acquisition (SCADA) systems).⁷⁹ Installation of electric systems can greatly reduce costs for operators if they enable less frequent site visits. Furthermore, these systems can perform important functions such as shutting in wells in the event of large leaks, offering further environmental (and potentially health and safety) benefits. The value of these systems is recognized by ARB in the underground storage monitoring provisions of the proposed rules.

Cost Effectiveness of Instrument Air or Electric Systems as Alternatives to Gas-Driven Pneumatic Controllers. Instrument air and electric systems are mature, reliable technologies. When electric controllers are combined with solar power systems, these non-emitting technologies are widely applicable.⁸⁰ Indeed, these technologies are widely used in California. Data from the ARB Oil and Gas Industry Survey for 2007 shows that both of these approaches are very widely used in California. 37 percent of controllers in the state were electric, while 47 percent were instrument air driven (and a full 87 percent of valve actuators in the state were air driven).⁸¹

Carbon Limits also found that these technologies are cost effective as alternatives to traditional gas-driven pneumatic controllers at a wide variety of oil and gas facilities. Carbon Limits used the capital and operating costs of these systems and traditional pneumatic

⁷⁶ *Id.* at 12.

⁷⁷ *Id.* at 15.

⁷⁸ *Id.* at 15.

⁷⁹ *Id.* at 15.

⁸⁰ Carbon Limits reports that instrument air is applicable at larger sites (roughly 20 or more controllers on site) when power is available from the grid or from an on-site generator (*See* Carbon Limits at 18) and that electric controllers are applicable at sites of all sizes if power is available, and, in combination with solar power, applicable at smaller sites (20 or fewer controllers) when power is not otherwise available. *See id.* at 15. However, Carbon Limits reports that there is no technical barrier to the use of electric controllers with solar panels at larger sites; there is simply little known precedent of this type of installation. *See id.* at 16.

⁸¹ ARB (2013), *2007 Oil and Gas Industry Survey Results - Final Report (Revised)*, at Table 9-2. (Ex. 36)

controllers,⁸² together with highly conservative estimates of emissions from gas-driven pneumatic controllers⁸³ and other parameters such as the value of conserved natural gas⁸⁴ to calculate the net cost of these systems per metric ton of avoided methane pollution, using a net present value formulation. Because there are a wide variety of site configurations for oil and gas sites, and because costs for these systems do not vary in a simple linear fashion with the number of controllers at the site and other parameters, Carbon Limits calculated the costs of both instrument air systems and electric systems for many permutations of a large number of site parameters, including:

- The number of pneumatic controllers at the site (1 – 40 controllers for electric systems, 21-40 controllers for instrument air systems).
- The number of pneumatic pumps at the site (0 – 1 pump).
- The type of pneumatic controllers at the site (from all continuous-bleed to all intermittent-bleed).
- The type of gas at the site (wet gas or dry gas).
- New site or retrofit site.
- Whether electricity is available at the site (for electric controllers at sites with 20 or fewer controllers).

Carbon Limits used US EPA's latest calculation of the social cost of methane (SC-CH₄) as the threshold for cost effectiveness. Specifically, they used the mean value of the SC-CH₄ calculated for a 3 percent discount rate for emissions in 2020, in 2016 dollars, or \$1,354 per metric ton of methane, as the threshold.⁸⁵ Using the global warming potential for methane of 72, which ARB uses in this rulemaking, the abatement costs ARB calculates for the proposed standards translate to abatement costs within the range of the social cost of methane.⁸⁶ In fact, the total abatement costs for the rule are lower than the 2016-adjusted SC-CH₄ calculated by ARB.

⁸² Costs were derived from interviews with oil and gas producers, system and component suppliers, and online quotes from component suppliers.

⁸³ Carbon Limits, *supra* note 74, at 21-22.

⁸⁴ The report uses a very low price of natural gas, \$2 per thousand cubic feet (mcf). *See id.* at 21.

⁸⁵ EPA reports that the mean SC-CH₄ emitted in 2020, calculated with a 3% discount rate, will be \$1,300 per metric ton CH₄ in 2012 dollars. EPA RIA, *supra* note 40. This is converted to \$1,354 per metric ton in 2016 dollars using a cumulative rate of inflation of 4.2 percent.

⁸⁶ ARB Economic Analysis at Table B-2.

TABLE 1

| ARB Rule Provision Methane Reduction Costs per Ton | VRU For Tanks | Reciprocating Compressors | LDAR | Pneumatic Devices | Well Simulations | Centrifugal Compressors | Total |
|--|---------------|---------------------------|---------|-------------------|------------------|-------------------------|---------|
| Cost Per Ton (\$/MTCH ₄ reduced) | \$648 | \$288 | \$1,224 | \$288 | \$6,552 | \$144 | \$1,224 |
| Cost Per Ton with savings (\$/MTCH ₄ reduced) | \$576 | \$72 | \$1,008 | \$72 | \$6,552 | (\$72) | \$1,080 |

Source: Table adapted from Table B-6 of Appendix B: Economic Analysis for the proposed rule. Costs in Table B-6 were converted to \$/metric ton of methane using the IPCC AR4 20-year GWP of 72, per the ARB rulemaking analyses.

It should be noted that the SC-CH₄ costs are likely conservative. Experts widely acknowledge that social cost estimates are almost certainly underestimates of true global damages—perhaps severe underestimates. Using different discount rates; selecting different models; applying different treatments to uncertainty, climate sensitivity, and the potential for catastrophic damages; and making other reasonable assumptions could yield very different, and much larger, social cost estimates for carbon and methane.⁸⁷

In general, replacing gas-driven pneumatic controllers with either instrument air or electric controllers (or both) is cost effective at the vast majority of site configuration, even with highly conservative assumptions about emissions factors for pneumatic controllers. This finding holds for both new installations and retrofit of existing sites with pneumatic controllers. In fact, Carbon Limits found that these technologies would *not* be cost effective for just a handful of site configurations. For example, at least one of the technologies is cost effective at:

- All sites with one (or more) pneumatic pumps.
- Any new wet gas site with more than two pneumatic controllers.

For large sites with electricity, instrument air is cost effective for:

- All retrofit sites.
- All wet gas sites.

As mentioned above, these results were calculated with very conservative (low) emissions factors for gas-powered pneumatic controllers. For example, at new sites, Carbon Limits assumes that each continuous-bleed pneumatic controller will have an emissions factor of 1.39 scfh.⁸⁸ This is EPA’s emissions factor for low-bleed pneumatic controllers,⁸⁹ which operators are required to use for new continuous-bleed pneumatic controllers under NSPS Subpart

⁸⁷ Richard L. Revesz, Peter H. Howard, Kenneth Arrow, Lawrence H. Goulder, Robert E. Kopp, Michael A. Livermore, Michael Oppenheimer & Thomas Sterner, *Global Warming: Improve Economic Models for Climate Change*, 508 NATURE 173 (2014). Available at: http://www.nature.com/polopoly_fs/1.14991!/menu/main/topColumns/topLeftColumn/pdf/508173a.pdf. (Ex. 37) This study focuses on social cost of carbon, but the EPA NSPS RIA notes that “because the SC-CO₂ and SC-CH₄ methodologies are similar, the limitations also apply to the resulting SC-CH₄ estimates.” (RIA Section 4.3).

⁸⁸ Carbon Limits, *supra* note 74, at 22.

⁸⁹ See for example, 40 CFR Part 98, Subpart W, Table W-1A.

OOOO.⁹⁰ However, both NSPS Subpart OOOO⁹¹ and ARB's proposed standards for continuous-bleed pneumatic controllers (proposed § 95668(f)(2)(A)(1)) allow the use of devices that emit up to 6 scfh. Further, several recent studies based on measured emissions from pneumatic controllers have found higher average emissions from continuous-bleed pneumatic controllers classified as "low-bleed controllers."⁹² If emissions factors consistent with these studies are used instead of the very conservative emissions factors used in the calculations described above, even more sites would have abatement costs below the SC-CH₄.⁹³

In summary, Carbon Limits found that, even with very conservative assumptions, electric systems and instrument air systems are cost effective at a broad range of oil and gas facility site configurations.

Other Approaches to Eliminate Pneumatic Controller Emissions. It is important to note that other approaches can be used to eliminate emissions from pneumatic controllers, beyond instrument air and electric controllers. As listed above, two important approaches are use of "self-contained" or "integral" controllers which are designed to release the gas used in the controller into a gas pipeline, typically downstream of the controller and the valve it actuates, and routing emissions from pneumatic controllers to vapor collection systems. Data from the ARB Oil and Gas Industry Survey for 2007 shows that both of these approaches are in use in California. California operators captured gas from 6 percent of intermittent-bleed pneumatic controllers and 11 percent of piston valve actuators driven by natural gas, statewide; operators also reported 1,054 "no-bleed" controllers, which appear to self-contained/integral controllers (note that air-driven and electric controllers are separate categories in the survey).⁹⁴

Carbon Limits notes that these technologies may be applicable and cost effective for oil and gas installations, and that they represent useful alternatives to instrument air and electric controllers.⁹⁵

Summary. There are a number of non-emitting technologies and approaches that can be used in lieu of traditional gas-driven pneumatic controllers. All are in use in California. The most significant of these from both effectiveness and cost perspectives are instrument air and electric systems. Recent analysis by Carbon Limits shows that, even with very conservative assumptions, electric systems and instrument air systems are cost effective technologies to reduce methane emissions at a broad range of oil and gas facility site configurations.

⁹⁰ 40 C.F.R. § 60.5390.

⁹¹ 40 C.F.R. § 60.5390(c)(1).

⁹² Allen *et al.* (2015), *supra* note 13.

The Prasino Group, Determining bleed rates for pneumatic devices in British Columbia; Final Report, (Dec. 18, 2013), at 19, ("Prasino Study"), available at http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholdersupport/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf. (Ex. 38)

⁹³ Carbon Limits, *supra* note 74, at 27 – 28, 33.

⁹⁴ ARB 2007 Survey, *supra* note 81 at Table 9-2.

⁹⁵ Carbon Limits, *supra* note 74, at 19-20.

2. *ARB Should Phase Out Existing Low-Bleed Continuous Devices and Require Quarterly Testing of Bleed Rate*

The proposed regulation is significantly weaker than the draft regulation that CARB posted on April 22, 2015. The proposal allows the use of continuous-bleed pneumatic devices installed before January 1, 2016, provided operators adhere to the provisions in proposed § 95668(f)(2)(A), which requires that these devices emit less than 6 scfh and that operators annually check that these devices are not emitting more than that amount and fix or replace them if they do emit over this threshold. This “grandfather” clause that allows for the *indefinite* use of continuous bleed devices is not warranted, in light of the fact that operators have a number of alternatives to continuous-bleed pneumatic controllers, and the finding that electric controllers and instrument air are proven, mature, widely applicable and cost effective technologies.

We thus recommend that ARB remove the provision allowing “low-bleed” continuous-bleed pneumatic devices that were in operation on January 1, 2016 to continue operating. If ARB concludes that such devices must be allowed to continue venting gas into the atmosphere, despite the numerous options operators have to eliminate these emissions, ARB must limit the period over which operators are allowed to continue these harmful emissions to at most a few years. Indefinite grandfathering is not warranted.

Further, the February 1, 2016 draft rule required operators to test existing devices “during each inspection period as specified in section 95669 by using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument)”.⁹⁶ However, the current draft only requires annual testing.⁹⁷ As ARB provided no explanation for the change in testing requirements and testing devices during inspections is feasible and necessary to ensure bleed rate information is up to date, we recommend that ARB amend the current proposal to require testing during each quarterly LDAR inspection, as previously proposed.

3. *Control Emissions from Intermittent-bleed Pneumatic Devices*

ARB’s proposal for intermittent-bleed pneumatic controllers will reduce emissions from these ubiquitous devices, due to the specific annual testing requirements to ensure that these devices do not leak gas into the air when not actuating.⁹⁸ However, we reiterate our concern that, beyond this provision, the proposed regulation, like previous drafts, does not limit emissions from these devices.

These devices are a very significant source of emissions. Oil and gas producers reported over 850,000 metric tons of methane emissions nationwide in 2014 from intermittent-bleed

⁹⁶ CARB Proposed Regulation Order, February 1, 2016 Draft, § 95668(f)(2)(C). Available at http://www.arb.ca.gov/cc/oil-gas/meetings/Draft%20ARB%20OG%20Regulation_Feb%201%202016%20Clean.pdf. (Ex. 39)

⁹⁷ Appendix A: Proposed Regulation order § 95668(f)(2)(A)(3).

⁹⁸ Proposed § 95668(f)(3).

devices to US EPA’s GHGRP, far higher than the 161,000 metric tons of methane they reported from continuous-bleed devices (both high-bleed and low-bleed).⁹⁹

Intermittent-Bleed Controller Counts for California. There is very strong evidence that there are a significant number of intermittent-bleed pneumatic controllers in California. Operators in California oil and gas production basins reported over 4,100 tons of methane in 2014 from over 2,000 intermittent-bleed devices, while reporting no emissions at all from continuous-bleed devices (see Table 2).¹⁰⁰ Alarming, reported emissions from intermittent-bleed devices are increasing, both nationwide and in California (California counts leveled off between 2013 and 2014, see Table 3).¹⁰¹

Table 2. Device counts and methane emissions (in metric tons of methane) for high-bleed, intermittent-bleed, and low-bleed pneumatic controllers from oil and natural gas production basins in California as reported to US EPA’s GHGRP for 2014. All listed AAPG oil and gas production basins are entirely within California. 730: Sacramento Basin; 745: San Joaquin Basin; 750: Santa Maria Basin; 760: Los Angeles Basin.

| <i>Pneumatic Device Counts, 2014</i> | | | | | |
|--|-----------|-----|-----|--------------|----------------|
| Device Type | CA Basins | | | | Total (count) |
| | 730 | 745 | 750 | 760 | |
| High | 0 | 0 | 0 | 0 | 0 |
| Int | 1,531 | 466 | 11 | 0 | 2,008 |
| Low | 0 | 0 | 0 | 0 | 0 |
| | | | | Total | 2,008 |
| <i>Pneumatic Device Methane Emissions, 2014</i> | | | | | |
| Device Type | CA Basins | | | | Total (MT CH4) |
| | 730 | 745 | 750 | 760 | |
| High | 0 | 0 | 0 | 0 | 0 |
| Int | 3,289 | 817 | 21 | 0 | 4,127 |
| Low | 0 | 0 | 0 | 0 | 0 |
| | | | | Total | 4,127 |

⁹⁹ US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_PNEUMATIC_DEVICE_TYPE. Converted from metric tons carbon dioxide equivalent to metric tons of methane using a GWP of 25.

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

Table 3. EPA GHGRP Reported Onshore Production Pneumatic Device Counts by Type in California for 2011-2014. Counts are the sum of counts from the four basins shown in Table 2 above.

| Pneumatic Device Type | 201 1 | 201 2 | 201 3 | 201 4 |
|--------------------------------------|-------------------|-------------------|-------------------|-------------------|
| High-Bleed Pneumatic Devices | 23 | - | - | - |
| Intermittent Bleed Pneumatic Devices | 1,9 54 | 3,2 83 | 4,1 43 | 4,1 27 |
| Low-Bleed Pneumatic Devices | 16 | - | - | - |
| Grand Total | 1,9 92 | 3,2 83 | 4,1 43 | 4,1 27 |

Reporters to the GHGRP determine pneumatic device type “using engineering estimates based on best available information.”¹⁰² That is, operators make the determination as to pneumatic device type according to engineering assessments and available information regarding the device. Determining whether a pneumatic controller is designed to release gas intermittently or continuously is fairly straightforward. While emissions from these devices and the industry as a whole have received significant attention in recent years,¹⁰³ we are aware of no evidence or arguments that operators are over-reporting the number of intermittent-bleed controllers.

Further, according to the ARB Oil and Gas Industry Survey for 2007, there were at least 405 intermittent bleed pneumatic devices in California (accounting for about 25 percent of the total natural gas driven pneumatic controllers in the survey inventory). This information was reported a number of years ago, whereas the most recent GHGRP data is for 2014 and was reported in 2015. With the increased attention on emissions in recent years and the requirements of the GHGRP in place for several years, operators may now be more aware of the population of specific types of pneumatic controllers at their facilities than they were in 2007. In addition, operators may have installed more new intermittent-bleed controllers and/or replaced some of their continuous-bleed controllers with intermittent-bleed controllers in response to federal regulations that prohibit the installation of new high-bleed continuous controllers.¹⁰⁴

Finally, we note that the ARB MRR data for various types of pneumatic controllers may be flawed. Unfortunately we have not been able to extract data for emissions specifically from intermittent-bleed controllers, or counts of intermittent-bleed controllers, from the publically available data from this program. However, the ARB MRR apparently requires operators to sort intermittent-bleed controllers into low-bleed and high-bleed categories (based on the 6 scfh threshold) for reporting controller *counts* in Cal e-GGRT, while *emissions* from all intermittent-bleed controllers are calculated using a single emissions factor (13.5 scfh), regardless of the bleed rate:

¹⁰² 40 CFR § 98.233(a)(3).

¹⁰³ For example, Allen *et al.* (2015), *supra* note 13; also US EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas and Petroleum Production Emissions*, (2016). Available at: <https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf>. (Ex. 40)

¹⁰⁴ 40 C.F.R. 0000 (2012).

3.14 How should emissions from unmetered, natural gas-powered intermittent-bleed pneumatic devices be quantified and reported, if the operator has documentation demonstrating that the actual bleed rate for the devices is less than six scf per hour?

Pursuant to MRR, “intermittent bleed devices which bleed at a cumulative rate of six standard cubic feet per hour or greater are considered high bleed devices” (section 95102(a)(252)), therefore, *emissions from devices that exceed this limit must be reported as high-bleed* in Cal e-GGRT and are subject to a compliance obligation under the Cap-and-Trade Program. A low-bleed pneumatic device is defined in MRR as a device that “vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour” (section 95102(a)). *Low-bleed pneumatic devices must be reported as low-bleed* in Cal e-GGRT and emissions from such devices are not subject to a compliance obligation under the Cap-and-Trade Program.

Emissions from all unmetered, natural gas-powered intermittent-bleed pneumatic devices must be quantified using the “intermittent bleed” emission factor of 13.5 scf/hour/component listed in Table 1A of Appendix A of MRR, using Equation 2 (section 95153(b)), regardless of bleed rate. If the operator has documentation that demonstrates that the devices bleed at an actual rate of less than six scf/hour/component, such as original equipment manufacturer’s specifications, or measurement data, the operator must still quantify the emissions using the 13.5 scf/hour/component emission factor; however, the emissions may be reported as “low bleed” pneumatic emissions in Cal e-GGRT. If the device bleeds at a rate of six scf/hour/component or greater, or there is no documentation available that demonstrates that the actual bleed rate of a device is less than or equal to six scf/hour/component, the emissions for such devices must be reported as “high bleed” pneumatic device emissions in Cal e-GGRT.¹⁰⁵

This treatment of intermittent-bleed pneumatic controllers is confusing at best and suggests that ARB MRR data may not be usable to differentiate intermittent-bleed and continuous-bleed controller counts and emissions.

In summary, the available evidence shows that there are thousands of intermittent-bleed pneumatic controllers in California, with thousands of metrics tons of methane emissions. Since the proposed regulation does not allow new installation of continuous-bleed pneumatic controllers that vent to the atmosphere, but allows continued installation of intermittent-bleed pneumatic controllers, we can expect more intermittent controllers to be installed in the future, making this source of methane pollution grow.

Emissions from Properly-Operating Intermittent-Bleed Pneumatic Controllers can be Substantial. While ARB’s proposal addresses one important source of emissions from intermittent-bleed pneumatic controllers – the fact that they frequently operator improperly and emit continuously – the emissions from properly operating devices will remain high without additional standards.

¹⁰⁵ ARB (2016), *Petroleum and Natural Gas Systems Emissions Reporting Guidance for California’s Mandatory Greenhouse Gas Reporting Regulation*, at Section 3.14 (emphasis added). Available at: <http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/oil-gas.pdf>. (Ex. 41)

Not all intermittent-bleed devices actuate frequently under normal and expected operating conditions – but some actuate very frequently, and therefore emit large amounts of natural gas. For example, Allen *et al.* (2015) observed that controllers for emergency shut-off devices (ESDs) made up 12 percent of the population of controllers that they studied.¹⁰⁶ These devices will actuate very rarely, if at all. In contrast, some intermittent-bleed devices actuate very frequently. Of the 377 devices studied by Allen *et al.* (2015), 24 were intermittent-bleed devices that actuated at least 10 times during the sampling period, which was typically 15 minutes. Four actuated over 50 times while sampled.¹⁰⁷ These devices can emit at high levels – five of the 40 highest emitting devices studied by Allen *et al.* (2015) are intermittent-bleed devices that the researchers assessed to be operating properly.¹⁰⁸ These controllers emitted up to 40 scfh of whole gas.¹⁰⁹ Devices with certain specific functions, such as level controllers on separators, are likely to actuate frequently.

Since the proposed standard for intermittent-bleed pneumatic controllers does not limit emissions during actuation in any way, operators would not be required to reduce these high emissions in any way.

Suggested Approach. As noted above in Section X.1, reliable non-emitting alternatives to intermittent-bleed pneumatic controllers are available today. These technologies are mature and generally applicable and have been deployed at hundreds of sites, including in California. Critically, using these technologies as alternatives to intermittent-bleed pneumatic controllers is cost effective as a means of reducing methane emissions.

As such, ARB’s standards should prohibit or phase out venting emissions from intermittent-bleed pneumatic controllers to the atmosphere. If ARB concludes that it is warranted, specific treatment of certain intermittent-bleed devices that very rarely actuate, such as ESDs could be appropriate. However, the fact that some controllers very rarely actuate cannot be used to justify inaction for the entire class of intermittent-bleed controllers.¹¹⁰

If ARB concludes that a simple standard prohibiting venting from intermittent-bleed pneumatic controllers is not warranted, despite the numerous alternative approaches and technologies that can be used to entirely avoid these emissions, then a standard that limits emissions from these devices is needed. Even where venting natural gas-driven pneumatic devices are used, lower-bleed intermittent pneumatic devices are available. Properly designed

¹⁰⁶ Allen *et al.* (2015), *supra* note 13.

¹⁰⁷ Derived from analysis of table S4-1 in *id.*, supplemental information. Available at: <http://pubs.acs.org/doi/suppl/10.1021/es5040156>. (Ex. 5b)

¹⁰⁸ See *id.* Supporting Information, section S-8. Temporal profiles of emissions from the 40 highest-emitting controllers sampled in the study are shown. Controllers LB01-PC01, LB07-PC01, LB04-PC01, LB06-PC05, and LB04-PC03 – five of the 40 highest emitting controllers – are clearly intermittent devices which were assessed to be “operating as expected.”

¹⁰⁹ *Id.* Controller LB01-PC01 emitted 40.2 scfh whole gas; the range for the controllers listed in the previous footnote was 19.1 – 40.2 scfh.

¹¹⁰ Since some intermittent-bleed devices actuate very rarely, their emissions are low. These devices bring the average emissions factor for intermittent-bleed devices down.

intermittent bleed devices can emit below 6 scfh in many applications.¹¹¹ The US EPA emissions factor for intermittent bleed pneumatics in natural gas transmission is 2.35 scfh,¹¹² well below 6 scfh. Wyoming requires *all* pneumatic controllers to be low emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.¹¹³ ARB could require operators to measure emissions from intermittent-bleed devices just as operators of continuous-bleed devices would be required to measure emissions. To verify that emissions were not above the threshold in the standard, a simple sampling protocol could be written, requiring measurement over a certain period of time, capturing emissions from any actuations that occurred during that time. Straightforward specifications for the time response and dynamic range of instrumentation could ensure that the devices used for these measurements accurately quantify the high flow rate from the controller occurring during actuation. This measurement approach would be similar to that used during a number of recent measurement studies of pneumatic controllers and other equipment, which included measurements from pneumatic controllers.¹¹⁴

Standards as described above would substantially reduce methane emissions at a reasonable cost, and serve as an important model for reducing emissions from pneumatic controllers in other jurisdictions.

4. *Pneumatic Pumps*

We commend ARB's proposal to require capture of all emissions from natural gas-driven pneumatic pumps. Pneumatic pump emissions can readily be routed to vapor collection systems; US EPA now requires emissions from new pneumatic pumps to be routed to a control device if such a device is on the site where the pneumatic pump is installed.¹¹⁵ Electric pumps are also available to perform the duties of pneumatic pumps. For example, solar-powered chemical injection pumps are quite common,¹¹⁶ and in general pumps can be electrified when electric controllers are adopted at a site, including when solar panels are used to power the systems. In fact, these systems become significantly more cost effective when they include electrification of a pneumatic pump.¹¹⁷

We believe that ARB intends the standards to apply to glycol assist pneumatic pumps, referred to as "Kimray Pumps" in EPA's GHG Inventory. These pumps are estimated to emit

¹¹¹ In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. American Petroleum Institute, "Technical Review of Pneumatic Controllers," at 7 (Oct. 14, 2011), available as Attachment K to American Petroleum Institute, Comment on OOOO New Source Performance Standards (Nov. 30, 2011), <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266>. (Ex. 42)

¹¹² 40 C.F.R. Pt. 98, subpart W, Table W-3.

¹¹³ This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers (email from Mark Smith, WDEQ, to David McCabe, September 22, 2014. Available at: http://www.arb.ca.gov/cc/oil-gas/meetings/CATF_et_al_attachment2_02192016.pdf). (Ex. 43)

¹¹⁴ Allen (2013), Allen et al (2015), and Prasino Study, *supra* notes 12, 13 and 92.

¹¹⁵ 40 C.F.R. § 60.5365a(h) and § 60.5393a.

¹¹⁶ Carbon Limits, *supra* note 74, at 13.

¹¹⁷ *Id.* at 26.

76,418 metric tons of natural gas per year (nationwide), while chemical injection pumps are estimated to emit 321,777 tons.¹¹⁸ Control of emissions from glycol assist pumps is somewhat less straightforward than control of emissions from chemical injection pumps, because the natural gas used to drive the pump is typically emitted via the dehydrator vent stack. However, there are a number of options to eliminate emissions from these pumps. Electrification is an option for these pumps, just as it is for chemical injection pumps.¹¹⁹ A secondary option is the use of a low-pressure glycol separator, which can separate methane-rich gas from the glycol before it enters the regenerator.¹²⁰ If this is done, the gas can be used to fuel the boiler on the regenerator or otherwise consumed for fuel on-site.¹²¹ Finally, controls are often used to reduce emissions from dehydrator vent stacks. However, some of these controls, which are typically designed to reduce emissions of volatile organic compounds and hazardous air pollutants, will not reduce methane emissions from the dehydrator vent stack even when operating correctly.¹²² Methane from a glycol assist pump will not be abated by these types of dehydrator controls.

ARB must ensure that all methane emissions from glycol assist pumps are properly controlled and that operators are not relying on dehydrator vent stack controls that will not properly control methane, such as condensers or carbon absorption systems, to control methane emissions from these pumps. As described above, there are a number of means to eliminate methane emissions from these pumps. Of course, in the case of dehydrators with controls that do not reduce methane emissions, the most appropriate approach would be to improve the emissions control on the dehydrator to reduce methane emissions from the glycol assist pump and from the dehydrator itself.

V. Reciprocating Compressors

We support ARB's approach to control emissions from all compressors, both in the production and non-production segments, through either vapor collection systems or through requirements to measure emissions at the vent point and to repair when those emissions exceed thresholds. The scope of ARB's proposed requirements on compressors is commendable as it addresses the emissions of compressors on well pads – something that EPA's recently finalized subpart OOOOa regulations fail to do. Moreover, measurement from compressors located in the midstream segments – those at natural gas gathering and boosting stations, processing plants, transmission compressor stations and underground storage facilities – will provide more useful data on the emissions of those compressors.

Furthermore, it is encouraging that pursuant to section 95668(d)(3)(A) and 95668(d)(3)(B), CARB's proposal would require inspections for leaks originating from

¹¹⁸ GHG Inventory, 2016. Annex 3. Tables A-127, A-134, A-136. (Ex. 44)

¹¹⁹ 80 Fed. Reg. at 56,627.

¹²⁰ Kimray, Inc., "Glycol Pumps Product Bulletin," (July 2011), at 3. (Ex. 45)

¹²¹ *Id.*

¹²² For example, the National Emissions Standards for Hazardous Air Pollutants applicable to glycol dehydrators at certain facilities (NESHAP Subpart HH) allows the use of condensers or carbon absorption systems to control emissions. See 40 C.F.R. § 63.771(d)(1)(ii) and § 63.771(f)(1)(ii). These systems will not control methane emissions (the boiling point of methane is far too low for it to be captured by a condenser, and methane is not absorbed by activated charcoal to any significant degree).

compressor components and rod packing seals from production compressors at the same frequency as that required by the LDAR provisions in section 96669(g).¹²³ Likewise, ARB's proposal requires frequent inspection of non-production compressor *components*.¹²⁴ However, CARB should extend that same requirement for frequent checks to emissions from rod packing seals to non-production compressors.

While ARB's proposed rule has many helpful and protective requirements, it should be strengthened. Since even the best new, properly installed rod packing seals allow some escape of natural gas,¹²⁵ vapor collection systems should be required whenever possible. We agree that there should be an alternative option to monitor emissions by measuring and repairing rod packing when the measured flow rate exceeds an established threshold, but that alternative should be applicable only when utilization of vapor collection system is not feasible. We note that the Ohio EPA has released a draft general permit that requires operators to capture all emissions from reciprocating compressor rod packing and direct those emissions to sales, fuel lines, or 98 percent control.¹²⁶ Even if directing collected vapors to one of the uses described under proposed section 95668(c)(2) is not possible, ARB should require operators to capture and control emissions with a vapor control device as described in proposed section 95668(c)(3)-(4).

We commend ARB for requiring flow rate measurements at the rod packing or seal vent stack, as opposed to measuring hydrocarbon concentration, for compressors at gathering and boosting stations, processing plants, transmission compressor stations and underground natural gas storage facilities. This method of direct flow rate measurement (*i.e.*, high volume sampling, bagging or calibrated flow measuring instrument) provides a much more accurate representation of the actual emissions, whereas hydrocarbon concentration is more weakly correlated with emissions.¹²⁷ Routing emissions through a vent stack makes measurements more accurate and more feasible for operators. However, as was the case with the draft standards, ARB's proposed regulations still only require annual measurements for non-production compressors when a vapor collection system is not installed. ARB should finalize a quarterly measurement frequency under proposed section 95668(d)(4)(B). Infrequent annual measurements can lead to two problems. First, annual measurements would allow potentially elevated emissions to continue over a longer period than quarterly measurements would allow. Second, the lax annual frequency could encourage operators of non-production compressors without vapor collection systems to continue operating without such systems. Therefore, ARB should require quarterly measurements for non-production compressors. As we have argued previously, direct measurement of emissions rates with instruments such as flow meters and high-flow samplers is inexpensive and some vendors providing LDAR service routinely measure emissions rates in this manner; requiring measurement of the emission rate at every regular LDAR inspection would only entail very minimal additional cost.

¹²³ As discussed in more detail above, improvements to the section 95669 are needed.

¹²⁴ Proposed section 95668(d)(4)(A).

¹²⁵ ARB Staff Report, *supra* note 2 at 97, Table 9.

¹²⁶ Ohio EPA, General Permit 17.1 Template, C(1)(b)(1)(d), available at <http://epa.ohio.gov/dapc/genpermit/permitsec.aspx>. (Ex. 46)

¹²⁷ Clearstone Engineering *et al.* (2006), *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*, 3 (available at http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf). (Ex. 47)

Additionally, the flow rate threshold at which ARB would require repair or replacement of rod packing or seals is far too high. As proposed, section 95668(d)(4)(D) requires repair of rod packing or seals when the measured flow rate is greater than 2 scfm per cylinder. ARB's analysis shows that using this threshold will result in costs of \$1.17/MT CO₂e, or \$84/MT methane.¹²⁸ Based on the Oil and Gas Industry Survey, ARB's analysis assumes that a compressor over 250 HP has on average 3.45 cylinders, and that the average leak rate for a cylinder during pressurized operation is 0.9 scfm.¹²⁹ Data from the survey shows that the average compressor cylinder that is emitting over the threshold of 2 scfm is emitting 3 scfm.¹³⁰ In calculating the reductions, ARB simply estimated a reduction of 1 scfm per cylinder in order to comply with the proposed standard.¹³¹ This vastly underestimates the emissions reductions that would be achieved under the proposed requirement to repair rod packing or seals if the flow rate exceeds 2 scfm.

As shown in ARB's Staff Analysis, a rod packing flow rate of 2 scfm is labeled as "poor" condition.¹³² Presumably, ARB's proposed regulation would require an operator to repair the rod packing to better than poor condition. Indeed, EPA estimates that new rod packing should emit 11-12 scfh, or roughly equivalent to 0.19 scfm. We recalculated abatement costs using the same methodology and cost inputs as ARB used in the Economic Analysis. However, for the emissions reduction achieved by the rule, we used 2.81 scfm (3 scfm to 0.19 scfm) instead of 1 scfm (3 scfm to 2 scfm) as ARB used. The resulting costs were -\$1.27 per ton CO₂e, *i.e.* the policy has net savings for operators.

Using a slightly different approach to calculating abatement cost from EPA's Natural Gas Star, but with ARB's cost assumptions¹³³ we calculated a number of different net abatement costs using the reductions that would be achieved using EPA's 0.19 scfm emission rate for a new rod packing.¹³⁴ The abatement costs calculated this way are somewhat different, but they appear to be more conservative than ARB's calculations and they show net savings at ARB's current repair threshold of 2 scfm, consistent with the calculation shown above. As Table 4 shows, ARB's cost analysis substantially overestimates the actual cost to operators and the costs of significantly tighter standards than ARB's proposed standard would be reasonable. At a flow rate threshold of 2 scfm the net cost per ton of methane removed is actually negative, meaning operators would make more money from the sale of the conserved gas than they incurred in costs. The total cost would be zero if ARB lowered the flow rate threshold to 1.82 scfm, and the net abatement cost approaches ARB's estimated average cost for the entire regulation at 0.48 scfm.

¹²⁸ ARB, *Appendix B: Economic Analysis*, at B-34. (Ex. 2b)

¹²⁹ *Id.* at B-29.

¹³⁰ *Id.* at B-29.

¹³¹ *Id.* at B-29.

¹³² ARB Staff Report, *supra* note 2 at 97, table 9.

¹³³ A cost of \$6,000 per rod packing, a 5 percent interest rate, an average of 6,546 pressurized operating hours and a price of \$3.44/mcf for gas.

¹³⁴ US EPA "Reducing Methane Emissions from Compressor Rod Packing Systems" (2006), available at: https://www3.epa.gov/gasstar/documents/ll_rodpack.pdf. (Ex. 48)

Table 4

| Replacement Threshold | | Net Abatement Cost | | |
|-----------------------|------|-----------------------|--------------------------------------|--------|
| scfm | scfh | \$/metric ton methane | \$/metric ton CO ₂ e (72) | \$/mcf |
| 2 | 120 | -\$22 | -\$0.31 | -\$0.3 |
| 1.82 | 109 | \$0 | \$0.00 | \$0 |
| 0.86 | 51 | \$331 | \$4.59 | \$5 |
| 0.61 | 37 | \$662 | \$9.19 | \$10 |
| 0.50 | 30 | \$992 | \$13.78 | \$15 |
| 0.48 | 29 | \$1,059 | \$14.70 | \$16 |
| 0.47 | 28 | \$1,125 | \$15.62 | \$17 |
| 0.43 | 26 | \$1,323 | \$18.38 | \$20 |
| 0.42 | 25 | \$1,389 | \$19.30 | \$21 |

Accordingly, CARB must reduce the threshold at which replacement or repair of rod packing is required. A standard set in the 0.4 – 0.5 scfm range would be cost-effective and more appropriately balance the need to reduce methane emissions, and the social costs of those emissions, while keeping costs for industry reasonable.

Finally, ARB should consider finalizing a requirement for operators of production compressors to perform direct measurement of the flow rate in a manner consistent with non-production compressors, as opposed to requiring repair based on concentration thresholds. As described above, the additional cost of direct emissions measurement during regular LDAR inspections would be quite small.

VI. Separator and Tank Systems

1. ARB Should Remove the “Low Production” Exemption

We urge ARB to remove the exemption for separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day. ARB added this exemption based on its own analysis of flash test data that indicated that emissions from such separation and tank systems will not reach the control threshold of 10 metric tons of methane per year.¹³⁵ This exemption is overly broad and may result in tanks that in fact exceed the control threshold going uncontrolled. ARB already proposes to require owners and operators of separator and tank systems covered by Section 95668(a) to either control emissions or conduct periodic flash analysis testing to determine whether or not controls are warranted. Owners and operators of separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day should still be required to conduct periodic flash analysis to ensure that any increase in production does not

¹³⁵ ARB Statement of Reasons, at 90.

result in methane emissions that trigger the control requirements. If ARB's analysis is correct, and emissions from such systems remain under 10 metric tons of methane annually, owners and operators will only be subject to the periodic modest flash analysis testing requirements which should not impose a significant burden on operators. For these reasons, we urge ARB to remove this exemption.

2. *Testing Should Occur Earlier and Controls Should be Installed Sooner*

ARB should tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems. In previously submitted comments, we expressed concern that the prior version of the draft regulation allowed vessels to operate without any emission controls for an unjustifiably long period of time. Section 95668(a)(3) of the current draft provides that “[b]y January 1, 2018, owners or operators of existing separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system” (with no requirement to actually control emissions unless this analysis demonstrates emissions in excess of ten metric tons of methane per year). While the prior draft of the rule required that annual flash analysis testing be conducted beginning January 1, 2017 and by no later than September 1, 2017, the latest draft clarifies the deadline for existing systems but unfortunately pushes it back to 2018. For existing systems, ARB should require that owners and operators conduct testing by a date certain that is earlier than September 1, 2017.

Furthermore, for existing separator and tank systems, the draft rule requires that by January 1, 2019, owners or operators of a system “with an annual emission rate greater than 10 metric tons per years of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream” with the use of a vapor collection system. §95668(a)(6). As with the deadline for flash analysis testing, ARB should require that owners and operators control emissions at an earlier date. As drafted, the rule would allow existing separator and tank systems that are currently emitting methane at a rate greater than 10 metric tons per year to wait almost two and a half years from now before controlling those emissions. This delay is unwarranted and the timeline for flash analysis testing and installation of a vapor collection system should be accelerated.

In previously submitted comments, we expressed concern that the prior version of the draft regulation may allow new vessels to operate without any emission controls for the first year of operation. The latest draft rule also clarifies the timing for new systems: “Beginning January 1, 2018, owners or operators of new separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system *within 90 days* of initial system startup.” § 95668(a)(4) (emphasis added). The rule also clarifies that beginning January 1, 2018, owners or operators of new systems with an annual emission rate greater than 10 metric tons per year of methane must control the emissions with the use of a vapor collection system *within 180 days* of conducting flash analysis testing. 95668(a)(7) (emphasis added). Thus, under the proposed rule, a new system that exceeds the 10 metric tons per year threshold may not have to control those emissions for 270 days (approximately 9 months) after initial system startup.

Emissions are likely to be highest during the first year. Oil and gas well production generally declines during the first year of operation. Throughput of materials (oil, produced water, and other substances) in vessels tracks production, meaning that potential vessel emissions follow this curve as well. Thus, the draft regulation could allow emissions without control during a large portion of the time when those emissions will be highest.

As noted in our prior comments, other jurisdictions have successfully implemented regulations that require control of tanks much sooner after production begins at a well. Colorado requires operators to assess whether emissions will be significant from tanks – and if so, to control vessels from the date of initial production at the well. As noted in our prior comments, in crafting emission control requirements for vessels, the Colorado Air Pollution Control Division expressed concern that even allowing operators to wait *ninety days* after commencement of production to install controls on vessels would allow significant and avoidable air pollution.¹³⁶ Colorado determined that it would be cost effective to require controls to be installed on all crude oil and produced water tanks immediately, allowing operators to remove controls from a tank once testing demonstrated that the tank’s uncontrolled emissions would fall below the applicable threshold. A presumption of control has the added benefit of providing operators with an incentive to test emissions promptly. ARB should follow Colorado’s lead and assume that vessels require emission controls unless and until operators demonstrate otherwise.¹³⁷

Alternately, US EPA requires that emissions from new and modified storage vessels that have potential to emit six tons of VOC or more per year must control emissions from those vessels by 60 days after the vessel goes in service.¹³⁸ We suggest that testing should, at the very least, be carried out within 30 days of initial production, and that ARB require that controls be in place within 60 days after initial production for tanks that have potential emissions above the threshold, in line with the federal standards (note that the federal standards have a different, VOC-based threshold than the draft ARB standard). However, we reiterate that ARB should first consider requiring control from the day of initial production when emissions from the tank can be anticipated to exceed 10 metric tons per year, in accordance with the Colorado approach.

ARB must also ensure that for new wells, the Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water properly assesses annual emissions. It is critical that operators assess potential emissions rapidly after operation of a tank begins, so that the tank can be controlled if needed. But ARB must also ensure that operators do not use a simple extrapolation of low production in the first days after production begins to conclude that potential emissions from the vessel will be less than the 10 metric tons per year threshold. Such extrapolation would be inappropriate because for new wells, particularly wells that were hydraulically fractured, production can rise dramatically over the initial weeks after production begins. ARB thus must ensure that operators use liquid

¹³⁶ CO Economic Impact Analysis, *supra* note 38.

¹³⁷ See CATF *et al.* February 2016 comments, *supra* note 1, for a comparison of the requirements and timelines in the CARB draft rule to those in the Colorado methane rule.

¹³⁸ See 40 C.F.R. §60.5395(d)(1)(i). “For each Group 2 storage vessel affected facility [that is, vessels constructed after 12 April 2013], you must achieve the required emissions reductions by April 15, 2014, **or within 60 days after startup**, whichever is later” (emphasis added).

throughput values in Equation 1 of Section 11 of the Test Procedure that are appropriate for yearly averages for new wells.

3. Provisions Requiring Clarification or Strengthening

ARB should also clarify or strengthen the following provisions:

- 95668(a)(5)(F): “The ARB Executive Officer may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.” Please clarify how the ARB Executive Officer would determine whether the test results “reflect representative results of similar systems.”
- 95668(a)(8): “If the results of three consecutive years of [flash analysis] test results show that the system has an annual emission rate of less than or equal to 10 metric tons per year of methane the owner or operator may reduce the frequency of testing and reporting to once every five years.” Testing once every five years is too infrequent to effectively determine if emissions have increased above 10 metric tons per year.
- 95668(a)(8)(A): “After the third consecutive year of testing, if the annual crude oil, condensate, or produced water throughput increases by more than 20 percent after one year from the date of previous flash analysis testing, then the annual methane emissions shall be recalculated using the laboratory reports from previous flash analysis testing.” The prior draft rule required recalculation of flash emissions with a *10 percent* increase in throughput, rather than 20 percent. The basis for this change is unclear since an increase in throughput of less than 20 percent could cause a meaningful increase in methane emissions. ARB should justify the 20 percent throughput threshold and if it cannot do so, require re-testing for any increase in throughput over that level tested in any of the prior testing years (or at the very least retain the 10 percent threshold). Furthermore, this provision should specify how soon after the increase of throughput must the flash emissions be recalculated. (The current draft appears to no longer include a provision specifically requiring flash analysis testing, record keeping and reporting to be conducted after adding a new well to the separator and tank system.)

VII. Liquids Unloading

We support ARB’s approach with regards to Liquids Unloading emissions, either through capturing emissions using a vapor collection system, or measuring/calculating the volume of natural gas vented, and regularly reporting that volume. Joint commenters request the following in order to strengthen the liquids unloading proposal.

First, we request that ARB revise its proposed definition of “Liquids Unloading” by striking the phrase “with the use of pressurized natural gas.”¹³⁹ Not all liquids unloading technologies use pressurized natural gas to remove liquids, so the proposed definition potentially creates a loophole in the control and reporting requirements.

¹³⁹ The current definition reads: “‘Liquids unloading’ means an activity conducted with the use of pressurized natural gas to remove liquids that accumulate at the bottom of a natural gas well and obstruct gas flow.” § 95667(a)(28).

We also urge ARB to make one improvement to the substantive control requirement and a few improvements to the reporting requirements in order to improve the protectiveness of the provision.

We urge ARB to follow the lead of Wyoming¹⁴⁰ and Colorado¹⁴¹ and to require operators to keep personnel on site when conducting manual liquids unloading activities. This ensures that any venting that occurs is kept to a minimum. We anticipate that a prudent operator would follow this practice as a matter of course, as having personnel onsite to supervise manual liquids unloading not only ensures that emissions are minimized but also results in a more effective and safe operation. ARB should include this requirement to ensure that such a prudent practice is followed across the board.

In addition, we recommend several additions to the reporting requirements to allow ARB to closely monitor liquids unloading emissions and develop targeted standards in the future, should the need arise. Given the number of mitigation techniques available to operators, we expect that liquids can be unloaded without venting in the vast majority of cases. In this light, it is important that ARB use the reporting requirements to understand *why* operators vent wells during liquids unloading. ARB thus should require operators to report a number of well variables and conditions in the cases where venting does occur.

The current standard requires operators to annually report the following information in the cases where liquids unloading emissions are not captured:

- Volume of natural gas vented to perform liquids unloading, and
- Equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (*e.g.*, foaming agent, velocity tubing, plunger lift, etc.)¹⁴²

ARB should require operators to report a broader set of parameters and conditions while being more specific about the information required in the proposal. For each liquids unloading event at each well, ARB should require operators to report:

- Volume of gas vented and duration of venting event.
- Volume of liquids removed from well during venting event.
- Well Characteristics:
 - API Number
 - Spud date and completion date
 - A complete casing diagram, with all required depths reported as both measured depth and true vertical depth, including:
 - Ground elevation from sea level
 - Reference elevation (*i.e.* rig floor or Kelly bushing)
 - Well orientation: horizontal, vertical, or directional
 - Well depth

¹⁴⁰ WY Permitting Guidance, *supra* note 30.

¹⁴¹ 5 C.C.R. 1001-9, § VII.H.1.b.

¹⁴² Proposed § 95668 (g)(2).

- Sizes and weights of all casing, liners and tubing
 - Depths of shoes, stubs and liner tops
 - Depths of perforation intervals
 - Diameter and depth of hole
- Liquids accumulation rate (barrels of water accumulated per day)
- Gas production rate (before and after unloading event)
- Sales line pressure
- Shut-in pressure
- Gas temperature at wellhead
- If liquids removal technology used, details of method:
 - Plunger lift: with or without smart automation
 - Foaming agent: type
 - Velocity tubing: diameter
 - Pumps
 - Gas lift
- If no liquids removal technology used:
 - The normal operating practice for venting the well: automatic vent timer or manual vent with or without monitoring
 - Vent time

We greatly appreciate the opportunity to comment on this important proposal and thank ARB for its leadership on this key climate and public health issue.

Respectfully submitted,

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Reducing Methane Emissions From Compressor Rod Packing Systems



Executive Summary

More than 51,000 reciprocating compressors are operating in the U.S. natural gas industry, each with an average of four cylinders, representing over 200,000 piston rod packing systems in service. These systems contribute over 72.4 Bcf per year of methane emissions to the atmosphere, one of the largest sources of emissions at natural gas compressor stations.

All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and amount of wear on the rings and rod shaft. A new packing system, properly aligned and fitted, may lose approximately 11 to 12 standard cubic feet per hour (scfh). As the system ages, however, leak rates will increase from wear on the packing rings and piston rod. One Natural Gas STAR Partner reported measuring emissions of 900 scfh on one compressor rod.

By using company-specific financial objectives and monitoring data, Partners can determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this “economic replacement threshold” include methane emission reductions and cost savings. Using this approach, one Natural Gas STAR Partner achieves savings of over \$233,000 annually at 2006 gas prices. An economic replacement threshold approach also results in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.

Technology Background

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. Areas of high leak frequency include flanges, valves, and fittings located on compressors. The highest volume of gas loss, however, is associated with piston rod packing systems.

Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Exhibit 1 shows a typical compressor rod packing system.

Compressor rod packing consists of a series of flexible rings that fit around the shaft to create a seal against leakage. The packing rings are lubricated with circulating oil to reduce wear, help seal the unit, and draw off heat. Other cooling methods include air cooling, water jacketing, and circulating coolants inside the packing box. Packing rings are held in place by a set of packing cups, normally one for each pair of rings, and kept tight against the shaft by a surrounding spring. The number of cups and rings will vary depending on the compression chamber pressures. A “nose gasket” on the end of the packing case prevents leaks around the packing cups.

Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh. Higher leak rates are a consequence of fit, alignment of the packing parts, and wear. Leakage typically occurs from four areas:

Economic and Environmental Benefits

| Method for Reducing Natural Gas Losses | Volume of Natural Gas Savings (Mcf/year) | Value of Natural Gas Savings (\$/year) | | | Implementation Cost (\$) | Payback (Months) | | |
|--|--|--|-------------|-------------|--------------------------|------------------|-------------|-------------|
| | | \$3 per Mcf | \$5 per Mcf | \$7 per Mcf | | \$3 per Mcf | \$5 per Mcf | \$7 per Mcf |
| Economic replacement of rings and rods in compressor rod packing | 865 ^a | \$2,595 | \$4,325 | \$6,055 | \$540 ^b | 3 | 2 | 1 |

General Assumptions:

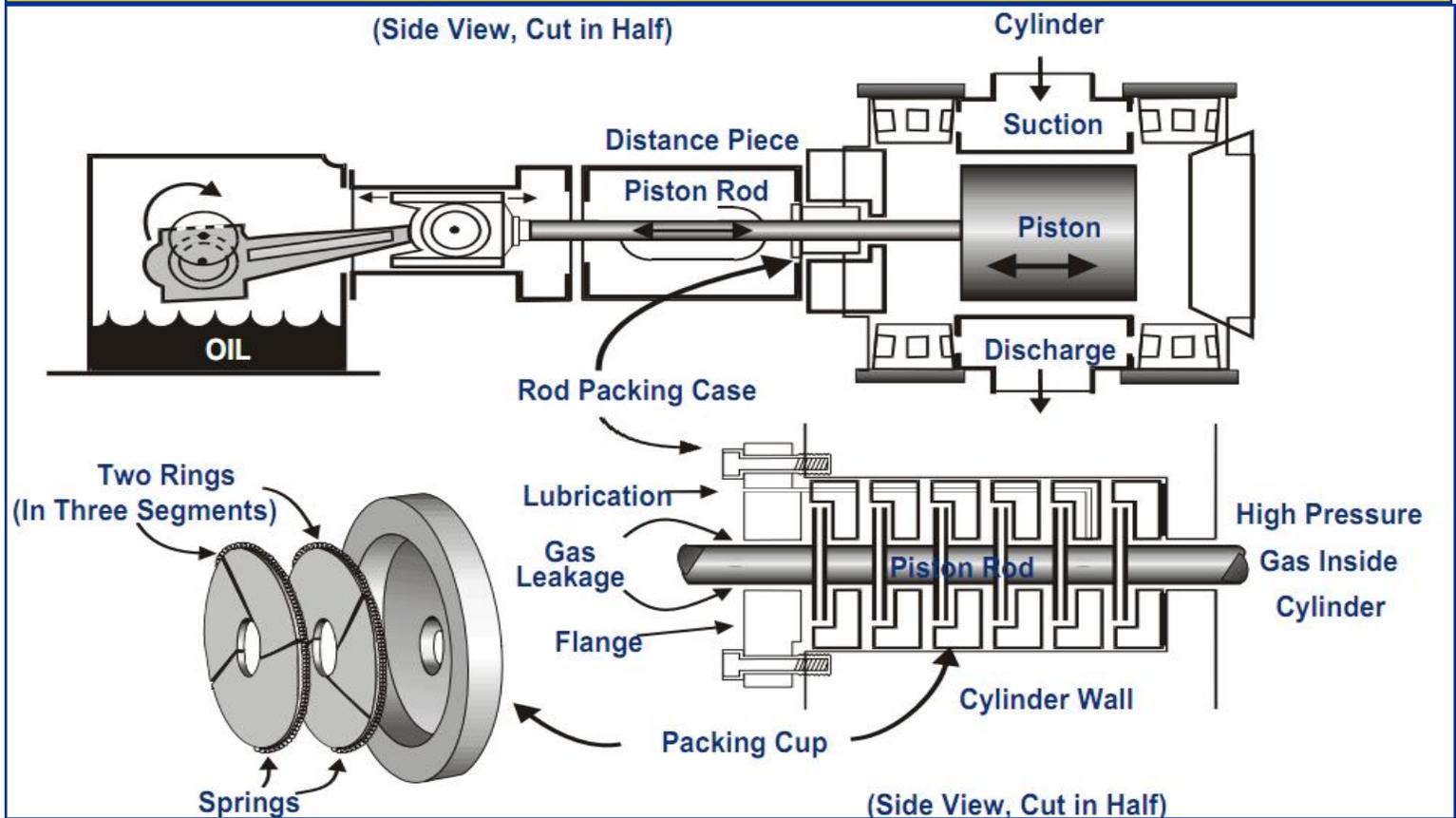
^a Pipeline Research Committee International (1999).

^b \$1,620 cost of ring replacement every three years rather than four years (industry average).

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

Exhibit 1: Typical Compressor Rod Packing System



- ★ Around the packing case through the nose gasket.
- ★ Between the packing cups, which are typically mounted metal-to-metal against each other.
- ★ Around the rings from slight movement in the cup groove as the rod moves back and forth.
- ★ Between the rings and shaft.

Leaking gases are vented to the atmosphere through packing vents on the flange. Leakage can be reduced through proper monitoring and a cost-effective schedule for replacing packing rings and piston rods. New ring materials and new designs for packing cases are emerging that should reduce emissions in the future.

Economic and Environmental Benefits

Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions to

the atmosphere and save money. For instance, conventional bronze-metallic packing rings wear out and need to be replaced every three to five years. However, as packing deteriorates, leak rates can increase to the level at which replacing packing rings more frequently can be economically justified. In addition, more frequent ring replacement might actually extend the life of the compressor rod. Partners who institute a program of monitoring and cost-effective replacement are able to achieve several benefits:

- ★ Reduced methane emissions.
- ★ Gas savings from lower leakage rates.
- ★ Extended service life of compressor rods.

Decision Process

Companies can determine a cost-effective replacement schedule by following five simple steps.

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

Step 1: Monitor and record baseline packing leakage and piston rod wear.

Establishing baseline leakage rates and monitoring piston rod wear allows Natural Gas STAR Partners to track increases in leakage and evaluate the economics of replacing packing rings and piston rods.

The vent port on the packing case flange provides a means for gas leakage to escape to the atmosphere. However, gas can also flow along the rod and/or from the gasket at the end of the packing case, thus bypassing the packing cup vent and entering the distance piece. Consequently, where possible, measurements should encompass emissions from both the packing cup vent and distance piece. Some systems vent the packing cup into the distance piece, while others have separate vents.

Gas leakage can be measured with either a hand held or an installed measuring device. Before measurements are initiated, a check of the packing vent system should be undertaken. Failure to account for emissions escaping into the distance piece may result in an underestimation of packing-related emissions by up to 40 percent, which could impact the economics of the decision process.

It is important to take measurements immediately after installing new seals (or new rods and seals). This measurement becomes the baseline for the new packing and can serve as a suitable default baseline for other cylinders and compressors of similar type, size, pressure, and age of rods. After installation of rings, Partners should routinely monitor and record leakage rates and related operating conditions (pressure, lubrication, temperatures) over the entire life of the packing rings, usually on a monthly or quarterly basis.

Rods can be monitored periodically during ring replacements by documenting shaft dimensions and surface roughness where the rod contacts the packing rings. Piston rods wear more slowly than packing rings, having a life of about 10 years. Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of

packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. The leakage attributable to rod wear is determined by the change in the baseline leakage rate after each successive ring replacement (assuming same operating conditions and ring type). This increase in baseline leakage can be used to establish an economic threshold for replacing the piston rod (see Step 4).

Step 2: Compare current leak rate to initial leak rate to determine leak reduction expected.

Using the monitoring data obtained in Step 1, the baseline emission measurement should be compared to the current leak rate to determine whether the current leak signals a need for packing or rod replacement. Exhibit 2 demonstrates how a comparison can be made.

Exhibit 2: Comparing Current versus Initial Leak Rates

Given:

IL = Initial leak rate at the last packing ring rod replacement
CL = Current leak rate
LRE = Leak reduction expected

Calculate:

$$\text{LRE} = \text{CL} - \text{IL}$$

For example, if the leak rate of a packing ring is currently measured at 100 standard cubic feet per hour (scfh), and the same component was measured at 11.5 scfh after the last replacement, then the leak reduction that can be expected is:

$$\begin{aligned}\text{LRE} &= 100 \text{ scfh} - 11.5 \text{ scfh} \\ \text{LRE} &= 88.5 \text{ scfh}\end{aligned}$$

For accurate analysis, Partners should calculate the “leak reduction expected” (LRE), which is the savings that will occur from installing new equipment separately for packing seals and piston rods. When determining the LRE for the installation of new rings only, assume all of the leakage increase since the last ring replacement is attributable to ring wear. When determining the LRE for replacing the piston rod and rings (note that new rings are always installed with a new rod), use the initial leakage measured immediately after the last rod replacement on this compressor. Where historical data may not be

Five Steps to Economic Packing and Piston Rod Replacement:

- Step 1: Monitor and record baseline packing leakage and piston rod wear.
- Step 2: Compare current leak rate to initial leak rate to determine leak reduction expected.
- Step 3: Assess costs of replacements.
- Step 4: Determine economic replacement threshold.
- Step 5: Replace packing and rods when cost-effective.

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

| | |
|-------------------------------|------|
| Production | 79 % |
| Processing | 87 % |
| Transmission and Distribution | 94 % |

available on individual compressors, data from other similar compressors with similar operating conditions can be used to establish baseline (initial leak) values.

Step 3: Assess costs of replacements.

Costs of replacing packing rings and piston rods vary between compressors. For packing ring replacements, variables include the number of compressor cylinders and the type of replacement ring. A Natural Gas STAR Partner reported that costs for a typical Teflon or moly-based, 8 to 10 cup ring set for a three-inch rod will range from \$135 to \$170 per cup, or about \$1,350 to \$1,700 total. Another source stated that a set of rings may vary between \$675 and \$1,080, or \$2,025 to \$3,375 if the cups and cases are included. Factors affecting equipment costs for rod replacements include rod dimension and type of rod. Estimates of the costs of rods can range from \$2,430 to \$4,725. Special coatings, such as ceramic, tungsten carbide, or chromium, can increase costs by \$1,350 or more—the cost of some rods may be as high as \$12,150 to \$13,500.

Installation costs vary as well, depending on site location and difficulties encountered during replacement. Both Partners and manufacturers estimate that installation costs are roughly equal to equipment costs. One Partner spent an average of \$1,420 per packing ring set for purchase and installation. Partners have found that monitoring and leak measurement costs are insignificant on a per-packing basis relative to the labor costs to install rings or rods.

Step 4: Determine economic replacement threshold.

With the information obtained from Steps 1 through 3, Partners can develop an “economic replacement threshold” that defines the specific point at which it is cost-effective to replace rings and rods. Partners have identified several methods for calculating this threshold, relying on company investment evaluation criteria and site-specific characteristics.

A simple approach is to use discounted cash flow principles to calculate an economic replacement threshold. Partners can calculate their economic replacement threshold for both packing seals and rods by using the following equation:

$$\text{Economic Replacement Threshold (scfh)} = \frac{CR * DF * 1,000}{H * GP}$$

Where:

CR = Cost of replacement (\$)

DF = Discount factor (%)

H = Hours of compressor operation per year

GP = Gas price (\$/Mcf)

The discount factor is the term used for capital recovery for equal annual revenues and is calculated from the following formula:

$$DF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where *i* equals the discount rate or company hurdle rate expressed as a decimal and *n* equals the payback period selected. Using this formula, a 10 percent discount rate (*i* = 0.10) and a one-year payback (*n* = 1) yield a discount factor of 1.10; for a two-year payback (*n* = 2), the discount factor is 0.576, etc.

Exhibit 3 presents an example for discounted payback. This table was constructed to show the LRE necessary to pay back the investment in a new ring packing set in one year, two years, and so on. Exhibit 3 shows that the \$1,620 cost for packing ring replacement can be paid back in one year with a leak reduction of 55 scfh, in two years with a leak reduction of 29 scfh; etc. (with future leak savings discounted at 10 percent). Thus, if a Partner's

Exhibit 3: Economic Replacement Threshold for Packing Rings

| Leak Reduction Expected (scfh) | Payback Period ^a (months) |
|--------------------------------|--------------------------------------|
| 55 | 7 |
| 29 | 12 |
| 20 | 18 |
| 16 | 22 |
| 13 | 27 |

^a Assumes packing ring replacement costs of \$1,620, \$7.00/Mcf gas, and 8,000 operating hours/year.

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The “Refinery Operation Index” is used to revise operating costs while the “Machinery: Oilfield Itemized Refining Cost Index” is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

internal investment criterion is a two-year payback, the Partner should establish an economic replacement threshold for ring replacement at 29 scfh. In other words, when the LRE of a ring replacement reaches 29 scfh, the Partner should replace ring packing.

Similar to rings, economic replacement threshold can be determined for rod replacement by establishing the leak reduction needed in order to justify the investment in a new rod assembly. Follow the same steps above, but substitute rod capital costs for cost of replacement (CR) to determine the economic replacement threshold.

After determining the economic replacement threshold, Partners should determine the amount of methane emissions attributable to the replacement. Current leakage (CL) measurements do not distinguish between contribution from worn rings and rod wear. However, over time, the initial leakage (IL) measurements will show a gradual increase in the baseline leak rate, indicating rod wear. Partners should measure and track the change in IL to determine the amount of emissions attributable to the aging rod. Partners need to establish a baseline by which to compare piston rod-related leakage. This can be accomplished by taking measurements when the rod is first installed or by comparing measurements from similar facilities that have new rods and packing. Once this baseline is established, Partners can conduct a discounted cash flow to determine the amount of rod-related leakage that signals the need for replacement.

Exhibit 4 uses the same approach as Exhibit 3 to provide the LRE economic replacement thresholds for replacing

Exhibit 4: Economic Replacement Threshold for Rods & Rings

| Leak Reduction Expected (scfh) | Payback Period ^a (months) |
|--------------------------------|--------------------------------------|
| 376 | 7 |
| 197 | 13 |
| 137 | 18 |
| 108 | 22 |
| 90 | 27 |

^a Assumes packing ring replacement costs of \$1,620, rod replacement costs of \$9,451, \$7.00/Mcf gas, and 8,000 operating hours/year.

rings and rods. This example is based on a cost of \$11,701 to replace both the rod and packing rings. The table shows that companies desiring a payback of one year require a LRE of 376 scfh, while a company satisfied with a three-year payback should replace rods and seals when the LRE is 137 scfh (with future savings discounted at 10 percent).

One note of caution: a poorly aligned rod or poorly fitted rings can result in a high current leakage measurement, and hence a high LRE, that might not indicate the need to replace the rod, but rather a need to refit rings or realign the rod. Monitoring rod dimensions (i.e., tapering, out-of-round, scratches, and surface roughness) is necessary in determining that the increase in IL over the baseline is in fact attributable to general rod wear.

Step 5: Replace packing and rods when cost-effective.

Monitoring emissions and replacing worn rods and packing rings at the economic replacement threshold will result in an immediate reduction in emissions and compressor fuel costs. Partners should compare compressor station data to the replacement thresholds. Partners should replace

One Partner's Experience

Consumers Energy replaced worn compressor rod packing rings on 15 compressor units with total estimated savings from reduced gas leakage of \$49,000 (based on leakage reductions of 7,000 Mcf per year, and assuming a gas price of \$7 per Mcf). The costs of replacing all the packing rings, including materials and labor, was \$23,000, resulting in a payback period of six months at 2006 costs.

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

packing rings and rods when actual LREs are equal to or exceed the economic replacement thresholds. Partners are also encouraged to select economic replacement thresholds that maximize the methane reduction.

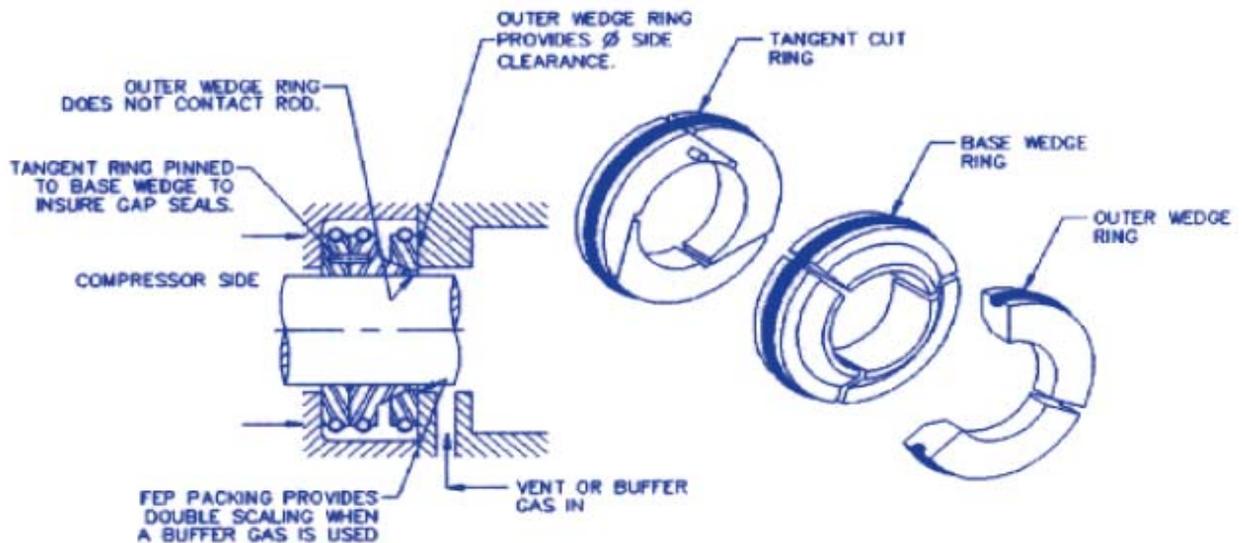
Additional Options

Partners in the Natural Gas STAR Program have not reached a consensus on standard emission reductions that can be achieved by changing compressor rod packing. Many variables are cited as affecting potential savings, including cylinder pressure, fit and alignment of packing parts, and amount of wear on the rings and rod shaft, as well as company-internal decision criteria. However, Partners agree that identifying a replacement threshold for replacing packing rings and piston rods is a practical method to reduce methane emissions from reciprocating compressors.

New materials can improve the life and performance of certain equipment and provide Partners with additional savings through reducing leakage and repair and replacement costs.

- ★ **Options for rings.** Carbon-impregnated Teflon is gradually replacing bronze metallic rings. One vendor claims that the price is about the same, with Teflon expected to last about one year longer than the conventional bronze rings. However, other factors—including proper installation, cooling, and lubrication—might play a greater role in the service life of a ring.
- ★ **Upgraded piston rods.** New or existing compressor rods coated with tungsten carbide have proven to increase service life for rods by reducing wear, as well as making them effective for “static-seal” installations (see Lessons Learned study, “*Reducing Emissions When Taking Compressors Off-Line*”). Coating each piston rod with tungsten carbide would cost an additional \$1,350 to \$2,700. Chrome coating is also used to reduce wear.
- ★ **Three-ring rod packing.** A three-ring rod packing system shown in Exhibit 5 is becoming more widespread. The rings are typically installed in one of the last two cups. The primary benefit of this

Exhibit 5: Three-Ring Fugitive Emission Rod Packing Assembly



FEP STYLE PACKING

Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)

arrangement is that this design can usually be installed without any replacement or modification of the packing case cup.

Lessons Learned

Partners have found that providing compressor station personnel with simple guidelines for economic replacement of reciprocating compressor piston rods and rod packing will greatly reduce methane emissions. This natural gas savings pays back the costs for more frequent replacements. The principal lessons learned are:

- ★ Develop a system for regularly measuring and monitoring leakage from piston rod packing cases. Regularly monitor lubrication and cooling to help reduce wear on packing rings. Poor heat conductivity at very high operating temperatures can be a significant factor in ring deterioration.
- ★ Establish baseline initial leakage (IL) rates for new rods and new packing rings, categorized by operating conditions and compressor types and sizes.
- ★ Share baseline initial leakage rate data with other stations to provide substitute data where specific data may not be available for all stations.
- ★ Establish a company-specific emission threshold for each compressor to serve as a useful tool for knowing when to replace packing rings and piston rods economically.
- ★ Upgrade piston rods where economically justified. The upgrades will result in fewer emissions over the life of the rod.
- ★ New packing ring materials, types, and entirely new packing systems are available and becoming more common where product values or environmental factors offset the higher costs.
- ★ For additional information, consult the Lessons Learned study entitled *Reducing Emissions When Taking Compressors Off-Line*.
- ★ When changing out packing rings and rods, record methane emissions reductions in Natural Gas STAR Program annual reports.

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Reducing Methane Emissions From Compressor Rod Packing Systems

(Cont'd)



**United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460**

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

TECHNICAL REPORT

EPA Phase II Aggregate Site Report

Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites

PREPARED FOR:

Project Manager: **Roger Fernandez**
U.S. Environmental Protection Agency Natural Gas STAR Program
U.S. EPA Grant No: XA-83046001-1



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Rev1

EXECUTIVE SUMMARY

A comprehensive measurement program has been conducted at five natural gas-processing plants in the United States to identify cost-effective opportunities for reducing natural gas losses due to fugitive equipment leaks and avoidable process inefficiencies or wastage. This program, referred to as Phase II, followed a Phase I program that surveyed four gas plants in 2000.

The second Phase study included upstream facilities such as well sites and gathering compressor stations in addition to the gas processing plants. The additional gas processing plants were selected to give a range of plant size, locations, throughput, plant age, and both sweet and sour gas facilities to ensure that the results represented the entire natural gas processing industry.

Raw natural gas is predominantly methane but may contain varying amounts of non-methane hydrocarbons (NMHC) and contaminants, such as hydrogen sulfide (H₂S), nitrogen (N₂), carbon dioxide (CO₂) and water vapor (H₂O). Natural gas losses to the atmosphere are direct emissions of these constituents. Natural gas losses into flare systems or excess fuel consumption result in atmospheric emissions of CO₂ and other combustion byproducts including unburned methane.

Here, cost effective opportunities to reduce natural gas losses are seen primarily as a sensible means of reducing methane and other greenhouse gas (GHG) emissions (predominantly CO₂), and to a lesser extent, NMHC emissions. All GHG emissions are expressed as CO₂-equivalent emissions (CO₂E) using a global warming potential of 21 for methane. A baseline assessment of the fugitive natural gas losses and target air pollutant emissions at each host facility is provided, and the potential savings and emission reductions from natural gas loss decreases are highlighted. Additionally, total hydrocarbon (THC) emission factors are presented for fugitive equipment leaks and the active natural gas-fueled process equipment surveyed.

All fieldwork was conducted during the first quarter 2004 and second quarter 2005. The work comprised a fugitive-emissions survey of equipment components in hydrocarbon gas service, measurement and characterization of flows into all key vent and flare systems, and limited performance testing of natural gas-fueled combustion equipment at three of the five surveyed sites. Emissions from selected pressure relief valves vented to the flare were measured at two sites. Residual flaring activities were also determined. Although not specifically targeted, any components in hydrocarbon-liquid or air service that were noticeably leaking were tagged and brought to the attention of site personnel. Complete component counts were prepared for the surveyed equipment.

The plants were also surveyed with an optical passive infrared camera designed specifically for leak detection. A comparison between leak detection methods is included in this second Phase report.

A total of 74,438 individual equipment components from five gas processing facilities, 12 well sites, and seven upstream gathering compressor stations were surveyed. Sufficient process information was collected to determine total annual emissions from the compiled measurement results. Additionally, specific emission-control opportunities were identified, and a preliminary cost-benefit analysis was performed to evaluate these opportunities. The analysis considered the estimated cost of repair and corresponding lifetime and the conserved gas value. Site personnel were solicited to provide input and assistance in identifying site-specific constraints and to help ensure that cost data were satisfactorily considered.

EMISSIONS INVENTORY OVERVIEW

Total atmospheric methane emissions from all sources at the combined sites are estimated at 8,071 tonnes per year. Corresponding GHG and NMHC emissions are estimated at 598,184 tonnes per year CO₂E and 3,625 tonnes per year, respectively. The majority of total methane emissions resulted from fugitive equipment leaks (55%). Incomplete combustion by natural gas-fuelled equipment and process venting are also noteworthy methane emissions sources (17% and 16%, respectively). The major GHG emissions sources are fuel consumption by compressor engines and process heaters (74%), fugitive equipment leaks (17%), process venting (5%), and flare/vent systems (3%). Fugitive equipment leaks are the primary NMHC emissions source (73%). In general, gathering compressor stations offered cost-effective opportunities with the majority of the methane emissions from fugitive leaks associated with leaking compressors. From the twelve wells surveyed, opportunities exist at well heads that have separators, tanks, and heater treaters.

NATURAL GAS LOSSES OVERVIEW

The value of all five sites natural gas losses - including direct atmospheric emissions, gas leakage into flare systems, and excess fuel consumption by process equipment - is estimated to be \$8.4 million per year (an average of \$1.7 million per year per plant). The *fugitive* emission opportunities totalled \$2.9 million dollar or \$580,000 per facility per year. The cost to survey and repair these leaks is approximately \$ 74,200 per facility (i.e. survey cost for one site at \$25,000 plus cost of repairs for leakers with positive net present value, averaged \$49,200 per site).

These estimates do not include the cost of identifying and evaluating natural gas loss reduction opportunities; however, such costs are typically small compared to the net benefit obtained. For example, the current five site survey costs, when expressed in terms of the total number of components in gas service, were approximately \$1.5 per component, which is more than the cost of conventional VOC LDAR programs. This per component cost may be reduced if a routine survey were to be implemented and maybe artificially high as a result of the R&D activities. Actual per-component costs vary between facilities and tend to increase with the operation complexity, facility remoteness, work condition severity, and the relative number of vents, combustion sources and control opportunities identified. The current study identified more than \$3,200 in annual

gross savings, or \$3,000 in net savings (including after repair or control costs), per component for control opportunities having a less than a 1-year payback based on a gas value of \$7.15/Mscf (\$6.78/GJ). Considering opportunity identification costs reduces the net savings by only about 4%. If a value is assigned to the resulting GHG credits, work is done as a routine commercial service rather than as a study, and efforts are focused on the plant areas most likely to offer meaningful control opportunities, improved economics would be realized.

Overall, it is estimated that up to 96.6% of total fugitive natural gas losses are cost-effective to reduce with no net financial burden to surveyed sites. If the cost of natural gas increases, the number of components that are cost effective to repair will not increase significantly however, the saving realized will scale commensurate with the price increase. These reductions would result in emission reductions of 61% for methane, 17% for GHG CO₂E, and 67% for NMHC considering emissions from all sources. The relatively low impact on GHG CO₂E emissions is due to the significant contribution of CO₂ emissions from fuel consumption to total GHG emissions.

The main cost-effective control opportunities identified at the sites are:

- **Fugitive Equipment Leaks:**

Approximately 2.2% of the equipment components (approximately 1,629 out of 74,438) in hydrocarbon service were determined to be leaking (i.e., had a screening value of 10,000 ppm or more) at the combined sites. Commensurate with the findings from the initial gas plant surveys, components in vibrational, high-use, and thermal-cycle gas services were the most leak prone. The majority of the identified natural gas losses from fugitive equipment leaks were attributed to a relatively small number of leaking components. Open-ended lines emissions were the greatest contributor to this source category, accounting for 32% of the total, followed by connectors (30%), compressor seals (20%), and block valves (15%). The remaining 3% were from pressure relief valves, regulators, orifice meters, control valves, and crank case vents.

It is estimated that implementing all cost-effective equipment-repair or replacement opportunities identified would reduce natural gas losses from *fugitive* equipment leaks by 96.6% and result in gross annual cost savings of approximately \$2.9 million (based on a gas value \$7.15/Mscf or \$6.78/GJ). This equates to an average gross annual savings of approximately \$580,000 per site. Site-specific values ranged from \$75,646 to \$1.2 million. Lower losses and fewer loss-reduction opportunities would be expected at newer plants. Conversely, higher losses and more loss-reduction opportunities would likely be found at older and/or poorly maintained plants.

Repairs to the 10 largest emitting cost-effective-to-repair components at each site (refer to Appendix I for a components list ranked by emission rate) would reduce natural gas losses by approximately 521 Mscfd, or 58%.

- **Flaring:**
The five sites flare or main vent systems residual gas flows (i.e., flows excluding blowdown and emergency relief events) totalled 496 Mscfd. In several cases, the system flows were sufficient to potentially justify installing a vent- or flare-gas recovery unit. Alternatively, the residual gas flow source or sources (e.g., excess purge gas consumption and leaking pressure-relief devices, drains, and blowdown valves connected to the flare header) could be repaired. However, these sources are often difficult to isolate, usually require a major plant shutdown to fix, and are likely to reoccur. Installing economically feasible flare-gas recovery units would reduce surveyed plants GHG emission by approximately 16,609 tonnes CO₂E per year, and take less than a year to pay out.
- **Natural Gas-Fueled Process Equipment:**
While several of the compressor engines tested would have benefited from tuning, most units proved to be operating efficiently (i.e., air-to-fuel ratios and flue gas combustibles concentrations were at or near manufacturers recommended values). This likely reflects the high attention level typically given to combustion equipment at continuously manned facilities such as those surveyed. Greater combustion efficiency improvement opportunities are believed to exist for tuning heaters and engines at unmanned field facilities. Total avoidable fuel consumption from servicing all economic-to-tune engines and heaters at the five sites is estimated to be 446 Mscfd, which equals GHG emission reductions of 13,100 tonnes CO₂E per year.

The natural gas-fueled engines surveyed were all properly matched with the current process load requirements (i.e., the units were operating within the optimum portion of their performance curve). Notwithstanding this, situations may arise where engines are operated outside their performance curve optimum area (e.g., due to changes in original load requirements caused by production changes or initial equipment mismatching with process applications) causing significant excessive operating costs.

KEY FINDINGS

- The value of natural gas losses from all five facilities in the Phase II DI&M survey - including direct atmospheric emissions, gas leakage into flare systems, and excess fuel consumption by process equipment - is estimated to be \$8.4 million per year (an average of \$1.7 million per year per plant). The findings from these additional 5 plant surveys solidify the economic benefits of voluntarily adopting and initiating DI&M.

The table below summarizes the finding from the Phase II DI&M site surveys.

| Table I - Summary of Phase II Plants Surveyed | | | | | | | |
|---|-------|------|-----------------|-----------------------------|-------------------------------|-------------------------|-----------------|
| Site # | Type | Age | Component Count | Fugitive Gas Losses (Mscfd) | Annual Value of Lost Gas (\$) | Gas Throughput (mMscfd) | % of Throughput |
| 1 | Sweet | 6 | 22,290 | 271 | \$757,259 | 500 | 0.05 |
| 2 | Sweet | 28 | 12,330 | 23 | \$75,646 | 206 | 0.01 |
| 3 | Sweet | 39 | 18,353 | 117 | \$612,593 | 130 | 0.09 |
| 4 | Sour | 27 | 16,687 | 69 | \$193,978 | 45 | 0.15 |
| 5 | Sour | 57 | 4,778 | 423 | \$1,296,510 | 87 | 0.48 |
| Average | | 31.4 | 14,887 | 903 | \$587,197 ^A | 193.6 | 0.16 |

^A This value excludes sources from combustion, flare activities, well sites and storage tanks.

- The results show that facilities surveyed with more than 30 years of service have significantly higher methane emissions per volume gas throughput, and higher overall leak frequencies than facilities with less than 30 years of service. The facilities survey during this Phase of the program ranged from 6 to 57 years with an average of 30.4 years. Facilities processing sour gas have higher methane emissions per volume gas throughout and leak frequencies than facilities processing sweet gas streams. Statistical comparisons for surveyed sites on the effects of gas plant service years and process stream type were not attempted due to the limited number of sites surveyed. It is recommended that additional analyses, including results from the Phase I and other surveys, be conducted to develop statistically significant correlations of fugitive equipment leak rates with service years and process gas type.
- A targeted DI&M program aimed at proven opportunities can significantly reduce the time and resources required to identify and repair those leaks that represent the “low hanging fruit” within the facility. Components associated with vibration (i.e. compressors) and heat-cycle (i.e. mole sieve) services contributed 97% of the total fugitive equipment leaks. These results again emphasize that employing a targeted DI&M program would significantly reduce the cost of initiating a DI&M program. However, significant additional opportunities were discovered at each site that would have been overlooked if the scope was narrowed to only include these targeted sources.
- A Phase I test site was selected for retest in Phase II to determine changes in fugitive leaks characteristics. Process changes at this site resulted in thirty percent of the Phase I components being decommissioned. These process units were replaced prior to the Phase II survey. While fugitive emissions from the new process units components tested in Phase II were only 20% of the fugitive emissions from the decommissioned components tested in Phase I, the overall Phase II site level fugitive emissions were still 50% higher than in Phase I. This

indicates higher Phase II fugitive emission leaks from 70% of components that were not replaced between Phases, and suggests that the facility DI&M program has not been effective at controlling fugitive equipment leaks at this site. In addition, a comparison of the average Phase I and Phase II emission factors by component type shows a very different distribution between Phase I and II sites.

TABLE OF CONTENTS

| <u>Section</u> | <u>Page</u> |
|--|-------------|
| EXECUTIVE SUMMARY | i |
| TABLE OF CONTENTS..... | vii |
| LIST OF FIGURES | ix |
| LIST OF TABLES..... | xi |
| GLOSSARY | xii |
| ACKNOWLEDGEMENTS..... | xix |
| 1 INTRODUCTION..... | 1 |
| 2 BACKGROUND..... | 2 |
| 3 METHODOLOGY | 5 |
| 3.1 Emissions Survey..... | 5 |
| 3.1.1 Component Screening..... | 6 |
| 3.1.2 Leak Detection Methods..... | 7 |
| 3.1.3 Leak-Rate Measurements..... | 12 |
| 3.1.4 Vents and Open-ended Lines Emissions Measurements | 14 |
| 3.1.5 Residual Flaring Rates Determination | 15 |
| 3.1.6 Natural Gas-Fueled Equipment Performance Testing..... | 15 |
| 3.1.7 Compression Equipment Analysis..... | 18 |
| 3.1.8 Storage Tanks Excess Emissions Evaluations | 19 |
| 3.1.9 Component Counts..... | 20 |
| 3.1.10 Average Emission Factors Development..... | 21 |
| 3.1.11 Emission Control Guidelines | 21 |
| 3.2 Equipment Repair Cost-Benefit Analyses..... | 21 |
| 3.2.1 Equipment Repair Cost Estimating..... | 21 |
| 3.2.2 Natural Gas Value..... | 22 |
| 3.2.3 Repair Life | 22 |
| 3.2.4 Cost Curves | 22 |
| 4 RESULTS..... | 23 |
| 4.1 Emission Inventory | 23 |
| 4.2 Natural Gas Losses..... | 27 |
| 4.3 Fugitive Equipment Leaks | 27 |
| 4.3.1 Average Emission Factors | 27 |
| 4.3.2 Average Leak-Rate Trends | 31 |
| 4.3.3 Leak Frequencies | 38 |
| 4.4 Tank Emissions..... | 40 |
| 4.5 Results for Retested Site | 40 |
| 4.5.1 Overall Plant | 40 |
| 4.5.2 Replaced Process Units..... | 41 |
| 4.6 Control Opportunities..... | 43 |
| 4.6.1 Cost Curve for Reduction of GHG Emissions..... | 43 |
| 4.6.2 Control Opportunities With a Payback of 1 Year or Less | 46 |
| 5 CONCLUSIONS AND RECOMMENDATIONS..... | 47 |
| 5.1 Conclusions..... | 47 |

| | | |
|-----|--|-----|
| 5.2 | Recommendations for Further Work..... | 48 |
| 6 | REFERENCES CITED | 50 |
| | Appendix I Measured THC Emission Rates Sorted by Emission Rate | 51 |
| | Appendix II Measured THC Emission Rates Sorted by Payout Period | 94 |
| | Appendix III Combustion Analysis and Efficiency Testing Results | 134 |
| | Appendix IV Average Equipment Component Schedules for Natural Gas Processing Plants | 367 |
| | Appendix V Financial Considerations and Assumptions | 368 |
| | Appendix VI Basic Component Repair Costs and Mean Repair Life..... | 369 |
| | Appendix VII V-Pac Measurement | 373 |

LIST OF FIGURES

| <u>Figure</u> | <u>Page</u> |
|--|-------------|
| Figure 1 Leak Rate Versus Concentration..... | 3 |
| Figure 2 Survey Team Using Gas Detector To Quantify Concentration And Screen..... | 6 |
| Figure 3 Physical Acoustics VPAC | 7 |
| Figure 4 Residual Flaring | 7 |
| Figure 5 Soap Solution Screening on a Two Inch Leaking Threaded Connector | 10 |
| Figure 6 Tagged Leaking Components..... | 10 |
| Figure 7 Cut-Away View Of A Natural Gas Compressor Showing The Potential Leak Points Including The Compressor Seals And Crankcase Vent. | 11 |
| Figure 8 Prototype GRI HiFlow™ Sampler | 14 |
| Figure 9 Typical Stationary Compressor Engines Crankcase Vent Configurations Recommended By Manufacturers..... | 17 |
| Figure 10 Distribution Of Methane By Source Category For All Sources..... | 24 |
| Figure 11 Distribution Of Non-Methane Hydrocarbon Emissions By Source Category . | 25 |
| Figure 12 Distribution Of Total GHG Emissions By Source Category..... | 26 |
| Figure 13 Distribution Of Natural Gas Losses By Source Category | 29 |
| Figure 14 Distribution Of Natural Gas Losses From Equipment Leaks By Type Of Component | 30 |
| Figure 15 Average THC Emissions For Connectors By Gas Streams | 33 |
| Figure 16 Average THC Emissions For Open-Ended Lines By Gas Stream | 33 |
| Figure 17 Average THC Emissions For Block Valves By Gas Stream..... | 34 |
| Figure 18 Average THC emissions for connectors by process unit..... | 34 |
| Figure 19 Average THC Emissions For Open-Ended Line By Process Unit..... | 35 |
| Figure 20 Average THC Emissions For Block Valves By Process Unit..... | 35 |
| Figure 21 Methane Emissions Per Unit Gas Throughput For Plants With Different Service Duration..... | 36 |

| | |
|--|----|
| Figure 22 Figure F Methane Emissions Per Unit Gas Throughput For Plants With Different Raw Gas Type..... | 37 |
| Figure 23 Methane Emissions Percentage By Process Units..... | 38 |
| Figure 24 Total THC Emissions Between Phases | 41 |
| Figure 25 Component Emission Rate Between Phases | 41 |
| Figure 26 Total THC Emissions Between Phases | 42 |
| Figure 27 Component Emission Rate Between Phases | 42 |
| Figure 28 Emissions From Economically Repairable Sources..... | 45 |
| Figure 29 Incremental Net Cost Curve For Cumulative CO ₂ E Emission Reductions At Surveyed Gas Plants..... | 45 |

LIST OF TABLES

| <u>Table</u> | <u>Page</u> |
|--|--------------------|
| Table I Summary of Plants Surveyed in Phase II | v |
| Table 1 Summary of Surveyed Plants..... | 5 |
| Table 2 Summary of Fugitive Losses from the Top Ten Leakers. | 28 |
| Table 3 Summary of Fugitive Leaks for Gas Plants, Gathering Compressor Stations, and Well Sites. | 28 |
| Table 4 Comparison of Average THC Emission Factors Derived from Data Collected at the Test Sites to Other Published Values. | 31 |
| Table 5 Number of components and leak frequency at each of the five gas plants..... | 39 |
| Table 6 Losses from Storage Tanks..... | 40 |
| Table 7 Summary of Top Ten Sources of Natural Gas Losses Identified..... | 46 |

GLOSSARY

- Blow-By** Gas from a piston cylinder that leaks past the piston rings into the crankcase.
- Carbon Dioxide Equivalent (CO₂E) -** Carbon dioxide equivalent is an expression of the total emissions from all the greenhouse gases, based on the gases relative ability to trap heat in the atmosphere.
- Greenhouse gases (GHGs) are atmospheric compounds that trap heat in the atmosphere by absorbing long-wave radiation from the earth's surface while allowing the sun's energy to pass through. The most relevant GHGs for natural gas systems are carbon dioxide (CO₂), methane (CH₄) and nitrous oxide (N₂O). Global warming potentials (GWPs) were developed as a simple measure of the global warming effects of various greenhouse gases emissions relative to carbon dioxide emissions. The current practice (IPCC, 1996) is to use a 100-year time horizon for global warming potentials. Therefore, the GWPs used in this document are: CO₂ = 1.0, CH₄ = 21.0 and N₂O = 310.
- Greenhouse gases emissions are converted to carbon dioxide equivalent (CO₂E) emissions by multiplying the mass emissions of each gas by the appropriate global warming potential and summing the CO₂E emissions. CO₂E emissions are expressed in metric tonnes.
- Centrifugal Compressor Seal Systems -** Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used. Seal leakage will tend to increase with wear between the seal and compressor shaft, operating pressure, and shaft rotational speed.
- Combustion Efficiency -** The extent to which all input combustible material has been completely oxidized (i.e., to produce H₂O, CO₂ and SO₂). Complete combustion is often approached but is never actually achieved. The main factors that contribute to incomplete combustion are thermodynamic, kinetic, mass transfer and heat transfer limitations. In fuel rich systems, oxygen deficiency is also a factor.

- Connectors - A connector is any flanged or threaded connection, or mechanical coupling, but excludes all welded or back-welded connections. If properly installed and maintained, a connector can provide essentially leak-free service for extended time periods. However, there are many factors that can cause leakage problems. Common leak causes include vibration, thermal stress and cycles, dirty or damaged contact surfaces, incorrect sealing material, improper tightening, misalignment, and external abuse.
- Crank Case - The crank case on reciprocating engines and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft. Integral compressors have a single crank case because the engine and compressor share a common crank shaft. Non-integral compressors typically have two crank cases, one on the engine side and another on the compression side.
- Destruction Efficiency - The extent to which a target substance present in the input combustibles has been destroyed (i.e., converted to intermediate, partially-oxidized, and fully-oxidized products of combustion). DE is typically expressed as a percentage: $100 * (in - out)/in$.
- Flare and vent systems - Venting and flaring are common disposal methods for gas processing plants waste gas. The stacks are designed to provide safe effluent dispersion. Flares are normally used where the waste gas contains odorous or toxic components (e.g., hydrogen sulfide). Otherwise, the gas is usually vented. Typically, separate flare/vent systems are used for high- and low-pressure waste gas streams.
- Fugitive Emissions - Unintentional leaks from equipment components including, but not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seals, system degassing vents, accumulator vessel vents, agitator seals, and access door seals. Fugitive sources tend to be continuous emitters and have low to moderate emission rates.
- Gas Plant - A gas processing plant is a facility for extracting condensable hydrocarbons from natural gas and for upgrading the gas quality to market specifications (i.e., removing contaminants such as H₂O, H₂S and CO₂ and possibly adjusting the heating value).

| | |
|--|--|
| Heat Rate - | The heat energy (based on the fuel net or lower heating value) which must be input to a combustion device to produce the rated power output. Heat rate is usually expressed in terms of net J/kW·h. |
| Integral Compressor | A reciprocating compressor that shares a common crankshaft and crankcase with the engine. |
| Methane Leak | Greater than 10,000 parts per million as measured by a dual-element hydrocarbon detector (i.e., catalytic-oxidation/thermal-conductivity). |
| Molecular Sieve | Absorbers composed of zeolites (aluminosilicate crystalline polymers) used to remove water vapor from natural gas. Zeolites are regenerated periodically by heating. |
| Long-Term Natural Gas Contract Price - | Historically, long-term contracts have been used by buyers to secure a natural gas supply and by sellers to reduce large reserve development risk. During the 1960s and 70s, these contracts were established for terms of up to 20 to 25 years and the gas price was determined by periodic negotiations. The recent trend is towards shorter contract durations, and most new long-term contracts index the gas price to spot market rates. Today, a typical long-term contract with a cogeneration plant is about 15 years. Given the sellers and buyers interest in risk management, there is also a trend towards greater standardization of long-term contracts to facilitate hedging activity in the financial or the over-the-counter markets. |
| Open-ended Valves and Lines - | <p>An open-ended valve is any valve that releases process fluids directly to the atmosphere from valve seat leakage. The leakage may be caused by improper seating due to an obstruction or sludge accumulation, or a damaged or worn seat. An open-ended line is a pipe or tube segment attached to a leaking valve and that opens to the atmosphere.</p> <p>Few open-ended valves and lines are designed into process systems. However, actual numbers can be quite significant at some sites due to poor operating practices and various process modifications that may occur over time.</p> <p>Some common examples of open ended valves and lines are:</p> |

- scrubber, compressor-unit, station, and mainline blowdown valves;
- supply-gas valve for a gas-operated engine starter (i.e., where natural gas is the supply medium);
- instrument block valves where the instrument has been removed for repair or other reasons; and
- purge or sampling points.

Power Output -

The net shaft power available from an engine after all losses and power take-offs (e.g., ignition-system power generators, cooling fans, turbo chargers and pumps for fuel, lubricating oil, and liquid coolant) have been subtracted. For heaters and boilers, it is the net heat transferred to a target process fluid or system.

Pressure-Relief or Safety Valves -

Pressure relief or safety valves are used to protect process piping and vessels from being accidentally over-pressured. They are spring loaded so that they are fully closed when the upstream pressure is below the set point, and only open when the set point is exceeded. Relief valves open in proportion to the overpressure to provide modulated venting. Safety valves pop to a full-open position on activation.

When relief or safety valves reseal after activation, they often leak because the original tight seat is not regained either due to seating surface damage or foreign material build-up on the seat plug. As a result, they are often responsible for fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure.

Gas that leaks from a pressure-relief valve may be detected at the vent pipe (or horn) end. Additionally, there normally is a monitoring port located on the bottom of the horn near the valve.

Products of Incomplete Combustion (PICs) -

These are any compounds, excluding CO₂, H₂O, SO₂, HCl and HF, which contain C, H, S, Cl or F and occur in combusted gases. These compounds may result from thermodynamic, kinetic or transport limitations in the various combustion zones. All input combustibles are potential PICs. Intermediate substances formed by dissociation and recombination effects may also occur as PICs (CO is often the most abundant combustible PIC

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formed).

Pump Seals -

Positive displacement pumps are normally used for pumping hydrocarbon liquids at oil and gas facilities. Positive displacement pumps have a reciprocating piston, diaphragm or plunger, or else a rotary screw or gear.

Packing, with or without a sealant, is the simplest means of controlling leakage around the pump shaft. It may be used on both rotating and reciprocating pumps. Specially designed packing materials are available for different service types. The selected material is placed in a stuffing box and the packing gland is tightened to compress the packing around the shaft. All packings leak and generally require frequent gland tightening and periodic packing replacement.

Particulate contamination, overheating, seal wear, sliding seal leakage, and vibration will contribute to increased leakage rates over time.

Reciprocating Compressor Packing Systems -

Packings are used on reciprocating compressors to control leakage around the piston rod on each cylinder. Conventional packing systems have always been prone to leaking a certain amount, even under the best of conditions. According to one manufacturer, leakage from within the cylinder or through any of the various vents will be on the order of 1.7 to 3.4 m³/h under normal conditions and for most gases. However, these rates may increase rapidly with normal system wear and degradation.

Standard Reference Conditions -

Most equipment manufacturers reference flow, concentration, and equipment performance data to ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 % relative humidity.

Thermal Efficiency -

The percentage or portion of input energy converted to useful work or heat output. For combustion equipment, typical convention is to express the input energy in terms of the net (lower) heating value of the fuel. This results in the following relation for thermal efficiency:

$$\eta = \text{Thermal Efficiency} = \frac{\text{Useful Work/Heat Output}}{\text{Net Heat/Energy Input}} \times 100\%$$

Alternatively, thermal efficiency may be expressed in terms

of energy losses as follows:

$$\eta = \left(1 - \frac{\Sigma \text{Energy Losses}}{\text{Net Heat/Energy Input}} \right) \times 100\%$$

Thermal efficiency losses can occur due to the following factors:

- combustion exhaust heat losses (i.e., residual heat value in the exhaust gases);
- heat rejected to cooling jacket water and lubrication oil;
- radiation from equipment hot surfaces;
- air infiltration;
- incomplete combustion; and
- mechanical losses (e.g., friction losses and energy needed to run cooling fans and lubricating-oil pumps).

Total Hydrocarbons -

All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.

Total Organic Compounds (TOC) -

TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).

Valves -

There are three main locations on a typical valve where leakage may occur: (1) from the valve body and around the valve stem, (2) around the end connections, or (3) past the valve seat. Leaks of the first type are referred to as valve leaks. Emissions from the end connections are classified as connector leaks. Leakage past the valve seat is only a potential emissions source if the valve, or any downstream piping, is open to the atmosphere. This is referred to as an open-ended valve or line.

The potential leak points on the different valve types are, as applicable: around the valve stem, body seals (e.g., where the bonnet bolts to the valve body, retainer connections), body fittings (e.g., grease nipples, bleed ports), packing guide, and any stem packing system monitoring ports. Typically, the most likely part to leak is the valve-stem packing.

The different valve types include gate, globe, butterfly, ball, and plug. The first two types are a rising-stem design

and the rest are quarter-turn valves. Valves may either be equipped with a hand-wheel or lever for manual operations, or an actuator or motor for automated operation.

Vented Emissions -

Vented emissions are releases to the atmosphere by design or operational practice, and may occur on either a continuous or intermittent basis. The most common vented emissions causes or sources are gas-operated devices that use natural gas as the supply medium (e.g., compressor start motors, chemical injection and odorization pumps, instrument control loops, valve actuators, and some types of glycol circulation pumps), equipment blowdowns and purging activities, and glycol dehydrators still-column off-gas venting.

Volatile Organic
Compounds (VOC) -

Any compound of carbon, excluding carbon monoxide, and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons.

ACKNOWLEDGEMENTS

The funding provided by US Environmental Protection Agency (Grant Number XA-83046001-1) in support of this project is gratefully acknowledged. Special thanks are given to the personnel at each of the host facilities for their help, interest in the work being done, and useful feedback, and to all the sponsors for their constructive review comments.

1 INTRODUCTION

An intensive fugitive emissions screening and measurement program was conducted during the first quarter 2004 and second quarter 2005 at five gas processing facilities in the USA. The selected facilities were of various ages, types, and throughputs and were evaluated with a strong emphasis on identifying and quantifying natural gas losses from leaking equipment components in heat-cycle and vibration services. The facilities included sweet and sour gas processing, and a variety of processes including compression, separation, storage, and flare systems.

The study's primary objective was to demonstrate the cost-effectiveness of conducting a comprehensive leak detection and repair (LDAR) program at domestic gas production and processing facilities using HiFlow™ Sampler technology. Field measurements also included an assessment of emissions from continuous vents, combustion equipment, and flare systems and natural gas-fuelled equipment diagnostic checks. Such efforts are employed to achieve sensible and verifiable reductions in methane, GHG, and NMHC emissions, while providing industry with potentially noteworthy emissions reduction opportunities with commensurate financial incentives. These opportunities were presented to surveyed plants in the plant level reports. Based on the compiled test results, the greatest opportunities for cost-effective reduction of natural gas losses are from the control of leaking equipment components and leakage of process gas into vent and flare systems. Therefore, the report emphasizes fugitive leak opportunities.

Background information, on key differences between the conventional EPA Method 21 approach to leak detection and repair and the approach used here, is provided in Section 2. A more detailed description of the current approach and other measurement techniques employed plus an overview of the basic assessment methodology are presented in Section 3. Section 3 also delineates the economic criteria used to evaluate the identified emission control opportunities.

The measurement program results are presented in Section 4. These results include an overview of the identified control opportunities, measured emissions and natural gas loss inventories, average emission factors, and leak statistics. The study conclusions and recommendations are presented in Section 5, and cited references are listed in Section 6. Detailed listings of all the identified equipment leaks are provided in Appendices I and II, ranked by emission rate and payout period, respectively. The following information is provided for each component: Site No., Tag No., Process Unit, Component Description, Emission Rate ($10^3 \text{ m}^3/\text{yr}$), Estimated Repair Costs (\$), Net Present Value of Repair (\$), CO₂E Emissions (tonne/yr), and Repair Payback Period (yr).

Appendix III presents detailed accounts of the combustion analysis and efficiency testing results for each tested unit. Average equipment component schedules by process unit type are provided in Appendix IV. The financial considerations and assumptions applied are summarized in Appendix V while the assumed component repair costs and mean repair lives are provided in Appendix VI. Physical Acoustics V-Pac measurements are detailed in Appendix VII.

2 BACKGROUND

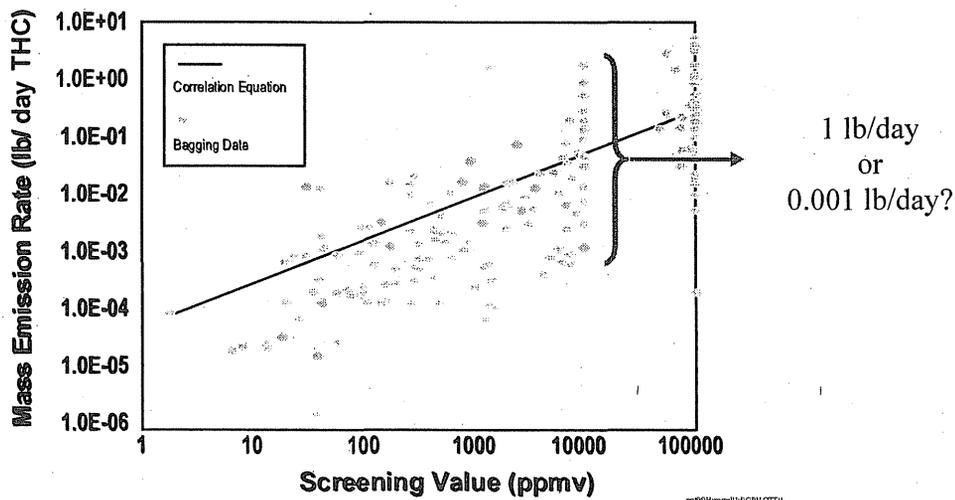
Under the settlement terms of a recent Consent Decree, deadlines are established for EPA to review and, if appropriate, revise the NSPS standards for Subparts J, VV and GGG, 40 CFR 60.100–109, 60.480–498, 60.590–593. The New Source Performance Standards in 40 CFR Part 60 KKK (back reference VV) provides the regulatory requirements for conducting a leak detection and repair (LDAR) program for the onshore natural gas processing industry. This standard is directed at controlling/reducing volatile organic compound (VOC) emissions and specifically excludes methane and ethane. Therefore, gas-processing facilities have typically only included the light liquid and refrigeration areas in leak detection programs. Subsequently, very little information pertaining to potential leakage from the remainder of the facility (i.e. non-regulated) was available. The primary project objectives were to evaluate leak potentials and the cost-effectiveness of implementing LDAR programs at natural gas processing facilities.

Most natural gas industry LDAR programs rely on U.S. EPA Method 21. Depending upon the leak screening instrument detector, the concentration of either total hydrocarbons (THC) or VOCs in the air from a leaking component is measured, and then the leak rate is estimated using a correlation equation or measured using the bag and sample procedure. In a conventional LDAR program for fugitive emissions control, U.S. EPA's Method 21 is utilized to screen the facility for leaks at a prescribed frequency (e.g. quarterly, bi-annually or annually). All components that screen above a given threshold (typically 10,000 parts per million) are to be repaired.

There are a numerous shortcomings with the Method 21 approach. The uncertainties in emissions estimates calculated using the correlation equation are very high. Additionally, the correlation equations only go to screening concentrations of 10,000 or 100,000 parts per million – any leak above these screening concentrations has the same estimated leak rate (known as a “pegged source” emission factor). Figure 1 shows the correlation equation and screening concentration values measured using Method 21 plotted against the leak rate measured with the bag and sample procedure. The data scatter is about \pm two orders of magnitude. The bag and sample procedure directly measures leak rates; however, is very time intensive and expensive and the correlation equation approach is therefore used for most large scale LDAR programs. Data collected in Phase 1 showed that 65% of the natural gas facilities fugitive components that screened above 10,000 parts per million are cost-effective to repair. Consequently, by repairing all components that screen above 10,000 parts per million per Method 21, resources are wasted by repairing components – 35% of the total based on the Phase I results – whose repair costs exceed the value of gas saved. Another shortcoming of the conventional Method 21 approach is that it does not accurately measure either the facility baseline emissions or the emissions reduction (error is \pm 300%). Because the emissions reduction cannot be accurately determined, the benefits of implementing an LDAR program cannot be evaluated.

The HiFlow™ Sampler, described in Section 3.1.2, quickly and accurately quantifies fugitive emissions leak rates and has significantly reduced natural gas plants LDAR programs costs. Cost-effective repairs, those with repair costs less than the saved gas value, can be identified and completed while non cost-effective repairs are not performed and maintenance resources are optimized. The Phase 1 data showed that 80 to 90 % of facility emissions are often emitted from a small fraction of the leaks; thus, significant emissions reductions can be achieved by repairing a few big leakers. In addition, a HiFlow™ Sampler LDAR program accurately measures the facility baseline emissions¹ and the emissions reduction can be accurately determined. Therefore, the LDAR program implementation benefits can be evaluated.

Figure 1 Leak Rate versus Concentration



The primary objective of the overall study is to assess baseline methane (CH₄) emissions at natural gas processing and production facilities, and delineate and quantify the extent of cost-effective opportunities for reducing these emissions. A secondary objective is to evaluate the potential for cost-effective reduction of other GHG emissions (primarily CO₂) through process efficiency gains, and to establish a Best Management Practice for conducting DI&M programs.

Primary sources of methane emissions include, leakage, venting, storage losses, incomplete combustion (fuel use and flaring). Other methane losses includes, increased fuel use due to avoidable inefficiencies, thermal efficiency of fired equipment, compression efficiency, tail gas incinerators, electric power generation, and horsepower mismatch to required work.

Phase II addressed data gaps identified during the Phase I study and improved the overall statistical significance of the Phase I study for system wide extrapolation of results and

serves as the basis for developing an industry specific best management practices guidance document.

Phase II provided the following:

- An increased number and type of gas processing facilities and components within the current database giving an improved statistical basis for extrapolation of the results system-wide.
- An indication of the effectiveness of repairs to the major leakers at a Phase I facility and the increases in leakage over time at gas plants.
- An initial indication of CH₄ and GHG emission reduction opportunities at gas production facilities upstream of the gas processing plant (e.g., gas-gathering systems including compression and well-site facilities).

Although the primary goal of Phase II was to expand the results of the prior Phase I DI&M study through broader industry participation and an increased emissions database, a secondary goal was to assess and integrate a suite of tools for improving survey efficiency. The scope of work and project approach for the second Phase was consistent with the Phase I study and allows for direct comparison with the previous results.

3 METHODOLOGY

This section describes the methodology used by the study team to identify and evaluate cost-effective emission-reduction opportunities at the gas processing facilities. The different measurement techniques considered for each primary source type are delineated.

The five selected test facilities were chosen to provide a representative cross section of gas plant ages with significant on-site compression since these types of facilities were expected to offer the greatest opportunities for cost-effective reduction of natural gas losses. As shown in Table 1, three sweet and two sour gas processing plants were selected. These plants ranged from 6 to 57 years in age, for an average age of 31, and all of them have compression facilities and mole sieve dehydration units. In comparison, the average age of gas processing facilities in the United States is estimated at 26 years.

| Site # | Type | Age | Component Count | Gas Throughput (MMscfd) |
|---------|-------|------|-----------------|-------------------------|
| 1 | Sweet | 6 | 22,290 | 500 |
| 2 | Sweet | 28 | 12,330 | 206 |
| 3 | Sweet | 39 | 18,353 | 130 |
| 4 | Sour | 27 | 16,687 | 45 |
| 5 | Sour | 57 | 4,778 | 87 |
| Average | | 31.4 | 14,887 | 193.6 |

The component counts presented in Table 1 above include components less than 0.5" nominal pipe size. Overall, 14.5% of these component counts are components less than 0.5" nominal pipe size.

3.1 Emissions Survey

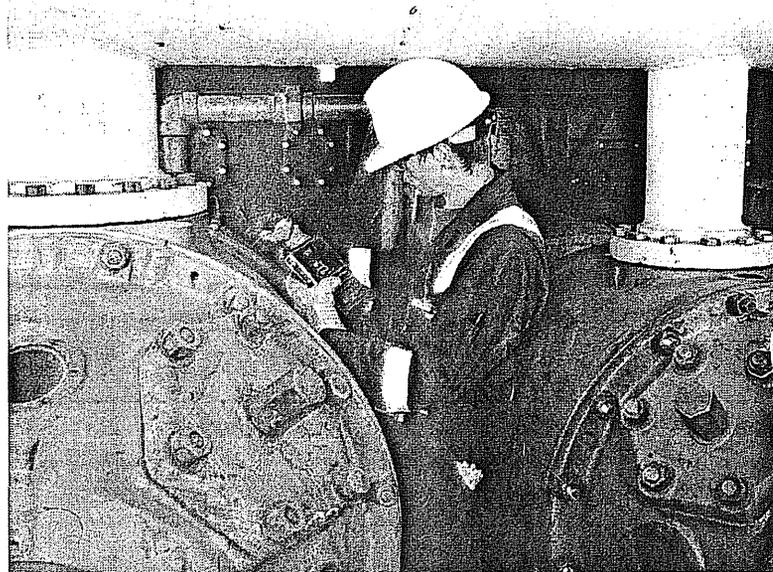
The site surveys included all or some of the following elements, as applicable:

- screening equipment components to detect leaks;
- measuring leaking equipment components (i.e., leakers) emission rates;
- measuring continuous vents emissions and emergency vents residual flows during passive periods;
- counting the surveyed equipment components;
- measuring residual flare-gas rates;
- performance testing natural gas-fueled combustion equipment;
- performance testing of compressors (newly added for Phase II);
- sampling process and waste streams;
- determining site-specific average emission factors for fugitive equipment leaks; and
- conducting an identified control opportunities cost-benefit analysis.

3.1.1 Component Screening

Equipment components on most process-, fuel- and waste-gas systems were screened for leaks. Components types surveyed included flanged and threaded connections (i.e., connectors), valves, pressure-relief devices, open-ended lines, blowdown vents (i.e., during passive periods), instrument fittings, regulator and actuator diaphragms, compressor seals, engine and compressor crankcase vents (see Figure 2), sewer drains, sump, drain tank vents and tank hatch seals.

Figure 2 Survey Team Using Gas Detector to Quantify Concentration and Screen Compressor Leaks



Components in light-liquid service generally were not screened since the program focus was natural gas losses. Furthermore, light-liquid service components do not contribute significantly to total hydrocarbon losses at gas processing plants due to their low average leak rates (U.S. EPA, 1995) and relative numbers. Leak detection (or screening) was conducted using bubble tests with soap solution, portable hydrocarbon gas detectors (Bascom-Turner Gas Sentry CGI-201 and CGI-211 and a GMI Gas Surveyor3) and an acoustic leak detector (SDT International, SDT-120).

Bubble tests, shown in Figure 3, were performed on the majority of components (including pipe threads, tubing connections, and valves) because it is usually the fastest screening technique. Components that could not be screened using bubble tests included any in high-temperature service, certain flanged connections and open-ended lines. These were screened using the gas detectors. Component determined to be leaking by the bubble tests were then screened using a hydrocarbon vapor analyzer. Hydrocarbon analyzer screening values of 10,000 parts per million or greater defined components as leaking or "leakers."

Under normal operation, waste gas volumes from blowdown or depressurization events are sent to the flare system. If the valves do not properly reseat after one of these events, gas will continuously leak through the valves. The Physical Acoustics Corporation VPAC™ model 5131 ultrasonic detectors were used to detect through- valve leakage into closed loop vent systems routed to flares.

Figure 3. Physical Acoustics VPAC

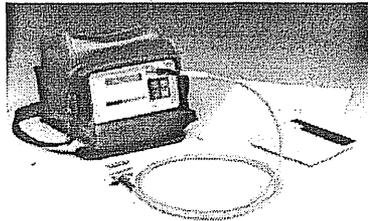
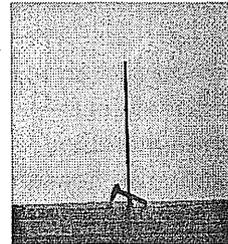


Figure 4. Residual Flaring



Ultrasonic measurements coupled with data on valve size, type, and differential pressure is used to derive mass rate loss estimates. The hand held instrument uses an acoustically coupled sensor that is held against the pipe upstream and downstream of the pressure relief valve and the relief valve body. At each location the sound level in decibels is detected. Leaking valves will have a larger signal than completely sealed valves. Appendix VII provides measurement details.

All identified leaking components were tagged (shown in Figure 4) and the specific leak source and date were noted on the tag. The emission rates for all leakers were determined using the procedures described in Sections 3.1.2 and 3.1.3. All leaker tags were left in place after the leak rate measurement to allow follow-up action by facility personnel. A total of 74,438 individual equipment components and numerous process vents, natural gas-fueled compressor and generator engines, process heaters, and flare/vent systems were surveyed. Sufficient process information was collected to determine total annual emissions from the compiled measurement results.

Additionally, specific emission-control opportunities were identified, and a preliminary cost-benefit analysis was performed to evaluate these opportunities. The analysis considers the estimated cost of repair and corresponding lifetime and the conserved gas value. Site personnel were solicited to provide input and assistance in identifying site-specific constraints and to help ensure that cost data were satisfactorily considered.

3.1.2 Leak Detection Methods

Conventional leak detection techniques, including bubble tests, handheld organic vapor analyzers and acoustic ultrasonic leak detection equipment, have traditionally been used to screen equipment components for leaks in accordance with Method 21 (U.S. EPA, 1997). These traditional leak detection techniques are

thorough; however, they tend to be quite time consuming. More recently, optical passive infrared camera technologies have been developed in an effort to improve the leak detection process efficiency. Although the optical IR cameras have performed well during numerous field trials, there are not yet sufficient data to demonstrate that the technology should be adopted in lieu of traditional screening techniques.

Although separated and excluded from the EPA portion of the scope of work, all five facilities integrated a passive midwave infrared camera in the leak surveys. A secondary program objective was to compare the performance of the passive IR camera optical leak detection method with conventional leak detection methods. Although individual DI&M surveys did not yield sufficient data to provide a quantitative comparison of the conventional methods and the camera, sufficient information for a qualitative comparison of the methodologies and performance exists.

As optical infrared technology advancements rapidly progress the state of the science, it is likely that EPA will consider addressing remote leak detection methods within future revisions to the New Source Performance Standard (Under the settlement terms of a recent Consent Decree, deadlines are established for EPA to review and, if appropriate, revise the NSPS standards for Subparts J, VV and GGG, 40 CFR 60.100–109, 60.480–498, 60.590–593.) The findings discussed below highlight considerations for future method development.

Noteworthy findings from integrating optical remote sensing in DI&M include:

- The IR camera is capable of screening leaks approximately 3 times faster than conventional methods (for two people: typically 2,400 components/day for conventional versus 6,400 components/day for the optical);
- The IR camera is not currently capable of quantifying a leak and can only be used to identify leak sources. The camera is capable of identifying leaks (using a variety of lenses) that are inaccessible to conventional techniques that principally rely on direct access.
- The camera offers visual confirmation of leaking emissions sources and allows rapid source identification; however, ambient hydrocarbon concentrations may interfere with the camera ability to isolate a leak source. Engine magnetos caused interference and precluded leak screening on fuel gas headers, individual cylinder connections, and fuel injectors, significant leakage sources on older engines;
- Water vapor overlays the hydrocarbon absorption spectra and therefore steam plumes are visually comparable to hydrocarbon leaks and very difficult to differentiate;
- Rain and fog limit the IR camera utilization; and
- The IR camera cost is approximately \$75,000 to \$100,000 compared to \$5,000 to \$10,000 for conventional leak screening tools. Typical daily costs for a conventional leak screening team is \$1,500 plus expenses while a typical daily charge for an experienced IR camera team is \$3,000 plus expenses.

Leaks can occur through valves and pressure relief valves that have not seated properly after activation. This leak is not out of the process equipment and so cannot be seen with optical methods or by organic vapor analyzers. Instead an acoustic method has been developed that measures the noise generated by gas flowing through a small gap. The acoustic detector compares the sound before the valve, at the valve and downstream from the valve and compares the sound to a database of previously measured leaks. This instrument was used to measure leaks at pressure relief valves.

Due to the high volume of flared hydrocarbons at several sites and the large number of possible sources tied into the flare system (e.g., leaking pressure-relief devices, drains, and blowdown valves connected to the header), connecting the flare to a vapor recovery unit should be considered as a cost effective option for capturing the residual gas flow. Another option is to target the individual residual gas flow sources; however, these sources are often difficult to isolate, usually require a major plant shutdown to fix (i.e., resulting in significant indirect costs), and are likely to reoccur.

Figure 5. Soap Solution Screening on a Two Inch Leaking Threaded Connector

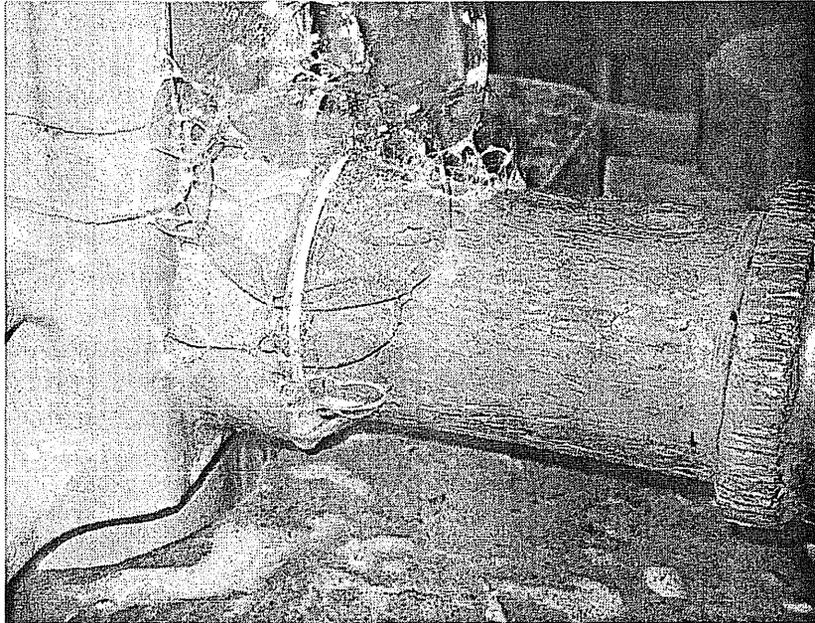


Figure 6. Tagged Leaking Components

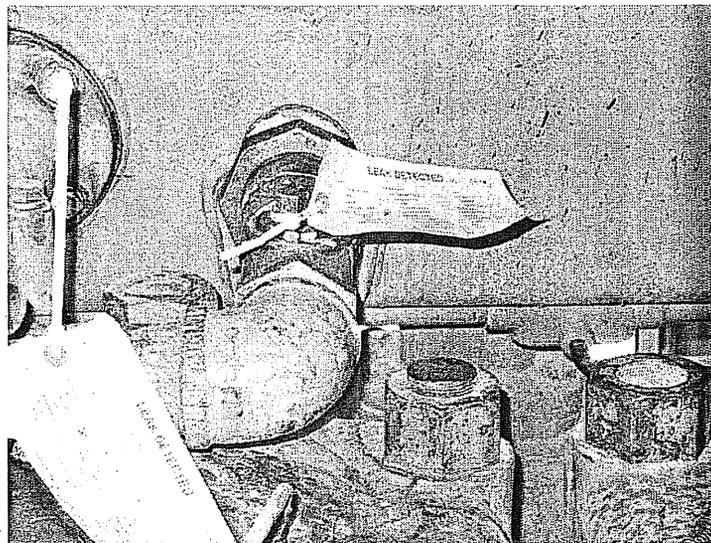
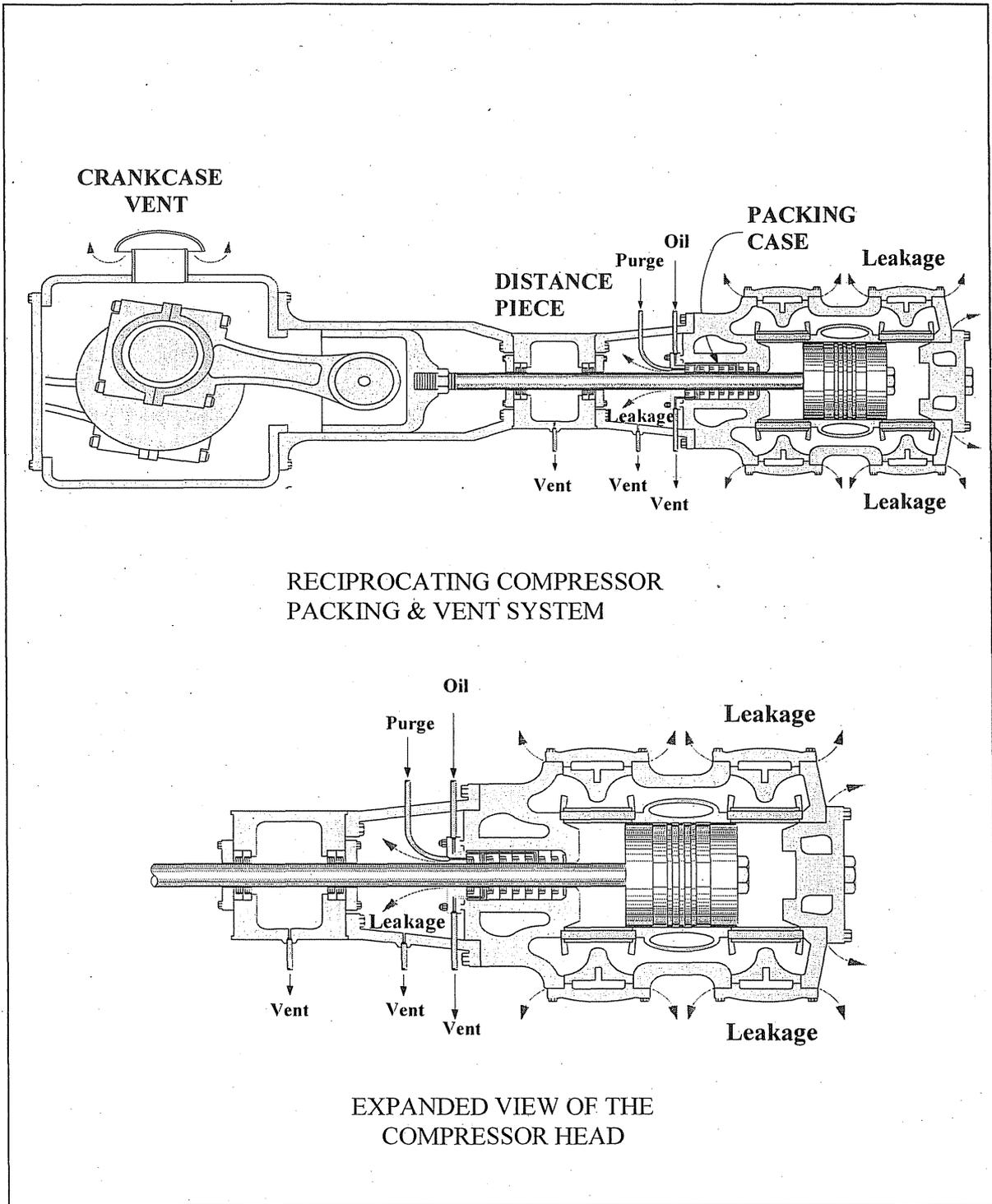


Figure 7. Cut-Away View Of A Natural Gas Compressor Showing The Potential Leak-Points Including The-Compressor-Seals And Crankcase Vent.



The following basic information was recorded for each leaking component:

- Type
- Model or Style
- Service
- Size
- Process Unit
- Process Stream
- Pressure and Temperature

3.1.3 Leak-Rate Measurements

The HiFlow™ Sampler was the primary emission rates measurement method for leaking equipment components. The HiFlow™ Sampler was not used for components leaking at rates above the equipment upper limit (i.e., about 14 m³/h for the current HiFlow™ design) and for most open-ended lines and vents. Either bagging or direct measurement techniques, as appropriate, were used in these cases (see Section 3.1.3). The same HiFlow™ prototype was used between Phase I and Phase II for consistency. The following provides a brief description of the HiFlow™ Sampler.

The HiFlow™ Sampler is an economic means of measuring individual leaking equipment components emission rates with sufficient accuracy for objective repair opportunities cost-benefit analyses. Bagging all leakers to differentiate between economic-to-repair and uneconomic-to-repair components is expensive and, therefore, is not normally done (typically, 10 to 30 leak-rate measurements per hour can be performed using the HiFlow™ Sampler compared to only 2 per hour using bagging techniques). Furthermore, compiling Method 21 (U.S. EPA, 1997) components screening data and then applying leak-rate correlations or stratified emission factors to determine leak rates does not provide sufficient accuracy for economic analysis. The correlation leak rate uncertainty for individual components is ± two orders of magnitude and the stratified emission factors are even less reliable. In comparison, the HiFlow™ Sampler and bagging measurements uncertainties are only about ±10 to 15%. Accordingly, the HiFlow™ Sampler (shown in Figure 6) provides a practicable means of making objective repair decisions. The reliability and use of the HiFlow™ Sampler has been demonstrated in a number of studies (Howard *et al.*, 1994; Lott *et al.*, 1995).

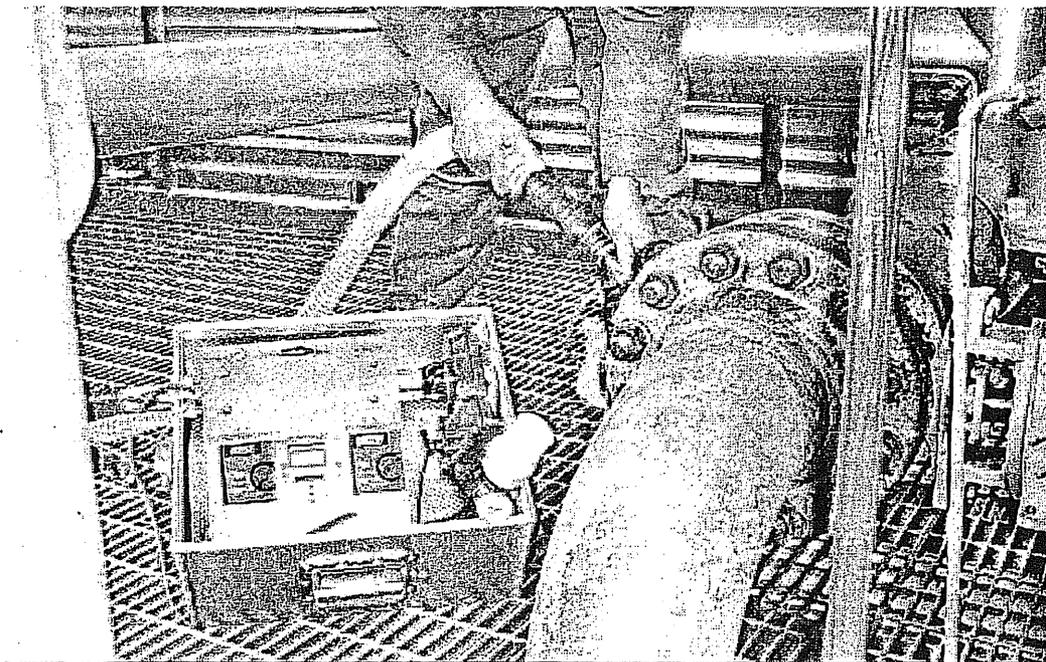
The HiFlow™ Sampler operating principle is simple – a variable-rate induced-flow sampling system provides total or near total leaking component emissions capture. Specially-designed attachments are used to encapsulate the leaking component and allow ambient air to flow over the component; the air-leaking gas mixture is drawn into the Sampler with a vacuum pump. A dual-element hydrocarbon detector (i.e., catalytic-oxidation/thermal-conductivity), inserted directly in the HiFlow™ sample line, measures hydrocarbon concentrations in the captured air-gas stream ranging from 0.01 to 100%. A background sample-

collection line and hydrocarbon detector allow the sample readings to be corrected for ambient gas concentrations, which is particularly important in buildings and confined areas. A thermal anemometer, also inserted directly into the sample line, monitors the sampled air-hydrocarbon gas mixture flow rate. The HiFlow™ Sampler is intrinsically safe and is equipped with a grounding wire to dissipate static charge formed as air passes through the sample collection line and instrument.

The HiFlow™ Sampler battery-operated fan can generate a maximum sampling velocity of approximately 366 m/min (1200 ft/min), which corresponds to a maximum leak rate measurement capacity of 14 m³/h (8.5 scfm). Increasing the sampling rate generally improves the leak capture efficiency up to the point of total capture. Increasing sampling rates beyond this point causes increased emissions dilution with ambient air. Excessive dilution may cause the pollutant concentration to either fall below the sample detector range or to decrease to background levels resulting in a zero reading. The sampling rate is adjusted manually using a backpressure valve mounted on the fan outlet. For large leaks, the backpressure valve is left open; while for small leaks, the airflow rate is reduced so that the hydrocarbon concentration is within the detector sensing range.

The HiFlow™ Sampler sample and background hydrocarbon detectors were calibrated with 100% methane and 2.5% methane-in-air to cover both ranges of the dual-element detector system. The detectors were zeroed using ambient air upwind of the facilities. The calibrations were done prior to HiFlow™ Sampler use at each site, and then periodically thereafter to ensure that no significant drift occurred. The HiFlow™ Sampler was also periodically calibrated by releasing known methane flows, determined using a bubblometer or diaphragm meter, into the sampler and comparing the leak rate measured by the HiFlow™ to the metered gas release rate. Three correction factors are applied to the raw data.

Figure 8. Prototype GRI HiFlow™ Sampler



3.1.4 Vents and Open-ended Lines Emissions Measurements

The emission rates from open-ended lines and vents were measured using an appropriate flow-through measurement device (i.e., a precision rotary meter, diaphragm flow meter, or rotameter, depending on the flow rate) if total flow capture was safe and practicable to achieve and the resulting backpressure on the vent system did not impact the gas flow. Otherwise, flows were determined by measuring the flow area and velocity profile across the vent line.

Where total flow capture was possible, the vent or open ended line pipe or tube was connected to the flow-through measurement device with PVC tubing. The tubing-pipe and tubing-flow meter connections were sealed with custom-fabricated slip-on sheaths made of neoprene or plastic sheeting. Each flow measurement was averaged over a 2 to 20 minute interval, depending on the flow volume and variability.

When measuring flows from vents, a distinction was made between continuous and intermittent vent systems. Emissions from intermittent vents during inactive periods (i.e. non-venting operation) were defined as leakage. Emissions from continuous vent systems and intermittent vent systems during active periods were defined as venting emissions. Vent and open-ended line leaks were detected by hydrocarbon sensor screening.

3.1.5 Residual Flaring Rates Determination

Flare line flows were determined using two methods:

- **Flare Line Velocity Profile and Flow Area Measurement** - Flow velocities were measured using a pitot tube, hot-wire anemometer or thermal dispersion anemometer. The traverse points were selected in accordance with U.S. EPA Methods 1 and 1A. Safe-to-access ports on the stack, the common line to the flare, or on each branch line connected to the flare system are required.
- **Flow Rate Calculated from Pressure Drops Measurements** - the pressure drop between the flare tip and a suitable upstream point on the flare line is measured and the gas flow required to produce that pressure drop is calculated. Several inches of water column pressure drop is needed for reasonable flow rate estimation. Low flow velocities in large diameter pipes may not produce measurable pressure drops despite significant volumetric flows.

The direct measurement method is more accurate and was used when sample ports were accessible. The gas stream hydrocarbon concentrations were either determined using a portable combustible-gas detector or from flare gas laboratory analyses (where available).

Continuous flare systems flows include purge gas flows and equipment fugitive leaks into the flare system. To distinguish between purge gas flows and leakage, the minimum required purge gas rate was calculated using the procedure presented by Stone *et al.* (1992). The difference between the total flare system gas flow rate and the calculated purge gas flow rate was assumed to be the leakage or potentially avoidable natural gas loss. The economics of conserving the gas losses can then be determined.

Primary sources of flaring and vented emissions include disposal of waste associated gas at oil production facilities, casing gas vents at heavy oil wells, gas operated devices, still column off-gas vents on glycol dehydrators, leakage into vent/flare header (5-10% of valves leak and 1-2% of these contribute 75%), excessive purge gas rates and inspection and maintenance activities including well testing, servicing, and pipeline tie-ins.

3.1.6 Natural Gas-Fueled Equipment Performance Testing

Natural gas-fueled engines, process heaters, and boilers were tested to identify avoidable inefficiencies causing excessive fuel consumption and emissions. The focus was on identifying situations where equipment required tuning, optimization, or repairs, or was mismatched with the current process demands causing operation outside the performance curve. The identification of

opportunities to recoup waste heat from the units or to reduce energy requirements through process modifications was beyond the project scope.

The testing on each unit involved analyzing the flue gas, measuring the flue gas temperature, obtaining a fuel gas composition analysis, and where possible, measuring the flow rate of one or more of the following: fuel gas, combustion air, and flue gas. The flue gas analyses were conducted using an Enerac 2000E Portable Combustion Analyzer equipped with detectors for O₂, CO, CO₂, NO_x, and combustibles and thermocouples for measuring ambient and stack-gas temperatures. The flue gas was sampled through either an exhaust stack sampling port or at the stack top. Additionally, the unit, make, and model and site ambient conditions (i.e., temperature and barometric pressure) were recorded.

Typically, insufficient process data were available to reliably estimate the total useful process work done by each unit, or to determine overall unit performance. Consequently, a simplified approach was used where the following parameters were evaluated and their deviations from proper operating conditions were indicators of improvement opportunities:

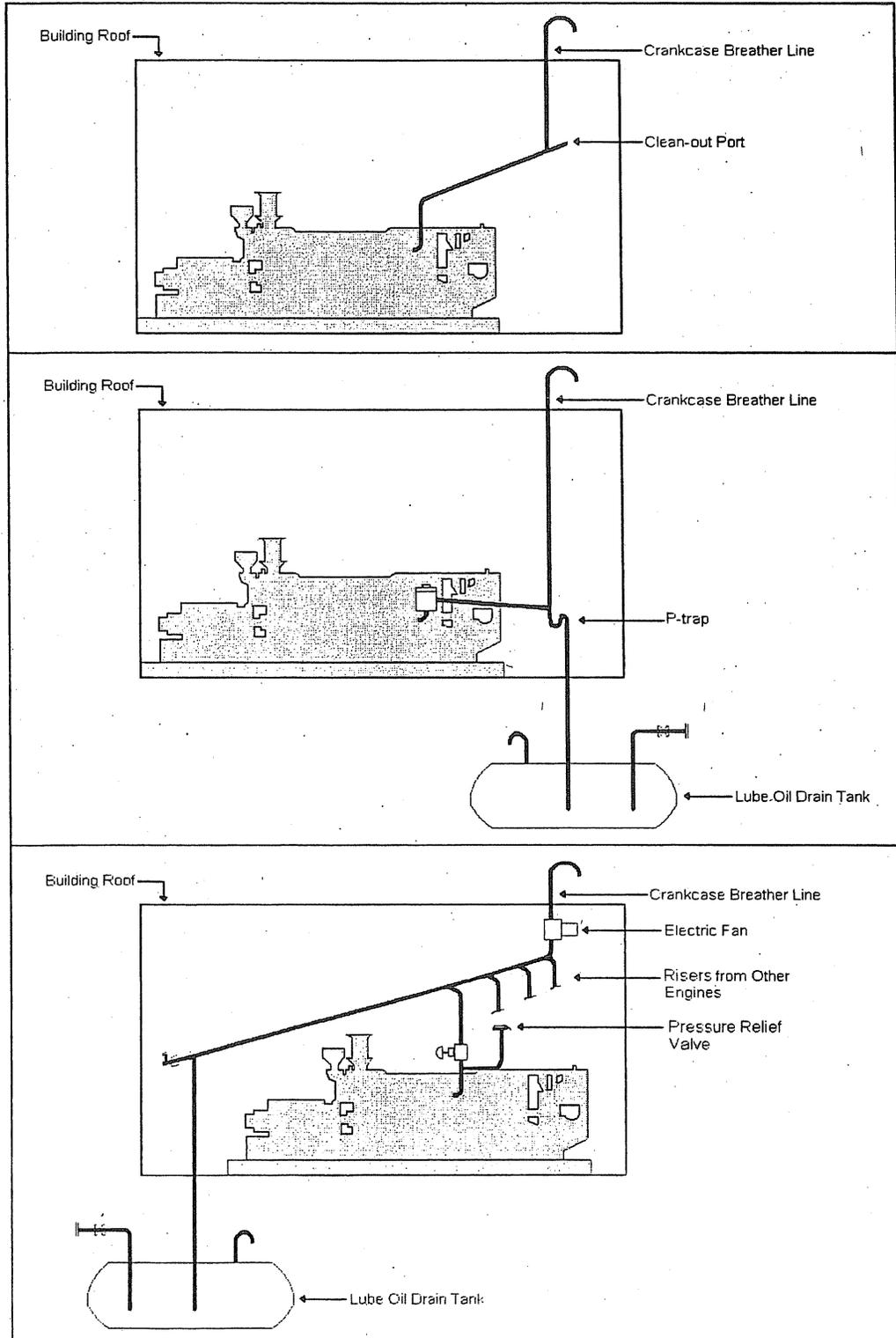
- flue gas residual heat content (i.e., stack losses);
- excess air setting; and
- flue gas concentrations of carbon monoxide and unburned hydrocarbons.

Additionally, reciprocating engines crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions. As a first approximation of the resulting performance loss, measurements were performed to quantify the combustible gases emitted as crankcase vent blow-by. These results are presented as fugitive equipment leaks. On integral compressor units (i.e., compressor units where the engine and compressor share a common crankshaft and crankcase), crankcase vent emissions potentially include engine cylinders blow-by and compressor seals leakage which enters the crankcase through the distance piece. This is shown in Figure 5.

In many cases, the engine crankcase was vented inside a building or work area. This poses a potential health and safety risk. Figure 7 depicts various venting configurations recommended by the engine manufacturers.

Key sources of combustion emissions include, oversized engines, heaters and boilers, poor tuning (e.g., air/fuel ratio), leakage past pistons in engines, lack of waste heat utilization, and fouled burner tubes.

Figure 9. Typical Stationary Compressor Engines Crankcase Vent Configurations Recommended by Manufacturers.



Where possible, equipment-specific emissions factors on either a kilogram-per-cubic-meter fuel basis (if the unit fuel consumption rate was known) or on a kilogram-per-day basis (if the flue gas flow rate was known) were generated for estimating CO, NO_x, CO₂ and combustibles emissions. A detailed calculations summary and a discussion of normal operating efficiencies and losses are provided in Appendix III.

3.1.7 Compression Equipment Analysis

This section outlines calculation methodology used in analyzing the compressor efficiencies and presents detailed results of the calculations. A reciprocating gas compression equipment analysis was conducted to identify avoidable compression inefficiencies caused by pulsation losses and internal gas leakage past the valves and piston rings. An acceptable energy loss from compression inefficiencies is 5% of the ideal energy requirement and excessive losses are generally avoidable (Hanlon, 2001). Another avoidable inefficiency associated with gas compression is excessive pressure drop through interstage coolers. Typically, interstage coolers have a design pressure drop of about 101 kPa, and excessive pressure drops may indicate cooler fouling.

The compression process is nearly adiabatic when no attempt is made to cool the gas internally as it is being compressed. If the process is assumed to be adiabatic and changes to the kinetic and potential energies of the gas are neglected, the work of compression varies with the change in enthalpy according to the following equation:

$$W = \dot{m}(h_d - h_s) \quad (\text{D.1})$$

Where:

- W is the compressor work
- \dot{m} is the mass flow rate of gas
- h_s is the suction enthalpy
- h_d is the discharge enthalpy

The following property data was collected for each stage of compression:

- $P_{s,m}$ – measured suction pressure
- $T_{s,m}$ – measured suction temperature
- $P_{d,m}$ – measured discharge pressure
- $T_{d,m}$ – measured discharge temperature

For a simple compressible system the state is specified by two independent intensive properties. Therefore, other properties of interest such as enthalpy and entropy follow from the temperature and pressure measurements and the actual work of compression can be calculated using Equation D.1.

For adiabatic compression the ideal process is isentropic. The suction state for the ideal process is still defined by the measured suction properties. Where as the ideal discharge state is defined is defined by the discharge entropy and measured discharge pressure. For an isentropic process entropy is conserved and the discharge entropy is determined from the suction state. The suction enthalpy follows from the state definition and the ideal compression work can be calculated using Equation D.1. This ideal compressor work is corrected to account for valve pressure drop based on the method presented in Figure 13-14 of Gas Processors Suppliers Association Engineering Data Book Volume 1. The corrected ideal state is then defined by the enthalpy calculated using equation D.1 and the measured discharge pressure. The corrected ideal discharge temperature follows from the state definition.

In practice the extent to which the corrected ideal compressor efficiency can be achieved is limited by physical constraints such as pulsation losses and valve slippage. For the purpose of this analysis an acceptable energy loss is taken as 5% of the corrected ideal energy requirements (Hanlon, 2001). The acceptable discharge state is then defined by the enthalpy calculated using Equation D.1 and the measure discharge pressure. The acceptable discharge temperature follows from the acceptable discharge state.

For situations where the actual compressor work is greater then the acceptable compressor work a potential savings is estimated. This estimate takes into account the efficiency of the compressor driver and the price of natural gas.

Key sources of compressor inefficiencies include, internal valve and cylinder leakage in reciprocating compressors, pulsation losses, excessive gas recirculation, non-optimal loading.

3.1.8 Storage Tanks Excess Emissions Evaluations

Storage tanks are a potentially significant emission sources due to evaporation losses, particularly where intentional product boiling or flashing occurs. Primary sources of storage tank emissions include:

- Flashing losses at production facilities;
- Unintentional gas carry-through to storage tanks;
- Leaking drain and dump valves;
- Malfunctioning level controllers;
- Inefficient upstream gas/liquid separation;
- Piping changes resulting in unstabilized product going to tanks;
- Malfunctioning vapor recovery systems;
- Faulty blanket gas regulators or pressure controllers; and
- Fouled vapor collection lines.

However, other less recognized, and often unnoticed; contributions to atmospheric emissions or vapor losses from storage tanks include the following:

- Process gas or volatile product leakage past drain or blowdown valves seats into the product header leading to the tanks;
- Inefficient upstream gas/liquid separation allowing some gas carry-through (by entrainment) to the tanks. This usually occurs where facility inlet liquid production (e.g., produced water) has increased significantly over time causing inlet separators to be undersized for current conditions;
- Piping modifications causing unintentional routing of high vapor pressure product to tanks not equipped with appropriate vapor controls;
- Storage tanks overheating or hot product rundown to tanks containing volatile material;
- Malfunctioning or improperly set blanket gas regulators and vapor control valves can cause excessive blanket gas use and, consequently, increased flows to a vent or control device (e.g., flare or vapor recovery compressor). The blanket gas is both a product vapors carrier and a potential pollutant itself (i.e., natural gas is usually used as the blanket medium for blanketed tanks at gas processing plants); and
- Leaking hatches and pressure-vacuum valves on tanks equipped with gas blanketing systems result in direct atmospheric emissions of product vapors and blanket gas.

The last two leaks are reported under flare systems and fugitive equipment leaks, respectively. The other leaks were determined by measuring venting rates (see Section 3.1.3) and comparing the observed emissions to calculated working losses for conditions at the time of testing.

3.1.9 Component Counts

Equipment component counts were prepared based on an initial review of the process and instrumentation drawings, followed by a site walk-through inspection of each process unit. The following component information was collected:

- type (e.g., connector, valve, control valve, pressure relief valve, pressure regulator, orifice meter, other flow meter, blowdown, open-ended line, etc.);
- style (e.g., threaded and flanged connection, coupling, ball valve, plug valve, globe valve, gate valve, butterfly valve, pump seal, compressor seal, regulator, sampling connection, etc.);
- nominal size;
- process temperature and pressure;
- service (i.e., natural gas, light hydrocarbon liquid); and
- application (i.e. process stream and unit).

3.1.10 Average Emission Factors Development

The average emission factor for each component type was determined by dividing the aggregate component emissions by the number of components. Total emissions are the sum of emissions from both leaking and non-leaking components. Leaking components (i.e., those with screening values of $\geq 10,000$ ppm) emission rates were quantified using the methods described in Section 3.1.2. Non-leaking components were assigned the average non-leaking emission rates presented in the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995).

3.1.11 Emission Control Guidelines

There are currently no regulations or codes of practice that apply specifically to fugitive equipment leaks emissions control for natural gas processing facilities. Guidelines typically used are maximum leak frequencies of 10% for compressor seals, 0.5% for connectors, and 2% for other component types

3.2 Equipment Repair Cost-Benefit Analyses

Practicable opportunities for reducing fugitive equipment leak and process venting emissions were assessed on a source-by-source basis. The net cost/benefits of identified control options were determined in dollars per tonne of CO₂-equivalent annual emissions reduction. The information and assumptions regarding the cost estimates, the lost gas value, and repair lives used in these analyses are summarized below. The financial discount rate and other financial considerations applied in these analyses are summarized in Appendix V.

3.2.1 Equipment Repair Cost Estimating

Detection and control costs are assessed on an individual-source or per-component basis according to estimated average site-specific costs. Actual costs will vary with the facility location and layout, the required work, the service type (i.e., sweet or sour), and the actual repairs or control measures required.

The basic cost to repair or replace a leaking equipment component is estimated based on the component type and size, typical billing rates quoted by the service providers (e.g., compressor maintenance and repair companies, and valve repair and servicing companies) and the estimated labour and materials requirements. Where possible, both direct and indirect costs are considered. Direct costs are the actual costs for parts, onsite labour, equipment, tools and disbursements, and are summarized in Appendix VI. Indirect costs are revenue losses due to any process shutdowns or interruptions beyond normally scheduled facility turnarounds, and the value of gas vented or flared during the specified repair or replacement activity. Where indirect costs render the repair or replacement cost ineffective, it is assumed that the work will be delayed until the next scheduled plant

turnaround. Otherwise, it is assumed that the repairs are made soon after the leak detection and evaluation.

3.2.2 Natural Gas Value

The value of natural gas was assumed to be \$7.15/Mscf (\$6.78/GJ). The propane, butane and condensate values were assumed to be: propane \$8.13/GJ; butanes \$9.63/GJ and condensate \$9.63/GJ. The actual value of avoided natural gas losses is very site-specific and can depend on many factors including:

- Local market pricing;
- Impact of emission reductions on specific energy consumption, equipment life, workplace safety, and system operability, reliability and deliverability;
- Contract terms;
- Facility remoteness;
- Gas concentrations of contaminants and NMHCs;
- Applicable taxes and tax shields.

3.2.3 Repair Life

It was assumed that a leak, once repaired, will remain fixed for some finite time period, and then will reoccur. The mean time between failures depends on the component type, style, quality, application, and activity levels (e.g., number of valve operations) and site maintenance practices. Estimates of the mean time between failures for each component type are provided in Appendix VI. These values are very crude estimates based on the author's experiences and limited host facilities feedback. The relatively low mean time between failures for connectors reflects wear and tear from inspection and maintenance of associated equipment units. In a formal leak detection and repair program, information on maintenance practices and mean times between failures is tracked and is used to identify problem service applications and to evaluate the need to change to component specifications and maintenance practices.

3.2.4 Cost Curves

A cost curve shows the estimated net cost required for different levels of site emission reductions. Each point on the curve represents the impact of implementing a different emission-reduction measure. The costs are based on a mix of facility and vendor data and consensus estimates developed in consultation with the facilities. The presented costs do not include those to find and evaluate emissions reduction opportunities and are therefore biased slightly low (typically, these costs are small compared to the control costs). Different control actions have different lifetimes; therefore, for comparison purposes, the credited emission reduction for each control option on the cost curve only includes the first year emission reduction (for these analyses, the shortest repair lifetime is assumed to

be one year). Control measures with lifetimes greater than one year will have reduced costs per unit emission reduction.

4 RESULTS

This section provides an overview of the atmospheric emissions and natural gas losses determined for each of the five sites, and delineate the main cost-effective loss-reduction opportunities. Additionally, average total hydrocarbon (THC) emission factors and leak statistics are presented for fugitive equipment leaks at these facilities.

Tagged-component information and individual leak rates for all leaking components are presented in Appendices I and II. Detailed results of the performance tests done on all active combustion sources are provided in Appendix III.

4.1 Emission Inventory

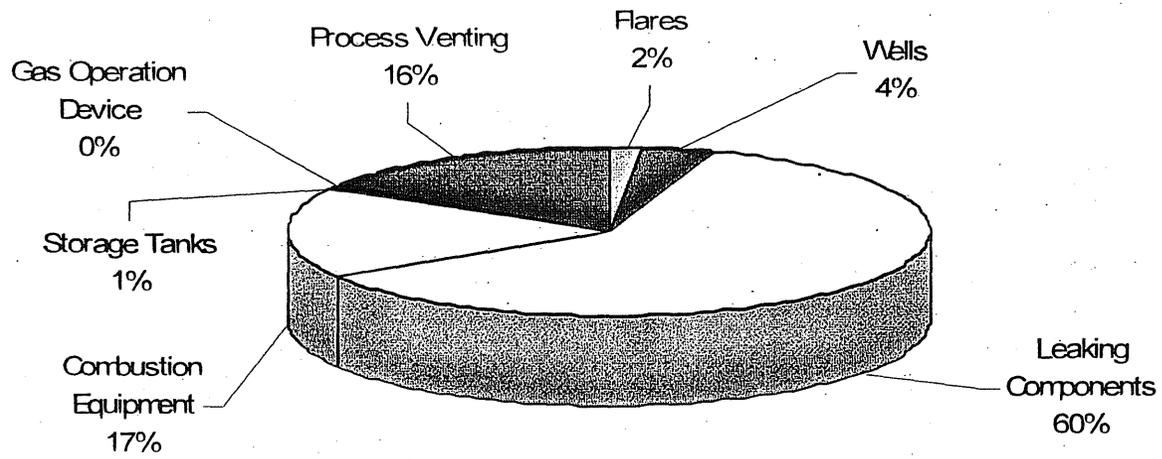
Total atmospheric emissions of methane, NMHC and GHG emissions from the five host gas processing plants amounted to 8,072 and 3,625 tonnes per year and 598,184 tonnes CO₂E per year, respectively. The relative distributions of these emissions by source category are presented in Figures 8 to 10. The carbon dioxide equivalent GHG emissions were calculated using the most recent 100-year global warming potentials (IPCC, 1996) (i.e., 1 for CO₂ and 21 for CH₄). GHG emissions consider methane and CO₂ only and do not include Nitrous Oxide (N₂O) emissions from combustion sources. The methane content of the measured THC emissions was determined based on typical gas analyses for the site and the analysis results for samples collected during the measurement program. Emissions of nitrous oxide were not evaluated but would be expected to contribute only a few % to total GHG emissions at each site.

As shown in Figure 8, fugitive equipment leaks (leaking components) are the dominant source of methane emissions, accounting for 60% from all sources. This is followed by incomplete fuel combustion (17%), process venting (16%), wells (4%), incomplete flare gas combustion (2%), and a small amount (1%) from storage tanks and gas operated devices.

Figure 9 shows fugitive leaks (leaking components) are the major source of NMHC emissions (73%). The rest (27%) was contributed primarily by combustion equipment and wells.

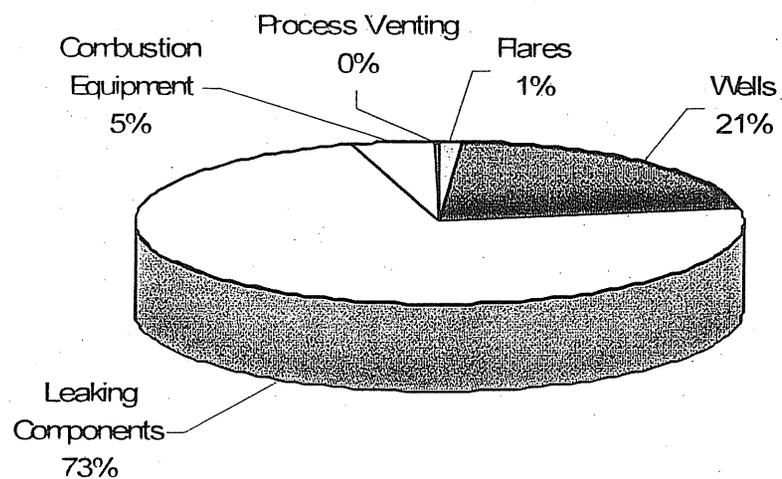
The CO₂E GHG emissions are predominantly from fuel consumption by combustion equipment (74%) as shown in Figure 10. However, fugitive equipment leaks (17%), as well as process vents (5%) may generally offer more cost-effective control opportunities.

Figure 10 Distribution of Methane by Source Category for All Sources.



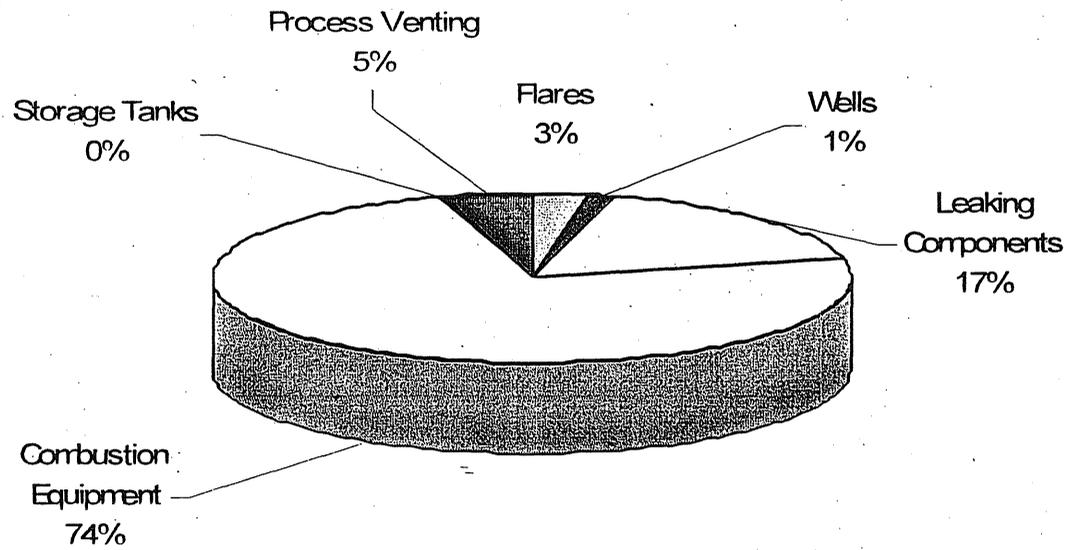
Methane Emissions = 8,072 tonne/yr

Figure 11 Distribution Of Non-Methane Hydrocarbon Emissions By Source Category



NMHC Emissions = 3,625 tonne/yr

Figure 12 Distribution Of Total GHG Emissions By Source Category.



GHG Emissions = 598,184 CO₂E tonne/yr

4.2 Natural Gas Losses

The value of natural gas is taken to be \$7.15 Mscf (\$6.78/GJ). The values for propane, butane and condensate are taken to be as follows: propane \$8.13/GJ; butanes \$9.63/GJ and condensate \$9.63/GJ. The determined gas losses include direct leakage and venting of natural gas to the atmosphere as well as losses into the process (e.g., excess fuel consumption by out-of-tune or inefficiently-operated engines and heaters, and gas leakage into flare systems). These latter losses lead to increased combustion emissions without any net process benefit.

The relative distribution of natural gas losses by source category is shown in Figure 11. Leaking equipment components are the greatest source of natural gas losses at the gas plants, accounting for 55% of the total. Other major sources include leakage into flare systems (24%), process venting (9%) and wells (8%). As shown in figure 12, natural gas losses from equipment leaks are contributed by open-ended lines, connectors, compressor seals and block valves, accounting for 32, 30, 20 and 15%, respectively. The top ten leakers at each site (other than site 1) contributed over half of the total natural gas losses from fugitive equipment leaks (refer to Table 2).

4.3 Fugitive Equipment Leaks

The following subsections characterize the fugitive equipment leaks for components in natural gas service at the surveyed gas plants. An overview of the fugitive leaks from gas processing plants, gathering compressor stations, and well sites is shown in Table 3. The lost values from these sources are \$536,270 from gas plants, \$49,018 from gathering compressor stations, and \$3,183 from well sites per year.

4.3.1 Average Emission Factors

Average emission factors were determined for each type of equipment component in natural gas service at the surveyed sites. The results are presented in Table 4 and are compared to corresponding factors published by U.S. EPA (1995) for oil and gas production operations and by U.S. EPA and GRI (1996) for natural gas facilities. Overall, the developed average emission factors are greater than those for oil and gas production facilities, and more comparable to the previous values for natural gas facilities.

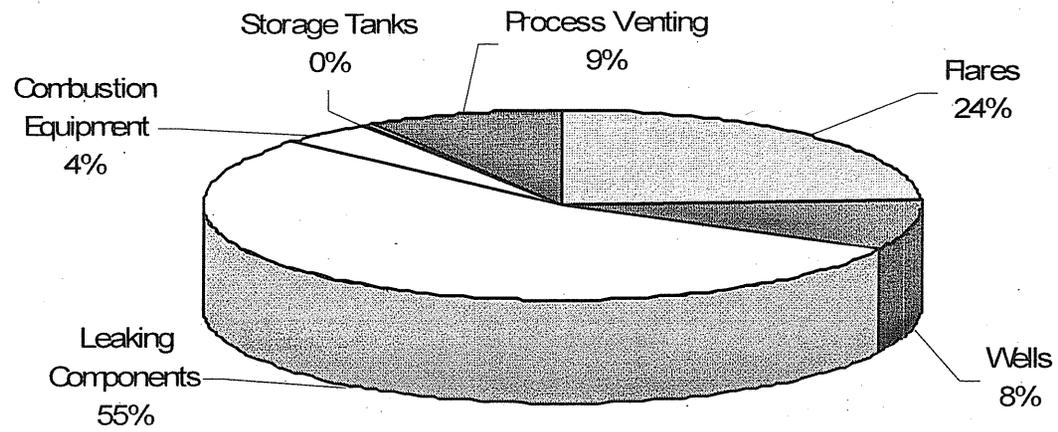
The average emission factors are simply the total emissions from all tested components divided by the total number of components of that type surveyed. Quantification of emissions from non-leaking components (i.e., components with screening values between zero and 10,000 parts per million) was not attempted. Instead, emissions from these components were assumed to be represented by the average no-leak emission rates presented in the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995).

| Plant No. | Gas Losses from Top 10 Leakers (Mscfd) | Gas Losses from Measurable Fugitive Leaks (Mscfd) | % Contribution by Top 10 Leakers | % of Total Leakers |
|-----------|--|---|----------------------------------|--------------------|
| 1 | 78 | 271 | 29 | 0.04 |
| 2 | 13 | 23 | 56 | 0.08 |
| 3 | 53 | 117 | 45 | 0.05 |
| 4 | 60 | 69 | 87 | 0.06 |
| 5 | 317 | 423 | 75 | 0.21 |
| Combined | 521 | 903 | | |

¹ Excluding leakage into flare systems.

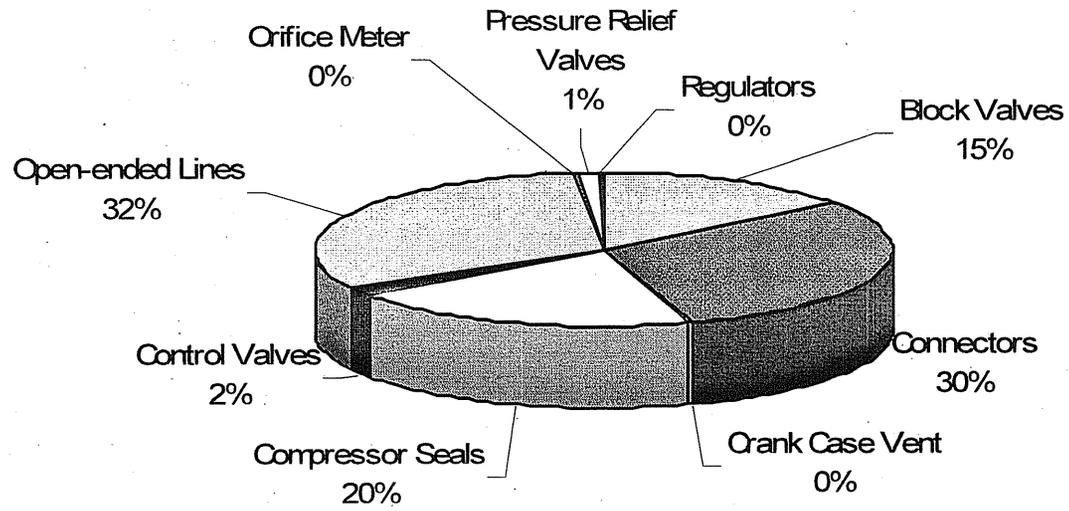
| Facility Type | Number of facility surveyed | Number of Components Screened (Components /facility) | Number of Leaks Identified (leaks /facility) | THC Emissions From leaking Components (Tonne /Yr/Facility) | Methane Emissions (Tonne /Yr/Facility) | GHG Emissions from Leaking Components (Tonne /yr/facility) | Value of Emissions From Leaking Components (\$/year /facility) |
|------------------------------|-----------------------------|--|--|--|--|--|--|
| Gas Plant | 5 | 12,243 | 232 | 1,348 | 882 | 18,561 | \$536,270 |
| Gathering Compressor Station | 7 | 2,423 | 87 | 131 | 97 | 2,044 | \$49,018 |
| Well Site | 12 | 238 | 11 | 8 | 6 | 117 | \$3,183 |

Figure 13 Distributions of Natural Gas Losses By Source Category



Total Natural Gas Emissions = 14,457 tonne/yr

Figure 14 Distribution Of Natural Gas Losses From Equipment Leaks By Type Of Component



| Table 4. Comparison Of Average THC Emission Factors Derived From Data Collected In Both Phases To Other Published Values. | | | | |
|--|---|-----------------------|-----------------------------|--|
| Source | Average Emission Factors (kg/h/source) | | | |
| | Phase I Study | Phase II Study | U.S. EPA^A | U.S. EPA Gas Facilities^{B,C} |
| Connectors | 2.22E-03 | 3.30E-03 | 2.00E-04 | 3.05E-04 |
| Block Valves | 1.10E-02 | 1.47E-02 | 4.50E-04 | 3.40E-03 |
| Control Valves | 4.85E-02 | 3.73E-02 | 4.50E-04 | N/A |
| Pressure Relief Valves | 6.73E-02 | 4.70E-04 | 8.8 E-03 | 2.24E-03 |
| Pressure Regulators | 1.74E-02 | 6.31E-03 | 8.8 E-03 | N/A |
| Orifice Meters | 3.58E-03 | 2.70E-03 | 8.8 E-03 | N/A |
| Crank Case Vents | 8.83E-01 | 1.20E-01 | N/A | N/A |
| Open-Ended Lines | 5.18E-02 | 2.39E-01 | 2.00E-03 | 9.02E-02 |
| Compressor Seals ^D | 8.52E-01 | 5.20E-01 | 8.8 E-03 | 1.17E+00 |

N/A Emission factor for this source type is not available.

^A Source: U.S. EPA. 1995. Protocol for Equipment Leak Emission Estimates. Research Triangle Park, NC 27711.

^B Source: U.S. EPA and GRI. 1996. Methane Emissions from the Natural Gas Industry. Volume 8: Equipment Leaks. Research Triangle Park, NC 27711.

^C The factors presented in the column are for methane emissions only but should be comparable to, although slightly less than, the corresponding THC values for the applicable component categories. The factors presented in the other two columns are for THC emissions.

^D Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

4.3.2 Average Leak-Rate Trends

A statistical analysis of the compiled leak data was performed to identify any trends or correlations that could be used to help focus leak detection and control efforts. The effects of component type and style, process temperature and pressure, component size, application (i.e., type of process unit on which the component is used), and type of process stream (e.g., fuel gas, residue gas, acid gas, etc) were evaluated. In the following section, the average emission factors are given as total hydrocarbons on a kg/h/source basis to be consistent with published average emission factors (U.S. EPA, 1995). The main findings are as follows:

- Average hydrocarbon fugitive emission rates for connectors, open-ended lines and block valves are shown by stream types as shown in Figure 13, 14, and 15, respectively. These three components account for 77% of the total natural

gas fugitive emissions. Components in fuel gas and process gas services, even though not registered to have the highest average emission rates, have consistently to be on the highest four averaged emission rates among these three component types. In Figure 14, open-ended lines in propane and C₄ streams have significantly higher average emissions rates. This resulted from a combination of low component counts and was dominated by a large leak identified in the categories. Each point on figures 13-15 denotes the average emission factor for the corresponding streams the component is serving on the horizontal axis. The integer shown adjacent to each emission factor value is the number of data used to develop the factor. The vertical line through each average emission factor denotes the 95% confidence limits based on the variance in the compiled data and number of data points assuming a normal distribution. Under each of the component categories shown, one can not conclude an average emission rate is a function of stream type due to the large 95% confidence interval. However, general trends were implicated.

- Average hydrocarbon fugitive emission rates for connectors, open-ended lines and block valves are shown *by process unit* as shown in Figures 16, 17, and 18, respectively. For all three component types shown, their average emission rates in compressors and mole sieve units are among the top three process unit types. While connectors, and block valves in sales units have relatively low average emission rates, open-ended line in sales unit registered the highest average emission rate among all process units. This resulted from the combination of low overall component counts of open-ended lines in sale unit and one single big leaker identified in this category.
- Components tend to have greater average emissions where subjected to frequent thermal cycling, vibrations, or cryogenic service (see figures 16-18).
- All other parameters had little or no impact on average emissions.

In the Figures below, C₂ = ethane, R = residue gas, FG = fuel gas, PG = process gas, P= propane refrigerant, C₄= butane, NGL = natural gas liquids, C₃= propane , LPG = liquefied petroleum gas.

Figure 15 Average THC Emissions For Connectors By Gas Streams

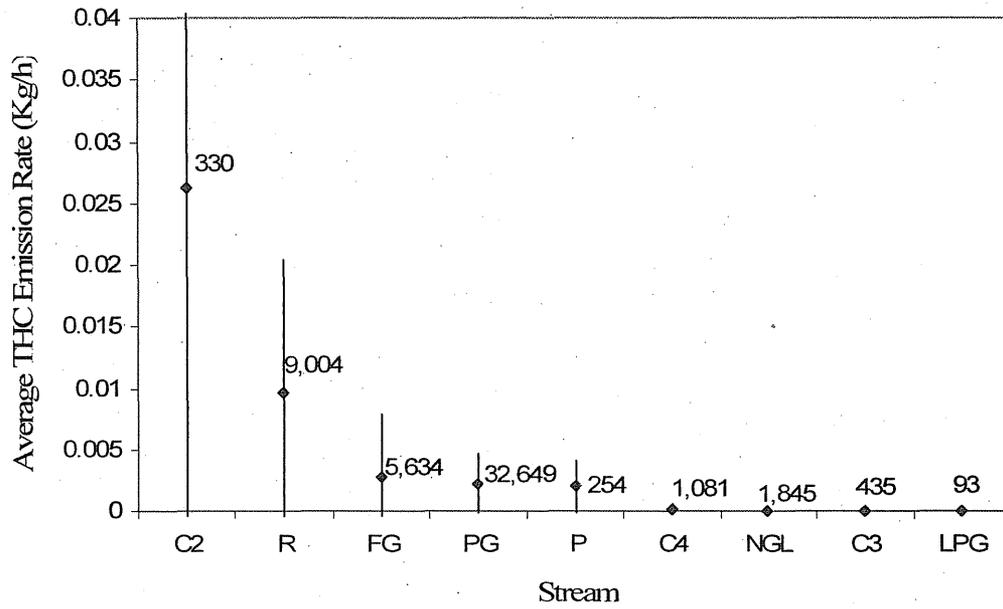


Figure 16 Average THC Emissions For Open-Ended Lines By Gas Stream

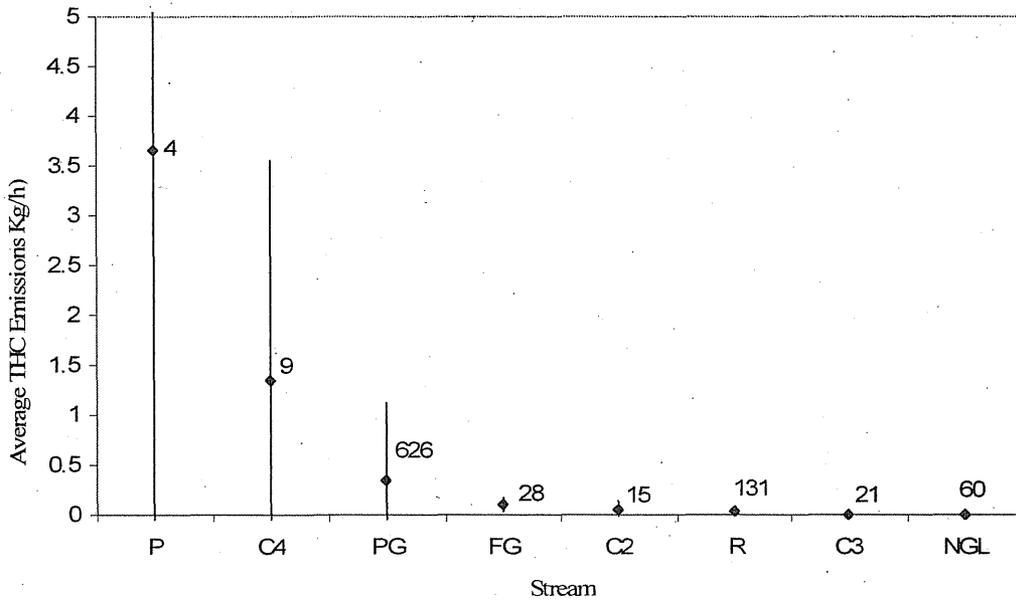


Figure 17 Average THC Emissions For Block Valves By Gas Stream

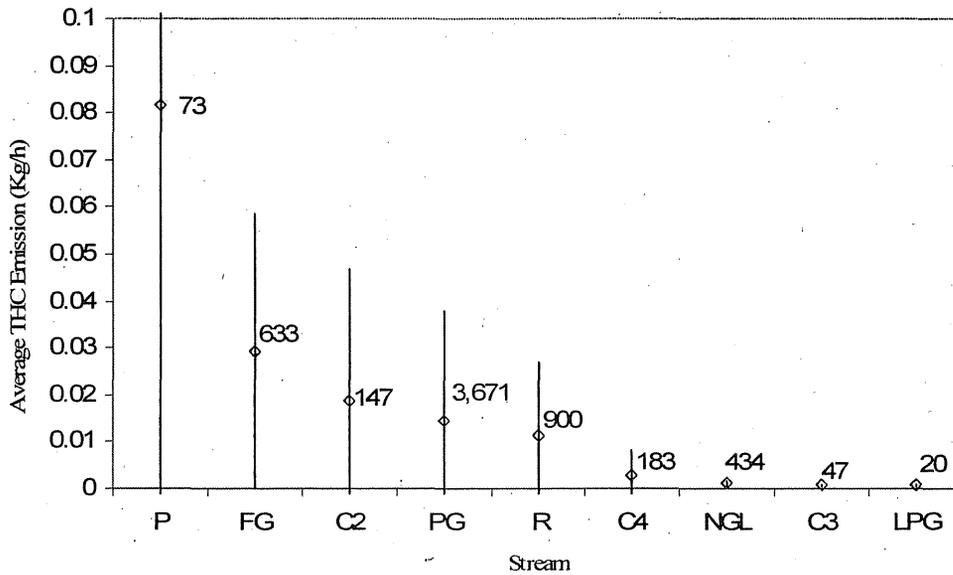


Figure 18 Average THC Emissions For Connectors By Process Unit

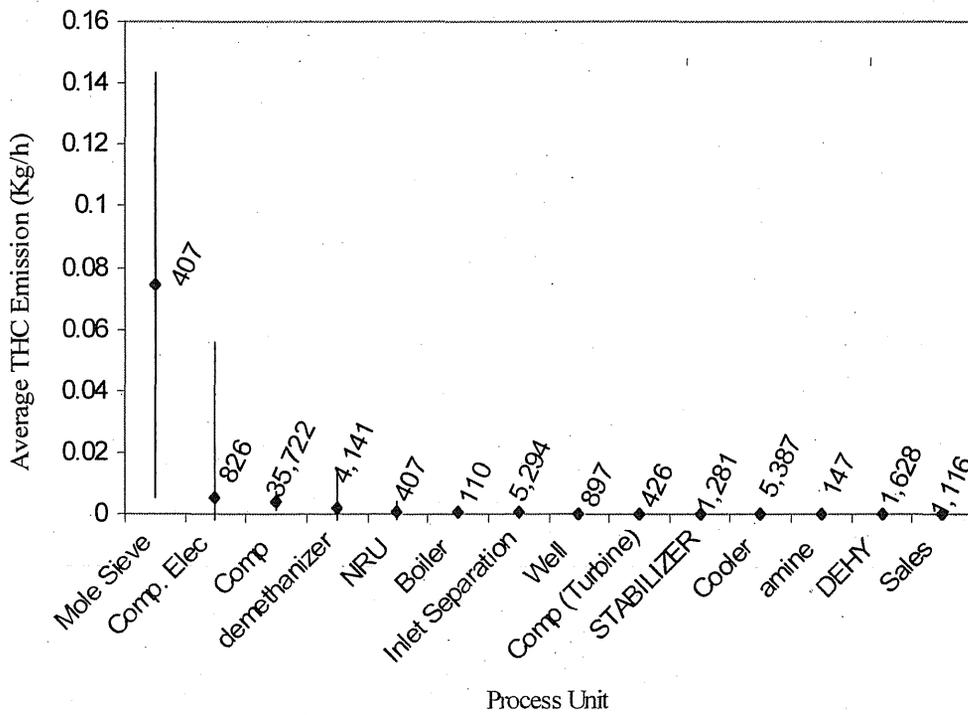


Figure 19 Average THC Emissions for Open-Ended Line By Process Unit

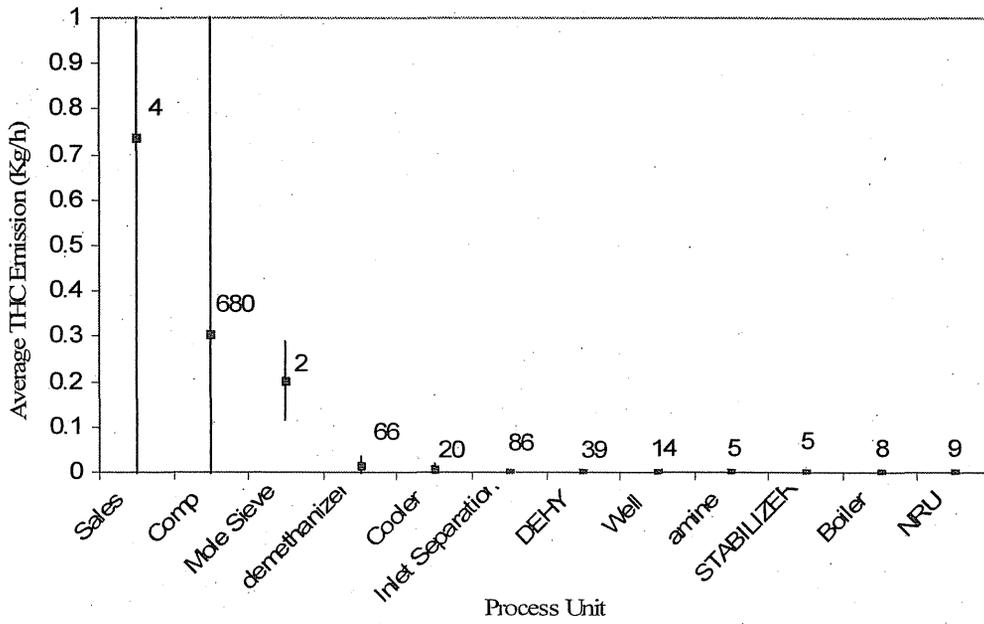
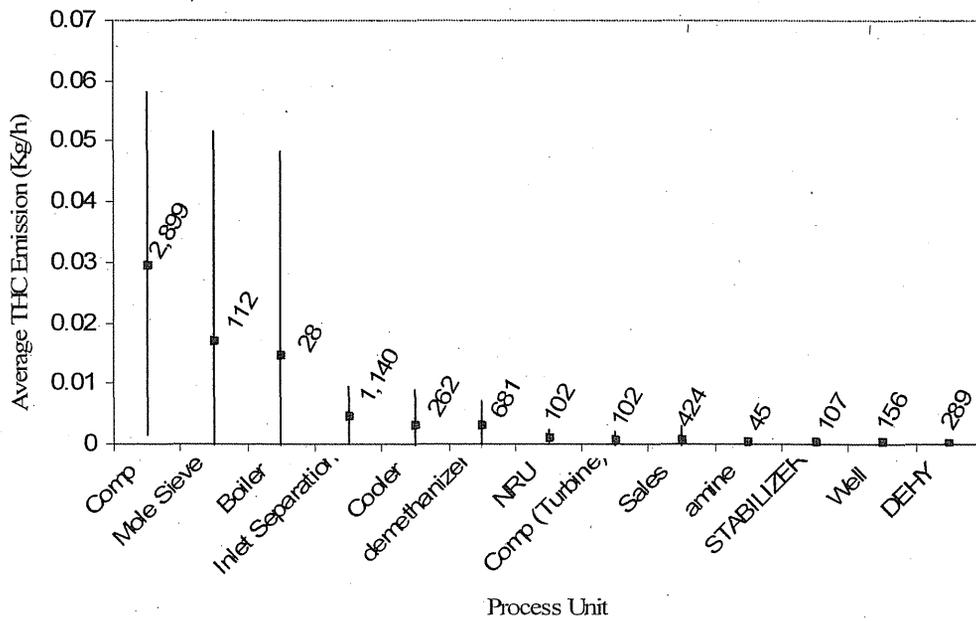


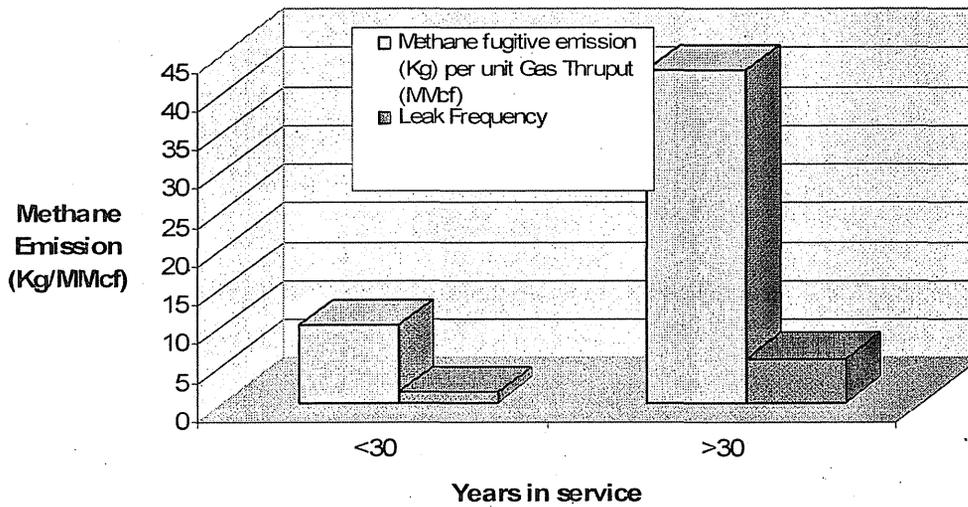
Figure 20 Average THC Emissions for Block Valves By Process Unit



Additional trends on the age of a facility, sweet/sour raw gas stream, and the potential of implementing a process-unit-targeted DI&M program are illustrated in the figures that follow.

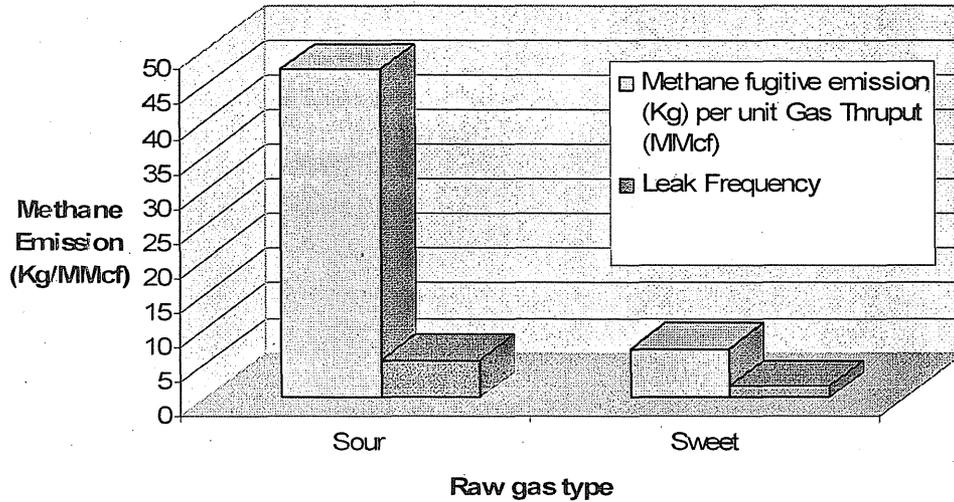
In Figure 19, the methane fugitive emission per unit gas throughput (kg / MMcf) and the leak frequency (%) are shown against years of service for the surveyed facilities. Facilities with longer than 30 years of service have higher methane fugitive emission per unit throughput and higher leak frequencies than those with less than 30 years of service. However, due to the limited number of surveyed facilities (3 with less than 30 years of service and 2 with longer than 30 years of service), it can not be concluded with statistical significance.

Figure 21 Methane Emissions Per Unit Gas Throughput For Plants With Different Service Duration



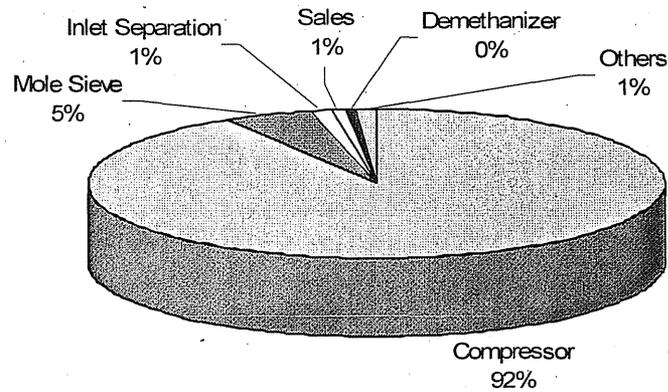
In Figure 20, the methane fugitive emission per unit gas throughput (kg / MMcf) and leak frequency are shown against raw gas type. Facilities with sour raw gas have significantly higher methane emission per unit gas throughput and higher leak frequency as well when compared with facilities with sweet raw gas input. As mentioned earlier, due to the limited number of surveyed facilities (3 with sweet and 2 with sour raw gas), the significance of sour versus sweet process plants can not be concluded with statistical significance.

Figure 22 Figure F Methane Emissions Per Unit Gas Throughput For Plants With Different Raw Gas Type



In Figure 21, fugitive methane emissions are shown against the process units. Compressor related components contributed the majority of methane fugitive emissions at 92% with the mole sieve being a distant second in methane emission contribution at 5%. These results validated the components under vibration (compressor units) and heat-cycle (mole sieve units) services are a lot more prone to leaks. The overwhelming percentage of methane emissions contributed by these two processes and related components warrants instituting a targeted DI&M program.

Figure 23 Methane Emissions Percentage by Process Units



4.3.3 Leak Frequencies

Fugitive equipment leaks are generally considered to be well controlled when the leak frequency for each component type (except connectors, compressor and pump seals) is 2% or less. For connectors, the allowable percentage of leaking components is 0.5%, and for compressor and pump seals the allowable percentage is 10%. Based on these guidelines, none of the categories for the combined plants would be considered adequately controlled (see Table 5). However, some categories at individual plants would have passed (i.e., connectors and block valves at Site 2). Table 5 below summarizes the most leak prone components. Compressor seals, orifice meters, control valves, and open ended lines constitute greater than 70% of the leak frequency. Figure 23 further illustrates the contribution of each component type to total THC emissions.

Table 5 Number of Components And Leak Frequency At Each Of The Five Gas Plants.

| | | Connectors | Block Valves | Control Valves | Pressure Relief Valves | Regulators | Orifice Meters | Crank Case Vents | Open-Ended Lines | Compressor Seals | Total |
|--------|------------------|------------|--------------|----------------|------------------------|------------|----------------|------------------|------------------|------------------|--------|
| Site 1 | Total Count | 20,045 | 1,581 | 91 | 43 | 63 | 8 | - | 332 | 127 | 22,290 |
| | Number of Leaker | 273 | 84 | 6 | 0 | 2 | 1 | - | 31 | 71 | 468 |
| | Leak Frequency % | 1.36 | 5.31 | 6.59 | 0.00 | 3.17 | 12.50 | - | 9.34 | 55.91 | 2.10 |
| Site 2 | Total Count | 10,705 | 1,392 | 82 | - | 69 | 25 | - | 57 | - | 12,330 |
| | Number of Leaker | 48 | 22 | 7 | - | 4 | 1 | - | 9 | - | 91 |
| | Leak Frequency % | 0.45 | 1.58 | 8.54 | - | 5.80 | 4.00 | - | 15.79 | - | 0.74 |
| Site 3 | Total Count | 15,552 | 2,225 | 108 | 59 | 46 | 10 | 3 | 291 | 59 | 18,353 |
| | Number of Leaker | 193 | 133 | 14 | 0 | 3 | 4 | 0 | 25 | 30 | 402 |
| | Leak Frequency % | 1.24 | 5.98 | 12.96 | 0.00 | 6.52 | 40.00 | 0.00 | 8.59 | 50.85 | 2.19 |
| Site 4 | Total Count | 14,509 | 1,657 | 158 | 21 | 131 | 11 | 23 | 160 | 17 | 16,687 |
| | Number of Leaker | 120 | 36 | 19 | 0 | 9 | 0 | 1 | 28 | 10 | 223 |
| | Leak Frequency % | 0.83 | 2.17 | 12.03 | 0.00 | 6.87 | 0.00 | 4.35 | 17.50 | 58.82 | 1.34 |
| Site 5 | Total Count | 3,558 | 837 | 56 | 1 | 11 | 3 | 1 | 215 | 96 | 4,778 |
| | Number of Leaker | 282 | 131 | 5 | 0 | 1 | 0 | 1 | 14 | 11 | 445 |
| | Leak Frequency % | 7.93 | 15.65 | 8.93 | 0.00 | 9.09 | 0.00 | 100.00 | 6.51 | 11.46 | 9.31 |
| Total | Total Count | 64,369 | 7,692 | 495 | 124 | 320 | 57 | 27 | 1,055 | 299 | 74,438 |
| | Number of Leaker | 916 | 406 | 51 | 0 | 19 | 6 | 2 | 107 | 122 | 1,629 |
| | Leak Frequency % | 1.42 | 5.28 | 10.30 | 0.00 | 5.94 | 10.53 | 7.41 | 10.14 | 40.80 | 2.19 |

4.4 Tank Emissions

Of the five sites surveyed, three contains leaky tanks that were measured during the site surveys. Thief hatches were found to be leaking and subsequently the volume flow was measured. The average value of gas loss is \$906,296 per year per site (see Table 6).

| Facility | THC Emissions (MMcf/year) | Methane Emissions (MMcf/year) | GHG Emissions (tonnes CO2E/year) | Value of Lost Product (\$/Year) |
|--------------------|--------------------------------------|--|---|--|
| Gas Plant 1 | 158.8 | 93.6 | 37,801 | 2,670,645 |
| Gas Plant 2 | 0.46 | 0.42 | 183 | 3,429 |
| Gas Plant 3 | 3.50 | 2.86 | 1,320 | 44,813 |
| Gas Plant 4 | NA | NA | NA | NA |
| Gas Plant 5 | NA | NA | NA | NA |
| Total | 162.7 | 96.9 | 39,304 | 2,718,887 |
| Average | 54.2 | 32.3 | 13,101 | 906,296 |

4.5 Results for Retested Site

One of the four surveyed sites from Phase I was retested in Phase II to investigate changes in its fugitive leak characteristics. Some of the process units from Phase I were decommissioned and replaced with new process units. Component count from the decommissioned process units (5,590 components) is about 30% of the total plant count from Phase I (18,390 components). The following sections discuss the process units that were replaced and the changes in fugitive emissions between the Phase I and Phase II plant surveys.

4.5.1 Overall Plant

Figure 22 shows the overall THC emissions between Phase I and II for the retest site. Component level emissions for each Phase were also demonstrated. The THC emissions increased about 50% from Phase I to Phase II. While the major THC contributors are the same between Phase I and II programs, the percentage contributions from each source following changes at the site were very different. The changes in the average THC emission rate for each component type are contrasted in Figure 23.

Figure 24 Total THC Emissions Between Phases

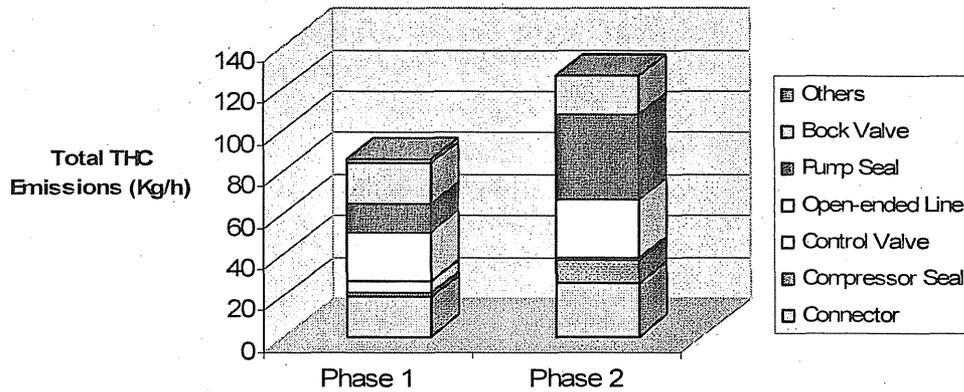
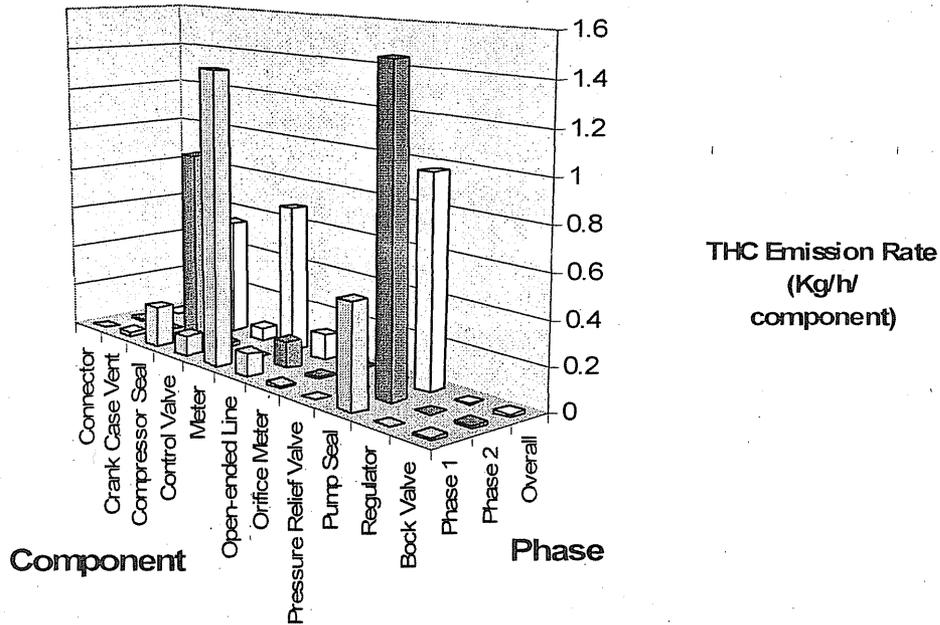


Figure 25 Component Emission Rate Between Phases



4.5.2 Replaced Process Units

About 30% of the original component count from Phase I was not active during the Phase II survey due to decommissioning and replacing equipment. These decommissioned process units were replaced with new process units and their

associated fugitive equipment emissions were compared with those from the decommissioned process units in Phase I. In Figure 24, the total THC emissions for these two sets of process units were compared. The THC emissions reduced by an estimate of 80% from Phase I (decommissioned units) to Phase II (new units). The average emission rates per component between Phase I and II are compared and are shown in Figure 25. With open-ended lines being the exception, all other components have significantly lower average emission rates in the newly added process units.

Figure 26 Total THC Emissions Between Phases

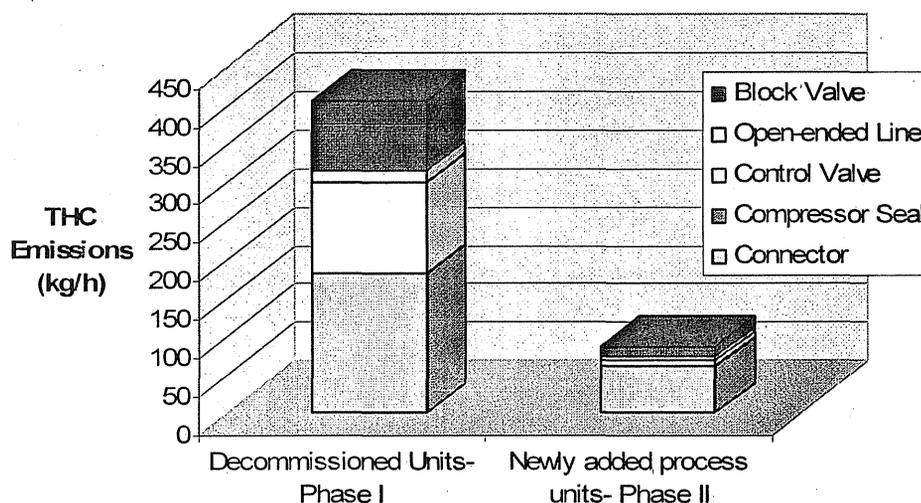
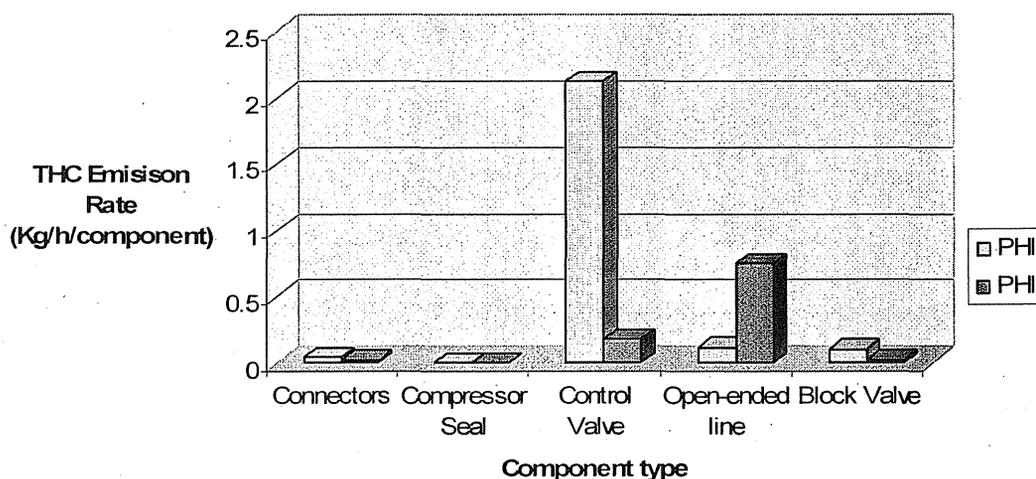


Figure 27 Component Emission Rate Between Phases



The results of this comparison tend to suggest that the DI&M program conducted at this facility has been ineffective at controlling emissions from fugitive equipment leaks. This apparent inability to control fugitive emissions using a

DI&M program may be attributed to a number of factors including: excessive duration between surveys; inadequate follow up to maintenance recommendations and insufficient documentation of maintenance activities. The 5 year time frame between these two surveys exceeds the estimated mean repair life for most components. This makes it difficult to assess the effectiveness of any repairs made in response to the Phase I survey because the leaks are likely to have reoccurred. Increasing the frequency of leak surveys to annually or bi-annually would allow for a better assessment of the effectiveness of maintenance activities and enable new leaks to be identified and repaired sooner. It is unclear what maintenance activities were undertaken in response to the Phase I survey. For example, a substantial leak from a weld failure identified during the Phase I survey was also found to be leaking during the Phase II survey. In order for the program to be effective, all cost-effective control opportunities should be acted on by either repairing the leak or reevaluating the economics to justify no action. Any maintenance performed in response to the survey should be adequately documented so the success of the repair can be addressed during subsequent site surveys. Accurate maintenance records will facilitate in tracking the true economics of the repair, and ultimately assist in establishing future control opportunities.

4.6 Control Opportunities

Practicable opportunities for reducing the identified natural gas losses were identified and assessed on a source-by-source basis. Overall, it is estimated that up to 96.6% of total fugitive natural gas losses could be avoided if all control opportunities with positive net cost or a positive payback are implemented (see Figure 26). This would result in corresponding reductions of 97% in fugitive methane emissions, 97% in fugitive GHG emissions, and 98% in fugitive NMHC emissions in the first year alone. Moreover, many of the control options have multi-year life expectancies resulting in significant emission reductions in subsequent years as well.

4.6.1 Cost Curve for Reduction of GHG Emissions

To further evaluate the control of natural gas losses as a means of reducing GHG emissions, it is useful to express the results in terms of a cost curve. Figure 27 presents the net annualized cost curve for implementation of the various opportunities identified at the five gas plants. The net cost of each target control opportunity is calculated as the equalized annual implementation cost over the life of the project (i.e., the net present cost of the opportunity expressed as an equivalent series of equal annual payments over the life of the project) divided by the resulting average annual CO₂-equivalent emission reduction.

Figure 27 shows that the incremental cost per tonne of CO₂E GHG emission reduction resulting from implementation of the available control opportunities in ranked order from most to least cost effective (i.e., see Table II-1 in Appendix II). The point at which the curve crosses over the abscissa axis (i.e., the axis of

cumulative CO₂E GHG emission reduction) is the amount of CO₂E emission reduction that could be achieved if only opportunities with a zero cost or a positive payback are implemented (i.e., 103,363 tonnes CO₂E reduction per year). This reduction amounts to 17% of total estimated GHG emissions from the five gas plants.

If a value is assigned to GHG emission reduction credits, then companies may choose to pursue opportunities even further out on the cost curve. The shape of the cost curve shows that there are a few very attractive control opportunities, a large number of moderate control opportunities, and eventually a point of diminishing returns.

Figure 1 Emissions From Economically Repairable Sources

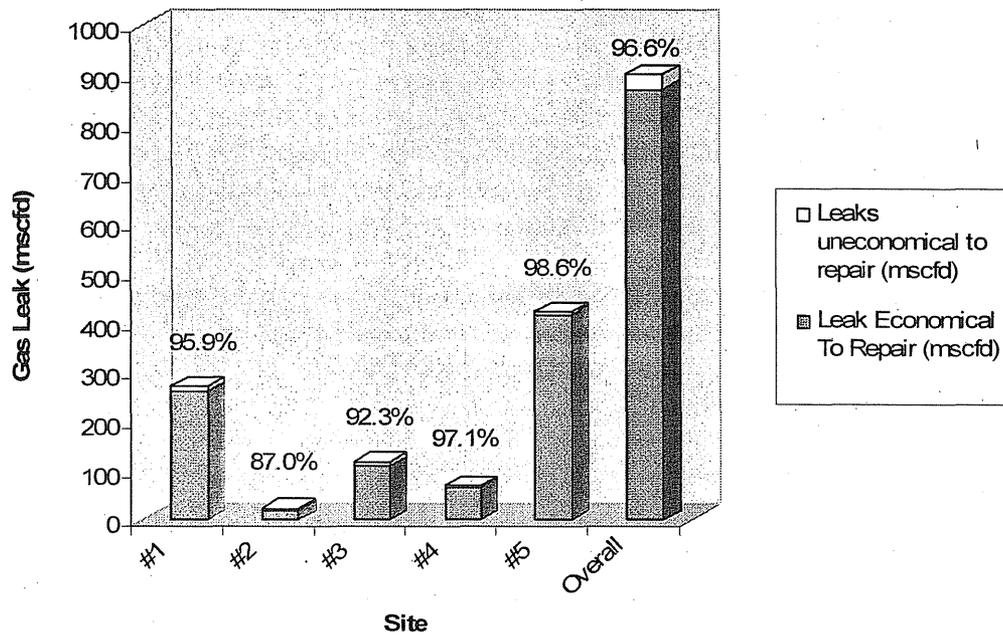
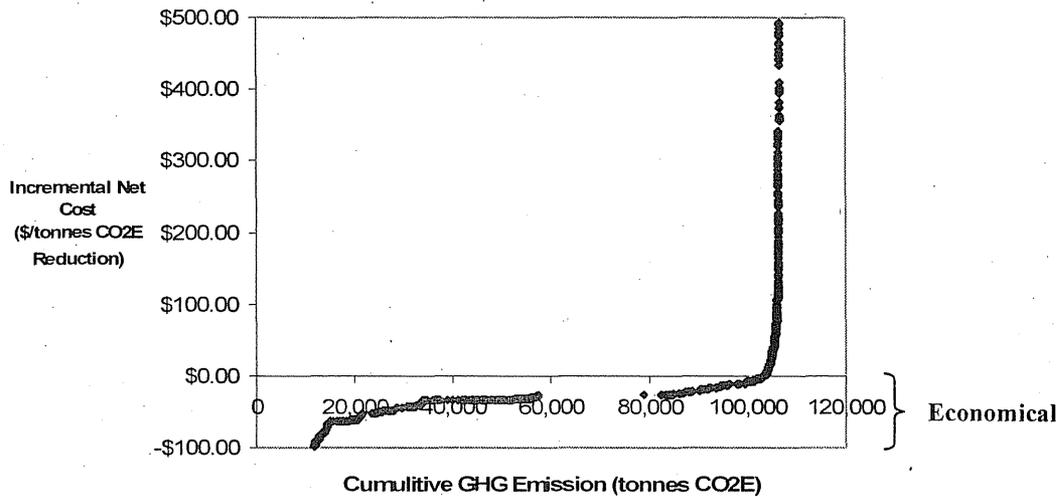


Figure 2 Incremental Net Cost Curve For Cumulative CO₂E Emission Reductions At Surveyed Gas Plants



4.6.2 Control Opportunities With a Payback of 1 Year or Less

On a purely financial basis, opportunities to reduce natural gas losses must compete against other investment opportunities to receive funding. A common parameter used to evaluate opportunities is either the effective rate of return on the investment or the payback period. To justify equipment upgrades or process enhancements, companies often look for a payback period of 1 year or less. Accordingly, it is useful to consider only opportunities to reduce natural gas losses that have a payback period of 1 year or less.

If only these control opportunities are implemented, it is estimated that total natural gas losses, including unnecessary fuel consumption, would be reduced by 97%. Corresponding reductions in NMHC and GHG emissions would both amount to 97% as well.

The 10 greatest individual control opportunities in the 1-year payback category are listed in Table 7. Collectively, they account for 42% of total natural gas losses in this category.

| Table 7. Summary of Top Ten Sources of Natural Gas Losses Identified | | | | | |
|---|----------|--|------------------------|-----------------------|-----------------------------|
| Tag ID | Site No. | Process Unit / Location | Component Type | Gas Leak Rate (Mscfd) | Value of Lost Gas (\$/year) |
| 5935 | 5 | Compressor - 2" waterjacket connection | Open-Ended Line - 2" | 194.25 | \$621,168 |
| 5488 | 4 | LP FG Scrubber - corrosion hole in bottle below HLL alarm | Corrosion Hole | 46.90 | \$102,893 |
| 6074 | 5 | Flare fuel gas line - | Corrosion Hole | 42.92 | \$111,631 |
| 6075 | 5 | Compressor | Variable Volume Pocket | 30.45 | \$97,380 |
| 5956 | 5 | Compressor | Compressor Seal | 16.27 | \$52,044 |
| 7355 | 1 | Compressor- distance piece vent (leak overwhelmed hiflow) | Compressor Seal | 11.27 | \$33,573 |
| 7010 | 1 | Residue compressor (north caterpillar) - common packing case drain | Compressor Seal | 9.75 | \$25,863 |
| 7168 | 1 | Residue compressor (#2 ingersoll-rand) - | Valve Cap | 9.34 | \$24,787 |
| 6708 | 3 | Amine Tank | PRV | 9.34 | \$24,559 |
| 7322 | 1 | Compressor -reptured diaphragm on 4 NPS control valve | Control Valve - 4" | 8.25 | \$21,899 |
| Total | | | | 378.75 | \$1,115,799 |

5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The second Phase added five additional gas processing plants to the four plants surveyed in the first Phase. The plants chosen for this study varied in plant age, throughput, size, location and sweet and sour gas. The second Phase also included well sites and gathering compressor stations located upstream from the gas processing plants. The variation ensures that the data collected represents an average for the natural gas processing industry. A comparison was conducted between the traditional leak detection methods and an optical passive infrared camera was conducted at all sites.

The sources with the greatest natural gas losses were not necessarily the most economical to control. Actual cost-effective emissions reduction opportunities may vary greatly between sites and not all gas plants will necessarily offer sufficient opportunities to justify the associated identification and control costs. In addition, actual economic opportunities depend on the natural gas value, and will therefore vary with fluctuations in the natural gas market price. Nonetheless, it is clear from the available data that significant cost-effective emissions reduction opportunities do exist at all surveyed facilities and a rational approach to finding these opportunities at all gas plants may be economically attractive to industry.

While any economical-to-repair leaking components detected by such efforts should be repaired, average leak rates based on combined data from the five test sites suggest that the most cost-effective approach would be to generally focus on the following types of components:

- block and control valves,
- orifice meters,
- open ended lines,
- pressure relief valves,
- regulators,
- flange connections,
- crankcase vents,
- compressor seals, and
- compressor valve stems and valve caps.

Additionally, components operating in thermal cycling (mole sieve) and vibration (compressor) applications have higher leak rates than other components. The results show that components in these two applications contributed 97% of the fugitive leaks and suggest that process-unit-targeted DI&M programs would have tremendous cost-effective emissions reduction potential. A DI&M program focusing on equipment in vibration and/or thermal cycling operation would likely identify and repair nearly all the large leaks at a fraction of a full facility DI&M program cost.

5.2 Recommendations for Further Work

Specific recommendations are:

- The amount and composition of emissions from engine and compressor crankcase vents, and field practices for the vent systems design should be examined more closely. In particular, the potential for air-toxic emissions from crankcase vents, especially those on engines, should be determined. Moreover, the practice of some companies to exhaust crankcase vents into buildings and work areas, a practice manufacturers discourage, should be evaluated.
- There are a wide variety of available technologies, as well as design and operating practices that would help companies cost-effectively reduce natural gas losses; however, these technologies and practices are under-utilized. One such example is the application of flow sensors, which can be installed on compressor seal vents at a relatively low cost. Flow sensors provide real-time excessive leakage detection. They may also be applied to crankcase and other vents. Only one of the five sites had installed seal vent flow sensors, and the operators did not monitor the sensors readings. Additionally, emergency flare systems are not normally equipped with flow meters, so in-leakage and excessive purge gas consumption often go unnoticed until natural gas losses produce a noticeably larger flame. Historically, meters were not installed because conventional obstruction meters do not provide reliable readings over the wide flow ranges and cause excessive system backpressure; however, non-intrusive ultrasonic flow meters, which overcome these problems, are now available. Moreover, ultrasonic techniques are available for identifying and quantifying leakage past valve seats into flare and vent systems.
- It is recommended that a best practices document be developed to disseminate and encourage the compilation and use of cost-effective emissions reduction practices. The document should also provide information required by companies to develop site-specific programs for reducing their methane and non-methane hydrocarbon losses, and greenhouse gas emissions (e.g., delineate source categories and/or facility areas to focus efforts on for maximum benefit, generic cost data for evaluating control options, recommended monitoring frequencies, and typical repairs life expectancy by source type and service category).
- Analysis of the Phase I and Phase II results to determine the relative cost-effectiveness of a facility wide DI&M program and a process-unit-targeted DI&M program focused on components in vibration (i.e. compressor) or heat-cycle (i.e. mole sieve) services

Further analysis combining the data from Phase I and Phase II to improve the results statistical significance. Analyses should include, at a minimum, the plant level trends identified in the Phase 2 report (i.e. impacts of facility age and sweet or sour gas on methane emissions). Potential benefits include an age-based and/or gas-type-based DI&M program that would also reduce the cost of DI&M program.

- Use of the combustion equipment and compressor performance tests (new tests implemented in Phase 2) in future surveys. These tests, when implemented in the surveyed facilities, contributed significantly to the methane and overall GHG emissions inventories.
- A follow up program to evaluate the impact of monitoring frequency on gas processing facilities DI&M programs cost effectiveness.

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General Permit 17.1 Template

Reciprocating or centrifugal compressor for natural gas service

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.
 - (1) None
 - b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.
 - (1) None
2. The emissions unit contained in this permit must comply with various federal New Source Performance Standards (NSPS). The complete NSPS requirements may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website <http://www.ecfr.gov> or by contacting the appropriate Ohio EPA District Office or local air agency. The permittee must comply with the applicable requirements of 40 CFR Part 60 Subpart OOOO/OOOOa as they apply to the emissions source.
3. Records related to this PTIO may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

Note: The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. [Reciprocating or centrifugal Natural Gas Compressor], [P001]

Operations, Property and/or Equipment Description:

Reciprocating or centrifugal compressor constructed, modified, or reconstructed after 8/23/11 and located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment, and designed to be driven by an engine or motor of less than or equal to 3600 horsepower. Includes emissions from normal compressor operation, and blowdown and other releases from periodic maintenance activities, as well as leakage through seals, packing and vents during periods of either intermittent or prolonged shutdown of the compressor.

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

(a) None.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

(a) None

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operations(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|--|
| a. | OAC rule 3745-31-05(A)(3) as effective June 30, 2008 | <p>Volatile organic compound (VOC) emissions shall not exceed 0.35 tons per month averaged over a 12-month rolling period.</p> <p>See c)(2) and c)(3).</p> |

| | | |
|----|--|--|
| | | See b(2)a. below. |
| b. | OAC rule 3745-31-05(A)(3)(a)(ii) as effective June 30, 2008 | The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the VOC emissions from this air contaminant source since the potential to emit is less than 10 tons/year. See b(2)b. below. |
| c. | 40 CFR Part 60 Subpart OOOO In accordance with 40 CFR 60.5365(c), this emissions unit is a centrifugal compressor or a reciprocating compressor subject to the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. 40 CFR 60.5380; 40 CFR 60.5385 | Meet all applicable requirements of 40 CFR Part 60, Subpart OOOO upon initial startup. |
| d. | OAC rule 3745-31-05(E) | The compressor shall be designed so that no gas from the rod packing seals (for a reciprocating unit) or wet shaft seals (for a centrifugal unit), compressor isolation valves, or compressor blowdown vents is emitted into the atmosphere. This requirement can be met by a design that captures 100% of the gasses from these sources, and routes them to (1) a flare designed for 98% destruction, (2) the fuel gas system for burning as a fuel, or (3) back into the product pipeline. The above design requirements shall be met at all times that pressure is present at the inlet or discharge isolation valve, including periods of either intermittent or prolonged shutdown of the compressor. |

(2) Additional Terms and Conditions

- a. The BAT emission limit applies until U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.
- b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP

c) Operational Restrictions

- (1) The permittee of a reciprocating unit shall operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of 40 CFR Part 60 Section 5411(a) at all times when pressure is present at the inlet or discharge isolation valve.

[40 CFR 60.5385(a)], [40 CFR 60.5410(c)], [40 CFR 60.5415(c)(3)], and [40 CFR 60.5370(a)]

- (2) The permittee of a centrifugal unit of wet seal seal design shall equip the unit with a cover that captures the seal emissions that meets the requirements of 40 CFR Part 60 Section 5411(b) and that connects to a closed vent system that meets the requirements of 40 CFR Part 60 Section 5411(a) and routes the emissions to a process or to a control device that meets the conditions specified in 40 CFR Section 5412 paragraphs (a), (b), and (c), except that where "95.0 percent by weight" appears under Section 5412, the permittee shall be subject to a 98.0 percent by weight requirement. Capture and control or diversion to a process shall be maintained at all times when pressure is present at the inlet or discharge isolation valve.
- (3) All emissions from maintenance blowdown events shall be captured and reduced by at least 98.0 percent by weight.
- (4) At all times when the reciprocating or centrifugal compressor is maintained in a depressurized state, the leakage passing through the isolation valves and released from the compressor through blowdown vents or other routes shall be captured and reduced by at least 98.0 percent by weight.
- (5) The permittee shall minimize the frequency and size of blowdown events by conducting routine operation and maintenance activities in a manner consistent with safety and good air pollution control practices.
- (6) The permittee of a reciprocating or a centrifugal unit shall demonstrate continuous compliance with the requirements of this permit by conforming to the applicable requirements of 40 CFR Part 60 Section 5415, except that where "95 percent by weight" appears, "98 percent by weight" shall apply.

d) Monitoring and/or Recordkeeping Requirements

- (1) The permittee shall perform initial and subsequent annual inspections of the closed vent system, covers, and bypass devices installed on the reciprocating or centrifugal compressor as prescribed by 40 CFR Part 60 Section 5416.

[40 CFR 60.5420(c)(3)], [40 CFR 60.5385(b) and (d)], [40 CFR 60.5410(c)(1) and (4)], [40 CFR 60.5415(c)(1)], and with [ORC 3704.03(T)]

- (2) The permittee shall maintain monthly records of the following information:
 - a. number of compressor blowdown events;
 - b. mole fraction of each VOC component in the gas stream using a representative analysis;
 - c. the volume of gas emitted from all compressor blowdown events for each month, in scf; and
 - d. the rolling, 12-month summation of the volume of gas emitted from all compressor blowdown events, in scf.

At the end of each year or PER reporting period, the permittee shall calculate the emissions from compressor maintenance blowdowns, using the calculation in the Testing Section, and shall maintain the record of the emission estimates for a period of five years.

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER be submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC rule 3745-15-03(B)(2) and (D)]

- (2) The permittee shall submit an initial annual report within 90 days after the end of the initial compliance period as determined according to 40 CFR 60.5410. Subsequent annual reports are due on the same date each year following the initial report. The annual reports shall include the following information:
 - a. company name and address of the affected facility;
 - b. identification of each affected facility included in the annual report*;
 - c. beginning and ending dates of the reporting period;
 - d. the identification of each reciprocating or centrifugal compressor;
 - e. the cumulative number hours of operation or the number of months of operation since initial startup of the reciprocating or

centrifugal compressor, or since the effective date of the NSPS, whichever is later;

- f. records of any deviations; and
- g. certification of the responsible official of truth, accuracy, and completeness.

* One report for multiple affected facilities may be submitted provided the report contains all of the information required and clearly identified for each.

[40 CFR 60.5420(b)(1) and (4)], [40 CFR 60.5410(c)(2) and (3)], [40 CFR 60.5385(d)], and [40 CFR 60.5415(c)(2)]

- (3) The permittee shall submit to the appropriate district or local office of the EPA Division of Air Pollution Control notification of:
 - a. the date construction or reconstruction of the emissions unit is commenced, no later than 30 days after such date; and
 - b. notification of any physical or operational change to the existing facility which may increase the emission rate of any air pollutant to which the standard applies (unless that change is specifically exempted under the NSPS or in 40 CFR 60.14(e)) shall be postmarked 60 days before the change is commenced (or as soon as practicable) and shall include information describing the precise nature of the change, productive capacity of the facility before and after the change, and the expected completion date of the change.

The Director may request additional relevant information subsequent to this notice.

[40 CFR 60.5410(c)(2)] and [40 CFR 60.7(a)(1) and (4)]

- (4) Any calculated exceedance of the VOC emission limit shall be included in the annual PER.

f) Testing Requirements

- (1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

Emissions Limitation:

VOC emissions shall not exceed 4.194 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the VOC emissions limitation shall be based upon the following calculation and the recordkeeping requirements in d)(1):

VOC (tons/month) = sum of the following for each VOC component:

$$= \left[\text{molecular weight} \times \left(\frac{\text{volume of gas emitted/month} \times \text{mole fraction of each VOC component/month}}{\text{molar volume conversion}} \right) \times (1 - 0.98 \text{ control factor}) \right]$$

Where:

molecular weight = constant, in lb/lb-mole;

volume of gas emitted/month = from records specified in d)(1)c, in scf;

mole % of each VOC component/month = from analysis required in d)(1)b, in %; and

molar volume conversion = 379.5 scf/lb-mole, at 60 deg F and 1 atm.

Compliance with the monthly average VOC emissions, for each rolling 12-month period, shall be determined by adding the result to the emissions calculated for the previous 11 months.

- (2) Compliance with Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Design Efficiency:

Install a system (high pressure flare, routing to fuel line, etc.) suitable for control of maintenance blowdown events with 100 percent capture and greater than or equal to 98 percent control efficiency for VOC.

Applicable Compliance Method:

Compliance is demonstrated by the system manufacturer's design efficiency with 100 percent capture and greater than or equal to 98 percent control efficiency.

b. Design Efficiency:

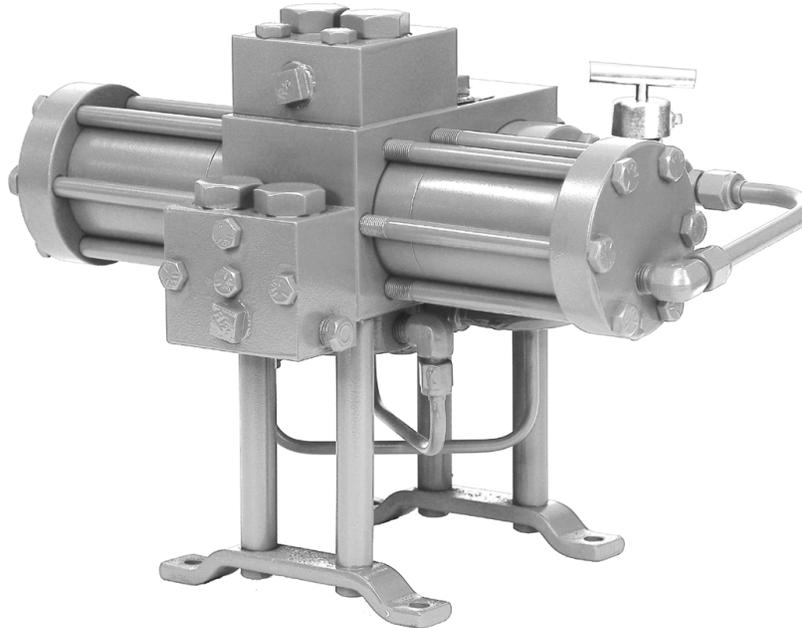
Install a flare or other device to perform 100 percent capture of leakage through seals and closed valves and reduce the quantity of VOC by at least 98 percent prior to release to the atmosphere, by combustion or by diversion into the product or the fuel system.

Applicable Compliance Method

Compliance is demonstrated by the equipment manufacturer's design efficiency with 100 percent capture and greater than or equal to 98 percent control efficiency.

g) Miscellaneous Requirements

Any amendment to Part 60, Subpart OOOOa shall supersede the Subpart OOOO compliance limitations and/or options contained in this permit.



Glycol Pump

Contents Page

| | |
|--------------------------------|-----------|
| Principles of Operation | 2 |
| Pump Dimensions | 6 |
| Specification | 6 |
| Elastomers | 8 |
| Pump Parameters | 9 |
| Model Code | 20 |

NOTE

This information is presented in good faith, Kimray assumes no liability for advise or recommendations made concerning results to be obtained from the user of any Kimray product or service. Responsibility for the selection, use and maintenance of any Kimray products remain with the purchaser and end-user.

Kimray reserves the right to modify or improve the designs or specifications of such products at any time without prior notice.

Introduction

The Glycol Pump utilizes the energy of wet glycol at absorber pressure as a source of power to circulate the glycol in a gas dehydrator. The pump transfers the energy available from the wet glycol, at absorber pressure, to an "equivalent" volume of dry glycol at reboiler pressure. In order to circulate the glycol, additional energy is needed to overcome friction losses within the pump and connecting piping. This additional energy is supplied by gas at absorber pressure.

| Summary: | |
|------------------|---|
| Pump Description | Energy Exchange |
| Normal Service | Glycol |
| Connection Size: | See table 4, page 6 |
| Connection Type: | NPT |
| Operating Range: | 300 - 2000 psi for PV 100 - 500 psi for SC |
| Temperature: | Standard -30° to 200° |

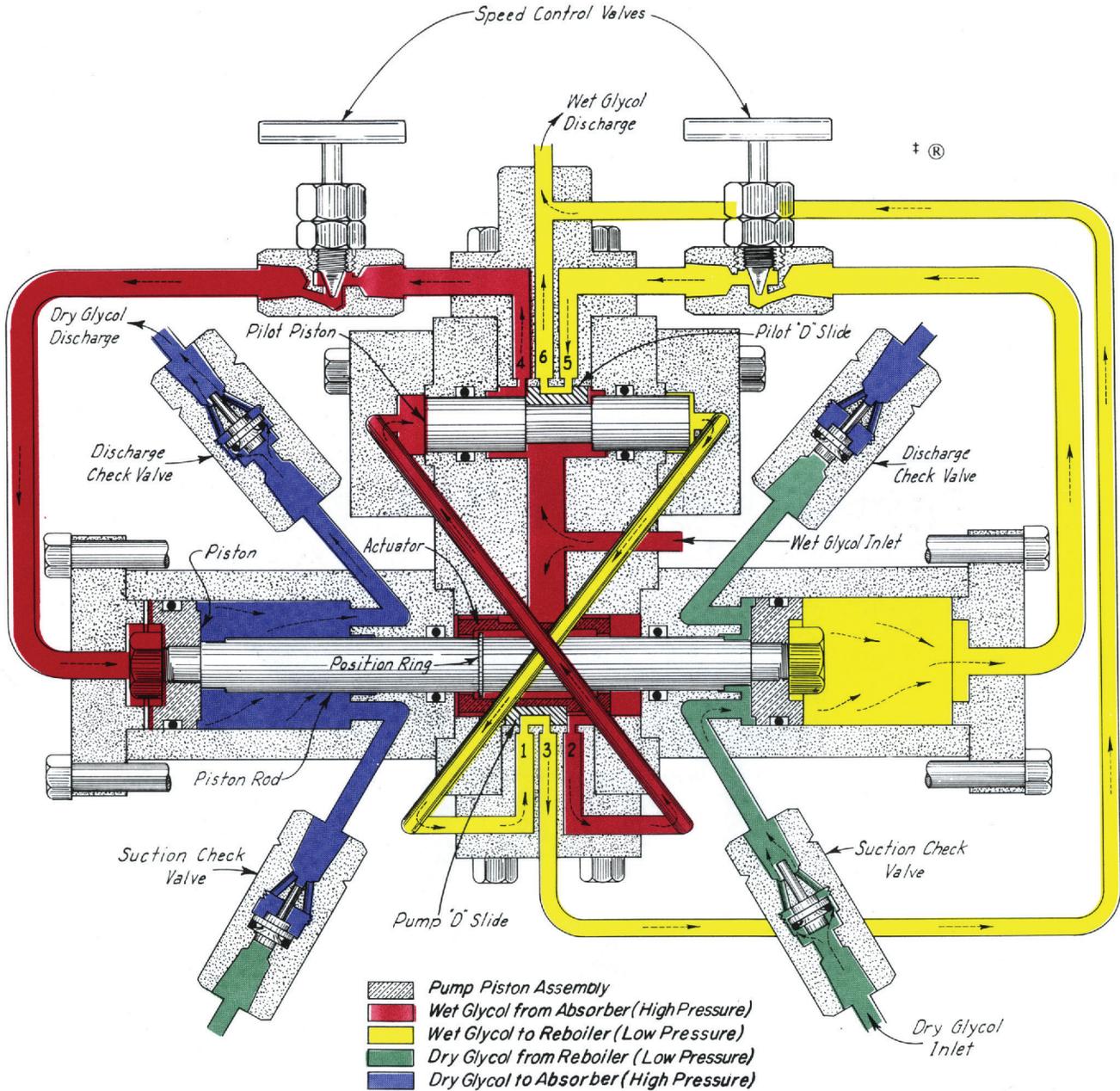


Figure 1

Principles of Operation

The Kimray glycol pump is double acting, powered by wet glycol and a small quantity of gas at absorber pressure (Red). Yellow denotes wet glycol (Blue) is being pumped to the absorber. Green is dry glycol suction from the reboiler.

Wet glycol (Red) from the absorber flows through port #4 and of the pump piston assembly, moving this assembly from left to right. Dry glycol (Blue) is being pumped from the left cylinder to the absorber while the right cylinder is being filled with dry glycol (Green) from the reboiler.

At the same time wet glycol (Yellow) is discharging from the right end of the pump piston assembly to a low pressure or atmospheric system. As the pump piston assembly nears the end of its stroke, the position ring on the piston rod contacts the right end of the actuator. Further movement to the right moves the actuator and pump "D" slide to uncover port number one and communicate ports two and three. This exhausts wet glycol (Red) to the right end of the pilot position. this causes the pilot piston and pilot "D" slide to be driven from right to left.

In it's new position, the pilot "D" slide uncovers port number five and communicate ports number four and six. This exhausts wet glycol (Red) from the left end of the pump piston assembly through ports four and six to the low pressure wet glycol (Yellow) system. Ports number 5 (which was communicated with port number 6) now admits wet glycol (Red) through the right hand speed control valve to the right end of the pump piston assembly. The pump piston assmby now starst the stroke from right to left. Follow above procedure reversing directions of flow.

Actions of each of the two basic pumps are completely dependent upon the other. The pilor "D" slide actuated by the pilot piston alternately feeds, and exhausts absorber pressure to the power cylinders at opposite ends of the piston rod assembly. Likewise, the pump "D" slide actuated by the piston rod assembly alternately feeds and exhausts absorber pressure to opposite ends of the pilot piston.

The force to circulate glycol within the dehydration system is supplied by absorber pressure acting on the area of the piston rod at its o-ring seals. The area of the piston rod is approximately 20 percent of that of the pressure acting on the area of the piston. Neglecting pump frection and line losses, the resultant force is sufficient to produce a theoretical discharge pressure 25 percent greater than absorber pressure. The theoretical discharge pressure, for example, at 1500 psig absorber pressure would be 1875 psig. This theoretical "over-pressure" would develop against a block discharge line but is not sufficient to cause damage or create a hazzard.

Approximately 25 to 30 psig pressure is required to overcome pump friction leaving the additional "over pressure" for the losses and circulation. It is recommended that these losses be held to approximately 10 percent of the absorber pressure or as noted in catalog.

Two speed control values are provided to regulate the flow of wet glycol and gas to and from the power cylinders. Reversing the direction of flow through the speed control valves provides a flushing action which cleans the valve orifices.

If the wet glycol, returning to the pump from the absorber were to be completely fill the cylinder, no additional gas would be needed. However, the wet glycol will only occupy approximately 65 percent of the total volume of the cylinder and connecting tubing leaving 35 percent to be filled by gas from the absorber. This gas volume amounts to 1.7S.C.F. per gallon of dry glycol at 300 psig absorber pressure and 8.3S.C.F. at 1500 psig and may be considered as continuing power cost for pump operation. This gas can be utilized in the regeneration process of the dehydrator for "rolling" and "stripping" purposes. It may also be recovered in a low pressure glycol gas separator and used to fire the reboiler. By supplying some absorber gas to the cylinders, the wet glycol level is maintained at the wet glycol outlet connection on the absorber and eliminates the need of a liquid level controller and its attendant problems. Excess liquids such as hydrocarbons are removed from the absorber at approximately 55 percent of the pump rate, reducing the hazard of dumping a large volume of hydrocarbons into the reboiler as would be the case with a liquid level controller.

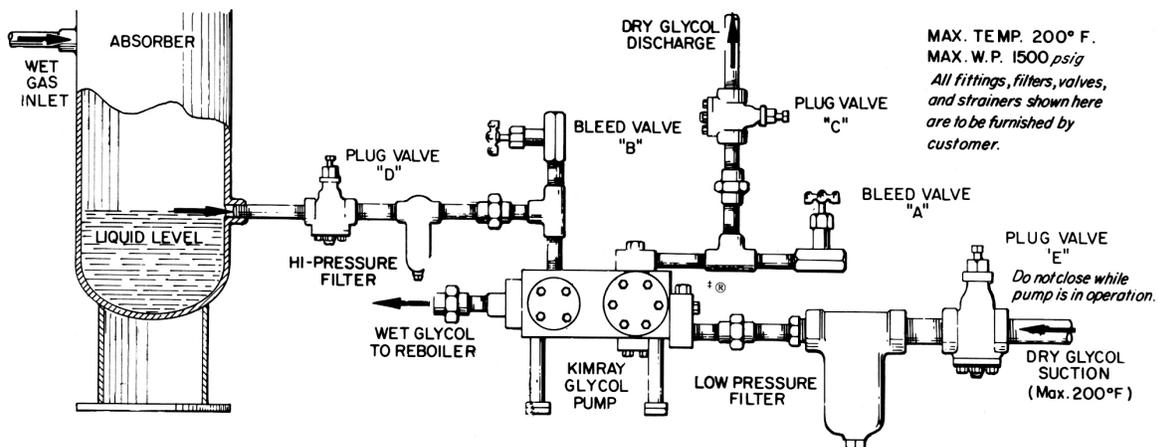


Figure 2

SYSTEM SHUTDOWN

1. Close plug valve "D" Allow pump to stop running.
2. Close plug valve "C" and "E".
3. Bleed pressure from bleed valve "A" and "B".

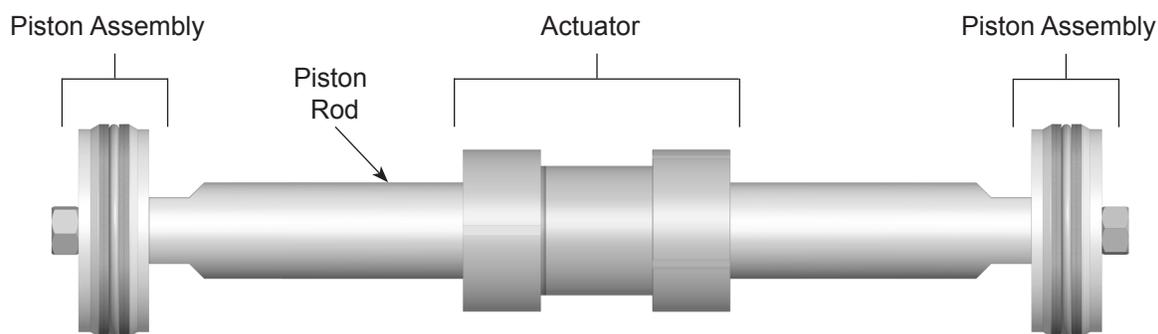


Figure 3

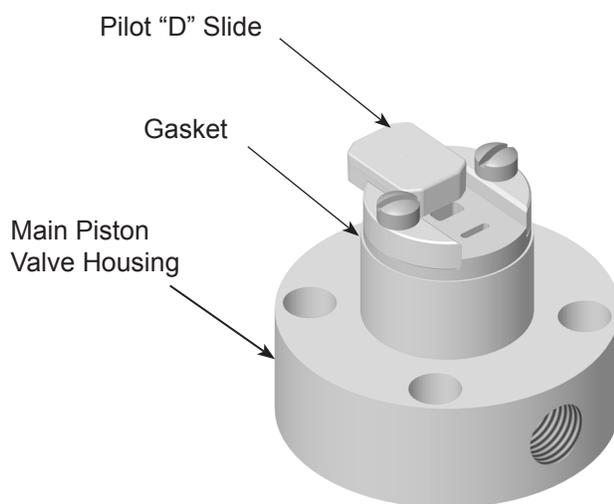


Figure 4

| Table 1 - PV & SC Series Glycol Pumps | | | | | | |
|---------------------------------------|---------------------------------------|------------|---------------------------|------|----------------------------------|------------|
| Model Number | Capacity Gal. / Hr. (Liters / Hr.) | | Rate Strokes / Minutes | | Operating Pressure psig (bar) | |
| | Min. | Max. | Min. | Max. | Min. | Max. |
| 1720PV | 8 (30.3) | 40 (151) | 12 | 40 | 300 (20.6) | 2000 (137) |
| 4020PV | 12 (45.4) | 40 (151) | 12 | 40 | 300 (20.6) | 2000 (137) |
| 9020PV | 27 (102) | 90 (340) | 12 | 40 | 300 (20.6) | 2000 (137) |
| 21020PV | 66 (250) | 210 (795) | 10 | 32 | 400 (27.5) | 2000 (137) |
| 45020PV | 166 (628) | 450 (1700) | 10 | 28 | 400 (27.5) | 2000 (137) |
| 2015SC | 8 (30.3) | 20 (75.7) | 5 | 55 | 100 (8.9) | 500 (34.4) |
| 5015SC | 12 (45.4) | 50 (189) | 10 | 50 | 100 (8.9) | 500 (34.4) |
| 10015SC | 22 (83.3) | 100 (379) | 10 | 48 | 100 (8.9) | 500 (34.4) |
| 20015SC | 60 (227) | 200 (757) | 10 | 40 | 100 (8.9) | 500 (34.4) |

Maximum design pressure for P.V. is 2000 psig and S.C. Model is 1500 psig.

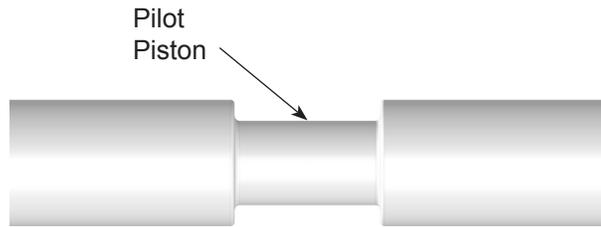


Figure 5

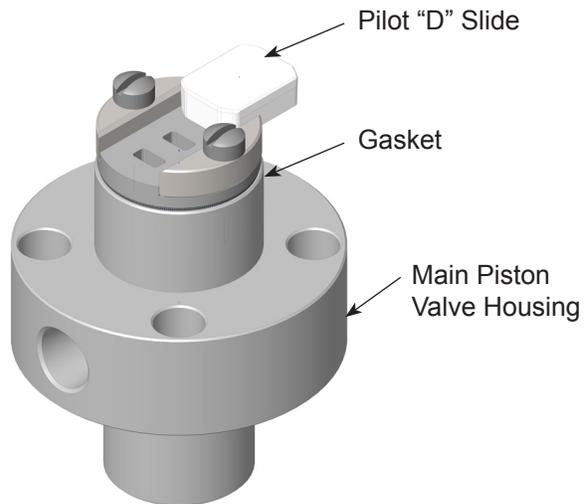


Figure 6

| Table 2 - Pressure Rating | | |
|------------------------------|-----------------------|-----------------------|
| Pressure Volume PV & SC Pump | | |
| Type | Max. Gallons Per Hour | Operating Pressure |
| 1720 PV | 40 | 300 to 2000 psig Max |
| 4020 PV | 40 | 300 to 2000 psig Max. |
| 9020 PV | 90 | 300 to 2000 psig Max. |
| 21020 PV | 210 | 400 to 2000 psig Max. |
| 45020 PV | 450 | 400 to 2000 psig Max. |
| 2015 SC | 20 | 100 to 500 psig Max |
| 5015 SC | 50 | 100 to 500 psig Max |
| 10015 SC | 100 | 100 to 500 psig Max |
| 20015 SC | 200 | 100 to 500 psig Max |

Circulating pump for gas glycol dehydrators.
 Circulating pump for gas amine desulphurizers.

Pump **PV** Working pressure of **300 - 2000 psig**.
 Pump **SC** Working pressure of **100 - 500 psig**

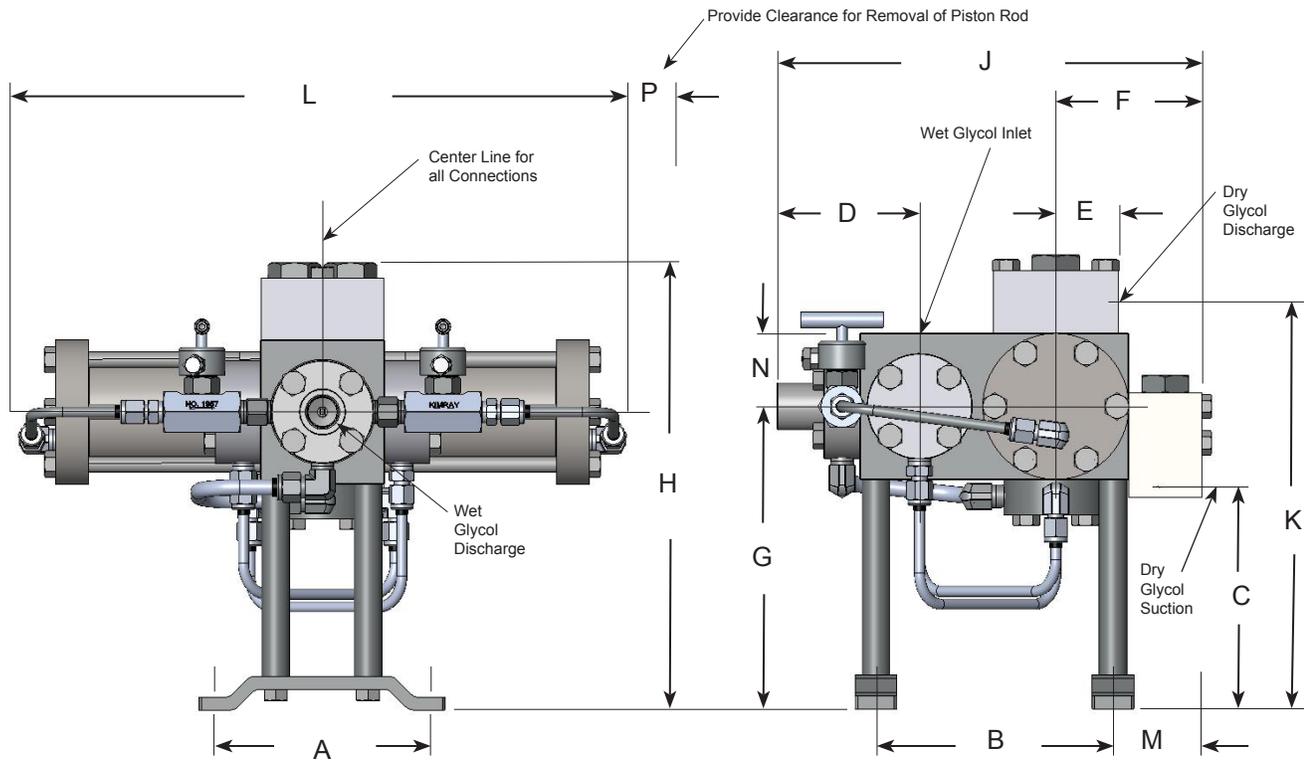


Figure 7

Table 3 - Glycol Pump Dimensions

| Model PV, SC | A | B | C | D | E | F | G | H | J | K | L | M | N | P |
|---------------------|------------------------|--------------------------|-----------------------|-----------------------|----------------------|-----------------------|------------------------|------------------------|-------------------------|------------------------|--------------------|-----------------------|----------------------|-------------------|
| 1720 PV | 5 1/4 in. (133 mm) | 5 11/16 in. (144 mm) | 5 3/4 in. (146 mm) | 5 7/16 in. (87 mm) | 1 1/2 in. (38 mm) | 3 1/2 in. (88 mm) | 7 1/4 in. (184 mm) | 10 7/8 in. (276 mm) | 10 3/16 in. (258 mm) | 9 5/8 in. (244 mm) | 15 in. (381 mm) | 2 1/8 in. (53 mm) | 1 3/4 in. (44 mm) | 3 in. (76 mm) |
| 4020 PV & 2015 SC | 5 1/4 in. (133 mm) | 5 11/16 in. (144 mm) | 5 3/4 in. (146 mm) | 5 7/16 in. (87 mm) | 1 1/2 in. (38 mm) | 3 1/2 in. (88 mm) | 7 1/4 in. (184 mm) | 10 7/8 in. (276 mm) | 10 3/16 in. (258 mm) | 9 5/8 in. (244 mm) | 15 in. (381 mm) | 2 1/8 in. (53 mm) | 1 3/4 in. (44 mm) | 3 in. (76 mm) |
| 9020 PV & 5015 SC | 6 1/4 in. (158 mm) | 5 11/16 in. (144 mm) | 6 3/8 in. (161 mm) | 5 in. (127 mm) | 1 3/4 in. (44 mm) | 4 1/4 in. (107 mm) | 8 3/4 in. (222 mm) | 13 1/4 in. (336 mm) | 13 7/8 in. (352 mm) | 11 3/4 in. (289 mm) | 20 in. (508 mm) | 2 1/2 in. (63 mm) | 2 in. (50 mm) | 3 in. (76 mm) |
| 21020 PV & 10015 SC | 7 5/8 in. (193 mm) | 10 1/8 ± 1/8 (257 mm) | 7 in. (177 mm) | 5 3/8 in. (136 mm) | 2 1/4 in. (57 mm) | 5 3/4 in. (146 mm) | 9 1/4 in. (234 mm) | 14 3/4 in. (374 mm) | 16 5/8 in. (422 mm) | 13 in. (330 mm) | 24 in. (608 mm) | 3 3/16 in. (80 mm) | 2 1/2 in. (63 mm) | 4 in. (101 mm) |
| 45020 PV & 20015 SC | 10 3/4 in. (273 mm) | 14 ± 1/8 (355 mm) | 9 in. (228 mm) | 6 5/8 in. (168 mm) | 2 5/8 in. (66 mm) | 6 1/2 in. (165 mm) | 11 3/8 in. (288 mm) | 19 in. (482 mm) | 21 1/8 in. (536 mm) | 16 3/8 in. (415 mm) | 34 in. (863 mm) | 3 3/4 in. (95 mm) | 3 1/2 in. (88 mm) | 6 in. (152 mm) |

Table 4 - Glycol Pump Specifications

| Model Number | Max. Cap | | Size of Pipe Connections | Mounting Bolts | Approx. Weight | Max. Strokes Per Minute | Glycol Output Strokes / Gal. | Glycol Output Gal. / Strokes |
|--------------|----------|-------|--------------------------|-----------------------|--------------------|-------------------------|------------------------------|------------------------------|
| | G.P.M | G.P.H | | | | | | |
| 1720 PV | .67 | 40 | 1/2 in NPT (12 mm) | 3/8 in. dia (9.42 mm) | 66 lbs (29.93 kg) | 40 | 59 | 0.017 |
| 4020 PV | .67 | 40 | 1/2 in NPT (12 mm) | 3/8 in. dia (9.42 mm) | 66 lbs (29.93 kg) | 40 | 59 | 0.017 |
| 9020 PV | 1.5 | 90 | 3/4 in NPT (19 mm) | 1/2 in. dia (12 mm) | 119 lbs (53.97 kg) | 40 | 26.3 | 0.038 |
| 21020 PV | 3.5 | 210 | 1 in NPT (25 mm) | 1/2 in. dia (12 mm) | 215 lbs (97.52 kg) | 32 | 9 | 0.111 |
| 45020 PV | 7.5 | 450 | 1 1/2 in NPT (38 mm) | 1/2 in. dia (12 mm) | 500 lbs (22.68 kg) | 28 | 3.5 | 0.283 |
| 2015 SC | .33 | 20 | 1/2 in NPT (12 mm) | 3/8 in. dia (9.52 mm) | 66 lbs (29.93 kg) | 55 | 147 | 0.0068 |
| 5015 SC | .83 | 50 | 3/4 in NPT (19 mm) | 1/2 in. dia (12 mm) | 119 lbs (53.97 kg) | 50 | 52 | 0.019 |
| 10015 SC | 1.67 | 100 | 1 in NPT (25 mm) | 1/2 in. dia (12 mm) | 215 lbs (97.52 kg) | 48 | 25 | 0.040 |
| 20015 SC | 3.33 | 200 | 1 1/2 in NPT (38 mm) | 1/2 in. dia (12 mm) | 500 lbs (22.68 kg) | 40 | 8.8 | 0.114 |

| Table 5 - Materials of Construction | | |
|-------------------------------------|-------------------------|---------------------|
| Valve Components | Standard | Optional |
| Body | Ductile, ASTM A395 | |
| Suction Block | Ductile, ASTM A395 | |
| Discharge Block | Ductile, ASTM A395 | |
| Main Valve Housing | Steel | |
| Pilot Valve Housing | Steel | |
| Port Plates | Stellite 3 | |
| Cylinder Heads | Ductile, ASTM A395 | |
| Pilot Piston Caps | Ductile, ASTM A395 | |
| Cylinders | Stainless Steel | |
| Pistons | Steel | |
| Pilot Pistons | 17-4 PH Stainless Steel | |
| Piston Rod | 17.4 PH Stainless Steel | |
| Piston Rod Glands | Ductile, ASTM A395 | |
| Fittings | Steel | SS6 |
| Tubing | 304 Stainless Steel | SS6 |
| O-Rings | Nitrile | Viton®, Afias®, HSN |
| Backups | Glass Filled Teflon | |

| Table 6 - Parts Required to Convert From PV to SC Series | | | | | |
|--|-------------------|--------------------|---------------------|----------------------|----------------------|
| Part Name | Quantity Required | 4020 PV to 2015 SC | 9020 PV to 10015 SC | 21020 PV to 10015 SC | 45020 PV to 20015 SC |
| Cylinder Liner | 2 | 2108 | 2373 | 2412 | ‡1505 |
| Piston | 2 | 1506 | 776 | 1507 | 1508 |
| Piston Seal Retainer | 2 | 1509 | 1510 | 1511 | 1512 |
| Piston "O" Ring | 2 | 156 | 773 | 774 | 329 |
| Back-up Ring | 4 | 1513 | 1457 | 1458 | 772 |
| "O" Ring | 2 | 154 | 154 | 155 | 1107 |
| Lock Nut (Piston) | 2 | * _ | 906 | 175 | 1140 |
| Cylinder "O" Ring | 2 | 773 | 774 | 329 | |

* The piston is the nut for this model and is furnished with a socket head set screw.

‡Full cylinder only.

‡Model 20015 SC only, requires 8, No. 772 Back-up rings.

Table 7 - Elastomer Options

| Part | Standard Material | Optional Material |
|---------|-------------------|---------------------|
| O-Rings | Buna | Viton®, Aflas®, HSN |

Table 8 - Elastomer Specifications

| | | ELASTOMERS | | | | | | | |
|---------------|------------------|----------------|-----------------------|----------------|--------------------------------|------------|------------------------|------------------------|-------------------------|
| | | AFLAS | ETHYLENE PROPYLENE | VITON | HIGHLY SATURATED NITRILE | BUNA-N | LOW TEMP. BUNA-N | POLY- ACRY- LATE | GEO- THERMAL EPDM |
| Kimray Suffix | | AF | EP | V | HSN | - | LTN | H | GEP |
| Resistance | Abrasion | GE | GE | G | G | G | G | G | GE |
| | Acid | E | G | E | E | F | F | P | G |
| | Chemical | E | E | E | FG | FG | FG | P | E |
| | Cold | P | GE | PF | G | G | E | P | GE |
| | Flame | E | P | E | P | P | P | P | P |
| | Heat | E | G | E | E | G | G | E | E |
| | Oil | E | P | E | E | E | E | E | F |
| | Ozone | E | E | E | G | P | P | E | E |
| | Set | PF | GE | E | GE | GE | GE | F | GE |
| | Tear | PF | GE | F | FG | FG | FG | FG | GE |
| | Water/Steam | GE | E | P | E | FG | FG | P | E |
| | Weather | E | E | E | G | F | F | E | E |
| | CO2 | GE | GE | PG | GE | FG | FG | P | GE |
| | H2S | E | P | P | FG | P | P | P | F |
| Methanol | PF | G | PF | P | P | P | P | G | |
| Properties | Dynamic | GE | GE | GE | GE | GE | GE | F | GE |
| | Electrical | E | E | F | F | F | F | F | E |
| | Impermeability | G | G | G | G | G | G | E | G |
| | Tensile Strength | FG | GE | GE | E | GE | GE | F | GE |
| | Temp. Range (°F) | +30° to +500°F | -65° to +300°F | -10° to +350°F | -15° to +300°F | -30 to 200 | -65 to 225 | ±0° to +300°F | 0 to 500 |
| | Temp. Range (°C) | 0° to +260°C | -54° to +148°C | -23° to +177°C | -26° to +149°C | -34 to 121 | -53 to 107 | -17° to 149°C | -17 to 260 |
| | Form | O | O | O | O | O | O | O | O |

RATINGS: P-POOR, F-FAIR, G-GOOD, E-EXCELLENT

Table 9 - Glycol Pump Parameters

| Pump | Bore | Rod Diameter | Stroke | Minimum Working Pressure | Maximum Working Pressure | Minimum Stroke / Minute | Maximum Stroke / Minute | Minimum Gallons / Hour | GPH Per Stroke / Minute | Glycol Output Stroke / Gallon. | Glycol Output Gallon / Stroke | Maximum Gallons / Hour |
|----------|-------------------|--------------------|-------------------|--------------------------|--------------------------|-------------------------|-------------------------|------------------------|-------------------------|--------------------------------|-------------------------------|------------------------|
| 1720 PV | 1.750 (44 mm) | .750 (19 mm) | 2.000 (50 mm) | 300 (20.6 bar) | 2000 (137 bar) | 8 | 40 | 8 | 1.00 | 59 | 0.017 | 40 |
| 4020 PV | 1.750 (44 mm) | .750 (19 mm) | 2.000 (50 mm) | 300 (20.6 bar) | 2000 (137 bar) | 12 | 40 | 12 | 1.00 | 59 | 0.017 | 40 |
| 9020 PV | 2.250 (57 mm) | 1.000 (25.4 mm) | 2.750 (69 mm) | 300 (20.6 bar) | 2000 (137 bar) | 12 | 40 | 27 | 2.25 | 26.3 | 0.038 | 90 |
| 21020 PV | 3.250 (82 mm) | 1.375 (34 mm) | 3.750 (95 mm) | 400 (27.5 bar) | 2000 (137 bar) | 10 | 32 | 66 | 6.56 | 9 | 0.111 | 210 |
| 45020 PV | 4.500 (114 mm) | 2.000 (50 mm) | 5.125 (130 mm) | 400 (27.5 bar) | 2000 (137 bar) | 10 | 28 | 166 | 16.07 | 3.5 | 0.283 | 450 |
| 2015 SC | 1.250 (31 mm) | .750 (19 mm) | 2.000 (50 mm) | 100 (6.89 bar) | 500 (34.4 bar) | 10 | 55 | 8 | 0.36 | 147 | 0.0068 | 20 |
| 5015 SC | 1.750 (44 mm) | 1.000 (25.4 mm) | 2.750 (69 mm) | 100 (6.89 bar) | 500 (34.4 bar) | 10 | 50 | 12 | 1.00 | 52 | 0.019 | 50 |
| 10015 SC | 2.250 (57 mm) | 1.375 (34 mm) | 3.750 (95 mm) | 100 (6.89 bar) | 500 (34.4 bar) | 10 | 48 | 22 | 2.08 | 25 | 0.040 | 100 |
| 20015 SC | 3.250 (82 mm) | 2.000 (50 mm) | 5.125 (130 mm) | 100 (6.89 bar) | 500 (34.4 bar) | 10 | 40 | 60 | 5.00 | 8.8 | 0.114 | 200 |

Circulation Rate Graph

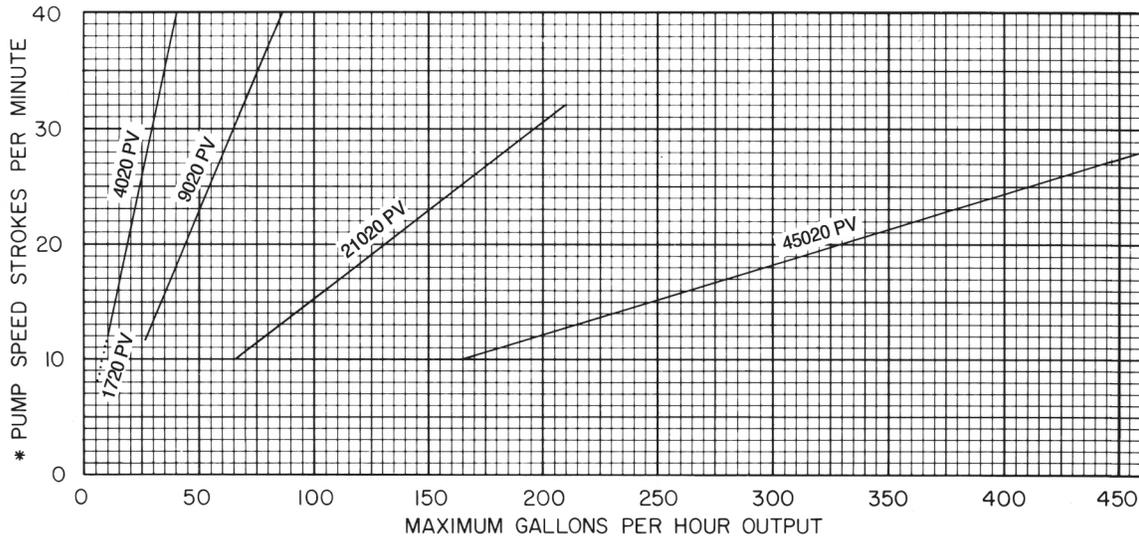


Figure 8

* It is not recommended to attempt to run pumps at speeds less than those indicated in the above graph.

Table 10 - PV Glycol Pumps

| Operating Pressure psig | 300 | 400 | 500 | 600 | 700 | 800 | 900 | 1000 | 1100 | 1200 | 1300 | 1400 | 1500 |
|-------------------------------|-----|-----|-----|-----|-----|-----|-----|------|------|------|------|------|------|
| Cut. Ft./Gallon @ 14.4 & 60°F | 1.7 | 2.3 | 2.8 | 3.4 | 3.9 | 4.5 | 5.0 | 5.6 | 6.7 | 6.7 | 7.2 | 7.9 | 8.3 |

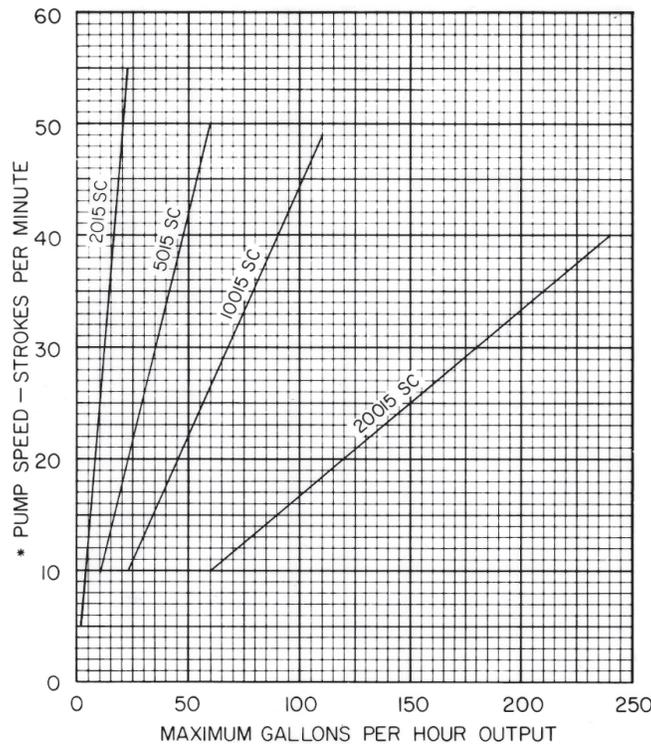
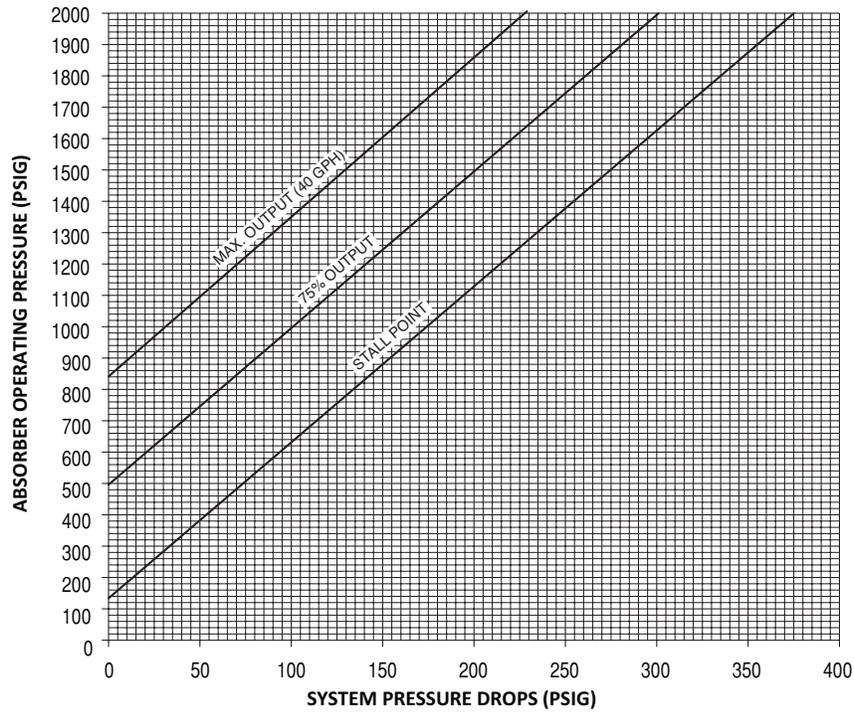


Figure 9

* It is not recommended to attempt to run pumps at speeds less than those indicated in the above graph..

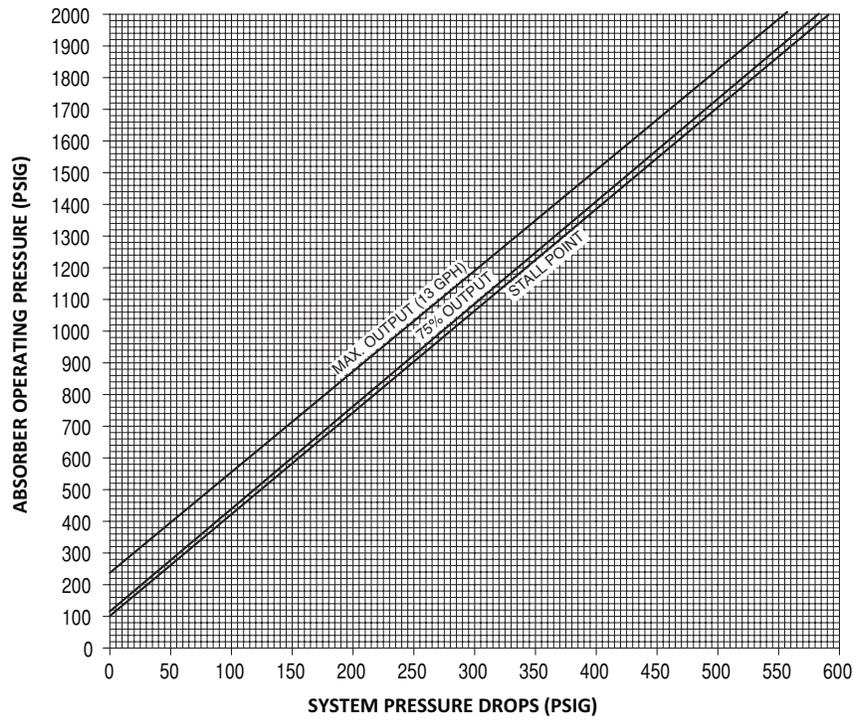
Table 11 - PV Glycol Pumps

| Operating Pressure psig | 100 | 200 | 300 | 400 |
|-------------------------------|-----|-----|-----|-----|
| Cut. Ft./Gallon @ 14.4 & 60°F | 1.7 | 2.3 | 2.8 | 3.4 |



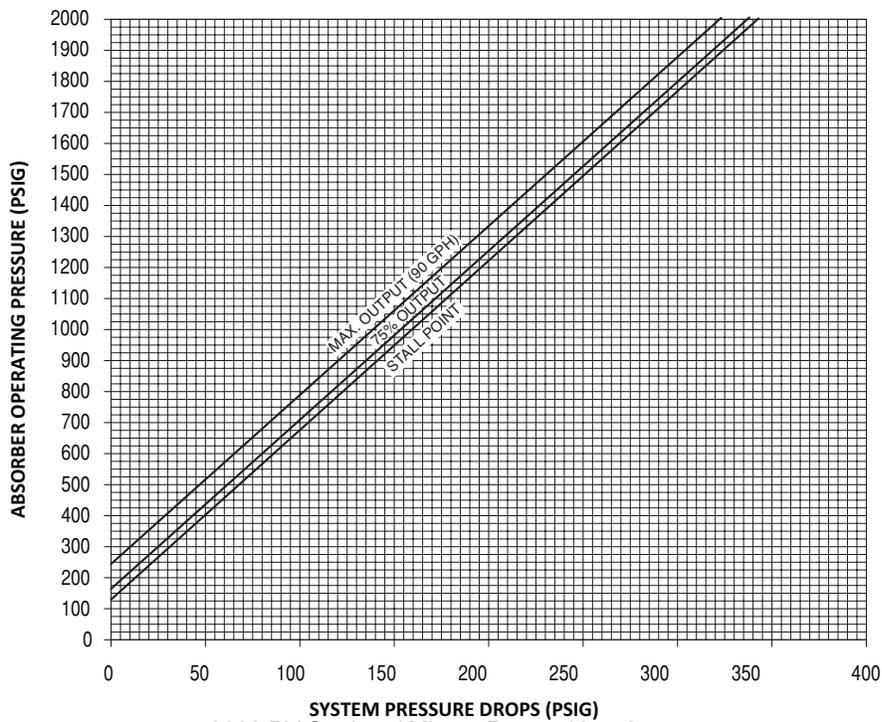
1720 PV Strokes / Minute Range 8 - 40

Figure 10



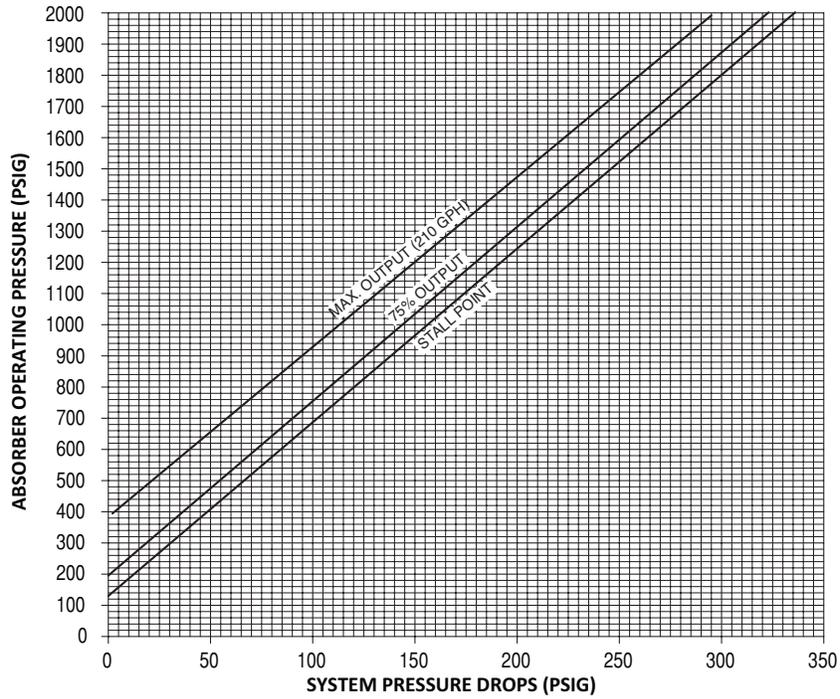
4020 PV Strokes / Minute Range 12 - 40

Figure 11

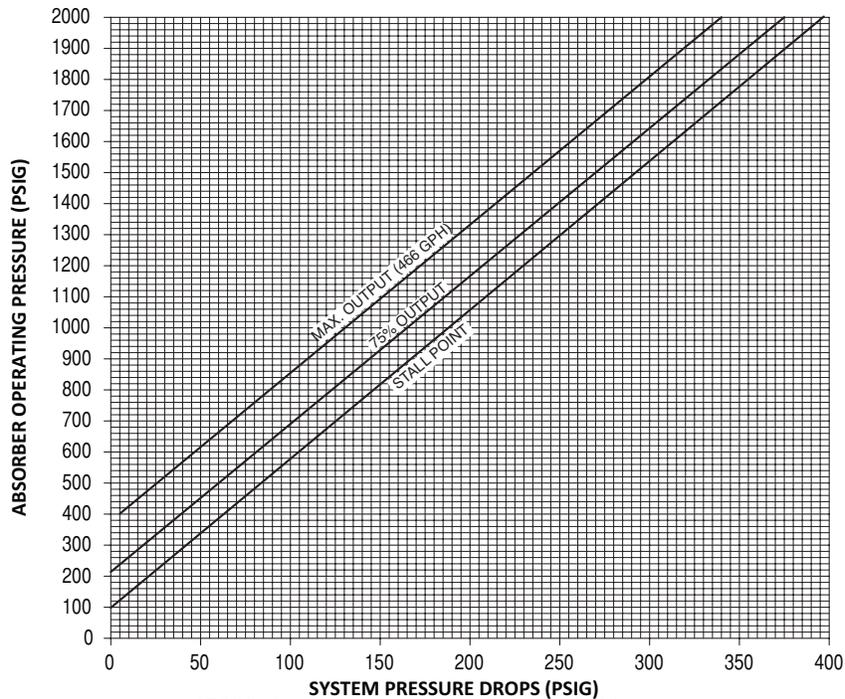


9020 PV Strokes / Minute Range 12 - 40

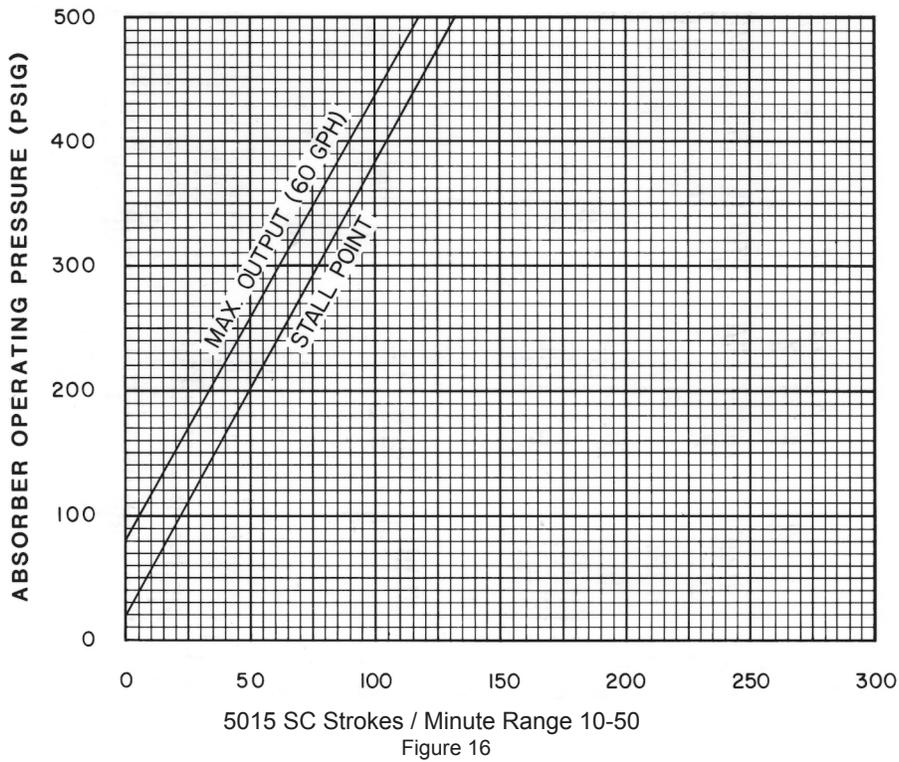
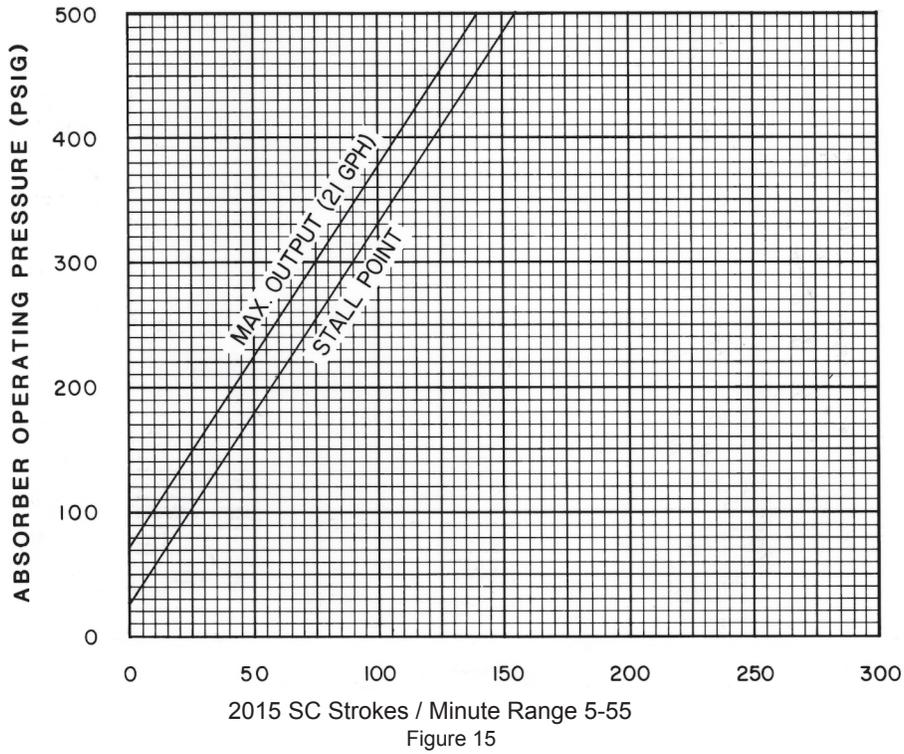
Figure 12

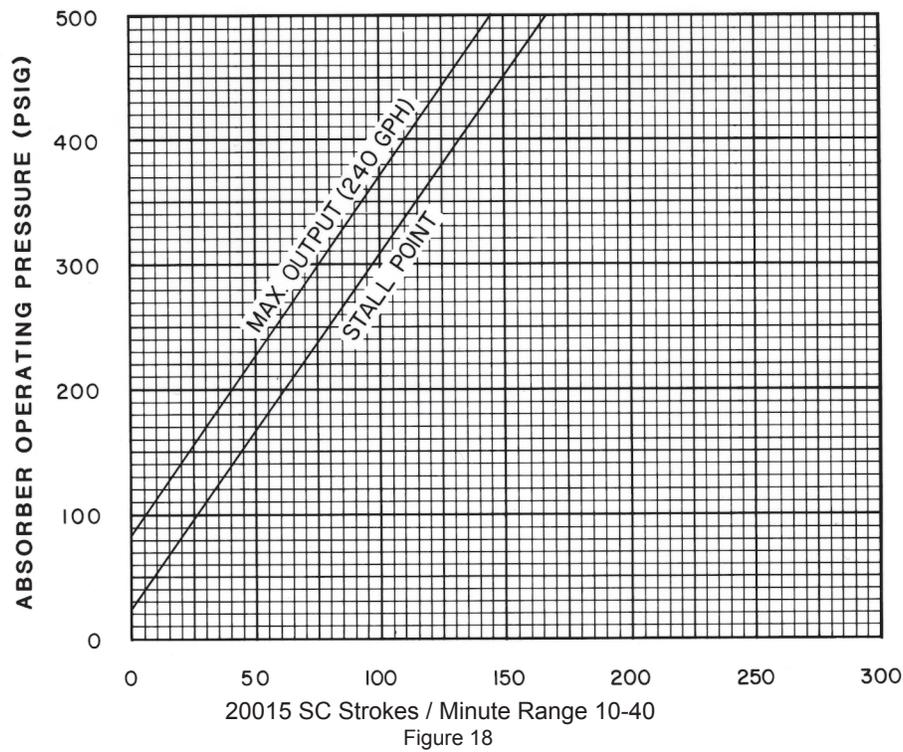
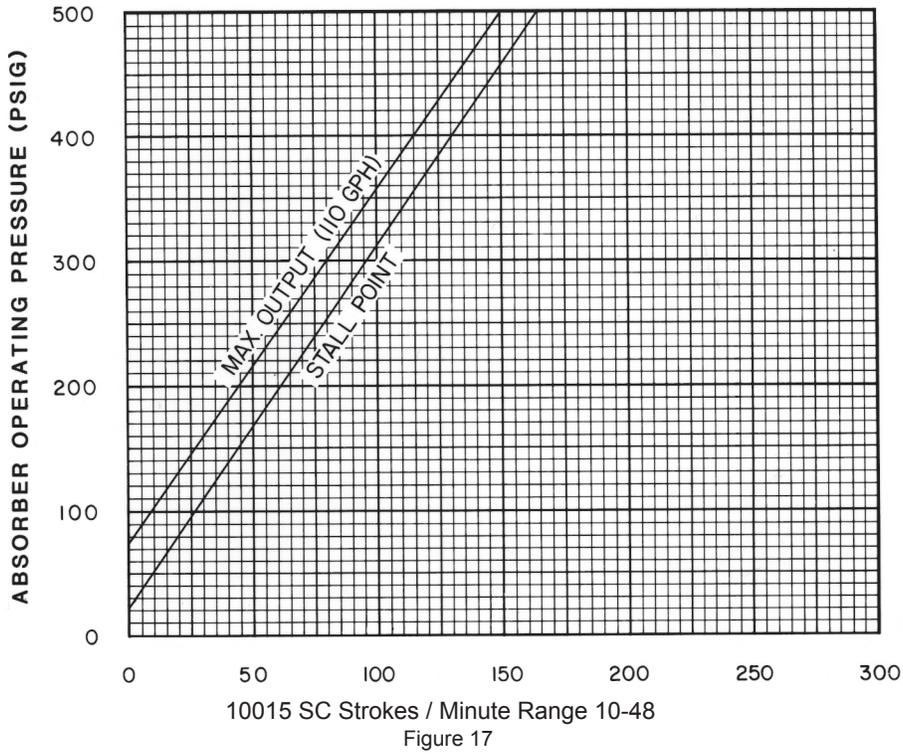


21020 PV Strokes / Minute Range 10-32
Figure 13



45020 PV Strokes / Minute Range 10-28
Figure 14





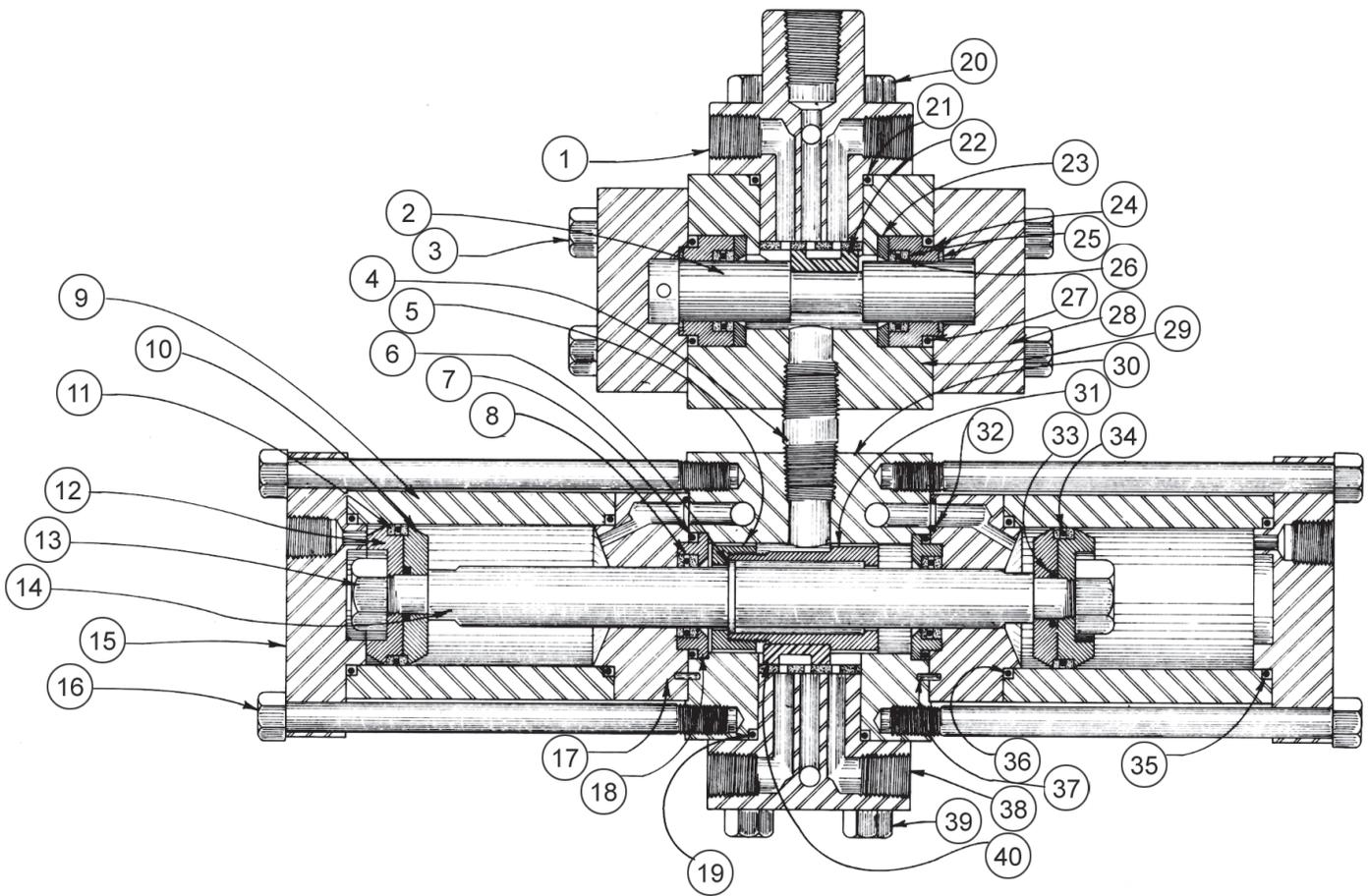


Figure 19

Key Description

- | | | |
|--------------------------------------|--------------------------------------|--------------------------------------|
| 1 Pilot Piston Valve Housing, Steel | 14 Piston Rod, Stainless Steel | 28 Pilot Piston Cap, Ductile Iron |
| 2 Pilot Piston, Stainless Steel | 15 Cylinder Head, Ductile Iron | 29 Body (Pilot Piston), Ductile Iron |
| 3 Screw, Plated Steel | 16 Screw, plated Steel | 30 Body (Main Piston), Ductile Iron |
| 4 Nipple, Plated Steel | 17 Piston Rod Gland, Ductile Iron | 31 "D" Slide Actuator, Steel |
| 5 Actuator Cap, Steel | 18 Piston Rod Seal Retainer, Steel | 32 O-Ring, Nitrile |
| 6 Snap Ring, Stainless Steel | 19 O-Ring, Nitrile | 33 O-Ring, Nitrile |
| 7 O-Ring, Nitrile | 20 Screw, Plated Steel | 34 O-Ring, Nitrile |
| 8 O-Ring & Back Up, Nitrile & Teflon | 21 O-Ring, Nitrile | 35 O-Ring, Nitrile |
| 9 Cylinder, PV - Stainless Steel | 22 "D" Slide, Nylon | 36 O-Ring, Nitrile |
| SC - Stainless Steel | 23 Pilot Piston Seal Retainer, Steel | 37 Index Pin, Stainless Steel |
| 10 Piston Seal Retainer, Steel | 24 Pilot Piston Bearing, Steel | 38 Main Piston Valve Housing, Steel |
| 11 Back Up, Teflon | 25 Back Up, Teflon | 39 Screw, Plated Steel |
| 12 Piston, Steel | 26 O-Ring, Nitrile | 40 "D" Slide, Nylon |
| 13 Nut, Plated Steel | 27 O-Ring, Nitrile | |

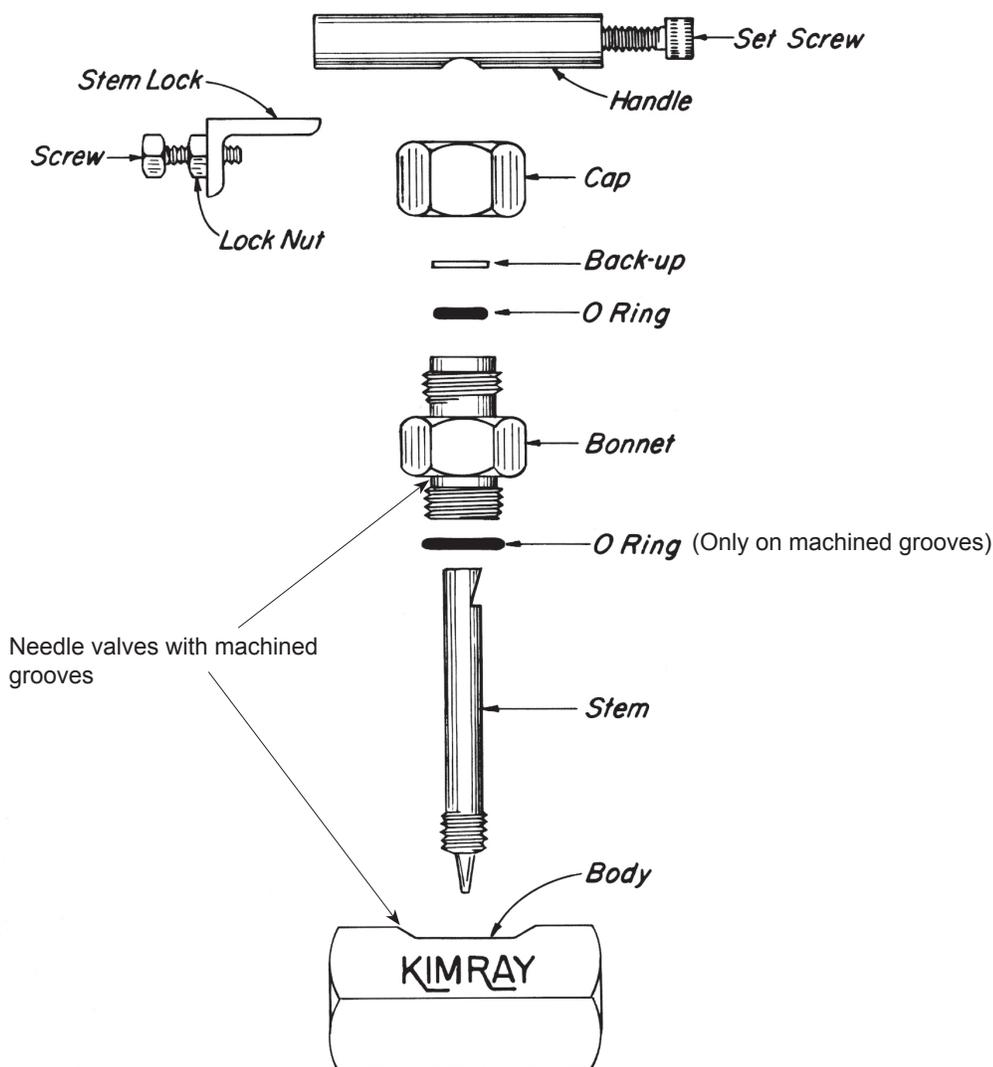
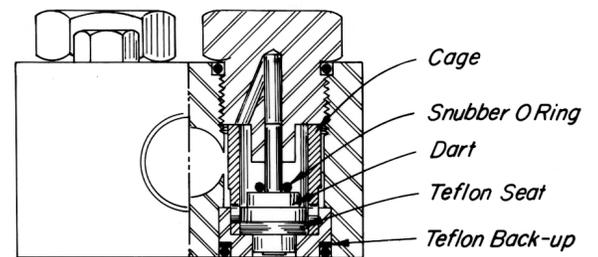
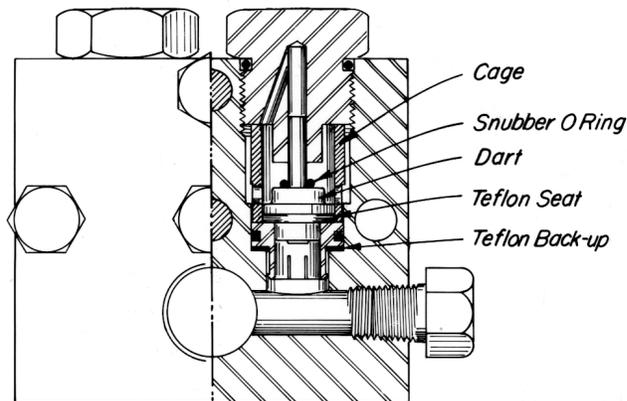


Figure 20

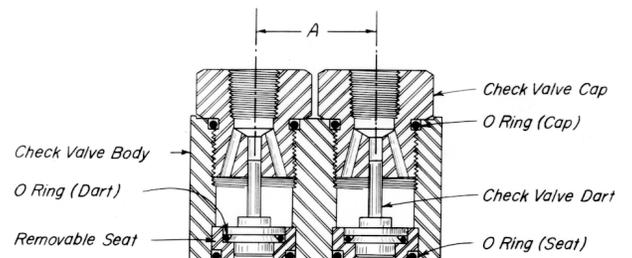
Table 12 - 6000 PSIG W.P. NEEDLE VALVES

| N.P.T SIZE | VALVE NO. | ORFICE SIZE | PUMP SIZE | BODY | BONNET | CAP | STEM | HANDLE | SET SCREW | BACK UP | O-RING | O-RING | STEM LOCK | STEM LOCK ASSY | SCREW | LOCK NUT |
|--|-----------|-------------|-----------|--------|--------|--------|-------|--------|-----------|---------|--------|--------|-----------|----------------|-------|----------|
| TYPE 303 STAINLESS STEEL STANDARD ON ALL PUMPS EXCEPT 45015 PV PUMP | | | | | | | | | | | | | | | | |
| 1/4 in. | 1911 | 1/16 in. | 1720 | 1911A | 1603D | 1603F | 1957A | 1603B | 1964 | 1978 | 638 | 265 | 6746 | 2271A | 2274 | 2275 |
| 1/4 in. | 1957 | 1/8 in. | 4020 | 1957C | 1603D | 1603F | 1957A | 1603B | 1964 | 1978 | 638 | 265 | 6746 | 2271A | 2274 | 2275 |
| 3/8 in. | 1956 | 3/16 in. | 9020 | 1956C | 1955D | 1955F | 1956A | 1955B | 1963 | 1979 | 153 | 2631 | 6747 | 2270A | 2274 | 2275 |
| 1/2 in. | 1955 | 9/32 in. | 21020 | 1955C | 1955D | 1955F | 1956A | 1955B | 1963 | 1979 | 153 | 2631 | 6747 | 2270A | 2274 | 2275 |
| CARBON STEEL STANDARD ON 45015 PV PUMP ONLY | | | | | | | | | | | | | | | | |
| 3/4 in. | 1954 | 13/32 in. | 45020 | 1954C | 1954D | 1954F | 1954A | 1954B | 1962 | 1980 | 154 | 2131 | 6748 | 2269A | 2274 | 2275 |
| TYPE 316 STAINLESS STEEL - AVAILABLE ON SPECIAL ORDER AND EXTRA COST | | | | | | | | | | | | | | | | |
| 1/4 in. | 1911S6 | 1/16 in. | 1720 | 1911A6 | 1603D6 | 1603F6 | 1957A | 1603B | 1964 | 1978 | 638 | 265 | 6746 | | 2274 | 2275 |
| 1/4 in. | 1957S6 | 1/8 in. | 4020 | 1957C6 | 1603D6 | 1603F6 | 1957A | 1603B | 1964 | 1978 | 638 | 265 | 6746 | | 2274 | 2275 |
| 3/8 in. | 1956S6 | 3/16 in. | 9020 | 1956C6 | 1955D6 | 1955F6 | 1956A | 1955B | 1963 | 1979 | 153 | 2631 | 6747 | | 2274 | 2275 |
| 1/2 in. | 1955S6 | 9/32 in. | 21020 | 1955C6 | 1955D6 | 1955F6 | 1955A | 1955B | 1963 | 1979 | 153 | 2631 | 6747 | | 2274 | 2275 |
| 3/4 in. | 1954S6 | 13/32 in. | 45020 | 1954C6 | 1954D6 | 1954F6 | 1954A | 1954B | 1962 | 1980 | 154 | 2131 | 6748 | | 2274 | 2275 |

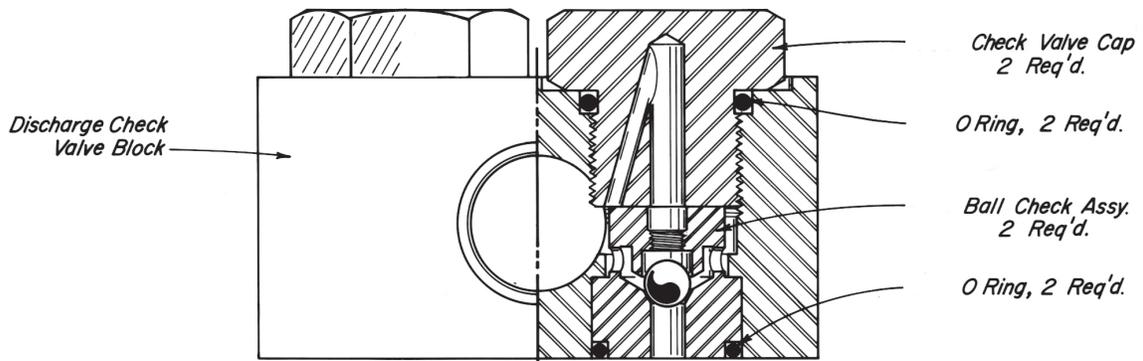
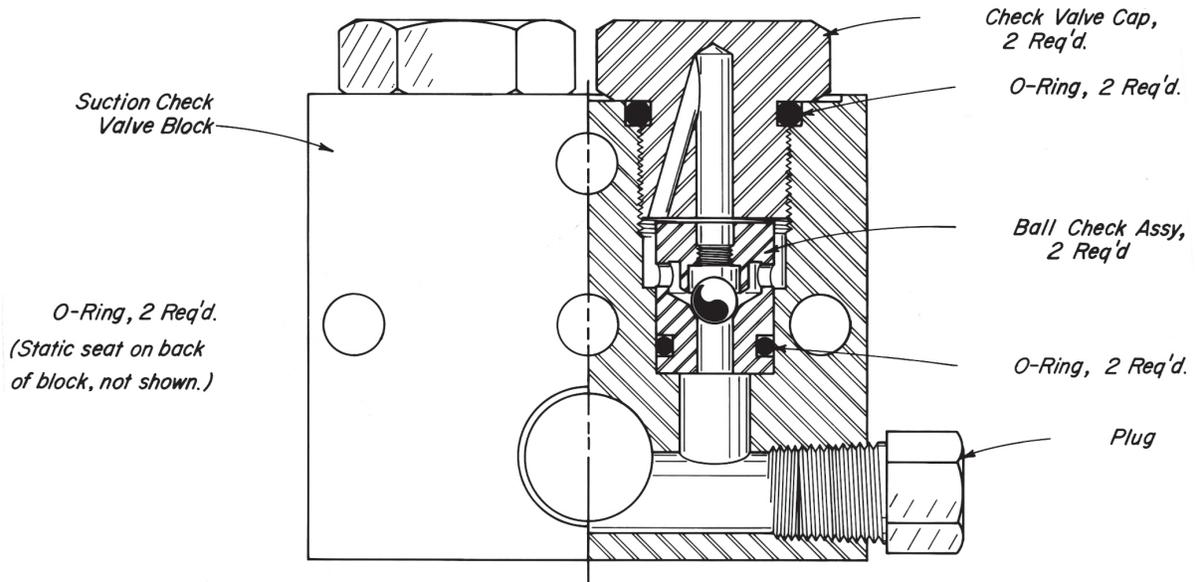
| Table 13 - Glycol Pump | | | | | | |
|------------------------|----------|----------|-----------------|-------------|-----------------|--------------------------|
| Pump Size | Cage No. | Dart No. | Suction Back-Up | Dis Back-Up | Scrubber O-Ring | Teflon Dart Without Cage |
| 1720 PV 2015 SC | 1941 | 1940 | 1907 | 1666 | 647 | 1735 |
| 5015 SC 9020 PV | 1938 | 1937 | 1908 | 1667 | 647 | 1736 |
| 10015 SC 21020 PV | 1933 | 1932 | 1909 | 1668 | 153 | 1737 |
| 20015 SC 45020 PV | 1935 | 1934 | 2445 | 1669 | 265 | 1738 |



| Table 14 - Split Discharge | | | | | | |
|----------------------------|-----------|-----------|---------------------|---------------------|-----------------------|-----------------------|
| Part Name | Qty Req'd | 1720 PV | 4020 PV and 2015 SC | 9020 PV and 5015 SC | 21020 PV and 10015 SC | 45020 PV and 20015 SC |
| Check Valve Body | 1 | 1940 | 1907 | 1195 | 1196 | 1197 |
| "O"-Ring Seat | 2 | 1937 | 1908 | 1151 | 156 | 801 |
| Removable Seat | 2 | 1932 | 1909 | 1131 | 1133 | 1173 |
| Rev. Rem. Seat | 2 | 1934 | 2445 | 1948 | 1949 | 1950 |
| "O"-Ring Dart | 2 | 855 | 855 | 154 | 924 | 156 |
| Dart | 2 | 1307 | 1307 | 853 | 854 | 1163 |
| "O"-Ring Cap | 2 | 155 | 155 | 156 | 157 | 801 |
| Check Valve Cap | 2 | 1327 | 1327 | 1114 | 1199 | 1198 |
| Tapped Hole Size | NPT | 1/4 in. | 1/4 in. | 3/8 in. | 1.2 in. | 3/4 in. |
| Dimension "A" | Inches | 1 1/2 in. | 1 1/2 in. | 1 11/16 | 2 5/16 | 3 |



Split Discharge



Base Codes for Kimray Glycol Pumps

Once all spaces are filled, remove all dashes and condense without spaces.

| | | | | |
|--|--|--|--|--|
| | | | | |
|--|--|--|--|--|

| Base Code | Trim Material | Elastomer | Certification |
|--|---------------|------------------------|--|
| Code | Code | Code | Code |
| Three character base code from page ii | Description | Description | Description |
| | Standard | Standard (Buna-N) | No Certifications |
| | - | AF | MTR |
| | HSN | High Saturated Nitrile | Material Test Reports (i.e. Steel Casting) |
| | V | Viton | Static Pressure Tests |

| Code | Description |
|------|----------------------|
| GAB | 4020 PV Glycol Pump |
| GAC | 2015 SC Glycol Pump |
| GAD | 1720 PV Glycol Pump |
| GAF | 9020 PV Glycol Pump |
| GAG | 5015 SC Glycol Pump |
| GAH | 21020 PV Glycol Pump |
| GAI | 10015 SC Glycol Pump |
| GAJ | 45020 PV Glycol Pump |
| GAK | 20015 SC Glycol Pump |

Kimray is an ISO 9001- certified manufacturer.
Kimray quality assurance process maintains strict controls
of materials and the certification of parts used in Kimray glycol pumps.

ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories

3.1. Methodology for Estimating Emissions of CH₄, N₂O, and Indirect Greenhouse Gases from Stationary Combustion

Estimates of CH₄ and N₂O Emissions

Methane (CH₄) and nitrous oxide (N₂O) emissions from stationary combustion were estimated using emission factors and methods from the Intergovernmental Panel on Climate Change (IPCC). Estimates were obtained by multiplying emission factors—by sector and fuel type—by fossil fuel and wood consumption data. This “top-down” methodology is characterized by two basic steps, described below. Data are presented in Table A-86 through Table A-91.

Step 1: Determine Energy Consumption by Sector and Fuel Type

Energy consumption from stationary combustion activities was grouped by sector: industrial, commercial, residential, electric power, and U.S. Territories. For CH₄ and N₂O from industrial, commercial, residential, and U.S. Territories, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption and wood consumption data for the United States were obtained from the Energy Information Administration’s (EIA) *Monthly Energy Review, February 2016* and Published Supplemental Tables on Petroleum Product detail (EIA 2016). Because the United States does not include U.S. Territories in its national energy statistics, fuel consumption data for U.S. Territories were collected separately from the EIA’s *International Energy Statistics* (Jacobs 2010).⁴⁰ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.⁴¹ Construction and agricultural fuel use was obtained from EPA (2013). The energy consumption data by sector were then adjusted from higher to lower heating values by multiplying by 0.90 for natural gas and wood and by 0.95 for coal and petroleum fuel. This is a simplified convention used by the International Energy Agency (IEA). Table A-86 provides annual energy consumption data for the years 1990 through 2014.

In this Inventory, the emission estimation methodology for the electric power sector was revised from Tier 1 to Tier 2 as fuel consumption by technology-type for the electricity generation sector was obtained from the Acid Rain Program Dataset (EPA 2015a). This combustion technology-and fuel-use data was available by facility from 1996 to 2014. Since there was a difference between the EPA (2015a) and EIA (2016) total energy consumption estimates, the remainder between total energy consumption using EPA (2015a) and EIA (2016) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2014.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2015a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2016) and the ratio of combustion technology and fuel types from EPA 2015a. The consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2015a) and EIA (2016) datasets. The difference in wood biomass consumption in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2016).

Step 2: Determine the Amount of CH₄ and N₂O Emitted

Activity data for industrial, commercial, residential, and U.S. Territories and fuel type for each of these sectors were then multiplied by default Tier 1 emission factors to obtain emission estimates. Emission factors for the residential, commercial, and industrial sectors were taken from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*

⁴⁰ U.S. Territories data also include combustion from mobile activities because data to allocate U.S. Territories’ energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

⁴¹ Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

(IPCC 2006). These N₂O emission factors by fuel type (consistent across sectors) were also assumed for U.S. Territories. The CH₄ emission factors by fuel type for U.S. Territories were estimated based on the emission factor for the primary sector in which each fuel was combusted. Table A-87 provides emission factors used for each sector and fuel type. For the electric power sector, emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors shown in Table A-88. Emission factors were used from the *2006 IPCC Guidelines* as the factors presented in these IPCC guidelines were taken directly from U.S. Environmental Protection Agency (EPA) publications on emissions rates for combustion sources.

Estimates of NO_x, CO, and NMVOC Emissions

Emissions estimates for NO_x, CO, and NMVOCs were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015b), and disaggregated based on EPA (2003).

For indirect greenhouse gases, the major source categories included coal, fuel oil, natural gas, wood, other fuels (i.e., bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion, which includes emissions from internal combustion engines not used in transportation. EPA periodically estimates emissions of NO_x, CO, and NMVOCs by sector and fuel type using a "bottom-up" estimating procedure. In other words, the emissions were calculated either for individual sources (e.g., industrial boilers) or for many sources combined, using basic activity data (e.g., fuel consumption or deliveries, etc.) as indicators of emissions. The national activity data used to calculate the individual categories were obtained from various sources. Depending upon the category, these activity data may include fuel consumption or deliveries of fuel, tons of refuse burned, raw material processed, etc. Activity data were used in conjunction with emission factors that relate the quantity of emissions to the activity.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2009) is represented by the following equation:

$$E_{p,s} = A_s \times EF_{p,s} \times (1 - C_{p,s}/100)$$

where,

- E = Emissions
- p = Pollutant
- s = Source category
- A = Activity level
- EF = Emission factor
- C = Percent control efficiency

The EPA currently derives the overall emission control efficiency of a category from a variety of sources, including published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U. S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion as described above is similar to the methodology recommended by the IPCC (IPCC 2006).

Table A-86: Fuel Consumption by Stationary Combustion for Calculating CH₄ and N₂O Emissions (Tbtu)

| Fuel/End-Use Sector | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Coal | 19,610 | 20,888 | 23,080 | 22,391 | 22,343 | 22,576 | 22,636 | 22,949 | 22,458 | 22,710 | 22,225 | 19,670 | 20,697 | 18,989 | 16,715 | 17,399 | 17,363 |
| Residential | 31 | 17 | 11 | 12 | 12 | 12 | 11 | 8 | 6 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial | 124 | 117 | 92 | 97 | 90 | 82 | 103 | 97 | 65 | 70 | 81 | 73 | 70 | 62 | 44 | 41 | 48 |
| Industrial | 1,640 | 1,527 | 1,349 | 1,358 | 1,244 | 1,249 | 1,262 | 1,219 | 1,189 | 1,131 | 1,081 | 877 | 952 | 866 | 782 | 800 | 796 |
| Electric Power | 17,807 | 19,217 | 21,618 | 20,920 | 20,987 | 21,199 | 21,228 | 21,591 | 21,161 | 21,465 | 21,026 | 18,682 | 19,639 | 18,024 | 15,852 | 16,521 | 16,483 |
| U.S. Territories | 7 | 10 | 10 | 4 | 11 | 34 | 32 | 33 | 37 | 37 | 37 | 37 | 37 | 37 | 37 | 37 | 37 |
| Petroleum | 6,166 | 5,659 | 6,148 | 6,632 | 6,010 | 6,394 | 6,561 | 6,486 | 6,201 | 6,064 | 5,241 | 4,670 | 4,728 | 4,417 | 4,065 | 4,204 | 4,030 |
| Residential | 1,375 | 1,262 | 1,429 | 1,465 | 1,361 | 1,468 | 1,468 | 1,368 | 1,202 | 1,220 | 1,202 | 1,138 | 1,116 | 1,060 | 847 | 936 | 990 |
| Commercial | 869 | 695 | 695 | 720 | 647 | 765 | 764 | 716 | 678 | 680 | 635 | 669 | 643 | 625 | 506 | 540 | 543 |
| Industrial | 2,750 | 2,380 | 2,283 | 2,535 | 2,371 | 2,496 | 2,669 | 2,776 | 3,111 | 2,996 | 2,427 | 1,949 | 2,054 | 1,962 | 1,924 | 2,037 | 1,869 |
| Electric Power | 797 | 860 | 1,269 | 1,279 | 1,074 | 1,043 | 1,007 | 1,004 | 590 | 618 | 488 | 383 | 412 | 266 | 273 | 180 | 153 |
| U.S. Territories | 375 | 462 | 472 | 632 | 557 | 622 | 653 | 623 | 620 | 550 | 490 | 531 | 502 | 504 | 516 | 510 | 475 |
| Natural Gas | 17,266 | 19,337 | 20,919 | 20,224 | 20,908 | 20,894 | 21,152 | 20,938 | 20,626 | 22,019 | 22,286 | 21,952 | 22,912 | 23,115 | 24,137 | 24,949 | 25,692 |
| Residential | 4,491 | 4,954 | 5,105 | 4,889 | 4,995 | 5,209 | 4,981 | 4,946 | 4,476 | 4,835 | 5,010 | 4,883 | 4,878 | 4,805 | 4,242 | 5,023 | 5,237 |
| Commercial | 2,682 | 3,096 | 3,252 | 3,097 | 3,212 | 3,261 | 3,201 | 3,073 | 2,902 | 3,085 | 3,228 | 3,187 | 3,165 | 3,216 | 2,960 | 3,380 | 3,569 |
| Industrial | 7,716 | 8,723 | 8,656 | 7,949 | 8,086 | 7,845 | 7,914 | 7,330 | 7,323 | 7,521 | 7,571 | 7,125 | 7,683 | 7,873 | 8,203 | 8,525 | 8,792 |
| Electric Power | 2,376 | 2,564 | 3,894 | 4,266 | 4,591 | 4,551 | 5,032 | 5,565 | 5,899 | 6,550 | 6,447 | 6,730 | 7,159 | 7,194 | 8,683 | 7,964 | 8,033 |
| U.S. Territories | 0 | 0 | 13 | 23 | 23 | 27 | 25 | 24 | 26 | 27 | 29 | 27 | 28 | 27 | 49 | 57 | 61 |
| Wood | 2,216 | 2,370 | 2,262 | 2,006 | 1,995 | 2,002 | 2,121 | 2,137 | 2,099 | 2,089 | 2,059 | 1,931 | 1,981 | 2,010 | 2,010 | 2,170 | 2,230 |
| Residential | 580 | 520 | 420 | 370 | 380 | 400 | 410 | 430 | 380 | 420 | 470 | 500 | 440 | 450 | 420 | 580 | 580 |
| Commercial | 66 | 72 | 71 | 67 | 69 | 71 | 70 | 70 | 65 | 70 | 73 | 73 | 72 | 69 | 61 | 70 | 73 |
| Industrial | 1,442 | 1,652 | 1,636 | 1,443 | 1,396 | 1,363 | 1,476 | 1,452 | 1,472 | 1,413 | 1,339 | 1,178 | 1,273 | 1,309 | 1,339 | 1,312 | 1,325 |
| Electric Power | 129 | 125 | 134 | 126 | 150 | 167 | 165 | 185 | 182 | 186 | 177 | 180 | 196 | 182 | 190 | 207 | 251 |
| U.S. Territories | NE |

NE – Not Estimated

Note: Totals may not sum due to independent rounding.

Table A-87: CH₄ and N₂O Emission Factors by Fuel Type and Sector (g/GJ)^a

| Fuel/End-Use Sector | CH ₄ | N ₂ O |
|---------------------|-----------------|------------------|
| Coal | | |
| Residential | 300 | 1.5 |
| Commercial | 10 | 1.5 |
| Industrial | 10 | 1.5 |
| Electric Power | 1 | 1.5 |
| U.S. Territories | 1 | 1.5 |
| Petroleum | | |
| Residential | 10 | 0.6 |
| Commercial | 10 | 0.6 |
| Industrial | 3 | 0.6 |
| Electric Power | 3 | 0.6 |
| U.S. Territories | 5 | 0.6 |
| Natural Gas | | |
| Residential | 5 | 0.1 |
| Commercial | 5 | 0.1 |
| Industrial | 1 | 0.1 |
| Electric Power | 4 | 0.1 |
| U.S. Territories | 1 | 0.1 |
| Wood | | |
| Residential | 300 | 4.0 |
| Commercial | 300 | 4.0 |
| Industrial | 30 | 4.0 |
| Electric Power | 30 | 4.0 |
| U.S. Territories | NA | NA |

NA - Not Applicable

^aGJ (Gigajoule) = 10⁹ joules. One joule = 9.486×10⁻⁴ Btu.**Table A-88: CH₄ and N₂O Emission Factors by Technology Type and Fuel Type for the Electric Power Sector (g/GJ)^a**

| Technology | Configuration | CH ₄ | N ₂ O |
|---|--------------------------------|-----------------|------------------|
| Liquid Fuels | | | |
| Residual Fuel Oil/Shale Oil Boilers | Normal Firing | 0.8 | 0.3 |
| | Tangential Firing | 0.8 | 0.3 |
| Gas/Diesel Oil Boilers | Normal Firing | 0.9 | 0.4 |
| | Tangential Firing | 0.9 | 0.4 |
| Large Diesel Oil Engines >600 hp (447kW) | | 4 | NA |
| Solid Fuels | | | |
| Pulverized Bituminous Combination Boilers | Dry Bottom, wall fired | 0.7 | 0.5 |
| | Dry Bottom, tangentially fired | 0.7 | 1.4 |
| | Wet bottom | 0.9 | 1.4 |
| Bituminous Spreader Stoker Boilers | With and without re-injection | 1 | 0.7 |
| Bituminous Fluidized Bed Combustor | Circulating Bed | 1 | 61 |
| | Bubbling Bed | 1 | 61 |
| Bituminous Cyclone Furnace | | 0.2 | 0.6 |
| Lignite Atmospheric Fluidized Bed | | NA | 71 |
| Natural Gas | | | |
| Boilers | | 1 | 1 |
| Gas-Fired Gas Turbines >3MW | | 1 | 1 |
| Large Dual-Fuel Engines | | 258 | NA |
| Combined Cycle | | 4 | 3 |
| Peat | | | |
| Peat Fluidized Bed Combustion | Circulating Bed | 3 | 7 |
| | Bubbling Bed | 3 | 3 |
| Biomass | | | |
| Wood/Wood Waste Boilers | | 11 | 7 |
| Wood Recovery Boilers | | 1 | 1 |

NA - Not Applicable

^aIbid.

Table A-89: NO_x Emissions from Stationary Combustion (kt)

| Sector/Fuel Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|---------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Electric Power | 6,045 | 5,792 | 4,829 | 4,454 | 4,265 | 3,930 | 3,595 | 3,434 | 3,249 | 3,064 | 2,847 | 2,552 | 2,226 | 1,893 | 1,654 | 1,665 | 1,609 |
| Coal | 5,119 | 5,061 | 4,130 | 3,802 | 3,634 | 3,349 | 3,063 | 2,926 | 2,768 | 2,611 | 2,426 | 2,175 | 1,896 | 1,613 | 1,409 | 1,419 | 1,371 |
| Fuel Oil | 200 | 87 | 147 | 149 | 142 | 131 | 120 | 114 | 108 | 102 | 95 | 85 | 74 | 63 | 55 | 55 | 54 |
| Natural gas | 513 | 510 | 376 | 325 | 310 | 286 | 262 | 250 | 236 | 223 | 207 | 186 | 162 | 138 | 120 | 121 | 117 |
| Wood | NA | NA | 36 | 37 | 36 | 33 | 30 | 29 | 27 | 26 | 24 | 21 | 19 | 16 | 14 | 14 | 13 |
| Other Fuels ^a | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Internal Combustion | 213 | 134 | 140 | 140 | 143 | 132 | 121 | 115 | 109 | 103 | 95 | 86 | 75 | 63 | 55 | 56 | 54 |
| Industrial | 2,559 | 2,650 | 2,278 | 2,296 | 1,699 | 1,641 | 1,580 | 1,515 | 1,400 | 1,285 | 1,165 | 1,126 | 1,087 | 1,048 | 1,048 | 1,048 | 1,048 |
| Coal | 530 | 541 | 484 | 518 | 384 | 371 | 357 | 342 | 316 | 290 | 263 | 254 | 245 | 237 | 237 | 237 | 237 |
| Fuel Oil | 240 | 224 | 166 | 153 | 114 | 110 | 106 | 101 | 94 | 86 | 78 | 75 | 73 | 70 | 70 | 70 | 70 |
| Natural gas | 877 | 999 | 710 | 711 | 526 | 508 | 489 | 469 | 433 | 398 | 361 | 348 | 336 | 324 | 324 | 324 | 324 |
| Wood | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Other Fuels ^a | 119 | 111 | 109 | 116 | 86 | 83 | 80 | 76 | 70 | 65 | 59 | 57 | 55 | 53 | 53 | 53 | 53 |
| Internal Combustion | 792 | 774 | 809 | 798 | 591 | 570 | 549 | 527 | 486 | 446 | 405 | 391 | 378 | 364 | 364 | 364 | 364 |
| Commercial | 671 | 607 | 507 | 428 | 438 | 408 | 378 | 490 | 471 | 452 | 433 | 445 | 456 | 548 | 548 | 548 | 548 |
| Coal | 36 | 35 | 21 | 21 | 19 | 19 | 19 | 19 | 18 | 17 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Fuel Oil | 88 | 94 | 52 | 52 | 50 | 49 | 49 | 49 | 46 | 43 | 39 | 39 | 38 | 37 | 37 | 37 | 37 |
| Natural gas | 181 | 210 | 161 | 165 | 157 | 156 | 155 | 145 | 135 | 124 | 122 | 120 | 118 | 118 | 118 | 118 | 118 |
| Wood | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Other Fuels ^a | 366 | 269 | 273 | 189 | 212 | 183 | 154 | 267 | 263 | 258 | 254 | 269 | 284 | 378 | 378 | 378 | 378 |
| Residential | 749 | 813 | 439 | 446 | 422 | 422 | 420 | 418 | 390 | 363 | 335 | 329 | 324 | 318 | 318 | 318 | 318 |
| Coal ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Fuel Oil ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Natural Gas ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Wood | 42 | 44 | 21 | 22 | 21 | 21 | 21 | 20 | 19 | 18 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Other Fuels ^a | 707 | 769 | 417 | 424 | 402 | 401 | 400 | 398 | 371 | 345 | 318 | 313 | 308 | 302 | 302 | 302 | 302 |
| Total | 10,023 | 9,862 | 8,053 | 7,623 | 6,825 | 6,401 | 5,973 | 5,858 | 5,511 | 5,163 | 4,780 | 4,452 | 4,092 | 3,807 | 3,567 | 3,579 | 3,522 |

NA - Not Applicable

^a Other Fuels include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 20145).^b Residential coal, fuel oil, and natural gas emissions are included in the Other Fuels category (EPA 2015b).

Note: Totals may not sum due to independent rounding.

Table A-90: CO Emissions from Stationary Combustion (kt)

| Sector/Fuel Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| Electric Power | 329 | 337 | 439 | 439 | 594 | 591 | 586 | 582 | 609 | 637 | 660 | 676 | 693 | 710 | 710 | 710 | 710 |
| Coal | 213 | 227 | 221 | 220 | 298 | 296 | 294 | 292 | 305 | 319 | 330 | 339 | 347 | 356 | 356 | 356 | 356 |
| Fuel Oil | 18 | 9 | 27 | 28 | 38 | 37 | 37 | 37 | 38 | 40 | 42 | 43 | 44 | 45 | 45 | 45 | 45 |
| Natural gas | 46 | 49 | 96 | 92 | 125 | 124 | 123 | 122 | 128 | 134 | 138 | 142 | 145 | 149 | 149 | 149 | 149 |
| Wood | NA |
| Other Fuels ^a | NA | NA | 31 | 32 | 44 | 43 | 43 | 43 | 45 | 47 | 48 | 50 | 51 | 52 | 52 | 52 | 52 |
| Internal Combustion | 52 | 52 | 63 | 67 | 91 | 90 | 90 | 89 | 93 | 97 | 101 | 103 | 106 | 108 | 108 | 108 | 108 |

| | | | | | | | | | | | | | | | | | |
|--------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Industrial | 797 | 958 | 1,106 | 1,137 | 1,150 | 1,116 | 1,081 | 1,045 | 968 | 892 | 815 | 834 | 853 | 872 | 872 | 872 | 872 |
| Coal | 95 | 88 | 118 | 125 | 127 | 123 | 119 | 115 | 107 | 98 | 90 | 92 | 94 | 96 | 96 | 96 | 96 |
| Fuel Oil | 67 | 64 | 48 | 45 | 46 | 44 | 43 | 42 | 39 | 35 | 32 | 33 | 34 | 35 | 35 | 35 | 35 |
| Natural gas | 205 | 313 | 355 | 366 | 370 | 359 | 348 | 336 | 312 | 287 | 262 | 268 | 274 | 281 | 281 | 281 | 281 |
| Wood | NA |
| Other Fuels ^a | 253 | 270 | 300 | 321 | 325 | 316 | 306 | 295 | 274 | 252 | 230 | 236 | 241 | 247 | 247 | 247 | 247 |
| Internal Combustion | 177 | 222 | 285 | 279 | 282 | 274 | 266 | 257 | 238 | 219 | 200 | 205 | 209 | 214 | 214 | 214 | 214 |
| Commercial | 205 | 211 | 151 | 154 | 177 | 173 | 169 | 166 | 156 | 146 | 137 | 138 | 140 | 142 | 142 | 142 | 142 |
| Coal | 13 | 14 | 14 | 13 | 15 | 15 | 15 | 14 | 14 | 13 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Fuel Oil | 16 | 17 | 17 | 17 | 20 | 19 | 19 | 19 | 18 | 16 | 15 | 16 | 16 | 16 | 16 | 16 | 16 |
| Natural gas | 40 | 49 | 83 | 84 | 97 | 95 | 93 | 91 | 86 | 80 | 75 | 76 | 77 | 78 | 78 | 78 | 78 |
| Wood | NA |
| Other Fuels ^a | 136 | 132 | 36 | 38 | 44 | 43 | 42 | 41 | 39 | 37 | 34 | 35 | 35 | 35 | 35 | 35 | 35 |
| Residential | 3,668 | 3,877 | 2,644 | 2,648 | 3,044 | 2,982 | 2,919 | 2,856 | 2,690 | 2,524 | 2,357 | 2,387 | 2,416 | 2,446 | 2,446 | 2,446 | 2,446 |
| Coal ^b | NA |
| Fuel Oil ^b | NA |
| Natural Gas ^b | NA |
| Wood | 3,430 | 3,629 | 2,416 | 2,424 | 2,787 | 2,730 | 2,673 | 2,615 | 2,463 | 2,310 | 2,158 | 2,185 | 2,212 | 2,239 | 2,239 | 2,239 | 2,239 |
| Other Fuels ^a | 238 | 248 | 228 | 224 | 257 | 252 | 247 | 241 | 227 | 213 | 199 | 202 | 204 | 207 | 207 | 207 | 207 |
| Total | 5,000 | 5,383 | 4,340 | 4,377 | 4,965 | 4,862 | 4,756 | 4,648 | 4,423 | 4,198 | 3,969 | 4,036 | 4,103 | 4,170 | 4,170 | 4,170 | 4,169 |

NA - Not Applicable

^a Other Fuels include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2015b).

^b Residential coal, fuel oil, and natural gas emissions are included in the Other Fuels category (EPA 2015b).

Note: Totals may not sum due to independent rounding.

Table A-91: NMVOC Emissions from Stationary Combustion (kt)

| Sector/Fuel Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|-----------|-----------|------------|------------|------------|------------|------------|
| Electric Power | 43 | 40 | 56 | 55 | 45 | 45 | 44 | 44 | 42 | 41 | 40 | 39 | 38 | 37 | 37 | 37 | 37 |
| Coal | 24 | 26 | 27 | 26 | 21 | 21 | 21 | 21 | 20 | 20 | 19 | 18 | 18 | 18 | 18 | 18 | 18 |
| Fuel Oil | 5 | 2 | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Natural Gas | 2 | 2 | 12 | 12 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 |
| Wood | NA | NA | NA | NA | NA | NA | NA | NA |
| Other Fuels ^a | NA | NA | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Internal Combustion | 11 | 9 | 11 | 10 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 7 | 7 |
| Industrial | 165 | 187 | 157 | 159 | 138 | 132 | 126 | 120 | 113 | 105 | 97 | 99 | 100 | 101 | 101 | 101 | 102 |
| Coal | 7 | 5 | 9 | 10 | 9 | 9 | 8 | 8 | 7 | 7 | 6 | 6 | 7 | 7 | 7 | 7 | 7 |
| Fuel Oil | 11 | 11 | 9 | 9 | 7 | 7 | 7 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Natural Gas | 52 | 66 | 53 | 54 | 47 | 45 | 43 | 41 | 38 | 36 | 33 | 33 | 34 | 34 | 34 | 34 | 34 |
| Wood | NA | NA | NA | NA | NA | NA | NA | NA |
| Other Fuels ^a | 46 | 45 | 27 | 29 | 25 | 24 | 23 | 22 | 21 | 19 | 18 | 18 | 18 | 19 | 19 | 19 | 19 |
| Internal Combustion | 49 | 60 | 58 | 57 | 49 | 47 | 45 | 43 | 40 | 37 | 35 | 35 | 36 | 36 | 36 | 36 | 36 |
| Commercial | 18 | 21 | 28 | 29 | 61 | 54 | 48 | 33 | 34 | 35 | 36 | 38 | 40 | 42 | 42 | 42 | 42 |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | + | + | + | + | + | + | + | + |

| | | | | | | | | | | | | | | | | | |
|--------------------------|------------|------------|--------------|--------------|--------------|--------------|--------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| Fuel Oil | 3 | 3 | 4 | 4 | 6 | 5 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Natural Gas | 7 | 10 | 14 | 14 | 23 | 18 | 14 | 9 | 8 | 7 | 6 | 7 | 7 | 7 | 7 | 7 | 7 |
| Wood | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Other Fuels ^a | 8 | 8 | 9 | 10 | 31 | 30 | 30 | 22 | 24 | 26 | 28 | 29 | 31 | 32 | 32 | 32 | 32 |
| Residential | 686 | 725 | 837 | 836 | 1,341 | 1,067 | 793 | 518 | 465 | 411 | 358 | 378 | 399 | 419 | 419 | 419 | 419 |
| Coal ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Fuel Oil ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Natural Gas ^b | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Wood | 651 | 688 | 809 | 809 | 1,297 | 1,032 | 767 | 502 | 450 | 398 | 346 | 366 | 386 | 406 | 406 | 406 | 406 |
| Other Fuels ^a | 35 | 37 | 27 | 27 | 43 | 35 | 26 | 17 | 15 | 13 | 12 | 12 | 13 | 14 | 14 | 14 | 14 |
| Total | 912 | 973 | 1,077 | 1,080 | 1,585 | 1,298 | 1,011 | 716 | 654 | 593 | 531 | 553 | 576 | 599 | 599 | 599 | 599 |

NA - Not Applicable

+ Does not exceed 0.5 kt.

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2015b).

^b Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2015b).

Note: Totals may not sum due to independent rounding.

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3.2. Methodology for Estimating Emissions of CH₄, N₂O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions

Estimating CO₂ Emissions by Transportation Mode

Transportation-related CO₂ emissions, as presented in the CO₂ Emissions from Fossil Fuel Combustion section of the Energy chapter, were calculated using the methodology described in Annex 2.1. This section provides additional information on the data sources and approach used for each transportation fuel type. As noted in Annex 2.1, CO₂ emissions estimates for the transportation sector were calculated directly for on-road diesel fuel and motor gasoline based on data sources for individual modes of transportation (considered a bottom up approach). For most other fuel and energy types (aviation gasoline, residual fuel oil, natural gas, LPG, and electricity), CO₂ emissions were calculated based on transportation sector-wide fuel consumption estimates from the Energy Information Administration (EIA 2016 and EIA 2015) and apportioned to individual modes (considered a “top down” approach). Carbon dioxide emissions from commercial jet fuel use are obtained directly from the Federal Aviation Administration (FAA 2016), while CO₂ emissions from other aircraft jet fuel consumption is determined using a top down approach.

Based on interagency discussions between EPA, EIA, and FHWA beginning in 2005, it was agreed that use of “bottom up” data would be more accurate for diesel fuel and motor gasoline consumption in the transportation sector, based on the availability of reliable data sources. A “bottom up” diesel calculation was first implemented in the 1990 through 2005 Inventory, and a bottom-up gasoline calculation was introduced in the 1990 through 2006 Inventory for the calculation of emissions from on-road vehicles. Estimated motor gasoline and diesel consumption data for on-road vehicles by vehicle type come from FHWA’s *Highway Statistics*, Table VM-1 (FHWA 1996 through 2015),⁴² and are based on federal and state fuel tax records. These fuel consumption estimates were then combined with estimates of fuel shares by vehicle type from DOE’s Transportation Energy Data Book Annex Tables A.1 through A.6 (DOE 1993 through 2015) to develop an estimate of fuel consumption for each vehicle type (i.e., passenger cars, light-duty trucks, buses, medium- and heavy-duty trucks, motorcycles). The on-road gas and diesel fuel consumption estimates by vehicle type were then adjusted for each year so that the sum of gasoline and diesel fuel consumption across all on-road vehicle categories matched the fuel consumption estimates in *Highway Statistics*’ Table MF-27 (FHWA 1996 through 2015). This resulted in a final “bottom up” estimate of motor gasoline and diesel fuel use by vehicle type, consistent with the FHWA total for on-road motor gasoline and diesel fuel use.

A primary challenge to switching from a top-down approach to a bottom-up approach for the transportation sector relates to potential incompatibilities with national energy statistics. From a multi-sector national standpoint, EIA develops the most accurate estimate of total motor gasoline and diesel fuel supplied and consumed in the United States. EIA then allocates this total fuel consumption to each major end-use sector (residential, commercial, industrial and transportation) using data from the *Fuel Oil and Kerosene Sales* (FOKS) report for distillate fuel oil and FHWA for motor gasoline. However, the “bottom-up” approach used for the on-road and non-road fuel consumption estimate, as described above, is considered to be the most representative of the transportation sector’s share of the EIA total consumption. Therefore, for years in which there was a disparity between EIA’s fuel allocation estimate for the transportation sector and the “bottom-up” estimate, adjustments were made to other end-use sector fuel allocations (residential, commercial and industrial) in order for the consumption of all sectors combined to equal the “top-down” EIA value.

In the case of motor gasoline, estimates of fuel use by recreational boats come from the NONROAD component of EPA’s MOVES2014a model (EPA 2015d), and these estimates, along with those from other sectors (e.g., commercial sector, industrial sector), were adjusted for years in which the bottom-up on-road motor gasoline consumption estimate exceeded the EIA estimate for total gasoline consumption of all sectors. Similarly, to ensure consistency with EIA’s total diesel estimate for all sectors, the diesel consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately.

⁴² In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-14 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category “Passenger Cars” has been replaced by “Light-duty Vehicles-Short Wheelbase” and “Other 2 axle-4 Tire Vehicles” has been replaced by “Light-duty Vehicles, Long Wheelbase.” This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

Estimates of diesel fuel consumption from rail were taken from the Association of American Railroads (AAR 2008 through 2015) for Class I railroads, the American Public Transportation Association (APTA 2007 through 2015 and APTA 2006) and Gaffney (2007) for commuter rail, the Upper Great Plains Transportation Institute (Benson 2002 through 2004) and Whorton (2006 through 2013) for Class II and III railroads, and DOE's *Transportation Energy Data Book* (DOE 1993 through 2015) for passenger rail. Estimates of diesel from ships and boats were taken from EIA's *Fuel Oil and Kerosene Sales* (1991 through 2015).

As noted above, for fuels other than motor gasoline and diesel, EIA's transportation sector total was apportioned to specific transportation sources. For jet fuel, estimates come from: FAA (2016) for domestic and international commercial aircraft, and DESC (2015) for domestic and international military aircraft. General aviation jet fuel consumption is calculated as the difference between total jet fuel consumption as reported by EIA and the total consumption from commercial and military jet fuel consumption. Commercial jet fuel CO₂ estimates are obtained directly from the Federal Aviation Administration (FAA 2016), while CO₂ emissions from domestic military and general aviation jet fuel consumption is determined using a top down approach. Domestic commercial jet fuels CO₂ from FAA is subtracted from total domestic jet fuel CO₂ emissions, and this remaining value is apportioned among domestic military and domestic general aviation based on their relative proportion of energy consumption. Estimates for biofuels, including ethanol and biodiesel were discussed separately in Chapter 3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels under the methodology for Estimating CO₂ from Fossil Combustion, and in Chapter 3.10 Wood Biomass and Ethanol Consumption and were not apportioned to specific transportation sources. Consumption estimates for biofuels were calculated based on data from the Energy Information Administration (EIA 2016).

Table A-92 displays estimated fuel consumption by fuel and vehicle type. Table A-93 displays estimated energy consumption by fuel and vehicle type. The values in both of these tables correspond to the figures used to calculate CO₂ emissions from transportation. Except as noted above, they are estimated based on EIA transportation sector energy estimates by fuel type, with activity data used to apportion consumption to the various modes of transport. The motor gasoline and diesel fuel consumption volumes published by EIA and FHWA include ethanol blended with gasoline and biodiesel blended with diesel. Biofuels blended with conventional fuels were subtracted from these consumption totals in order to be consistent with IPCC methodological guidance and UNFCCC reporting obligations, for which net carbon fluxes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change and Forestry chapter, not in Energy chapter totals. Ethanol fuel volumes were removed from motor gasoline consumption estimates for years 1990 through 2014 and biodiesel fuel volumes were removed from diesel fuel consumption volumes for years 2001 through 2014, as there was negligible use of biodiesel as a diesel blending component prior to 2001. The subtraction or removal of biofuels blended into motor gasoline and diesel were conducted following the methodology outlined in Step 2 ("Remove Biofuels from Petroleum") of the EIA's *Monthly Energy Review* (MER) Section 12 notes.

In order to remove the volume of biodiesel blended into diesel fuel, the refinery and blender net volume inputs of renewable diesel fuel sourced from EIA Petroleum Supply Annual (EIA 2015) *Table 18 - Refinery Net Input of Crude Oil and Petroleum Products* and *Table 20 - Blender Net Inputs of Petroleum Products* were subtracted from the transportation sector's total diesel fuel consumption volume (for both the "top-down" EIA and "bottom-up" FHWA estimates). To remove the fuel ethanol blended into motor gasoline, ethanol energy consumption data sourced from MER *Table 10.2b - Renewable Energy Consumption: Industrial and Transportation Sectors* (EIA 2016) were subtracted from the total EIA and FHWA transportation motor gasoline energy consumption estimates.

Total ethanol and biodiesel consumption estimates are shown separately in Table A-94.⁴³

⁴³ Note that the refinery and blender net volume inputs of renewable diesel fuel sourced from EIA's Petroleum Supply Annual (PSA) differs from the biodiesel volume presented in Table A-94. The PSA data is representative of the amount of biodiesel that refineries and blenders added to diesel fuel to make low level biodiesel blends. This is the appropriate value to subtract from total diesel fuel volume, as it represents the amount of biofuel blended into diesel to create low-level biodiesel blends. The biodiesel consumption value presented in Table A-93 is representative of the total biodiesel consumed and includes biodiesel components in all types of fuel formulations, from low level (<5%) to high level (6-20%, 100%) blends of biodiesel. This value is sourced from MER Table 10.4 and is calculated as biodiesel production plus biodiesel net imports minus biodiesel stock exchange.

Table A-92. Fuel Consumption by Fuel and Vehicle Type (million gallons unless otherwise specified)

| Fuel/Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 ^a | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Motor Gasoline^{b,c} | 110,417 | 117,429 | 128,174 | 129,590 | 132,169 | 132,600 | 134,336 | 133,294 | 131,337 | 130,768 | 125,050 | 124,189 | 123,175 | 120,497 | 120,035 | 120,138 | 122,188 |
| Passenger Cars | 69,763 | 67,496 | 72,320 | 72,920 | 74,313 | 71,931 | 71,504 | 73,856 | 70,791 | 88,607 | 84,714 | 83,918 | 83,230 | 82,621 | 82,464 | 82,463 | 82,694 |
| Light-Duty Trucks | 34,698 | 44,074 | 50,398 | 50,871 | 52,023 | 55,417 | 57,540 | 53,733 | 54,798 | 34,933 | 33,074 | 33,473 | 33,262 | 31,612 | 31,270 | 31,305 | 33,086 |
| Motorcycles | 194 | 199 | 208 | 192 | 189 | 184 | 193 | 182 | 210 | 472 | 487 | 468 | 411 | 401 | 459 | 437 | 427 |
| Buses | 39 | 41 | 43 | 40 | 38 | 36 | 49 | 41 | 41 | 79 | 81 | 84 | 82 | 80 | 92 | 95 | 100 |
| Medium- and Heavy-Duty Trucks | 4,350 | 4,044 | 4,065 | 3,961 | 4,006 | 3,446 | 3,475 | 3,922 | 3,961 | 5,164 | 5,220 | 4,798 | 4,773 | 4,383 | 4,358 | 4,455 | 4,506 |
| Recreational Boats ^d | 1,374 | 1,575 | 1,140 | 1,606 | 1,601 | 1,587 | 1,574 | 1,560 | 1,536 | 1,514 | 1,474 | 1,448 | 1,417 | 1,401 | 1,391 | 1,382 | 1,376 |
| Distillate Fuel Oil (Diesel Fuel)^{b,c} | 25,631 | 31,604 | 39,241 | 39,057 | 40,347 | 41,176 | 42,667 | 44,658 | 45,844 | 46,427 | 44,026 | 39,873 | 41,477 | 42,280 | 42,045 | 42,672 | 44,031 |
| Passenger Cars | 771 | 765 | 356 | 357 | 364 | 412 | 419 | 414 | 403 | 403 | 363 | 354 | 367 | 399 | 401 | 399 | 408 |
| Light-Duty Trucks | 1,119 | 1,452 | 1,961 | 2,029 | 2,133 | 2,652 | 2,822 | 2,518 | 2,611 | 1,327 | 1,184 | 1,180 | 1,227 | 1,277 | 1,271 | 1,265 | 1,365 |
| Buses | 781 | 851 | 997 | 906 | 860 | 930 | 1,316 | 1,030 | 1,034 | 1,520 | 1,436 | 1,335 | 1,326 | 1,419 | 1,515 | 1,525 | 1,634 |
| Medium- and Heavy-Duty Trucks | 18,574 | 23,240 | 30,179 | 30,124 | 31,417 | 31,539 | 32,598 | 35,159 | 36,089 | 37,518 | 35,726 | 32,364 | 33,683 | 33,859 | 33,877 | 34,426 | 35,541 |
| Recreational Boats | 190 | 228 | 270 | 278 | 286 | 294 | 302 | 311 | 319 | 327 | 335 | 343 | 351 | 357 | 364 | 368 | 376 |
| Ships and Other Boats | 735 | 1,204 | 1,372 | 1,244 | 1,197 | 1,173 | 802 | 780 | 724 | 794 | 767 | 768 | 726 | 993 | 733 | 741 | 606 |
| Rail ^e | 3,461 | 3,863 | 4,106 | 4,119 | 4,089 | 4,176 | 4,407 | 4,446 | 4,664 | 4,538 | 4,215 | 3,529 | 3,798 | 3,975 | 3,884 | 3,948 | 4,101 |
| Jet Fuel^f | 19,186 | 17,991 | 20,002 | 19,454 | 19,004 | 18,389 | 19,147 | 19,420 | 18,695 | 18,407 | 17,749 | 15,809 | 15,537 | 15,036 | 14,705 | 15,088 | 15,237 |
| Commercial Aircraft | 11,569 | 12,136 | 14,672 | 13,121 | 12,774 | 12,943 | 13,147 | 13,976 | 14,426 | 14,708 | 13,400 | 12,588 | 11,931 | 12,067 | 11,932 | 12,031 | 12,131 |
| General Aviation Aircraft | 4,034 | 3,361 | 3,163 | 3,975 | 4,119 | 3,323 | 3,815 | 3,583 | 2,590 | 2,043 | 2,682 | 1,787 | 2,322 | 1,895 | 1,659 | 2,033 | 1,676 |
| Military Aircraft | 3,583 | 2,495 | 2,167 | 2,359 | 2,110 | 2,123 | 2,185 | 1,860 | 1,679 | 1,656 | 1,667 | 1,434 | 1,283 | 1,074 | 1,114 | 1,024 | 1,430 |
| Aviation Gasoline^f | 374 | 329 | 302 | 291 | 281 | 251 | 260 | 294 | 278 | 263 | 235 | 221 | 225 | 225 | 209 | 186 | 181 |
| General Aviation Aircraft | 374 | 329 | 302 | 291 | 281 | 251 | 260 | 294 | 278 | 263 | 235 | 221 | 225 | 225 | 209 | 186 | 181 |
| Residual Fuel Oil^{f,g} | 2,006 | 2,587 | 2,963 | 1,066 | 1,522 | 662 | 1,245 | 1,713 | 2,046 | 2,579 | 1,812 | 1,241 | 1,818 | 1,723 | 1,410 | 1,345 | 517 |
| Ships and Other Boats | 2,006 | 2,587 | 2,963 | 1,066 | 1,522 | 662 | 1,245 | 1,713 | 2,046 | 2,579 | 1,812 | 1,241 | 1,818 | 1,723 | 1,410 | 1,345 | 517 |
| Natural Gas^f (trillion cubic feet) | 0.7 | 0.7 | 0.7 | 0.6 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.9 | 0.9 |
| Passenger Cars | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Light-Duty Trucks | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Buses | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pipelines | 0.7 | 0.7 | 0.6 | 0.6 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.9 |
| LPG^f | 265 | 206 | 138 | 159 | 166 | 207 | 222 | 327 | 320 | 257 | 468 | 331 | 348 | 404 | 442 | 525 | 519 |
| Buses | - | 1.6 | 1.5 | 0.3 | 0.6 | 0.7 | 0.7 | 1.0 | 1.0 | - | - | - | - | - | - | 4.6 | 4.6 |
| Light-Duty Trucks | 106 | 98 | 88 | 108 | 117 | 144 | 167 | 247 | 229 | 185 | 340 | 228 | 243 | 283 | 316 | 368 | 364 |
| Medium- and Heavy-Duty Trucks | 159 | 106 | 49 | 51 | 49 | 62 | 55 | 79 | 89 | 72 | 128 | 103 | 106 | 121 | 126 | 152 | 150 |
| Electricity^{f,h} | 4,751 | 4,975 | 5,382 | 5,724 | 5,517 | 6,810 | 7,224 | 7,506 | 7,358 | 8,173 | 7,653 | 7,768 | 7,712 | 7,672 | 7,320 | 7,625 | 7,758 |
| Rail | 4,751 | 4,975 | 5,382 | 5,724 | 5,517 | 6,810 | 7,224 | 7,506 | 7,358 | 8,173 | 7,653 | 7,768 | 7,712 | 7,672 | 7,320 | 7,625 | 7,758 |

- Unreported or zero

^a In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2014 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in fuel consumption data by vehicle class between 2006 and 2007.

^b Figures do not include ethanol blended in motor gasoline or biodiesel blended into distillate fuel oil. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter. This table is calculated with the heat content for gasoline without ethanol (from Table A.2 in the EIA Annual Energy Review) rather than the annually variable quantity-weighted heat content for gasoline with ethanol, which varies by year. In addition, updates to the distillate fuel oil heat content data from EIA for years 1993 through present resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^c Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^d Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

^e Class II and Class II diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^f Estimated based on EIA transportation sector energy estimates by fuel type, with bottom-up activity data used for apportionment to modes.

^g Fluctuations in reported fuel consumption may reflect data collection problems.

^h Million Kilowatt-hours

Table A-93: Energy Consumption by Fuel and Vehicle Type (Tbtu)

| Fuel/Vehicle Type ^a | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 ^b | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|-------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Motor Gasoline^{c, d} | 13,810 | 14,687 | 16,031 | 16,208 | 16,531 | 16,585 | 16,802 | 16,671 | 16,426 | 16,259 | 15,548 | 15,441 | 15,315 | 14,982 | 14,924 | 14,937 | 15,192 |
| Passenger Cars | 8,725 | 8,442 | 9,045 | 9,120 | 9,294 | 8,996 | 8,943 | 9,237 | 8,854 | 11,017 | 10,533 | 10,434 | 10,348 | 10,272 | 10,253 | 10,253 | 10,282 |
| Light-Duty Trucks | 4,340 | 5,512 | 6,303 | 6,363 | 6,507 | 6,931 | 7,197 | 6,720 | 6,854 | 4,343 | 4,112 | 4,162 | 4,136 | 3,930 | 3,888 | 3,892 | 4,114 |
| Motorcycles | 24 | 25 | 26 | 24 | 24 | 23 | 24 | 23 | 26 | 59 | 61 | 58 | 51 | 50 | 57 | 54 | 53 |
| Buses | 5 | 5 | 5 | 5 | 5 | 4 | 6 | 5 | 5 | 10 | 10 | 10 | 10 | 10 | 11 | 12 | 12 |
| Medium- and Heavy-Duty Trucks | 544 | 506 | 508 | 495 | 501 | 431 | 435 | 491 | 495 | 642 | 649 | 597 | 593 | 545 | 542 | 554 | 560 |
| Recreational Boats ^e | 172 | 197 | 143 | 201 | 200 | 199 | 197 | 195 | 192 | 188 | 183 | 180 | 176 | 174 | 173 | 172 | 171 |
| Distillate Fuel Oil (Diesel Fuel)^{a, d} | 3,555 | 4,379 | 5,437 | 5,411 | 5,590 | 5,705 | 5,910 | 6,186 | 6,334 | 6,395 | 6,059 | 5,488 | 5,706 | 5,814 | 5,780 | 5,866 | 6,052 |
| Passenger Cars | 107 | 106 | 49 | 50 | 50 | 57 | 58 | 57 | 56 | 55 | 50 | 49 | 51 | 55 | 55 | 55 | 56 |
| Light-Duty Trucks | 155 | 201 | 272 | 281 | 296 | 367 | 391 | 349 | 361 | 183 | 163 | 162 | 169 | 176 | 175 | 174 | 188 |
| Buses | 108 | 118 | 138 | 126 | 119 | 129 | 182 | 143 | 143 | 209 | 198 | 184 | 182 | 195 | 208 | 210 | 225 |
| Medium- and Heavy-Duty Trucks | 2,576 | 3,220 | 4,181 | 4,174 | 4,353 | 4,370 | 4,516 | 4,870 | 4,986 | 5,168 | 4,917 | 4,455 | 4,634 | 4,656 | 4,657 | 4,733 | 4,885 |
| Recreational Boats | 26 | 32 | 37 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| Ships and Other Boats | 102 | 167 | 190 | 172 | 166 | 163 | 111 | 108 | 100 | 109 | 106 | 106 | 100 | 137 | 101 | 102 | 83 |
| Rail ^f | 480 | 535 | 569 | 571 | 566 | 579 | 610 | 616 | 644 | 625 | 580 | 486 | 523 | 547 | 534 | 543 | 564 |
| Jet Fuel^g | 2,590 | 2,429 | 2,700 | 2,626 | 2,565 | 2,482 | 2,585 | 2,622 | 2,524 | 2,485 | 2,396 | 2,134 | 2,097 | 2,030 | 1,985 | 2,037 | 2,057 |
| Commercial Aircraft | 1,562 | 1,638 | 1,981 | 1,771 | 1,725 | 1,747 | 1,775 | 1,887 | 1,948 | 1,986 | 1,809 | 1,699 | 1,611 | 1,629 | 1,611 | 1,624 | 1,638 |
| General Aviation Aircraft | 545 | 454 | 427 | 537 | 556 | 449 | 515 | 484 | 350 | 276 | 362 | 241 | 314 | 256 | 224 | 274 | 226 |
| Military Aircraft ^a | 484 | 337 | 293 | 318 | 285 | 287 | 295 | 251 | 227 | 224 | 225 | 194 | 173 | 145 | 150 | 138 | 193 |
| Aviation Gasoline^g | 45 | 40 | 36 | 35 | 34 | 30 | 31 | 35 | 33 | 32 | 28 | 27 | 27 | 27 | 25 | 22 | 22 |
| General Aviation Aircraft | 45 | 40 | 36 | 35 | 34 | 30 | 31 | 35 | 33 | 32 | 28 | 27 | 27 | 27 | 25 | 22 | 22 |
| Residual Fuel Oil^{g, h} | 300 | 387 | 443 | 159 | 228 | 99 | 186 | 256 | 306 | 386 | 271 | 186 | 272 | 258 | 211 | 201 | 73 |
| Ships and Other Boats | 300 | 387 | 443 | 159 | 228 | 99 | 186 | 256 | 306 | 386 | 271 | 186 | 272 | 258 | 211 | 201 | 73 |
| Natural Gas^g | 680 | 724 | 672 | 658 | 699 | 627 | 602 | 624 | 625 | 663 | 692 | 715 | 719 | 734 | 780 | 887 | 899 |
| Passenger Cars | - | 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Light-Duty Trucks | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Buses | - | 1 | 8 | 9 | 12 | 14 | 16 | 16 | 16 | 19 | 21 | 22 | 20 | 20 | 20 | 21 | 21 |
| Pipelines | 680 | 721 | 664 | 649 | 687 | 614 | 586 | 608 | 609 | 645 | 672 | 693 | 699 | 713 | 760 | 867 | 878 |
| LPG^g | 23 | 18 | 12 | 14 | 14 | 18 | 19 | 28 | 27 | 22 | 40 | 28 | 29 | 34 | 37 | 44 | 44 |
| Buses | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Light-Duty Trucks | 9 | 8 | 8 | 9 | 10 | 12 | 14 | 21 | 20 | 16 | 29 | 19 | 21 | 24 | 27 | 31 | 31 |
| Medium- and Heavy-Duty Trucks | 14 | 9 | 4 | 4 | 4 | 5 | 5 | 7 | 8 | 6 | 11 | 9 | 9 | 10 | 11 | 13 | 13 |
| Electricity^g | 16 | 17 | 18 | 20 | 19 | 23 | 25 | 26 | 25 | 28 | 26 | 27 | 26 | 26 | 25 | 26 | 26 |
| Rail | 16 | 17 | 18 | 20 | 19 | 23 | 25 | 26 | 25 | 28 | 26 | 27 | 26 | 26 | 25 | 26 | 26 |
| Total | 21,019 | 22,681 | 25,350 | 25,131 | 25,680 | 25,570 | 26,160 | 26,449 | 26,302 | 26,270 | 25,061 | 24,045 | 24,192 | 23,905 | 23,768 | 24,022 | 24,369 |

-Unreported or zero

^a Note that updates to the distillate fuel oil heat content data from EIA for years 1993 through present resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^b In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2014 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in fuel consumption data by vehicle class between 2006 and 2007.

^c Figures do not include ethanol blended in motor gasoline or biodiesel blended into distillate fuel oil. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter.

^d Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^e Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

^f Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^g Estimated based on EIA transportation sector energy estimates, with bottom-up data used for apportionment to modes.

^h Fluctuations in reported fuel consumption may reflect data collection problems. Residual fuel oil for ships and other boats data is based on EIA's December 2015 Monthly Energy Review data.

Table A-94: Transportation Sector Biofuel Consumption by Fuel Type (million gallons)

| Fuel Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------|------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|--------|--------|--------|--------|--------|--------|
| Ethanol | 712 | 1,326 | 1,590 | 1,660 | 1,975 | 2,689 | 3,375 | 3,860 | 5,207 | 6,563 | 9,263 | 10,537 | 12,282 | 12,329 | 12,324 | 12,646 | 12,900 |
| Biodiesel | NA | NA | NA | 10 | 16 | 14 | 27 | 91 | 261 | 354 | 304 | 322 | 260 | 886 | 899 | 1,429 | 1,417 |

NA – Not Available

Note: According to the MER, there was no biodiesel consumption prior to 2001.

Estimates of CH₄ and N₂O Emissions

Mobile source emissions of greenhouse gases other than CO₂ are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emissions estimates of CH₄ and N₂O were derived using a methodology similar to that outlined in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

Activity data were obtained from a number of U.S. government agencies and other publications. Depending on the category, these basic activity data included fuel consumption and vehicle miles traveled (VMT). These estimates were then multiplied by emission factors, expressed as grams per unit of fuel consumed or per vehicle mile.

Methodology for On-Road Gasoline and Diesel Vehicles

Step 1: Determine Vehicle Miles Traveled by Vehicle Type, Fuel Type, and Model Year

VMT by vehicle type (e.g., passenger cars, light-duty trucks, medium- and heavy-duty trucks,⁴⁴ buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2015).⁴⁵ As these vehicle categories are not fuel-specific, VMT for each vehicle type was disaggregated by fuel type (gasoline, diesel) so that the appropriate emission factors could be applied. VMT from *Highway Statistics* Table VM-1 (FHWA 1996 through 2015) was allocated to fuel types (gasoline, diesel, other) using historical estimates of fuel shares reported in the Appendix to the *Transportation Energy Data Book, Tables A.5 and A.6* (DOE 1993 through 2015). These fuel shares are drawn from various sources, including the Vehicle Inventory and Use Survey, the National Vehicle Population Profile, and the American Public Transportation Association. Fuel shares were first adjusted proportionately such that gasoline and diesel shares for each vehicle/fuel type category equaled 100 percent of national VMT. VMT for alternative fuel vehicles (AFVs) was calculated separately, and the methodology is explained in the following section on AFVs. Estimates of VMT from AFVs were then subtracted from the appropriate total VMT estimates to develop the final VMT estimates by vehicle/fuel type category.⁴⁶ The resulting national VMT estimates for gasoline and diesel on-road vehicles are presented in Table A-95 and Table A-96, respectively.

Total VMT for each on-road category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, medium- and heavy-duty diesel vehicles, and motorcycles) were distributed across 30 model years shown for 2014 in Table A-97. This distribution was derived by weighting the appropriate age distribution of the U.S. vehicle fleet according to vehicle registrations by the average annual age-specific vehicle mileage accumulation of U.S. vehicles. Age distribution values were obtained from EPA's MOBILE6 model for all years before 1999 (EPA 2000) and EPA's MOVES2014a model for years 2009 forward (EPA 2015d).⁴⁷ Age-specific vehicle mileage accumulations were also obtained from EPA's MOVES2014a model (EPA 2015d).⁴⁸

Step 2: Allocate VMT Data to Control Technology Type

VMT by vehicle type for each model year was distributed across various control technologies as shown in Table A-103 through Table A-106. The categories "EPA Tier 0" and "EPA Tier 1" were used instead of the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the *Revised 1996 IPCC Guidelines*. EPA Tier 0, EPA Tier 1, EPA Tier 2, and LEV refer to U.S. emission regulations, rather than control technologies; however, each does correspond to particular combinations of control technologies and engine design. EPA Tier 2 and its predecessors EPA

⁴⁴ Medium- and heavy-duty trucks correspond to FHWA's reporting categories of single-unit trucks and combination trucks. Single-unit trucks are defined as single frame trucks that have 2-axes and at least 6 tires or a gross vehicle weight rating (GVWR) exceeding 10,000 lbs.

⁴⁵ In 2011 FHWA changed its methods for estimated vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-14 time period. This resulted in large changes in VMT data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

⁴⁶ In Inventories through 2002, gasoline-electric hybrid vehicles were considered part of an "alternative fuel and advanced technology" category. However, vehicles are now only separated into gasoline, diesel, or alternative fuel categories, and gas-electric hybrids are now considered within the gasoline vehicle category.

⁴⁷ Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2015b) provides a variable age distribution and 31-year vehicle age span beginning in year 1999.

⁴⁸ The updated vehicle distribution and mileage accumulation rates by vintage obtained from the MOVES 2014a model resulted in a decrease in emissions due to more miles driven by newer light-duty gasoline vehicles.

Tier 1 and Tier 0 apply to vehicles equipped with three-way catalysts. The introduction of “early three-way catalysts,” and “advanced three-way catalysts,” as described in the *Revised 1996 IPCC Guidelines*, roughly correspond to the introduction of EPA Tier 0 and EPA Tier 1 regulations (EPA 1998b).⁴⁹ EPA Tier 2 regulations affect vehicles produced starting in 2004 and are responsible for a noticeable decrease in N₂O emissions compared EPA Tier 1 emissions technology (EPA 1999b).

Control technology assignments for light and heavy-duty conventional fuel vehicles for model years 1972 (when regulations began to take effect) through 1995 were estimated in EPA (1998). Assignments for 1998 through 2014 were determined using confidential engine family sales data submitted to EPA (EPA 2015f). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2015e). This information was used to determine the fraction of sales of each class of vehicle that met EPA Tier 0, EPA Tier 1, Tier 2, and LEV standards. Assignments for 1996 and 1997 were estimated based on the fact that EPA Tier 1 standards for light-duty vehicles were fully phased in by 1996. Tier 2 began initial phase-in by 2004.

Step 3: Determine CH₄ and N₂O Emission Factors by Vehicle, Fuel, and Control Technology Type

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were based on EPA, CARB and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was later analyzed to determine quantities of gases present. The emission characteristics of Segment 2 was used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon MOBILE6.2’s ratio of start to running emissions for each vehicle class to approximate average driving characteristics.

Step 4: Determine the Amount of CH₄ and N₂O Emitted by Vehicle, Fuel, and Control Technology Type

Emissions of CH₄ and N₂O were then calculated by multiplying total VMT by vehicle, fuel, and control technology type by the emission factors developed in Step 3.

Methodology for Alternative Fuel Vehicles (AFVs)

Step 1: Determine Vehicle Miles Traveled by Vehicle and Fuel Type

VMT for alternative fuel and advanced technology vehicles were calculated from “Methodology for Highway Vehicle Alternative Fuel GHG Projections Estimates” (Browning, 2015). Alternative Fuels include Compressed Natural Gas (CNG), Liquid Natural Gas (LNG), Liquefied Petroleum Gas (LPG), Ethanol, Methanol, Biodiesel, Hydrogen and Electricity. Most of the vehicles that use these fuels run on an Internal Combustion Engine (ICE) powered by the alternative fuel, although many of the vehicles can run on either the alternative fuel or gasoline (or diesel), or some combination.⁵⁰ Except for electric vehicles and plug-in hybrid vehicles, the alternative fuel vehicle VMT were calculated using the Energy Information Administration (EIA) Alternative Fuel Vehicle Data. The EIA data provides vehicle counts and fuel use for fleet vehicles used by electricity providers, federal agencies, natural gas providers, propane providers, state agencies and transit agencies for calendar years 2003 through 2013. For 1992 to 2002, EIA Data Tables were used to estimate fuel consumption and vehicle counts by vehicle type. These tables give total vehicle fuel use and vehicle counts by fuel and calendar year for the United States over the period 1992 through 2010. Breakdowns by vehicle type for 1992 through 2002 (both fuel consumed and vehicle counts) were assumed to be at the same ratio as for 2003 where data existed. For 1990, 1991 and 2014, fuel consumed by alternative fuel and vehicle type were extrapolated based on a regression analysis using the best curve fit based upon R² using the nearest 5 years of data.

For the current Inventory, counts of electric vehicles (EVs) and plug-in hybrid-electric vehicles (PHEVs) were taken from data compiled by the Electric Drive Transportation Association from 2011 to 2014 (EDTA 2015). EVs were

⁴⁹ For further description, see “Definitions of Emission Control Technologies and Standards” section of this annex below.

⁵⁰ Fuel types used in combination depend on the vehicle class. For light-duty vehicles, gasoline is generally blended with ethanol and diesel is blended with biodiesel; dual-fuel vehicles can run on gasoline or an alternative fuel – either natural gas or LPG – but not at the same time, while flex-fuel vehicles are designed to run on E85 (85 percent ethanol) or gasoline, or any mixture of the two in between. Heavy-duty vehicles are more likely to run on diesel fuel, natural gas, or LPG.

divided into cars and trucks using confidential engine family sales data submitted to EPA (EPA 2015f). Fuel use per vehicle for personal EVs and PHEVs were assumed to be the same as those for the public fleet vehicles surveyed by EIA and provided in their data tables.

Because AFVs run on different fuel types, their fuel use characteristics are not directly comparable. Accordingly, fuel economy for each vehicle type is expressed in gasoline equivalent terms, i.e., how much gasoline contains the equivalent amount of energy as the alternative fuel. Energy economy ratios (the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles) were taken from the Argonne National Laboratory's GREET2015 model (ANL 2015). These ratios were used to estimate fuel economy in miles per gasoline gallon equivalent for each alternative fuel and vehicle type. Energy use per fuel type was then divided among the various weight categories and vehicle technologies that use that fuel. Total VMT per vehicle type for each calendar year was then determined by dividing the energy usage by the fuel economy. Note that for AFVs capable of running on both/either traditional and alternative fuels, the VMT given reflects only those miles driven that were powered by the alternative fuel, as explained in Browning (2015). VMT estimates for AFVs by vehicle category (passenger car, light-duty truck, medium-duty and heavy-duty vehicles) are shown in Table A-97, while more detailed estimates of VMT by control technology are shown in Table A-98.

Step 2: Determine CH₄ and N₂O Emission Factors by Vehicle and Alternative Fuel Type

Methane and N₂O emission factors for alternative fuel vehicles (AFVs) are calculated according to studies by Argonne National Laboratory (2006) and Lipman & Delucchi (2002), and are reported in ICF (2006a). In these studies, N₂O and CH₄ emissions for AFVs were expressed as a multiplier corresponding to conventional vehicle counterpart emissions. Emission estimates in these studies represent the current AFV fleet and were compared against Tier 1 emissions from light-duty gasoline vehicles to develop new multipliers. Alternative fuel heavy-duty vehicles were compared against gasoline heavy-duty vehicles as most alternative fuel heavy-duty vehicles use catalytic after treatment and perform more like gasoline vehicles than diesel vehicles. These emission factors are shown in Table A-108.

Step 3: Determine the Amount of CH₄ and N₂O Emitted by Vehicle and Fuel Type

Emissions of CH₄ and N₂O were calculated by multiplying total VMT for each vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Road Mobile Sources

Methane and N₂O emissions from non-road mobile sources were estimated by applying emission factors to the amount of fuel consumed by mode and vehicle type.

Activity data for non-road vehicles include annual fuel consumption statistics by transportation mode and fuel type, as shown in Table A-102. Consumption data for ships and other boats (i.e., vessel bunkering) were obtained from DHS (2008) and EIA (1991 through 2015) for distillate fuel, and DHS (2008) and EIA (2015) for residual fuel; marine transport fuel consumption data for U.S. Territories (EIA 2015) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.⁵¹ Gasoline consumption by recreational boats was obtained from the NONROAD component of EPA's MOVES2014a model (EPA 2015d). Annual diesel consumption for Class I rail was obtained from the Association of American Railroads (AAR 2008 through 2015), diesel consumption from commuter rail was obtained from APTA (2007 through 2015) and Gaffney (2007), and consumption by Class II and III rail was provided by Benson (2002 through 2004) and Whorton (2006 through 2013).⁵² Diesel consumption by commuter and intercity rail was obtained from DOE (1993 through 2015). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2016) and FAA (2016), as described in Annex 2.1: Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels (DESC 2015 and FAA 2016). Pipeline fuel consumption was obtained from EIA (2007 through 2015) (note: pipelines are a transportation source but are stationary, not mobile, sources). Data on fuel consumption by all non-transportation mobile sources were obtained from the NONROAD component of EPA's MOVES2014a model (EPA 2015d) and from FHWA (1996 through 2015) for gasoline consumption for trucks used off-road.⁵³

⁵¹ See International Bunker Fuels section of the Energy Chapter.

⁵² Diesel consumption from Class II and Class III railroad were unavailable for 2014. Values are proxied from 2013, which is the last year the data was available.

⁵³ "Non-transportation mobile sources" are defined as any vehicle or equipment not used on the traditional road system, but excluding aircraft, rail and watercraft. This category includes snowmobiles, golf carts, riding lawn mowers, agricultural equipment, and trucks used for off-road purposes, among others.

Emissions of CH₄ and N₂O from non-road mobile sources were calculated by multiplying U.S. default emission factors in the 2006 IPCC Guidelines by activity data for each source type (see Table A-109).

Estimates of NO_x, CO, and NMVOC Emissions

The emission estimates of NO_x, CO, and NMVOCs from mobile combustion (transportation) were obtained from preliminary data (EPA 2015g), which, in final iteration, will be published on the EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site. This EPA report provides emission estimates for these gases by fuel type using a procedure whereby emissions were calculated using basic activity data, such as amount of fuel delivered or miles traveled, as indicators of emissions. Table A-110 through Table A-112 provides complete emission estimates for 1990 through 2014.

Table A-95: Vehicle Miles Traveled for Gasoline On-Road Vehicles (million miles)

| Year | Passenger Cars | Light-Duty Trucks | Heavy-Duty Vehicles ^b | Motorcycles |
|-------------------|----------------|-------------------|----------------------------------|-------------|
| 1990 | 1,391.4 | 554.8 | 25.8 | 9.6 |
| 1991 | 1,341.9 | 627.8 | 25.4 | 9.2 |
| 1992 | 1,355.1 | 683.4 | 25.1 | 9.6 |
| 1993 | 1,356.8 | 721.0 | 24.9 | 9.9 |
| 1994 | 1,387.7 | 739.2 | 25.3 | 10.2 |
| 1995 | 1,421.0 | 763.0 | 25.1 | 9.8 |
| 1996 | 1,455.1 | 788.6 | 24.4 | 9.9 |
| 1997 | 1,489.0 | 821.6 | 24.0 | 10.1 |
| 1998 | 1,537.1 | 837.7 | 24.1 | 10.3 |
| 1999 | 1,559.6 | 868.3 | 24.3 | 10.6 |
| 2000 | 1,592.2 | 887.6 | 24.2 | 10.5 |
| 2001 | 1,620.0 | 905.9 | 23.9 | 9.6 |
| 2002 | 1,650.0 | 926.8 | 23.9 | 9.6 |
| 2003 | 1,663.5 | 944.1 | 24.2 | 9.6 |
| 2004 | 1,691.1 | 985.5 | 24.6 | 10.1 |
| 2005 | 1,699.6 | 998.8 | 24.8 | 10.5 |
| 2006 | 1,681.8 | 1,038.6 | 24.8 | 12.0 |
| 2007 | 2,093.7 | 562.8 | 34.2 | 21.4 |
| 2008 | 2,014.5 | 580.9 | 35.0 | 20.8 |
| 2009 | 2,005.5 | 592.4 | 32.5 | 20.8 |
| 2010 | 2,015.4 | 597.4 | 32.3 | 18.5 |
| 2011 ^a | 2,035.7 | 579.6 | 30.2 | 18.5 |
| 2012 | 2,051.6 | 576.8 | 30.5 | 21.4 |
| 2013 | 2,062.1 | 578.7 | 31.2 | 20.4 |
| 2014 | 2,058.2 | 612.4 | 31.7 | 20.0 |

Source: Derived from FHWA (1996 through 2014), Browning (2015).

^a In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007 to 2014 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in VMT data by vehicle class between 2006 and 2007.

^b Heavy-Duty Vehicles includes Medium-Duty Trucks, Heavy-Duty Trucks, and Buses.

Note: In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990-2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

Note: Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

Table A-96: Vehicle Miles Traveled for Diesel On-Road Vehicles (million miles)

| Year | Passenger Cars | Light-Duty Trucks | Heavy-Duty Vehicles ^a |
|-------------------|----------------|-------------------|----------------------------------|
| 1990 | 16.9 | 19.7 | 125.7 |
| 1991 | 16.3 | 21.6 | 129.4 |
| 1992 | 16.5 | 23.4 | 133.6 |
| 1993 | 17.9 | 24.7 | 140.6 |
| 1994 | 18.3 | 25.3 | 150.8 |
| 1995 | 17.3 | 26.9 | 159.0 |
| 1996 | 14.7 | 27.8 | 164.6 |
| 1997 | 13.5 | 29.0 | 173.8 |
| 1998 | 12.4 | 30.5 | 178.8 |
| 1999 | 9.4 | 32.6 | 185.6 |
| 2000 | 8.0 | 35.2 | 188.4 |
| 2001 | 8.1 | 37.0 | 191.5 |
| 2002 | 8.3 | 38.9 | 196.7 |
| 2003 | 8.4 | 39.7 | 199.6 |
| 2004 | 8.5 | 41.4 | 202.1 |
| 2005 | 8.5 | 41.9 | 203.4 |
| 2006 | 8.4 | 43.4 | 202.3 |
| 2007 | 10.5 | 23.3 | 281.8 |
| 2008 | 10.1 | 24.1 | 288.1 |
| 2009 | 10.0 | 24.6 | 267.6 |
| 2010 | 10.1 | 24.8 | 265.8 |
| 2011 ^b | 10.1 | 23.3 | 245.6 |
| 2012 | 10.1 | 23.1 | 247.9 |
| 2013 | 10.1 | 22.6 | 250.5 |
| 2014 | 10.0 | 24.0 | 255.0 |

Source: Derived from FHWA (1996 through 2015), Browning (2015).

^a Heavy-Duty Vehicles includes Medium-Duty Trucks, Heavy-Duty Trucks, and Buses.

^b In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007 to 2014 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in VMT data by vehicle class between 2006 and 2007.

Note: In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990 to 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

Note: Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015).

Table A-97: Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (million miles)

| Year | Passenger Cars | Light-Duty Trucks | Heavy-Duty Vehicles ^a |
|------|----------------|-------------------|----------------------------------|
| 1990 | 0.0 | 0.1 | 0.5 |
| 1991 | 0.0 | 0.1 | 0.5 |
| 1992 | 0.0 | 0.1 | 0.4 |
| 1993 | 0.0 | 0.1 | 0.6 |
| 1994 | 0.1 | 0.1 | 0.5 |
| 1995 | 0.1 | 0.1 | 0.5 |
| 1996 | 0.1 | 0.1 | 0.5 |
| 1997 | 0.1 | 0.1 | 0.5 |
| 1998 | 0.1 | 0.1 | 0.5 |
| 1999 | 0.1 | 0.1 | 0.5 |
| 2000 | 0.1 | 0.2 | 0.6 |
| 2001 | 0.2 | 0.2 | 0.7 |
| 2002 | 0.2 | 0.3 | 0.8 |
| 2003 | 0.3 | 0.3 | 0.9 |
| 2004 | 0.2 | 0.3 | 1.0 |
| 2005 | 0.3 | 0.3 | 1.3 |
| 2006 | 0.3 | 0.5 | 2.2 |
| 2007 | 0.2 | 0.6 | 2.7 |

| | | | |
|------|-----|-----|-----|
| 2008 | 0.2 | 0.5 | 2.4 |
| 2009 | 0.2 | 0.5 | 2.5 |
| 2010 | 0.2 | 0.5 | 2.2 |
| 2011 | 0.5 | 1.2 | 5.6 |
| 2012 | 1.1 | 1.3 | 5.6 |
| 2013 | 2.3 | 2.0 | 8.5 |
| 2014 | 3.8 | 2.1 | 8.4 |

Source: Derived from Browning (2015).

^a Heavy Duty-Vehicles includes medium-duty trucks, heavy-duty trucks, and buses.

Note: In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990-2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

Table A-98: Detailed Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (10⁶ Miles)

| Vehicle Type/Year | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Light-Duty Cars | 4.0 | 61.5 | 115.9 | 150.0 | 222.9 | 267.6 | 249.4 | 254.7 | 296.3 | 225.6 | 219.5 | 217.2 | 235.5 | 537.9 | 1,065.8 | 2,314.6 | 3,815.1 |
| Methanol-Flex Fuel ICE | + | 48.9 | 15.2 | 11.5 | 8.8 | + | + | + | + | + | + | + | + | + | + | + | + |
| Ethanol-Flex Fuel ICE | + | 0.3 | 20.9 | 25.4 | 31.0 | 35.2 | 42.2 | 51.0 | 59.2 | 72.8 | 84.2 | 96.2 | 122.2 | 118.5 | 148.9 | 173.5 | 193.7 |
| CNG ICE | + | 0.1 | 5.5 | 9.1 | 12.3 | 14.5 | 17.3 | 15.9 | 14.7 | 14.6 | 13.1 | 12.3 | 11.7 | 12.3 | 12.5 | 13.3 | 12.5 |
| CNG Bi-fuel | + | 0.2 | 18.0 | 29.5 | 40.3 | 47.6 | 53.5 | 40.6 | 25.4 | 19.3 | 13.0 | 10.1 | 8.1 | 7.1 | 4.5 | 3.5 | 2.3 |
| LPG ICE | 1.1 | 1.2 | 1.2 | 1.2 | 1.3 | 1.3 | 0.3 | 0.1 | 0.2 | 1.7 | 1.7 | 1.7 | + | 0.2 | 0.2 | 0.4 | 1.0 |
| LPG Bi-fuel | 2.8 | 3.0 | 3.0 | 3.0 | 3.2 | 3.3 | 7.9 | 3.3 | 3.7 | 1.7 | 1.6 | 1.8 | 1.2 | 0.3 | 0.3 | 0.2 | + |
| Biodiesel (BD100) | + | + | 1.0 | 2.0 | 3.0 | 2.3 | 4.4 | 14.6 | 41.4 | 50.2 | 39.1 | 46.4 | 39.4 | 149.4 | 180.3 | 310.3 | 333.2 |
| NEVs | + | 7.5 | 49.8 | 66.4 | 119.4 | 158.7 | 121.2 | 127.2 | 149.4 | 63.6 | 64.2 | 46.8 | 51.8 | 58.1 | 48.4 | 52.7 | 58.3 |
| Electric Vehicle | + | 0.2 | 1.5 | 1.9 | 3.5 | 4.6 | 2.5 | 1.9 | 2.3 | 1.5 | 2.3 | 1.5 | 0.9 | 169.3 | 533.5 | 1,484.1 | 2,771.9 |
| SI PHEV - Electricity | + | + | + | + | + | + | + | + | + | + | + | + | + | 22.6 | 137.2 | 276.5 | 442.2 |
| Fuel Cell Hydrogen | + | + | + | + | + | + | + | + | + | 0.3 | 0.2 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| Light-Duty Trucks | 77.4 | 93.3 | 180.9 | 225.0 | 274.4 | 302.9 | 271.8 | 333.1 | 491.8 | 556.3 | 458.8 | 511.5 | 463.9 | 1,223.3 | 1,341.2 | 2,036.1 | 2,086.2 |
| Ethanol-Flex Fuel ICE | + | 0.3 | 23.4 | 28.0 | 33.9 | 38.1 | 45.4 | 54.5 | 62.8 | 77.0 | 89.6 | 102.7 | 130.9 | 144.2 | 191.8 | 227.2 | 278.7 |
| CNG ICE | + | 0.1 | 5.6 | 9.1 | 12.2 | 14.3 | 15.9 | 14.5 | 15.2 | 13.7 | 10.8 | 10.3 | 9.2 | 9.7 | 9.9 | 9.5 | 10.2 |
| CNG Bi-fuel | + | 0.4 | 47.2 | 76.6 | 103.4 | 121.0 | 84.4 | 72.8 | 68.8 | 61.3 | 26.3 | 22.0 | 20.6 | 19.7 | 16.0 | 17.4 | 17.2 |
| LPG ICE | 22.4 | 26.5 | 27.6 | 27.7 | 28.5 | 29.3 | 23.7 | 32.6 | 28.9 | 23.3 | 11.6 | 13.5 | 10.8 | 10.6 | 6.5 | 6.9 | 5.4 |
| LPG Bi-fuel | 55.0 | 65.1 | 67.7 | 68.3 | 70.3 | 72.4 | 71.4 | 67.6 | 54.8 | 32.0 | 24.8 | 28.9 | 25.1 | 13.2 | 5.3 | 6.4 | 2.9 |
| LNG | + | + | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.2 | 0.2 | 0.3 | 0.2 | + | + | + | + | + |
| Biodiesel (BD100) | + | + | 4.1 | 8.1 | 13.5 | 11.2 | 24.0 | 85.3 | 253.9 | 341.1 | 287.9 | 326.6 | 260.2 | 1,020.9 | 1,107.2 | 1,752.0 | 1,741.4 |
| Electric Vehicle | + | 0.8 | 5.3 | 7.0 | 12.5 | 16.5 | 6.8 | 5.6 | 7.1 | 7.7 | 7.5 | 7.3 | 7.0 | 4.6 | 4.4 | 16.4 | 30.1 |
| Fuel Cell Hydrogen | + | + | + | + | + | + | + | + | + | 0.1 | 0.1 | 0.2 | 0.1 | 0.3 | 0.2 | 0.2 | 0.2 |
| Medium Duty Trucks | 324.5 | 317.4 | 308.6 | 327.8 | 353.9 | 364.6 | 265.7 | 352.8 | 543.5 | 640.9 | 580.1 | 607.0 | 457.1 | 1,414.9 | 1,475.6 | 2,335.2 | 2,360.6 |
| CNG ICE | + | + | 1.1 | 1.8 | 2.4 | 2.9 | 2.9 | 4.1 | 2.8 | 5.8 | 8.0 | 6.9 | 6.6 | 9.0 | 10.6 | 11.1 | 13.1 |
| CNG Bi-fuel | + | 0.1 | 10.5 | 17.2 | 23.3 | 27.4 | 14.6 | 15.5 | 13.0 | 11.4 | 9.7 | 8.0 | 7.5 | 7.3 | 8.3 | 8.7 | 10.2 |
| LPG ICE | 271.5 | 265.4 | 242.4 | 246.1 | 254.4 | 262.8 | 166.6 | 155.6 | 82.1 | 61.3 | 46.5 | 41.5 | 36.5 | 34.1 | 32.3 | 29.6 | 29.2 |
| LPG Bi-fuel | 53.0 | 51.8 | 47.3 | 48.1 | 49.7 | 51.3 | 41.6 | 43.8 | 23.6 | 10.3 | 16.5 | 8.4 | 10.3 | 9.3 | 12.6 | 13.7 | 16.2 |
| LNG | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | 0.1 | 0.1 |
| Biodiesel (BD100) | + | + | 7.3 | 14.5 | 24.0 | 20.2 | 39.8 | 133.7 | 422.0 | 552.0 | 499.4 | 542.3 | 396.2 | 1,355.2 | 1,411.8 | 2,271.9 | 2,291.8 |
| Heavy-Duty Trucks | 130.4 | 127.6 | 137.1 | 159.1 | 186.5 | 181.1 | 217.7 | 439.5 | 1,046.6 | 1,388.9 | 1,180.1 | 1,227.1 | 1,023.1 | 3,368.5 | 3,368.0 | 5,320.4 | 5,300.8 |
| Neat Ethanol ICE | + | + | + | + | + | 1.3 | 1.6 | 1.9 | 2.2 | 2.7 | 3.1 | 3.5 | 4.5 | 7.0 | 11.3 | 15.7 | 22.2 |
| CNG ICE | + | + | 0.9 | 1.5 | 2.0 | 2.4 | 1.9 | 1.9 | 2.7 | 2.9 | 2.7 | 3.4 | 3.6 | 3.6 | 4.1 | 5.0 | 6.1 |
| LPG ICE | 122.1 | 119.5 | 109.1 | 110.7 | 114.4 | 118.1 | 106.4 | 87.2 | 76.6 | 65.8 | 56.2 | 49.6 | 41.0 | 43.1 | 28.0 | 27.6 | 20.6 |
| LPG Bi-fuel | 8.3 | 8.1 | 7.4 | 7.5 | 7.8 | 8.0 | 6.4 | 5.4 | 4.8 | 4.6 | 4.6 | 5.4 | 5.6 | 8.3 | 6.5 | 7.1 | 5.9 |
| LNG | + | + | + | + | + | + | + | 0.1 | 0.1 | + | 0.1 | + | + | + | + | + | + |
| Biodiesel (BD100) | + | + | 19.7 | 39.3 | 62.3 | 51.2 | 101.4 | 343.0 | 960.2 | 1,312.8 | 1,113.4 | 1,165.1 | 968.4 | 3,306.4 | 3,318.2 | 5,265.1 | 5,246.0 |
| Buses | 24.6 | 46.3 | 150.7 | 225.9 | 299.2 | 349.1 | 496.6 | 524.6 | 629.8 | 625.6 | 656.3 | 685.3 | 695.5 | 779.6 | 770.3 | 833.7 | 804.8 |
| Neat Methanol ICE | 7.8 | 12.7 | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + |
| Neat Ethanol ICE | + | 5.9 | 0.1 | + | + | + | + | + | + | + | + | + | + | + | 0.1 | 0.1 | 0.1 |
| CNG ICE | + | 1.1 | 104.1 | 170.3 | 231.7 | 271.8 | 392.8 | 413.5 | 481.7 | 509.8 | 546.2 | 581.7 | 605.4 | 637.1 | 628.3 | 650.1 | 623.7 |
| LPG ICE | 16.4 | 15.8 | 14.4 | 14.6 | 15.2 | 15.6 | 17.5 | 11.7 | 13.3 | 12.3 | 13.4 | 9.0 | 8.1 | 4.8 | 4.7 | 5.0 | 5.2 |

| | | | | | | | | | | | | | | | | | |
|--------------------|--------------|--------------|--------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|-----------------|
| LNG | 0.4 | 8.9 | 23.2 | 28.5 | 30.1 | 33.7 | 58.9 | 61.4 | 66.8 | 40.2 | 39.8 | 36.0 | 36.8 | 39.5 | 41.1 | 29.4 | 27.5 |
| Biodiesel (BD100) | + | + | 0.8 | 1.6 | 2.6 | 2.0 | 4.1 | 13.2 | 38.9 | 53.3 | 46.6 | 51.7 | 38.1 | 90.1 | 90.7 | 143.5 | 142.8 |
| Electric | + | 1.8 | 8.2 | 10.9 | 19.6 | 26.0 | 23.2 | 24.8 | 29.0 | 9.9 | 10.2 | 6.8 | 7.0 | 7.7 | 5.1 | 5.3 | 5.2 |
| Fuel Cell Hydrogen | + | + | + | + | + | + | + | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 |
| Total VMT | 560.8 | 646.0 | 893.4 | 1,087.9 | 1,336.9 | 1,465.2 | 1,501.2 | 1,904.7 | 3,008.0 | 3,437.3 | 3,094.9 | 3,248.2 | 2,875.1 | 7,324.2 | 8,020.9 | 12,840.0 | 14,367.6 |

+ Does not exceed 0.05 million vehicle miles traveled

Note: Throughout the rest of this Inventory, medium-duty trucks are grouped with heavy-duty trucks; they are reported separately here because these two categories may run on a slightly different range of fuel types.

In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data.

EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated for the 2014

Inventory and apply to the 1990-2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

Source: Derived from Browning (2015).

Table A-99: Age Distribution by Vehicle/Fuel Type for On-Road Vehicles,^a 2014

| Vehicle Age | LDGV | LDGT | HDGV | LDDV | LDDT | HDDV | MC |
|--------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| 0 | 7.1% | 7.9% | 6.2% | 14.7% | 8.6% | 6.0% | 7.2% |
| 1 | 6.8% | 7.5% | 5.6% | 14.1% | 8.1% | 5.4% | 6.9% |
| 2 | 6.6% | 7.1% | 5.1% | 13.6% | 7.8% | 5.0% | 6.5% |
| 3 | 4.1% | 4.8% | 2.9% | 8.4% | 5.3% | 3.1% | 5.2% |
| 4 | 4.6% | 4.2% | 1.9% | 8.1% | 3.1% | 2.1% | 4.7% |
| 5 | 4.2% | 3.2% | 1.7% | 5.4% | 2.8% | 2.5% | 4.9% |
| 6 | 5.3% | 5.4% | 3.4% | 0.5% | 6.9% | 3.8% | 8.6% |
| 7 | 5.7% | 5.7% | 3.1% | 0.3% | 6.1% | 7.4% | 7.7% |
| 8 | 5.3% | 5.7% | 4.4% | 6.4% | 7.8% | 6.4% | 7.3% |
| 9 | 5.2% | 5.8% | 3.4% | 4.4% | 6.6% | 5.9% | 6.4% |
| 10 | 4.8% | 5.8% | 4.3% | 2.6% | 5.9% | 4.1% | 5.4% |
| 11 | 5.0% | 5.2% | 3.7% | 3.4% | 5.3% | 3.6% | 4.6% |
| 12 | 4.9% | 4.9% | 3.7% | 3.7% | 4.5% | 2.9% | 4.1% |
| 13 | 4.6% | 4.3% | 3.1% | 2.4% | 5.1% | 3.8% | 3.4% |
| 14 | 4.5% | 4.0% | 6.0% | 2.0% | 2.7% | 5.9% | 2.8% |
| 15 | 3.5% | 3.4% | 5.8% | 1.1% | 3.9% | 4.7% | 2.1% |
| 16 | 2.8% | 2.7% | 2.4% | 1.1% | 1.4% | 3.2% | 1.8% |
| 17 | 2.6% | 2.3% | 4.5% | 0.4% | 1.8% | 3.0% | 1.7% |
| 18 | 2.1% | 1.7% | 2.7% | 0.4% | 1.4% | 2.7% | 1.5% |
| 19 | 2.1% | 1.6% | 3.7% | 0.3% | 1.0% | 3.3% | 1.1% |
| 20 | 1.6% | 1.4% | 2.9% | 0.0% | 0.6% | 2.5% | 1.3% |
| 21 | 1.4% | 1.0% | 2.3% | 0.2% | 0.6% | 1.8% | 1.1% |
| 22 | 1.1% | 0.8% | 1.8% | 0.2% | 0.6% | 1.3% | 0.9% |
| 23 | 0.9% | 0.6% | 1.5% | 0.5% | 0.3% | 1.2% | 0.7% |
| 24 | 0.8% | 0.6% | 2.0% | 0.1% | 0.3% | 1.5% | 0.6% |
| 25 | 0.6% | 0.6% | 2.4% | 0.1% | 0.2% | 1.5% | 0.4% |
| 26 | 0.5% | 0.5% | 2.0% | 0.0% | 0.2% | 1.3% | 0.4% |
| 27 | 0.4% | 0.4% | 1.8% | 0.9% | 0.1% | 1.1% | 0.3% |
| 28 | 0.3% | 0.4% | 1.8% | 0.5% | 0.3% | 0.8% | 0.3% |
| 29 | 0.3% | 0.3% | 1.4% | 1.6% | 0.2% | 0.8% | 0.2% |
| 30 | 0.3% | 0.2% | 2.4% | 2.5% | 0.2% | 1.3% | 0.2% |
| Total | 100.0% |

Source: EPA (2015b).

Note: This year's Inventory includes updated vehicle population data based on the MOVES 2014a Model.

^a The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

Table A-100: Annual Average Vehicle Mileage Accumulation per Vehicle^a (miles)

| Vehicle Age | LDGV | LDGT | HDGV | LDDV | LDDT | HDDV | MC ^b |
|-------------|--------|--------|--------|--------|--------|--------|-----------------|
| 0 | 13,809 | 15,607 | 19,166 | 13,809 | 15,608 | 41,091 | 7,566 |
| 1 | 13,547 | 15,314 | 19,169 | 13,547 | 15,314 | 40,875 | 4,040 |
| 2 | 13,263 | 14,983 | 19,173 | 13,263 | 14,983 | 41,583 | 3,057 |
| 3 | 12,960 | 14,621 | 17,828 | 12,960 | 14,621 | 48,627 | 2,527 |
| 4 | 12,641 | 14,231 | 15,436 | 12,641 | 14,231 | 47,399 | 2,187 |
| 5 | 12,307 | 13,816 | 14,949 | 12,307 | 13,816 | 48,996 | 1,944 |
| 6 | 11,959 | 13,380 | 15,707 | 11,959 | 13,380 | 34,924 | 1,763 |
| 7 | 11,601 | 12,928 | 13,175 | 11,601 | 12,928 | 46,171 | 1,619 |
| 8 | 11,234 | 12,463 | 13,437 | 11,234 | 12,463 | 38,948 | 1,498 |
| 9 | 10,861 | 11,990 | 11,436 | 10,861 | 11,990 | 36,966 | 1,400 |
| 10 | 10,483 | 11,511 | 11,274 | 10,483 | 11,511 | 30,576 | 1,316 |
| 11 | 10,104 | 11,031 | 10,074 | 10,104 | 11,031 | 29,579 | 1,241 |
| 12 | 9,725 | 10,555 | 9,275 | 9,725 | 10,555 | 25,374 | 1,180 |
| 13 | 9,347 | 10,087 | 7,987 | 9,347 | 10,087 | 23,342 | 1,120 |
| 14 | 8,974 | 9,630 | 8,500 | 8,974 | 9,630 | 21,710 | 1,067 |
| 15 | 8,608 | 9,187 | 7,310 | 8,608 | 9,187 | 18,601 | 1,021 |
| 16 | 8,250 | 8,764 | 6,062 | 8,250 | 8,764 | 16,648 | 984 |

| | | | | | | | |
|----|-------|-------|-------|-------|-------|--------|-----|
| 17 | 7,902 | 8,362 | 5,478 | 7,902 | 8,362 | 12,487 | 946 |
| 18 | 7,567 | 7,989 | 5,183 | 7,567 | 7,989 | 13,300 | 908 |
| 19 | 7,247 | 7,648 | 5,149 | 7,247 | 7,648 | 11,161 | 878 |
| 20 | 6,945 | 7,340 | 4,657 | 6,945 | 7,340 | 9,880 | 847 |
| 21 | 6,662 | 7,072 | 4,650 | 6,662 | 7,072 | 9,275 | 825 |
| 22 | 6,400 | 6,845 | 3,963 | 6,400 | 6,845 | 8,528 | 802 |
| 23 | 6,161 | 6,668 | 3,920 | 6,161 | 6,668 | 7,821 | 757 |
| 24 | 5,949 | 6,540 | 3,693 | 5,949 | 6,540 | 6,747 | 711 |
| 25 | 5,764 | 6,465 | 3,484 | 5,764 | 6,465 | 5,858 | 666 |
| 26 | 5,609 | 6,451 | 3,157 | 5,609 | 6,451 | 5,308 | 613 |
| 27 | 5,486 | 6,451 | 2,920 | 5,486 | 6,451 | 5,090 | 567 |
| 28 | 5,397 | 6,451 | 2,736 | 5,397 | 6,451 | 4,296 | 537 |
| 29 | 5,345 | 6,451 | 2,724 | 5,345 | 6,451 | 3,475 | 499 |
| 30 | 5,345 | 6,451 | 2,408 | 5,345 | 6,451 | 2,598 | 462 |

Source: EPA (2015b).

^a The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

^b Because of a lack of data, all motorcycles over 12 years old are considered to have the same emissions and travel characteristics, and therefore are presented in aggregate.

Table A-101: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, ^a 2014

| Vehicle Age | LDGV | LDGT | HDGV | LDDV | LDDT | HDDV | MC |
|--------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| 0 | 9.18% | 10.20% | 11.71% | 17.18% | 10.81% | 8.56% | 24.81% |
| 1 | 8.61% | 9.46% | 10.55% | 16.11% | 10.01% | 7.64% | 12.70% |
| 2 | 8.14% | 8.84% | 9.70% | 15.25% | 9.35% | 7.27% | 9.04% |
| 3 | 4.92% | 5.79% | 5.12% | 9.21% | 6.27% | 5.32% | 5.99% |
| 4 | 5.39% | 4.98% | 2.96% | 8.67% | 3.57% | 3.43% | 4.68% |
| 5 | 4.76% | 3.63% | 2.57% | 5.57% | 3.12% | 4.34% | 4.31% |
| 6 | 5.85% | 6.00% | 5.20% | 0.49% | 7.40% | 4.63% | 6.93% |
| 7 | 6.17% | 6.05% | 4.02% | 0.33% | 6.38% | 11.95% | 5.66% |
| 8 | 5.52% | 5.85% | 5.79% | 6.04% | 7.78% | 8.69% | 4.96% |
| 9 | 5.29% | 5.77% | 3.89% | 4.01% | 6.40% | 7.54% | 4.06% |
| 10 | 4.73% | 5.48% | 4.76% | 2.32% | 5.43% | 4.36% | 3.24% |
| 11 | 4.70% | 4.74% | 3.70% | 2.91% | 4.72% | 3.73% | 2.62% |
| 12 | 4.45% | 4.32% | 3.41% | 3.03% | 3.86% | 2.58% | 2.19% |
| 13 | 3.96% | 3.62% | 2.42% | 1.86% | 4.17% | 3.12% | 1.76% |
| 14 | 3.75% | 3.21% | 5.04% | 1.52% | 2.11% | 4.48% | 1.34% |
| 15 | 2.82% | 2.60% | 4.16% | 0.84% | 2.87% | 3.05% | 0.97% |
| 16 | 2.18% | 1.95% | 1.46% | 0.76% | 1.02% | 1.83% | 0.80% |
| 17 | 1.89% | 1.61% | 2.43% | 0.27% | 1.22% | 1.32% | 0.73% |
| 18 | 1.47% | 1.12% | 1.37% | 0.29% | 0.89% | 1.25% | 0.62% |
| 19 | 1.41% | 1.04% | 1.90% | 0.21% | 0.63% | 1.30% | 0.45% |
| 20 | 1.04% | 0.85% | 1.34% | 0.02% | 0.35% | 0.86% | 0.50% |
| 21 | 0.84% | 0.59% | 1.07% | 0.09% | 0.36% | 0.60% | 0.40% |
| 22 | 0.67% | 0.43% | 0.71% | 0.12% | 0.32% | 0.38% | 0.32% |
| 23 | 0.54% | 0.35% | 0.56% | 0.24% | 0.18% | 0.34% | 0.24% |
| 24 | 0.44% | 0.31% | 0.73% | 0.07% | 0.14% | 0.36% | 0.18% |
| 25 | 0.35% | 0.31% | 0.82% | 0.05% | 0.13% | 0.30% | 0.13% |
| 26 | 0.26% | 0.27% | 0.61% | 0.01% | 0.10% | 0.24% | 0.10% |
| 27 | 0.21% | 0.20% | 0.53% | 0.43% | 0.04% | 0.19% | 0.09% |
| 28 | 0.17% | 0.20% | 0.50% | 0.24% | 0.15% | 0.12% | 0.07% |
| 29 | 0.13% | 0.13% | 0.38% | 0.72% | 0.11% | 0.09% | 0.06% |
| 30 | 0.15% | 0.11% | 0.58% | 1.12% | 0.11% | 0.11% | 0.05% |
| Total | 100.00% |

Model that affects this distribution.

^a The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

Note: Estimated by weighting data in by data in Table A-100. This year's Inventory includes updated vehicle population data based on the MOVES 2014a

Table A-102: Fuel Consumption for Off-Road Sources by Fuel Type (million gallons)

| Vehicle Type/Year | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Aircraft^a | 19,560 | 18,320 | 20,304 | 19,745 | 19,284 | 18,640 | 19,407 | 19,714 | 18,973 | 18,670 | 17,984 | 16,030 | 15,762 | 15,262 | 14,914 | 15,274 | 15,418 |
| Aviation Gasoline | 374 | 329 | 302 | 291 | 281 | 251 | 260 | 294 | 278 | 263 | 235 | 221 | 225 | 225 | 209 | 186 | 181 |
| Jet Fuel | 19,186 | 17,991 | 20,002 | 19,454 | 19,004 | 18,389 | 19,147 | 19,420 | 18,695 | 18,407 | 17,749 | 15,809 | 15,537 | 15,036 | 14,705 | 15,088 | 15,237 |
| Commercial Aviation ^b | 11,569 | 12,136 | 14,672 | 13,121 | 12,774 | 12,943 | 13,147 | 13,976 | 14,426 | 14,708 | 13,400 | 12,588 | 11,931 | 12,067 | 11,932 | 12,031 | 12,131 |
| Ships and Other Boats | 4,507 | 5,789 | 6,407 | 4,393 | 4,810 | 4,066 | 4,277 | 4,858 | 5,120 | 5,723 | 4,860 | 4,289 | 5,740 | 5,915 | 5,340 | 5,293 | 4,329 |
| Diesel | 1,043 | 1,546 | 1,750 | 1,630 | 1,592 | 1,711 | 1,347 | 1,470 | 1,409 | 1,489 | 1,470 | 1,480 | 1,446 | 1,727 | 1,475 | 1,499 | 1,370 |
| Gasoline | 1,403 | 1,597 | 1,629 | 1,632 | 1,630 | 1,625 | 1,616 | 1,607 | 1,597 | 1,587 | 1,577 | 1,568 | 1,556 | 1,545 | 1,535 | 1,528 | 1,522 |
| Residual | 2,061 | 2,646 | 3,028 | 1,131 | 1,588 | 730 | 1,313 | 1,781 | 2,115 | 2,647 | 1,812 | 1,241 | 2,738 | 2,643 | 2,330 | 2,265 | 1,437 |
| Construction/Mining Equipment^c | 4,160 | 4,835 | 5,523 | 5,984 | 6,156 | 6,339 | 6,522 | 6,617 | 6,755 | 6,785 | 6,939 | 7,066 | 7,312 | 7,418 | 7,586 | 8,187 | 7,949 |
| Diesel | 3,674 | 4,387 | 5,181 | 5,329 | 5,477 | 5,625 | 5,774 | 5,922 | 6,069 | 6,216 | 6,363 | 6,511 | 6,658 | 6,806 | 6,954 | 7,102 | 7,250 |
| Gasoline | 486 | 448 | 342 | 654 | 678 | 714 | 749 | 695 | 686 | 569 | 575 | 556 | 655 | 612 | 632 | 1,085 | 698 |
| Agricultural Equipment^d | 3,134 | 3,698 | 3,929 | 4,163 | 4,277 | 4,383 | 4,708 | 4,776 | 5,011 | 4,926 | 4,582 | 4,708 | 4,807 | 4,998 | 5,157 | 5,021 | 5,094 |
| Diesel | 2,321 | 2,772 | 3,277 | 3,361 | 3,445 | 3,530 | 3,614 | 3,699 | 3,782 | 3,865 | 3,948 | 4,032 | 4,115 | 4,199 | 4,282 | 4,366 | 4,450 |
| Gasoline | 813 | 927 | 652 | 802 | 832 | 853 | 1,094 | 1,078 | 1,229 | 1,061 | 634 | 676 | 692 | 799 | 875 | 655 | 644 |
| Rail | 3,461 | 3,864 | 4,106 | 4,119 | 4,089 | 4,176 | 4,407 | 4,446 | 4,665 | 4,539 | 4,216 | 3,535 | 3,807 | 3,999 | 3,921 | 4,025 | 4,180 |
| Diesel | 3,461 | 3,864 | 4,106 | 4,119 | 4,089 | 4,176 | 4,407 | 4,446 | 4,665 | 4,539 | 4,216 | 3,535 | 3,807 | 3,999 | 3,921 | 4,025 | 4,180 |
| Other^e | 5,916 | 6,525 | 6,798 | 7,630 | 7,813 | 8,022 | 8,236 | 8,255 | 8,370 | 8,229 | 8,360 | 8,455 | 8,804 | 8,768 | 8,703 | 8,800 | 8,952 |
| Diesel | 1,423 | 1,720 | 2,050 | 2,114 | 2,181 | 2,247 | 2,313 | 2,380 | 2,446 | 2,512 | 2,579 | 2,645 | 2,711 | 2,778 | 2,844 | 2,910 | 2,977 |
| Gasoline | 4,493 | 4,805 | 4,748 | 5,515 | 5,632 | 5,775 | 5,922 | 5,875 | 5,924 | 5,717 | 5,782 | 5,810 | 6,093 | 5,990 | 5,859 | 5,890 | 5,975 |
| Total | 40,738 | 43,031 | 47,067 | 46,032 | 46,429 | 45,627 | 47,557 | 48,666 | 48,894 | 48,872 | 46,941 | 44,083 | 46,233 | 46,359 | 45,622 | 46,600 | 45,922 |

^a For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.

^b Commercial aviation, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

^c Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^d Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^e "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: In 2015, EPA incorporated the NONROAD2008 model into MOVES2014a. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

Sources: AAR (2008 through 2014), APTA (2007 through 2013), BEA (1991 through 2014), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2014), DESC (2014), DOE (1993 through 2013), DOT (1991 through 2014), EIA (2002), EIA (2007b), EIA (2016), EIA (2007 through 2014), EIA (1991 through 2014), EPA (2015d), FAA (2016), Gaffney (2007), and Whorton (2006 through 2013).

Table A-103: Control Technology Assignments for Gasoline Passenger Cars (Percent of VMT)

| Model Years | Non-catalyst | Oxidation | EPA Tier 0 | EPA Tier 1 | LEV | EPA Tier 2 |
|-------------|--------------|-----------|------------|------------|-----|------------|
| 1973-1974 | 100% | - | - | - | - | - |
| 1975 | 20% | 80% | - | - | - | - |
| 1976-1977 | 15% | 85% | - | - | - | - |
| 1978-1979 | 10% | 90% | - | - | - | - |
| 1980 | 5% | 88% | 7% | - | - | - |
| 1981 | - | 15% | 85% | - | - | - |
| 1982 | - | 14% | 86% | - | - | - |
| 1983 | - | 12% | 88% | - | - | - |
| 1984-1993 | - | - | 100% | - | - | - |
| 1994 | - | - | 60% | 40% | - | - |
| 1995 | - | - | 20% | 80% | - | - |
| 1996 | - | - | 1% | 97% | 2% | - |
| 1997 | - | - | 0.5% | 96.5% | 3% | - |
| 1998 | - | - | <1% | 87% | 13% | - |
| 1999 | - | - | <1% | 67% | 33% | - |
| 2000 | - | - | - | 44% | 56% | - |
| 2001 | - | - | - | 3% | 97% | - |
| 2002 | - | - | - | 1% | 99% | - |
| 2003 | - | - | - | <1% | 87% | 13% |
| 2004 | - | - | - | <1% | 41% | 59% |
| 2005 | - | - | - | - | 38% | 62% |
| 2006 | - | - | - | - | 18% | 82% |
| 2007 | - | - | - | - | 4% | 96% |
| 2008 | - | - | - | - | 2% | 98% |
| 2009-14 | - | - | - | - | - | 100% |

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

- Not applicable.

Note: Detailed descriptions of emissions control technologies are provided in the following section of this Annex.

Table A-104: Control Technology Assignments for Gasoline Light-Duty Trucks (Percent of VMT)^a

| Model Years | Non-catalyst | Oxidation | EPA Tier 0 | EPA Tier 1 | LEV ^b | EPA Tier 2 |
|-------------|--------------|-----------|------------|------------|------------------|------------|
| 1973-1974 | 100% | - | - | - | - | - |
| 1975 | 30% | 70% | - | - | - | - |
| 1976 | 20% | 80% | - | - | - | - |
| 1977-1978 | 25% | 75% | - | - | - | - |
| 1979-1980 | 20% | 80% | - | - | - | - |
| 1981 | - | 95% | 5% | - | - | - |
| 1982 | - | 90% | 10% | - | - | - |
| 1983 | - | 80% | 20% | - | - | - |
| 1984 | - | 70% | 30% | - | - | - |
| 1985 | - | 60% | 40% | - | - | - |
| 1986 | - | 50% | 50% | - | - | - |
| 1987-1993 | - | 5% | 95% | - | - | - |
| 1994 | - | - | 60% | 40% | - | - |
| 1995 | - | - | 20% | 80% | - | - |
| 1996 | - | - | - | 100% | - | - |
| 1997 | - | - | - | 100% | - | - |
| 1998 | - | - | - | 80% | 20% | - |
| 1999 | - | - | - | 57% | 43% | - |
| 2000 | - | - | - | 65% | 35% | - |
| 2001 | - | - | - | 1% | 99% | - |
| 2002 | - | - | - | 10% | 90% | - |
| 2003 | - | - | - | <1% | 53% | 47% |
| 2004 | - | - | - | - | 72% | 28% |
| 2005 | - | - | - | - | 38% | 62% |
| 2006 | - | - | - | - | 25% | 75% |
| 2007 | - | - | - | - | 14% | 86% |
| 2008-2014 | - | - | - | - | - | 100% |

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

- Not applicable.

^a Detailed descriptions of emissions control technologies are provided in the following section of this Annex.

^b The proportion of LEVs as a whole has decreased since 2001, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a carmaker can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

Table A-105: Control Technology Assignments for Gasoline Heavy-Duty Vehicles (Percent of VMT)^a

| Model Years | Uncontrolled | Non-catalyst | Oxidation | EPA Tier 0 | EPA Tier 1 | LEV ^b | EPA Tier 2 |
|-------------|--------------|--------------|-----------|------------|------------|------------------|------------|
| ≤1981 | 100% | - | - | - | - | - | - |
| 1982-1984 | 95% | - | 5% | - | - | - | - |
| 1985-1986 | - | 95% | 5% | - | - | - | - |
| 1987 | - | 70% | 15% | 15% | - | - | - |
| 1988-1989 | - | 60% | 25% | 15% | - | - | - |
| 1990-1995 | - | 45% | 30% | 25% | - | - | - |
| 1996 | - | - | 25% | 10% | 65% | - | - |
| 1997 | - | - | 10% | 5% | 85% | - | - |
| 1998 | - | - | - | - | 96% | 4% | - |
| 1999 | - | - | - | - | 78% | 22% | - |
| 2000 | - | - | - | - | 54% | 46% | - |
| 2001 | - | - | - | - | 64% | 36% | - |
| 2002 | - | - | - | - | 69% | 31% | - |
| 2003 | - | - | - | - | 65% | 30% | 5% |
| 2004 | - | - | - | - | 5% | 37% | 59% |
| 2005 | - | - | - | - | - | 23% | 77% |
| 2006 | - | - | - | - | - | 20% | 80% |
| 2007 | - | - | - | - | - | 10% | 90% |
| 2008-2014 | - | - | - | - | - | 0% | 100% |

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

- Not applicable.

^a Detailed descriptions of emissions control technologies are provided in the following section of this Annex.

^b The proportion of LEVs as a whole has decreased since 2000, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a manufacturer can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

Table A-106: Control Technology Assignments for Diesel On-Road Vehicles and Motorcycles

| Vehicle Type/Control Technology | Model Years |
|---|-------------|
| Diesel Passenger Cars and Light-Duty Trucks | |
| Uncontrolled | 1960-1982 |
| Moderate control | 1983-1995 |
| Advanced control | 1996-2014 |
| Diesel Medium- and Heavy-Duty Trucks and Buses | |
| Uncontrolled | 1960-1990 |
| Moderate control | 1991-2003 |
| Advanced control | 2004-2006 |
| Aftertreatment | 2007-2014 |
| Motorcycles | |
| Uncontrolled | 1960-1995 |
| Non-catalyst controls | 1996-2014 |

Note: Detailed descriptions of emissions control technologies are provided in the following section of this Annex.

Source: EPA (1998) and Browning (2005).

Table A-107: Emission Factors for CH₄ and N₂O for On-Road Vehicles

| Vehicle Type/Control Technology | N ₂ O (g/mi) | CH ₄ (g/mi) |
|---------------------------------|----------------------------|---------------------------|
| Gasoline Passenger Cars | | |
| EPA Tier 2 | 0.0036 | 0.0173 |
| Low Emission Vehicles | 0.0150 | 0.0105 |
| EPA Tier 1 ^a | 0.0429 | 0.0271 |
| EPA Tier 0 ^a | 0.0647 | 0.0704 |
| Oxidation Catalyst | 0.0504 | 0.1355 |
| Non-Catalyst Control | 0.0197 | 0.1696 |

| | | |
|---|--------|--------|
| Uncontrolled | 0.0197 | 0.1780 |
| Gasoline Light-Duty Trucks | | |
| EPA Tier 2 | 0.0066 | 0.0163 |
| Low Emission Vehicles | 0.0157 | 0.0148 |
| EPA Tier 1 ^a | 0.0871 | 0.0452 |
| EPA Tier 0 ^a | 0.1056 | 0.0776 |
| Oxidation Catalyst | 0.0639 | 0.1516 |
| Non-Catalyst Control | 0.0218 | 0.1908 |
| Uncontrolled | 0.0220 | 0.2024 |
| Gasoline Heavy-Duty Vehicles | | |
| EPA Tier 2 | 0.0134 | 0.0333 |
| Low Emission Vehicles | 0.0320 | 0.0303 |
| EPA Tier 1 ^a | 0.1750 | 0.0655 |
| EPA Tier 0 ^a | 0.2135 | 0.2630 |
| Oxidation Catalyst | 0.1317 | 0.2356 |
| Non-Catalyst Control | 0.0473 | 0.4181 |
| Uncontrolled | 0.0497 | 0.4604 |
| Diesel Passenger Cars | | |
| Advanced | 0.0010 | 0.0005 |
| Moderate | 0.0010 | 0.0005 |
| Uncontrolled | 0.0012 | 0.0006 |
| Diesel Light-Duty Trucks | | |
| Advanced | 0.0015 | 0.0010 |
| Moderate | 0.0014 | 0.0009 |
| Uncontrolled | 0.0017 | 0.0011 |
| Diesel Medium- and Heavy-Duty Trucks and Buses | | |
| Aftertreatment | 0.0048 | 0.0051 |
| Advanced | 0.0048 | 0.0051 |
| Moderate | 0.0048 | 0.0051 |
| Uncontrolled | 0.0048 | 0.0051 |
| Motorcycles | | |
| Non-Catalyst Control | 0.0069 | 0.0672 |
| Uncontrolled | 0.0087 | 0.0899 |

Source: ICF (2006b and 2004).

^a The categories "EPA Tier 0" and "EPA Tier 1" were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the 2006 IPCC Guidelines. Detailed descriptions of emissions control technologies are provided at the end of this Annex.

Table A-108: Emission Factors for CH₄ and N₂O for Alternative Fuel Vehicles (g/mi)

| | N ₂ O | CH ₄ |
|--------------------------------------|------------------|-----------------|
| Light Duty Vehicles | | |
| Methanol | 0.067 | 0.018 |
| CNG | 0.050 | 0.737 |
| LPG | 0.067 | 0.037 |
| Ethanol | 0.067 | 0.055 |
| Biodiesel (BD20) | 0.001 | 0.0005 |
| Medium- and Heavy-Duty Trucks | | |
| Methanol | 0.175 | 0.066 |
| CNG | 0.175 | 1.966 |
| LNG | 0.175 | 1.966 |
| LPG | 0.175 | 0.066 |
| Ethanol | 0.175 | 0.197 |
| Biodiesel (BD20) | 0.005 | 0.005 |
| Buses | | |
| Methanol | 0.175 | 0.066 |
| CNG | 0.175 | 1.966 |
| Ethanol | 0.175 | 0.197 |
| Biodiesel (BD20) | 0.005 | 0.005 |

Source: Developed by ICF (2006a) using ANL (2006) and Lipman and Delucchi (2002).

Table A-109: Emission Factors for CH₄ and N₂O Emissions from Non-Road Mobile Combustion (g/kg fuel)

| Vehicle Type/Fuel Type | N ₂ O | CH ₄ |
|--|------------------|-----------------|
| Ships and Boats | | |
| Residual | 0.16 | 0.03 |
| Gasoline | 0.08 | 0.23 |
| Diesel | 0.14 | 0.02 |
| Rail | | |
| Diesel | 0.08 | 0.25 |
| Agricultural Equipment^a | | |
| Gasoline | 0.08 | 0.45 |
| Diesel | 0.08 | 0.45 |
| Construction/Mining Equipment^b | | |
| Gasoline | 0.08 | 0.18 |
| Diesel | 0.08 | 0.18 |
| Other Non-Road | | |
| All "Other" Categories ^c | 0.08 | 0.18 |
| Aircraft | | |
| Jet Fuel ^d | 0.10 | 0.00 |
| Aviation Gasoline | 0.04 | 2.64 |

Source: IPCC (2006) and ICF (2009).

^a Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^b Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^c "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

^d Emissions of CH₄ from jet fuels have been zeroed out across the time series. Recent research indicates that modern aircraft jet engines are typically net consumers of methane (Santoni et al. 2011). Methane is emitted at low power and idle operation, but at higher power modes aircraft engines consumer methane. Over the range of engine operating modes, aircraft engines are net consumers of methane on average. Based on this data, methane emissions factors for jet aircraft were changed to zero in this year's Inventory to reflect the latest emissions testing data.

Table A-110: NO_x Emissions from Mobile Combustion (kt)

| Fuel Type/Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---------------|---------------|---------------|--------------|---------------|---------------|---------------|---------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Gasoline On-Road | 5,746 | 4,560 | 3,812 | 3,715 | 4,940 | 4,621 | 4,303 | 3,984 | 3,819 | 3,654 | 3,317 | 2,966 | 2,724 | 2,805 | 2,585 | 2,365 | 2,145 |
| Passenger Cars | 3,847 | 2,752 | 2,084 | 2,027 | 2,695 | 2,521 | 2,347 | 2,174 | 2,083 | 1,993 | 1,810 | 1,618 | 1,486 | 1,530 | 1,410 | 1,290 | 1,170 |
| Light-Duty Trucks | 1,364 | 1,325 | 1,303 | 1,285 | 1,708 | 1,598 | 1,488 | 1,378 | 1,321 | 1,264 | 1,147 | 1,026 | 942 | 970 | 894 | 818 | 742 |
| Medium- and Heavy-Duty Trucks and Buses | 515 | 469 | 411 | 390 | 518 | 485 | 452 | 418 | 401 | 383 | 348 | 311 | 286 | 294 | 271 | 248 | 225 |
| Motorcycles | 20 | 14 | 13 | 14 | 18 | 17 | 16 | 15 | 14 | 13 | 12 | 11 | 10 | 10 | 10 | 9 | 8 |
| Diesel On-Road | 2,956 | 3,493 | 3,803 | 3,338 | 4,438 | 4,152 | 3,866 | 3,580 | 3,431 | 3,283 | 2,980 | 2,665 | 2,448 | 2,520 | 2,323 | 2,125 | 1,927 |
| Passenger Cars | 39 | 19 | 7 | 6 | 8 | 7 | 7 | 6 | 6 | 6 | 5 | 5 | 4 | 4 | 4 | 4 | 3 |
| Light-Duty Trucks | 20 | 12 | 6 | 5 | 7 | 7 | 6 | 6 | 6 | 5 | 5 | 4 | 4 | 4 | 4 | 3 | 3 |
| Medium- and Heavy-Duty Trucks and Buses | 2,897 | 3,462 | 3,791 | 3,326 | 4,423 | 4,138 | 3,853 | 3,568 | 3,420 | 3,272 | 2,970 | 2,656 | 2,439 | 2,512 | 2,315 | 2,118 | 1,921 |
| Alternative Fuel On-Road^a | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE |
| Non-Road | 2,160 | 2,483 | 2,584 | 2,643 | 3,107 | 2,981 | 2,856 | 2,731 | 2,490 | 2,249 | 2,226 | 2,166 | 2,118 | 1,968 | 1,881 | 1,793 | 1,705 |
| Ships and Boats | 402 | 488 | 506 | 544 | 643 | 617 | 591 | 565 | 515 | 465 | 460 | 448 | 438 | 407 | 389 | 371 | 353 |
| Rail | 338 | 433 | 451 | 485 | 574 | 550 | 527 | 504 | 460 | 415 | 411 | 400 | 391 | 363 | 347 | 331 | 315 |
| Aircraft ^b | 25 | 31 | 40 | 39 | 46 | 45 | 43 | 41 | 37 | 34 | 33 | 32 | 32 | 29 | 28 | 27 | 25 |
| Agricultural Equipment ^c | 437 | 478 | 484 | 480 | 562 | 539 | 516 | 494 | 450 | 407 | 402 | 392 | 383 | 356 | 340 | 324 | 308 |
| Construction/Mining Equipment ^d | 641 | 697 | 697 | 690 | 807 | 774 | 742 | 709 | 647 | 584 | 578 | 563 | 550 | 511 | 488 | 466 | 443 |
| Other ^e | 318 | 357 | 407 | 406 | 476 | 456 | 437 | 418 | 381 | 344 | 341 | 332 | 324 | 301 | 288 | 274 | 261 |
| Total | 10,862 | 10,536 | 10,199 | 9,696 | 12,485 | 11,755 | 11,025 | 10,295 | 9,740 | 9,186 | 8,523 | 7,797 | 7,290 | 7,294 | 6,788 | 6,283 | 5,777 |

IE - Included Elsewhere

^a NO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.^c Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.^d Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.^e "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: The source of this data is the National Emissions Inventory. Updates to estimates from MOVES2014a is a change that affects the emissions time series.

Note: Totals may not sum due to independent rounding.

Table A-111: CO Emissions from Mobile Combustion (kt)

| Fuel Type/Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Gasoline On-Road | 98,328 | 74,673 | 60,657 | 56,716 | 46,115 | 43,498 | 40,882 | 38,265 | 35,781 | 33,298 | 29,626 | 24,515 | 25,235 | 24,442 | 22,925 | 21,408 | 19,890 |
| Passenger Cars | 60,757 | 42,065 | 32,867 | 31,600 | 25,693 | 24,235 | 22,777 | 21,319 | 19,936 | 18,552 | 16,506 | 13,659 | 14,060 | 13,618 | 12,773 | 11,927 | 11,082 |
| Light-Duty Trucks | 29,237 | 27,048 | 24,532 | 22,574 | 18,355 | 17,313 | 16,272 | 15,230 | 14,242 | 13,253 | 11,792 | 9,758 | 10,044 | 9,729 | 9,125 | 8,521 | 7,917 |
| Medium- and Heavy-Duty Trucks and Buses | 8,093 | 5,404 | 3,104 | 2,411 | 1,960 | 1,849 | 1,738 | 1,627 | 1,521 | 1,416 | 1,259 | 1,042 | 1,073 | 1,039 | 975 | 910 | 846 |
| Motorcycles | 240 | 155 | 154 | 131 | 107 | 101 | 95 | 89 | 83 | 77 | 69 | 57 | 58 | 57 | 53 | 50 | 46 |
| Diesel On-Road | 1,696 | 1,424 | 1,088 | 869 | 707 | 667 | 626 | 586 | 548 | 510 | 454 | 376 | 387 | 375 | 351 | 328 | 305 |
| Passenger Cars | 35 | 18 | 7 | 6 | 5 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 |
| Light-Duty Trucks | 22 | 16 | 6 | 5 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 |
| Medium- and Heavy-Duty Trucks and Buses | 1,639 | 1,391 | 1,075 | 858 | 698 | 658 | 618 | 579 | 541 | 504 | 448 | 371 | 382 | 370 | 347 | 324 | 301 |
| Alternative Fuel On-Road^a | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE |
| Non-Road | 19,337 | 21,533 | 21,814 | 22,266 | 20,414 | 20,197 | 19,980 | 19,763 | 18,382 | 17,001 | 16,137 | 14,365 | 13,853 | 13,488 | 13,214 | 12,940 | 12,666 |
| Ships and Boats | 1,559 | 1,781 | 1,825 | 1,831 | 1,679 | 1,661 | 1,643 | 1,626 | 1,512 | 1,398 | 1,327 | 1,182 | 1,140 | 1,109 | 1,087 | 1,064 | 1,042 |
| Rail | 85 | 93 | 90 | 90 | 82 | 81 | 81 | 80 | 74 | 69 | 65 | 58 | 56 | 54 | 53 | 52 | 51 |
| Aircraft ^b | 217 | 224 | 245 | 233 | 214 | 212 | 210 | 207 | 193 | 178 | 169 | 151 | 145 | 141 | 139 | 136 | 133 |
| Agricultural Equipment ^c | 581 | 628 | 626 | 621 | 569 | 563 | 557 | 551 | 513 | 474 | 450 | 401 | 386 | 376 | 369 | 361 | 353 |
| Construction/Mining Equipment ^d | 1,090 | 1,132 | 1,047 | 1,041 | 955 | 944 | 934 | 924 | 860 | 795 | 755 | 672 | 648 | 631 | 618 | 605 | 592 |
| Other ^e | 15,805 | 17,676 | 17,981 | 18,449 | 16,914 | 16,735 | 16,555 | 16,375 | 15,231 | 14,087 | 13,371 | 11,903 | 11,479 | 11,176 | 10,949 | 10,722 | 10,494 |
| Total | 119,360 | 97,630 | 83,559 | 79,851 | 67,235 | 64,362 | 61,488 | 58,615 | 54,712 | 50,809 | 46,217 | 39,256 | 39,475 | 38,305 | 36,491 | 34,676 | 32,861 |

IE - Included Elsewhere

^a CO emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.^c Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.^d Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.^e "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: The source of this data is the National Emissions Inventory. Updates to estimates from MOVES2014a is a change that affects the emissions time series. Totals may not sum due to independent rounding.

Table A-112: NMVOCs Emissions from Mobile Combustion (kt)

| Fuel Type/Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Gasoline On-Road | 8,110 | 5,819 | 4,615 | 4,285 | 3,473 | 3,308 | 3,144 | 2,979 | 2,997 | 3,015 | 2,641 | 2,384 | 2,393 | 2,485 | 2,279 | 2,074 | 1,868 |
| Passenger Cars | 5,120 | 3,394 | 2,610 | 2,393 | 1,939 | 1,847 | 1,756 | 1,664 | 1,674 | 1,684 | 1,475 | 1,332 | 1,336 | 1,388 | 1,273 | 1,158 | 1,043 |
| Light-Duty Trucks | 2,374 | 2,019 | 1,750 | 1,664 | 1,348 | 1,285 | 1,221 | 1,157 | 1,164 | 1,171 | 1,025 | 926 | 929 | 965 | 885 | 805 | 725 |
| Medium- and Heavy-Duty Trucks and Buses | 575 | 382 | 232 | 206 | 167 | 159 | 151 | 143 | 144 | 145 | 127 | 115 | 115 | 120 | 110 | 100 | 90 |
| Motorcycles | 42 | 24 | 23 | 22 | 18 | 17 | 16 | 15 | 15 | 15 | 14 | 12 | 12 | 13 | 12 | 11 | 10 |
| Diesel On-Road | 406 | 304 | 216 | 207 | 168 | 160 | 152 | 144 | 145 | 146 | 128 | 115 | 116 | 120 | 110 | 100 | 90 |
| Passenger Cars | 16 | 8 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 |
| Light-Duty Trucks | 14 | 9 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Medium- and Heavy-Duty Trucks and Buses | 377 | 286 | 209 | 201 | 163 | 155 | 147 | 140 | 140 | 141 | 124 | 112 | 112 | 116 | 107 | 97 | 88 |
| Alternative Fuel On-Road^a | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE | IE |
| Non-Road | 2,415 | 2,622 | 2,398 | 2,379 | 2,800 | 2,733 | 2,667 | 2,600 | 2,491 | 2,383 | 2,310 | 2,150 | 2,082 | 1,957 | 1,863 | 1,768 | 1,674 |
| Ships and Boats | 608 | 739 | 744 | 730 | 859 | 839 | 818 | 798 | 764 | 731 | 709 | 660 | 639 | 600 | 572 | 543 | 514 |
| Rail | 33 | 36 | 35 | 35 | 42 | 41 | 40 | 39 | 37 | 35 | 34 | 32 | 31 | 29 | 28 | 26 | 25 |
| Aircraft ^b | 28 | 28 | 24 | 19 | 23 | 22 | 22 | 21 | 20 | 19 | 19 | 17 | 17 | 16 | 15 | 14 | 14 |
| Agricultural Equipment ^c | 85 | 86 | 76 | 72 | 85 | 83 | 81 | 79 | 76 | 73 | 70 | 65 | 63 | 60 | 57 | 54 | 51 |
| Construction/Mining Equipment ^d | 149 | 152 | 130 | 125 | 147 | 144 | 140 | 137 | 131 | 125 | 121 | 113 | 109 | 103 | 98 | 93 | 88 |
| Other ^e | 1,512 | 1,580 | 1,390 | 1,397 | 1,644 | 1,605 | 1,566 | 1,527 | 1,463 | 1,399 | 1,356 | 1,263 | 1,223 | 1,149 | 1,094 | 1,038 | 983 |
| Total | 10,932 | 8,745 | 7,230 | 6,872 | 6,440 | 6,201 | 5,962 | 5,724 | 5,634 | 5,544 | 5,078 | 4,650 | 4,591 | 4,562 | 4,252 | 3,942 | 3,632 |

IE - Included Elsewhere

^a NMVOC emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.^c Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.^d Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.^e "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: The source of this data is the National Emissions Inventory. Updates to estimates from MOVES2014a is a change that affects the emissions time series. Totals may not sum due to independent rounding.

Definitions of Emission Control Technologies and Standards

The N₂O and CH₄ emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table A-103 through Table A-106 show the years in which these technologies or standards were in place and the penetration level for each vehicle type. These categories are defined below and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Uncontrolled

Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline passenger cars and light-duty trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to have no control technologies in place.

Gasoline Emission Controls

Below are the control technologies and emissions standards applicable to gasoline vehicles.

Non-catalyst

These emission controls were common in gasoline passenger cars and light-duty gasoline trucks during model years (1973-1974) but phased out thereafter, in heavy-duty gasoline vehicles beginning in the mid-1980s, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NO_x standards.

Oxidation Catalyst

This control technology designation represents the introduction of the catalytic converter, and was the most common technology in gasoline passenger cars and light-duty gasoline trucks made from 1975 to 1980 (cars) and 1975 to 1985 (trucks). This technology was also used in some heavy-duty gasoline vehicles between 1982 and 1997. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity. One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline.

EPA Tier 0

This emission standard from the Clean Air Act was met through the implementation of early "three-way" catalysts, therefore this technology was used in gasoline passenger cars and light-duty gasoline trucks sold beginning in the early 1980s, and remained common until 1994. This more sophisticated emission control system improves the efficiency of the catalyst by converting CO and HC to CO₂ and H₂O, reducing NO_x to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor. In addition, this type of catalyst includes a fuel metering system (carburetor or fuel injection) with electronic "trim" (also known as a "closed-loop system"). New cars with three-way catalysts met the Clean Air Act's amended standards (enacted in 1977) of reducing HC to 0.41 g/mile by 1980, CO to 3.4 g/mile by 1981 and NO_x to 1.0 g/mile by 1981.

EPA Tier 1

This emission standard created through the 1990 amendments to the Clean Air Act limited passenger car NO_x emissions to 0.4 g/mi, and HC emissions to 0.25 g/mi. These bounds respectively amounted to a 60 and 40 percent reduction from the EPA Tier 0 standard set in 1981. For light-duty trucks, this standard set emissions at 0.4 to 1.1 g/mi for NO_x, and 0.25 to 0.39 g/mi for HCs, depending on the weight of the truck. Emission reductions were met through the use of more advanced emission control systems, and applied to light-duty gasoline vehicles beginning in 1994. These advanced emission control systems included advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

EPA Tier 2

This emission standard was specified in the 1990 amendments to the Clean Air Act, limiting passenger car NO_x emissions to 0.07 g/mi on average and aligning emissions standards for passenger cars and light-duty trucks. Manufacturers can meet this average emission level by producing vehicles in 11 emission "Bins," the three highest of which expire in 2006.

These new emission levels represent a 77 to 95 percent reduction in emissions from the EPA Tier 1 standard set in 1994. Emission reductions were met through the use of more advanced emission control systems and lower sulfur fuels and are applied to vehicles beginning in 2004. These advanced emission control systems include improved combustion, advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

Low Emission Vehicles (LEV)

This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH₄ or N₂O emission factor data for LEVs to distinguish among the different types of vehicles. Zero emission vehicles (ZEVs) are incorporated into the alternative fuel and advanced technology vehicle assessments.

Diesel Emission Controls

Below are the three levels of emissions control for diesel vehicles.

Moderate control

Improved injection timing technology and combustion system design for light- and heavy-duty diesel vehicles (generally in place in model years 1983 to 1995) are considered moderate control technologies. These controls were implemented to meet emission standards for diesel trucks and buses adopted by the EPA in 1985 to be met in 1991 and 1994.

Advanced control

EGR and modern electronic control of the fuel injection system are designated as advanced control technologies. These technologies provide diesel vehicles with the level of emission control necessary to comply with standards in place from 1996 through 2006.

Aftertreatment

Use of diesel particulate filters (DPFs), oxidation catalysts and NO_x absorbers or selective catalytic reduction (SCR) systems are designated as aftertreatment control. These technologies provide diesel vehicles with a level of emission control necessary to comply with standards in place from 2007 on.

Supplemental Information on GHG Emissions from Transportation and Other Mobile Sources

This section of this Annex includes supplemental information on the contribution of transportation and other mobile sources to U.S. greenhouse gas emissions. In the main body of the Inventory report, emission estimates are generally presented by greenhouse gas, with separate discussions of the methodologies used to estimate CO₂, N₂O, CH₄, and HFC emissions. Although the inventory is not required to provide detail beyond what is contained in the body of this report, the IPCC allows presentation of additional data and detail on emission sources. The purpose of this sub-annex, within the Annex that details the calculation methods and data used for non-CO₂ calculations, is to provide all transportation estimates presented throughout the report in one place.

This section of this Annex reports total greenhouse gas emissions from transportation and other (non-transportation) mobile sources in CO₂ equivalents, with information on the contribution by greenhouse gas and by mode, vehicle type, and fuel type. In order to calculate these figures, additional analyses were conducted to develop estimates of CO₂ from non-transportation mobile sources (e.g., agricultural equipment, construction/mining equipment, recreational vehicles), and to provide more detailed breakdowns of emissions by source.

Estimation of CO₂ from Non-Transportation Mobile Sources

The estimates of N₂O and CH₄ from fuel combustion presented in the Energy chapter of the Inventory include both transportation sources and other mobile sources. Other mobile sources include construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources that have utility associated with their movement but do not have a primary purpose of transporting people or goods (e.g., snowmobiles, riding lawnmowers, etc.). Estimates of CO₂ from non-transportation mobile sources, based on EIA fuel consumption estimates, are included in the agricultural, industrial, and commercial sectors. In order to provide comparable information on transportation and mobile sources, Table A-113 provides estimates of CO₂ from these other mobile sources, developed from EPA's NONROAD model and FHWA's *Highway*

Statistics. These other mobile source estimates were developed using the same fuel consumption data utilized in developing the N₂O and CH₄ estimates.

Table A-113: CO₂ Emissions from Non-Transportation Mobile Sources (MMT CO₂ Eq.)

| Fuel Type/Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Agricultural Equipment ^a | 31.0 | 36.6 | 39.3 | 41.5 | 42.7 | 43.7 | 46.7 | 47.4 | 49.6 | 49.0 | 46.0 | 47.2 | 48.2 | 49.9 | 51.4 | 50.4 | 51.2 |
| Construction/Mining Equipment ^b | 42.0 | 48.9 | 56.2 | 60.4 | 62.2 | 64.0 | 65.8 | 66.9 | 68.3 | 68.8 | 70.3 | 71.6 | 73.9 | 75.1 | 76.8 | 82.2 | 80.4 |
| Other Sources ^c | 54.5 | 59.9 | 62.6 | 70.1 | 71.8 | 73.7 | 75.7 | 75.9 | 77.1 | 75.9 | 76.6 | 77.3 | 80.2 | 79.9 | 79.4 | 80.3 | 81.7 |
| Total | 127.6 | 145.4 | 158.1 | 172.0 | 176.7 | 181.3 | 188.2 | 190.2 | 195.1 | 193.7 | 192.9 | 196.1 | 202.3 | 204.9 | 207.6 | 212.9 | 213.3 |

^a Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^b Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^c "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: In 2015, EPA incorporated the NONROAD2008 model into MOVES2014a. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

Estimation of HFC Emissions from Transportation Sources

In addition to CO₂, N₂O and CH₄ emissions, transportation sources also result in emissions of HFCs. HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events. There are three categories of transportation-related HFC emissions; Mobile air-conditioning represents the emissions from air conditioning units in passenger cars and light-duty trucks; Comfort Cooling represents the emissions from air conditioning units in passenger trains and buses; and Refrigerated Transport represents the emissions from units used to cool freight during transportation.

Table A-114 below presents these HFC emissions. Table A-115 presents all transportation and mobile source greenhouse gas emissions, including HFC emissions.

Table A-114: HFC Emissions from Transportation Sources (MMT CO₂Eq.)

| Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Mobile AC | - | 18.9 | 53.5 | 59.1 | 61.3 | 62.7 | 64.3 | 65.0 | 65.6 | 66.0 | 66.3 | 65.2 | 61.7 | 55.7 | 49.9 | 44.0 | 40.9 |
| Passenger Cars | - | 11.2 | 28.1 | 30.7 | 31.5 | 31.6 | 31.8 | 31.7 | 31.7 | 31.5 | 31.2 | 29.9 | 27.5 | 23.9 | 20.6 | 17.3 | 16.0 |
| Light-Duty Trucks | - | 7.8 | 25.4 | 28.4 | 29.8 | 31.1 | 32.4 | 33.3 | 33.9 | 34.5 | 35.1 | 35.2 | 34.2 | 31.7 | 29.3 | 26.7 | 25.0 |
| Comfort Cooling for Trains and Buses | - | + | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| School and Tour Buses | - | + | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Transit Buses | - | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | 0.1 |
| Rail | - | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + |
| Refrigerated Transport | - | 0.2 | 0.8 | 1.0 | 1.2 | 1.4 | 1.6 | 1.8 | 2.0 | 2.3 | 2.6 | 2.9 | 3.5 | 4.1 | 4.7 | 5.3 | 5.8 |
| Medium- and Heavy-Duty Trucks | - | 0.1 | 0.6 | 0.8 | 0.9 | 1.2 | 1.4 | 1.5 | 1.7 | 1.9 | 2.2 | 2.4 | 2.9 | 3.4 | 3.9 | 4.4 | 4.4 |
| Rail | - | 0.0 | 0.2 | 0.2 | 0.3 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 1.4 |
| Ships and Other Boats | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | - | 19.1 | 54.5 | 60.3 | 62.7 | 64.3 | 66.1 | 67.1 | 67.9 | 68.7 | 69.3 | 68.5 | 65.6 | 60.2 | 55.1 | 49.8 | 47.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

- Unreported or zero

Note: Totals may not sum due to independent rounding.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Mode/Vehicle Type/Fuel Type

Table A-115 presents estimates of greenhouse gas emissions from an expanded analysis including all transportation and additional mobile sources, as well as emissions from electricity generation by the consuming category, in CO₂ equivalents. In total, transportation and non-transportation mobile sources emitted 2,029.7 MMT CO₂ Eq. in 2014, an increase of 21 percent from 1990. Transportation sources account for 1,814.5 MMT CO₂ Eq. while non-transportation mobile sources account for 215.3 MMT CO₂ Eq. These estimates include HFC emissions for mobile AC, comfort cooling for trains and buses, and refrigerated transport. These estimates were generated using the estimates of CO₂ emissions from transportation sources reported in the Carbon Dioxide Emissions from Fossil Fuel Combustion section, and CH₄ emissions and N₂O emissions reported in the Mobile Combustion section of the Energy chapter; information on HFCs from mobile air conditioners, comfort cooling for trains and buses, and refrigerated transportation from the Substitutes for Ozone Depleting Substances section of the IPPU chapter; and estimates of CO₂ emitted from non-transportation mobile sources reported in Table A-111 above.

Although all emissions reported here are based on estimates reported throughout this Inventory, some additional calculations were performed in order to provide a detailed breakdown of emissions by mode and vehicle category. In the case of N₂O and CH₄, additional calculations were performed to develop emission estimates by type of aircraft and type of heavy-duty vehicle (i.e., medium- and heavy-duty trucks or buses) to match the level of detail for CO₂ emissions. N₂O estimates for both jet fuel and aviation gasoline, and CH₄ estimates for aviation gasoline were developed for individual aircraft types by multiplying the emissions estimates for each fuel type (jet fuel and aviation gasoline) by the portion of fuel used by each aircraft type (from FAA 2016 and DESC 2015). Emissions of CH₄ from jet fuels are no longer considered to be emitted from aircraft gas turbine engines burning jet fuel A at higher power settings. This update applies to the entire time series.⁵⁴ Recent research indicates that modern aircraft jet engines are typically net consumers of methane (Santoni et al 2011). Methane is emitted at low power and idle operation, but at higher power modes aircraft engines consume methane. Over the range of engine operating modes, aircraft engines are net consumers of methane on average. Based on this data, CH₄ emission factors for jet aircraft were reported as zero to reflect the latest emissions testing data.

Similarly, N₂O and CH₄ estimates were developed for medium- and heavy-duty trucks and buses by multiplying the emission estimates for heavy-duty vehicles for each fuel type (gasoline, diesel) from the Mobile Combustion section in the Energy chapter, by the portion of fuel used by each vehicle type (from DOE 1993 through 2015). Carbon dioxide emissions from non-transportation mobile sources are calculated using data from EPA's NONROAD component of MOVES2014a (EPA 2015d). Otherwise, the table and figure are drawn directly from emission estimates presented elsewhere in the Inventory, and are dependent on the methodologies presented in Annex 2.1 (for CO₂), Chapter 4, and Annex 3.8 (for HFCs), and earlier in this Annex (for CH₄ and N₂O).

Transportation sources include on-road vehicles, aircraft, boats and ships, rail, and pipelines (note: pipelines are a transportation source but are stationary, not mobile sources). In addition, transportation-related greenhouse gas emissions also include HFC released from mobile air-conditioners and refrigerated transport, and the release of CO₂ from lubricants (such as motor oil) used in transportation. Together, transportation sources were responsible for 1,814.5 MMT CO₂ Eq. in 2014.

On-road vehicles were responsible for about 75 percent of all transportation and non-transportation mobile greenhouse gas emissions in 2014. Although passenger cars make up the largest component of on-road vehicle greenhouse gas emissions, medium- and heavy-duty trucks have been the primary sources of growth in on-road vehicle emissions. Between 1990 and 2014, greenhouse gas emissions from passenger cars increased by 16 percent, while emissions from light-duty trucks increased by one percent.⁵⁵ Meanwhile, greenhouse gas emissions from medium- and heavy-duty trucks increased 76 percent between 1990 and 2014, reflecting the increased volume of total freight movement and an increasing share transported by trucks.

⁵⁴ Recommended Best Practice for Quantifying Speciated Organic Gas Emissions from Aircraft Equipped with Turbofan, Turbojet and Turboprop Engines," EPA-420-R-09-901, May 27, 2009 (see <<http://www.epa.gov/otaq/regs/nonroad/aviation/420r09901.pdf>>).

⁵⁵ In 2011 FHWA changed how they defined vehicle types for the purposes of reporting VMT for the years 2007-2010. The old approach to vehicle classification was based on body type and split passenger vehicles into "Passenger Cars" and "Other 2 Axle 4-Tire Vehicles". The new approach is a vehicle classification system based on wheelbase. Vehicles with a wheelbase less than or equal to 121 inches are counted as "Light-duty Vehicles—Short Wheelbase". Passenger vehicles with a wheelbase greater than 121 inches are counted as "Light-duty Vehicles - Long Wheelbase". This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

Greenhouse gas emissions from aircraft decreased 20 percent between 1990 and 2014. Emissions from military aircraft decreased 56 percent between 1990 and 2014. Commercial aircraft emissions rose 27 percent between 1990 and 2007 then dropped 18 percent from 2007 to 2014, a change of approximately 5 percent between 1990 and 2014.

Non-transportation mobile sources, such as construction/mining equipment, agricultural equipment, and industrial/commercial equipment, emitted approximately 215.3 MMT CO₂ Eq. in 2014. Together, these sources emitted more greenhouse gases than ships and boats, and rail combined. Emissions from non-transportation mobile sources increased rapidly, growing approximately 67 percent between 1990 and 2014. Methane and N₂O emissions from these sources are included in the “Mobile Combustion” section and CO₂ emissions are included in the relevant economic sectors.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Gas

Table A-116 presents estimates of greenhouse gas emissions from transportation and other mobile sources broken down by greenhouse gas. As this table shows, CO₂ accounts for the vast majority of transportation greenhouse gas emissions (approximately 97 percent in 2014). Emissions of CO₂ from transportation and mobile sources increased by 327.8 MMT CO₂ Eq. between 1990 and 2014. In contrast, the combined emissions of CH₄ and N₂O decreased by 28.5 MMT CO₂ Eq. over the same period, due largely to the introduction of control technologies designed to reduce criteria pollutant emissions.⁵⁶ Meanwhile, HFC emissions from mobile air-conditioners and refrigerated transport increased from virtually no emissions in 1990 to 47.2 MMT CO₂ Eq. in 2014 as these chemicals were phased in as substitutes for ozone depleting substances. It should be noted, however, that the ozone depleting substances that HFCs replaced are also powerful greenhouse gases, but are not included in national greenhouse gas inventories per UNFCCC reporting requirements.

Greenhouse Gas Emissions from Freight and Passenger Transportation

Table A-117 and

Table A-118 present greenhouse gas estimates from transportation, broken down into the passenger and freight categories. Passenger modes include light-duty vehicles, buses, passenger rail, aircraft (general aviation and commercial aircraft), recreational boats, and mobile airconditioners, and are illustrated in Table A-117. Freight modes include medium- and heavy-duty trucks, freight rail, refrigerated transport, waterborne freight vessels, pipelines, and commercial aircraft and are illustrated in

Table A-118. Commercial aircraft do carry some freight, in addition to passengers, and emissions have been split between passenger and freight transportation. The amount of commercial aircraft emissions to allocate to the passenger and freight categories was calculated using BTS data on freight shipped by commercial aircraft, and the total number of passengers enplaned. Each passenger was considered to weigh an average of 150 pounds, with a luggage weight of 50 pounds. The total freight weight and total passenger weight carried were used to determine percent shares which were used to split the total commercial aircraft emission estimates. The remaining transportation and mobile emissions were from sources not considered to be either freight or passenger modes (e.g., construction/mining and agricultural equipment, lubricants).

The estimates in these tables are derived from the estimates presented in Table A-115. In addition, estimates of fuel consumption from DOE (1993 through 2015) were used to allocate rail emissions between passenger and freight categories.

In 2014, passenger transportation modes emitted 1,261.5 MMT CO₂ Eq., while freight transportation modes emitted 518.3 MMT CO₂ Eq. Between 1990 and 2014, the percentage growth of greenhouse gas emissions from freight sources was 47 percent, while emissions from passenger sources grew by 9 percent. This difference in growth is due largely to the rapid increase in emissions associated with medium- and heavy-duty trucks.

⁵⁶ The decline in CFC emissions is not captured in the official transportation estimates.

Table A-115: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (MMT CO₂ Eq.)

| Mode / Vehicle Type / Fuel Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent Change 1990-2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|--------------------------|
| Transportation Total^a | 1,554.4 | 1,698.4 | 1,926.7 | 1,911.3 | 1,951.4 | 1,941.2 | 1,986.0 | 2,004.4 | 1,998.1 | 1,999.3 | 1,902.0 | 1,823.6 | 1,832.0 | 1,803.9 | 1,784.3 | 1,794.0 | 1,814.5 | 17% |
| On-Road Vehicles | 1,233.5 | 1,370.5 | 1,572.8 | 1,583.1 | 1,621.4 | 1,630.6 | 1,663.8 | 1,672.4 | 1,668.5 | 1,664.6 | 1,586.5 | 1,540.9 | 1,541.7 | 1,515.0 | 1,504.6 | 1,504.3 | 1,531.1 | 24% |
| Passenger Cars | 656.6 | 646.7 | 697.3 | 704.1 | 716.9 | 694.2 | 690.2 | 708.9 | 683.0 | 843.5 | 802.3 | 792.8 | 783.6 | 774.3 | 767.9 | 763.2 | 762.5 | 16% |
| Gasoline ^b | 648.7 | 627.6 | 665.5 | 669.7 | 681.7 | 658.4 | 654.1 | 673.0 | 647.2 | 807.9 | 767.4 | 759.3 | 752.3 | 746.3 | 743.2 | 741.8 | 742.4 | 14% |
| Diesel ^{b, c} | 7.9 | 7.8 | 3.7 | 3.7 | 3.7 | 4.2 | 4.3 | 4.2 | 4.1 | 4.1 | 3.7 | 3.6 | 3.7 | 4.1 | 4.1 | 4.1 | 4.1 | -48% |
| AFVs ^d | + | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,608% |
| HFCs from Mobile AC | + | 11.2 | 28.1 | 30.7 | 31.5 | 31.6 | 31.8 | 31.7 | 31.7 | 31.5 | 31.2 | 29.9 | 27.5 | 23.9 | 20.6 | 17.3 | 16.0 | NA |
| Light-Duty Trucks | 335.6 | 436.8 | 515.0 | 520.8 | 532.7 | 567.4 | 589.0 | 551.5 | 564.0 | 367.2 | 348.6 | 351.5 | 348.9 | 332.0 | 326.0 | 323.4 | 338.1 | 1% |
| Gasoline ^b | 323.5 | 413.6 | 469.0 | 471.0 | 480.4 | 508.3 | 526.7 | 491.1 | 502.2 | 318.1 | 299.7 | 303.1 | 300.9 | 285.8 | 282.1 | 281.9 | 297.4 | -8% |
| Diesel ^{b, c} | 11.5 | 14.9 | 20.1 | 20.8 | 21.9 | 27.2 | 28.9 | 25.8 | 26.7 | 13.5 | 12.1 | 12.0 | 12.5 | 13.0 | 12.9 | 12.9 | 13.9 | 21% |
| AFVs ^d | 0.6 | 0.5 | 0.5 | 0.6 | 0.6 | 0.8 | 0.9 | 1.3 | 1.2 | 1.0 | 1.8 | 1.2 | 1.3 | 1.5 | 1.6 | 1.9 | 1.9 | 234% |
| HFCs from Mobile AC | + | 7.8 | 25.4 | 28.4 | 29.8 | 31.1 | 32.4 | 33.3 | 33.9 | 34.5 | 35.1 | 35.2 | 34.2 | 31.7 | 29.3 | 26.7 | 25.0 | NA |
| Medium- and Heavy-Duty Trucks | 231.1 | 275.9 | 347.5 | 346.1 | 360.0 | 356.6 | 367.7 | 398.2 | 407.4 | 432.0 | 414.2 | 376.3 | 389.7 | 388.4 | 388.7 | 395.7 | 407.4 | 76% |
| Gasoline ^b | 39.5 | 36.8 | 37.0 | 36.1 | 36.6 | 31.6 | 31.8 | 35.7 | 36.1 | 47.1 | 47.3 | 43.4 | 43.2 | 39.6 | 39.3 | 40.1 | 40.5 | 2% |
| Diesel ^{b, c} | 190.7 | 238.4 | 309.5 | 309.0 | 322.2 | 323.5 | 334.3 | 360.5 | 369.1 | 382.6 | 364.0 | 329.9 | 343.1 | 344.7 | 344.8 | 350.4 | 361.7 | 90% |
| AFVs ^d | 0.9 | 0.6 | 0.3 | 0.3 | 0.3 | 0.4 | 0.3 | 0.4 | 0.5 | 0.4 | 0.7 | 0.5 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 | -8% |
| HFCs from Refrigerated Transport ^e | + | 0.1 | 0.6 | 0.8 | 0.9 | 1.2 | 1.4 | 1.5 | 1.7 | 1.9 | 2.2 | 2.4 | 2.9 | 3.4 | 3.9 | 4.4 | 4.4 | NA |
| Buses | 8.4 | 9.2 | 11.2 | 10.3 | 10.0 | 10.8 | 15.1 | 12.1 | 12.2 | 17.6 | 16.9 | 16.0 | 15.8 | 16.8 | 17.8 | 18.0 | 19.1 | 129% |
| Gasoline ^b | 0.4 | 0.4 | 0.4 | 0.4 | 0.3 | 0.3 | 0.5 | 0.4 | 0.4 | 0.7 | 0.7 | 0.8 | 0.7 | 0.7 | 0.8 | 0.9 | 0.9 | 154% |
| Diesel ^{b, c} | 8.0 | 8.7 | 10.2 | 9.3 | 8.8 | 9.5 | 13.5 | 10.6 | 10.6 | 15.5 | 14.6 | 13.6 | 13.5 | 14.4 | 15.4 | 15.5 | 16.6 | 107% |
| AFVs ^d | + | 0.1 | 0.5 | 0.5 | 0.6 | 0.8 | 0.9 | 0.9 | 0.9 | 1.0 | 1.2 | 1.2 | 1.1 | 1.2 | 1.1 | 1.2 | 1.2 | 88,269% |
| HFCs from Comfort Cooling | + | 0.0 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | NA |
| Motorcycles | 1.8 | 1.8 | 1.9 | 1.7 | 1.7 | 1.7 | 1.8 | 1.7 | 1.9 | 4.3 | 4.4 | 4.2 | 3.7 | 3.6 | 4.2 | 4.0 | 3.9 | 118% |
| Gasoline ^b | 1.8 | 1.8 | 1.9 | 1.7 | 1.7 | 1.7 | 1.8 | 1.7 | 1.9 | 4.3 | 4.4 | 4.2 | 3.7 | 3.6 | 4.2 | 4.0 | 3.9 | 118% |
| Aircraft General Aviation | 189.2 | 176.7 | 199.4 | 193.9 | 189.4 | 183.1 | 190.6 | 193.6 | 186.3 | 183.4 | 176.7 | 157.4 | 154.8 | 149.9 | 146.5 | 150.1 | 151.5 | -20% |
| Aircraft | 42.9 | 35.8 | 35.9 | 43.7 | 45.1 | 36.9 | 41.9 | 40.1 | 30.1 | 24.4 | 30.5 | 21.2 | 26.7 | 22.5 | 19.9 | 23.6 | 19.7 | -54% |

| | | | | | | | | | | | | | | | | | | |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|-------------|
| Jet Fuel | 39.8 | 33.0 | 33.4 | 41.2 | 42.7 | 34.7 | 39.7 | 37.6 | 27.7 | 22.2 | 28.5 | 19.4 | 24.8 | 20.6 | 18.2 | 22.0 | 18.2 | -54% |
| Aviation Gasoline | 3.2 | 2.8 | 2.6 | 2.5 | 2.4 | 2.1 | 2.2 | 2.5 | 2.4 | 2.2 | 2.0 | 1.9 | 1.9 | 1.9 | 1.8 | 1.6 | 1.5 | -52% |
| Commercial Aircraft | 110.9 | 116.3 | 140.6 | 125.8 | 122.4 | 124.0 | 126.0 | 134.0 | 138.3 | 141.0 | 128.4 | 120.6 | 114.4 | 115.7 | 114.3 | 115.4 | 116.3 | 5% |
| Jet Fuel | 110.9 | 116.3 | 140.6 | 125.8 | 122.4 | 124.0 | 126.0 | 134.0 | 138.3 | 141.0 | 128.4 | 120.6 | 114.4 | 115.7 | 114.3 | 115.4 | 116.3 | 5% |
| Military Aircraft | 35.3 | 24.5 | 22.9 | 24.5 | 21.9 | 22.2 | 22.7 | 19.5 | 18.0 | 18.0 | 17.7 | 15.5 | 13.7 | 11.7 | 12.2 | 11.1 | 15.5 | -56% |
| Jet Fuel | 35.3 | 24.5 | 22.9 | 24.5 | 21.9 | 22.2 | 22.7 | 19.5 | 18.0 | 18.0 | 17.7 | 15.5 | 13.7 | 11.7 | 12.2 | 11.1 | 15.5 | -56% |
| Ships and Boats^g | 44.9 | 58.5 | 61.1 | 42.4 | 47.2 | 37.1 | 39.8 | 44.9 | 48.0 | 54.7 | 45.3 | 38.6 | 44.7 | 46.4 | 40.1 | 39.4 | 28.6 | -36% |
| Gasoline | 12.4 | 14.1 | 10.2 | 14.4 | 14.4 | 14.2 | 14.1 | 14.0 | 13.8 | 13.6 | 13.2 | 13.0 | 12.7 | 12.6 | 12.5 | 12.4 | 12.3 | 0% |
| Distillate Fuel ^c | 9.6 | 14.9 | 17.1 | 15.8 | 15.4 | 15.3 | 11.5 | 11.4 | 10.8 | 11.6 | 11.4 | 11.5 | 11.1 | 14.0 | 11.4 | 11.5 | 10.2 | 6% |
| Residual Fuel ^h | 22.9 | 29.5 | 33.8 | 12.2 | 17.4 | 7.6 | 14.2 | 19.6 | 23.4 | 29.4 | 20.7 | 14.2 | 20.9 | 19.8 | 16.2 | 15.5 | 6.0 | -75% |
| HFCs from Refrigerated Transport ^e | + | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | NA |
| Rail | 39.0 | 43.1 | 46.1 | 46.5 | 46.1 | 47.8 | 50.5 | 51.1 | 53.0 | 52.2 | 48.5 | 41.3 | 44.2 | 45.9 | 44.6 | 45.5 | 47.6 | 22% |
| Distillate Fuel ^{c,i} | 35.8 | 40.0 | 42.5 | 42.6 | 42.3 | 43.2 | 45.6 | 46.0 | 48.1 | 46.7 | 43.3 | 36.3 | 39.0 | 40.8 | 39.9 | 40.5 | 42.1 | 17% |
| Electricity | 3.1 | 3.1 | 3.5 | 3.7 | 3.5 | 4.3 | 4.6 | 4.8 | 4.6 | 5.1 | 4.7 | 4.5 | 4.5 | 4.3 | 3.9 | 4.1 | 4.1 | 34% |
| Other Emissions from Rail Electricity Use ^j | 0.1 | 0.1 | + | + | + | + | 0.1 | 0.1 | + | 0.1 | + | + | + | + | + | + | + | -30% |
| HFCs from Comfort Cooling | + | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | NA |
| HFCs from Refrigerated Transport ^e | + | 0.0 | 0.2 | 0.2 | 0.3 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 1.4 | NA |
| Pipelines^k | 36.0 | 38.2 | 35.2 | 34.4 | 36.4 | 32.5 | 31.1 | 32.2 | 32.3 | 34.2 | 35.6 | 36.7 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 | 29% |
| Natural Gas | 36.0 | 38.2 | 35.2 | 34.4 | 36.4 | 32.5 | 31.1 | 32.2 | 32.3 | 34.2 | 35.6 | 36.7 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 | 29% |
| Other Transportation | 11.8 | 11.3 | 12.1 | 11.1 | 10.9 | 10.1 | 10.2 | 10.2 | 9.9 | 10.2 | 9.5 | 8.5 | 9.5 | 9.0 | 8.3 | 8.8 | 9.1 | -23% |
| Lubricants | 11.8 | 11.3 | 12.1 | 11.1 | 10.9 | 10.1 | 10.2 | 10.2 | 9.9 | 10.2 | 9.5 | 8.5 | 9.5 | 9.0 | 8.3 | 8.8 | 9.1 | -23% |
| Non-Transportation Mobile Total | 128.8 | 146.8 | 159.6 | 173.6 | 178.3 | 183.0 | 190.0 | 191.9 | 196.9 | 195.5 | 194.7 | 198.0 | 204.2 | 206.8 | 209.6 | 214.9 | 215.3 | 67% |
| Agricultural Equipment^l | 31.4 | 37.0 | 39.8 | 42.0 | 43.1 | 44.2 | 47.2 | 47.9 | 50.2 | 49.5 | 46.5 | 47.7 | 48.7 | 50.5 | 52.0 | 51.0 | 51.7 | 65% |
| Gasoline | 7.3 | 8.3 | 5.8 | 7.1 | 7.4 | 7.6 | 9.7 | 9.6 | 11.0 | 9.4 | 5.6 | 5.9 | 6.0 | 7.0 | 7.6 | 5.7 | 5.6 | -23% |
| Diesel | 24.1 | 28.7 | 34.0 | 34.9 | 35.7 | 36.6 | 37.5 | 38.4 | 39.2 | 40.1 | 40.9 | 41.8 | 42.7 | 43.5 | 44.4 | 45.3 | 46.1 | 92% |
| Construction/ Mining Equipment^m | 42.4 | 49.4 | 56.6 | 61.0 | 62.7 | 64.5 | 66.4 | 67.4 | 68.9 | 69.4 | 70.9 | 72.2 | 74.6 | 75.7 | 77.4 | 82.9 | 81.1 | 91% |
| Gasoline | 4.4 | 4.0 | 3.0 | 5.8 | 6.0 | 6.3 | 6.6 | 6.2 | 6.1 | 5.1 | 5.1 | 4.9 | 5.7 | 5.3 | 5.5 | 9.4 | 6.1 | 39% |
| Diesel | 38.0 | 45.4 | 53.6 | 55.1 | 56.7 | 58.2 | 59.7 | 61.3 | 62.8 | 64.3 | 65.8 | 67.4 | 68.9 | 70.4 | 72.0 | 73.5 | 75.0 | 97% |

| | | | | | | | | | | | | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|------------|
| Other Equipment^a | 55.0 | 60.4 | 63.2 | 70.7 | 72.5 | 74.3 | 76.4 | 76.6 | 77.8 | 76.6 | 77.3 | 78.0 | 80.9 | 80.6 | 80.1 | 81.0 | 82.5 | 50% |
| Gasoline | 40.3 | 42.6 | 42.0 | 48.8 | 49.9 | 51.1 | 52.4 | 51.9 | 52.5 | 50.6 | 50.6 | 50.6 | 52.9 | 51.9 | 50.7 | 50.9 | 51.6 | 28% |
| Diesel | 14.7 | 17.8 | 21.2 | 21.9 | 22.6 | 23.3 | 23.9 | 24.6 | 25.3 | 26.0 | 26.7 | 27.4 | 28.1 | 28.7 | 29.4 | 30.1 | 30.8 | 109% |
| Transportation and Non-Transportation Mobile Total | 1,683.1 | 1,845.2 | 2,086.4 | 2,085.0 | 2,129.7 | 2,124.2 | 2,176.0 | 2,196.4 | 2,195.0 | 2,194.8 | 2,096.7 | 2,021.5 | 2,036.2 | 2,010.8 | 1,993.9 | 2,008.9 | 2,029.7 | 21% |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA - Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

^a Not including emissions from international bunker fuels.

^b Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is as a proxy.

^c Updates to the distillate fuel oil heat content data from EIA for years 1993 through present resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^d In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990-2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^e Updated Commodity Flow Survey data was used to allocate refrigerated transport emissions to the trucking, rail and marine sectors in 2014.

^f Updates to the jet fuel heat content used in the mobile N₂O emissions estimates for years 1990 through present resulted in small changes to the time series emissions compared to the previous Inventory.

^g Fluctuations in emission estimates reflect data collection problems. Note that CH₄ and N₂O from U.S. Territories are included in this value, but not CO₂ emissions from U.S. Territories, which are estimated separately in the section on U.S. Territories.

^h Domestic residual fuel for ships and boats is estimated by taking the total amount of residual fuel and subtracting out an estimate of international bunker fuel use.

ⁱ Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^j Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants), electrical transmission and distribution, and a portion of Other Process Uses of Carbonates (from pollution control equipment installed in electricity generation plants).

^k Includes only CO₂ from natural gas used to power natural gas pipelines; does not include emissions from electricity use or non-CO₂ gases.

^l Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^m Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

ⁿ "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: Increases to CH₄ and N₂O emissions from mobile combustion relative to previous Inventories are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES2014a) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. See Section 3.1 "CH₄ and N₂O from Mobile Combustion" for more detail. In 2015, EPA incorporated the NONROAD2008 model into MOVES2014a. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

Table A-116: Transportation and Mobile Source Emissions by Gas (MMT CO₂ Eq.)

| | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent Change 1990-2014 |
|--------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|--------------------------|
| CO ₂ | 1,636.2 | 1,769.6 | 1,979.1 | 1,976.1 | 2,021.7 | 2,018.0 | 2,070.1 | 2,092.1 | 2,092.1 | 2,095.1 | 1,998.9 | 1,926.1 | 1,944.5 | 1,925.8 | 1,916.5 | 1,938.7 | 1,964.1 | 20% |
| N ₂ O | 41.2 | 51.2 | 49.0 | 45.0 | 42.1 | 38.9 | 36.8 | 34.4 | 32.2 | 28.4 | 26.0 | 24.5 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 | -60% |
| CH ₄ | 5.6 | 5.2 | 3.7 | 3.5 | 3.2 | 3.0 | 2.9 | 2.7 | 2.7 | 2.5 | 2.4 | 2.3 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 | -64% |
| HFC | - | 19.1 | 54.5 | 60.3 | 62.7 | 64.3 | 66.1 | 67.1 | 67.9 | 68.7 | 69.3 | 68.5 | 65.6 | 60.2 | 55.1 | 49.8 | 47.2 | NA |
| Total^a | 1,683.1 | 1,845.1 | 2,086.3 | 2,084.9 | 2,129.7 | 2,124.2 | 2,175.9 | 2,196.3 | 2,194.9 | 2,194.7 | 2,096.7 | 2,021.5 | 2,036.1 | 2,010.7 | 1,993.8 | 2,008.8 | 2,029.6 | 21% |

- Unreported or zero

NA - Not applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

^aTotal excludes other emissions from electricity generation and CH₄ and N₂O emissions from electric rail.

Note: The current Inventory includes updated vehicle population data based on the MOVES 2014a Model.

Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

Figure A-4: Domestic Greenhouse Gas Emissions by Mode and Vehicle Type, 1990 to 2014 (MMT CO₂ Eq.)

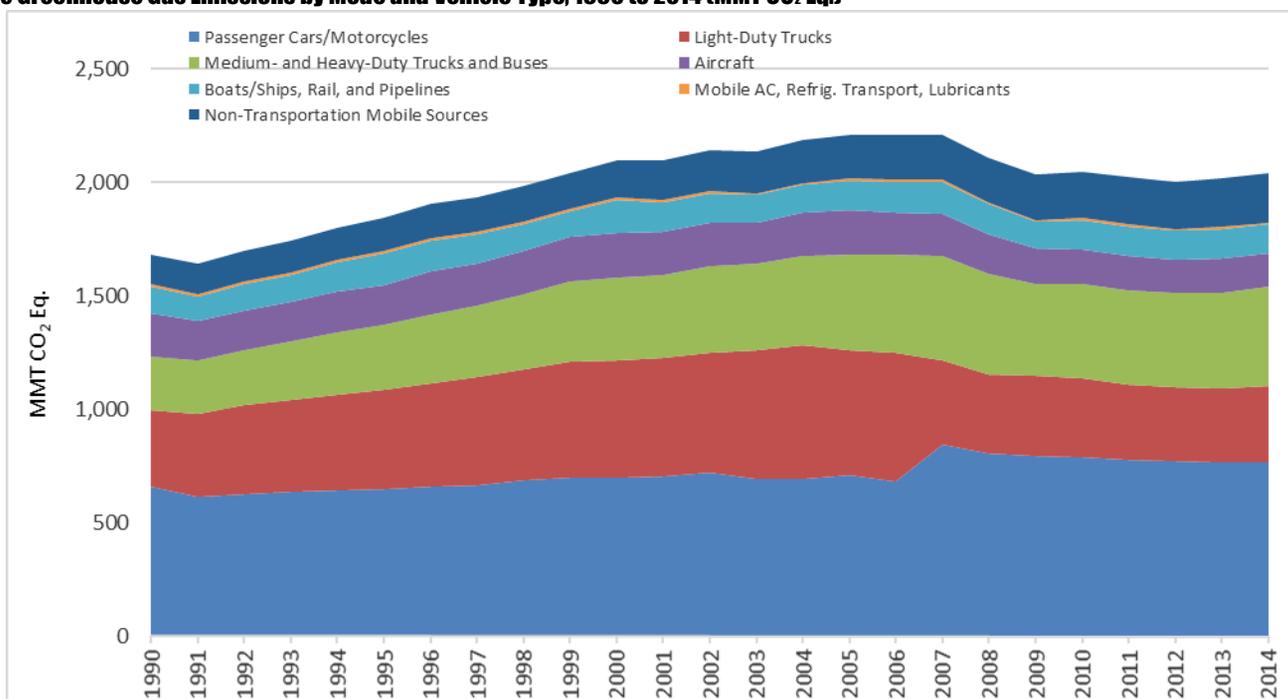


Table A-17: Greenhouse Gas Emissions from Passenger Transportation (MMT CO₂ Eq.)

| Vehicle Type | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent Change 1990-2014 |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|--------------------------|
| On-Road Vehicles^a | 1,002.4 | 1,094.6 | 1,225.3 | 1,236.9 | 1,261.4 | 1,274.0 | 1,296.0 | 1,274.2 | 1,261.1 | 1,232.6 | 1,172.3 | 1,164.6 | 1,151.9 | 1,126.6 | 1,115.9 | 1,108.6 | 1,123.7 | 12% |
| Passenger Cars | 656.6 | 646.7 | 697.3 | 704.1 | 716.9 | 694.2 | 690.2 | 708.9 | 683.0 | 843.5 | 802.3 | 792.8 | 783.6 | 774.3 | 767.9 | 763.2 | 762.5 | 16% |
| Light-Duty Trucks | 335.6 | 436.8 | 515.0 | 520.8 | 532.7 | 567.4 | 589.0 | 551.5 | 564.0 | 367.2 | 348.6 | 351.5 | 348.9 | 332.0 | 326.0 | 323.4 | 338.1 | 1% |
| Buses | 8.4 | 9.2 | 11.2 | 10.3 | 10.0 | 10.8 | 15.1 | 12.1 | 12.2 | 17.6 | 16.9 | 16.0 | 15.8 | 16.8 | 17.8 | 18.0 | 19.1 | 129% |
| Motorcycles | 1.8 | 1.8 | 1.9 | 1.7 | 1.7 | 1.7 | 1.8 | 1.7 | 1.9 | 4.3 | 4.4 | 4.2 | 3.7 | 3.6 | 4.2 | 4.0 | 3.9 | 118% |
| Aircraft | 134.6 | 132.0 | 152.2 | 147.7 | 146.3 | 139.4 | 146.8 | 152.7 | 146.6 | 144.9 | 140.9 | 125.2 | 124.8 | 122.1 | 118.5 | 123.1 | 119.7 | -11% |
| General Aviation | 42.9 | 35.8 | 35.9 | 43.7 | 45.1 | 36.9 | 41.9 | 40.1 | 30.1 | 24.4 | 30.5 | 21.2 | 26.7 | 22.5 | 19.9 | 23.6 | 19.7 | -54% |
| Commercial Aircraft | 91.7 | 96.2 | 116.3 | 104.0 | 101.2 | 102.6 | 104.9 | 112.6 | 116.5 | 120.4 | 110.4 | 103.9 | 98.0 | 99.6 | 98.6 | 99.5 | 100.0 | 9% |

| | | | | | | | | | | | | | | | | | | |
|--------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------|
| Recreational Boats | 14.3 | 16.4 | 13.0 | 17.2 | 17.3 | 17.2 | 17.2 | 17.2 | 17.1 | 17.0 | 16.6 | 16.5 | 16.3 | 16.2 | 16.2 | 12.4 | 12.3 | -14% |
| Passenger Rail | 4.4 | 4.5 | 5.2 | 5.4 | 5.1 | 5.8 | 6.0 | 6.2 | 6.0 | 6.6 | 6.2 | 6.1 | 6.2 | 5.9 | 5.5 | 5.8 | 5.8 | 33% |
| Total | 1,155.7 | 1,247.5 | 1,395.7 | 1,407.2 | 1,430.1 | 1,436.5 | 1,466.1 | 1,450.3 | 1,430.8 | 1,401.0 | 1,336.0 | 1,312.4 | 1,299.1 | 1,270.9 | 1,256.1 | 1,249.8 | 1,261.5 | 9% |

^aThe current Inventory includes updated vehicle population data based on the MOVES 2014a Model.

Notes: Data from DOE (1993 through 2015) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates. Updates to the distillate fuel oil heat content data from EIA for years 1993 through present resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory. In 2015, EPA incorporated the NONROAD2008 model into MOVES2014a. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations. In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990-2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes

Table A-118: Greenhouse Gas Emissions from Domestic Freight Transportation (MMT CO₂ Eq.)

| By Mode | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent Change 1990-2014 |
|------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------------------|
| Trucking ^a | 231.1 | 275.9 | 347.5 | 346.1 | 360.0 | 356.6 | 367.7 | 398.2 | 407.4 | 432.0 | 414.2 | 376.3 | 389.7 | 388.4 | 388.7 | 395.7 | 407.4 | 76% |
| Freight Rail | 34.5 | 38.6 | 40.9 | 41.1 | 40.9 | 41.9 | 44.4 | 44.8 | 47.0 | 45.6 | 42.2 | 35.1 | 38.0 | 39.9 | 39.0 | 39.7 | 41.8 | 21% |
| Ships and Other | | | | | | | | | | | | | | | | | | |
| Boats | 30.6 | 42.1 | 48.1 | 25.1 | 29.9 | 19.8 | 22.6 | 27.8 | 31.0 | 37.7 | 28.7 | 22.2 | 28.5 | 30.2 | 23.9 | 15.7 | 6.3 | -80% |
| Pipelines ^b | 36.0 | 38.2 | 35.2 | 34.4 | 36.4 | 32.5 | 31.1 | 32.2 | 32.3 | 34.2 | 35.6 | 36.7 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 | 29% |
| Commercial | | | | | | | | | | | | | | | | | | |
| Aircraft | 19.2 | 20.1 | 24.3 | 21.8 | 21.2 | 21.5 | 21.1 | 21.4 | 21.8 | 20.5 | 18.0 | 16.7 | 16.3 | 16.0 | 15.8 | 15.9 | 16.2 | -15% |
| Total | 351.4 | 415.0 | 496.1 | 468.5 | 488.4 | 472.3 | 487.0 | 524.3 | 539.4 | 570.0 | 538.7 | 487.0 | 509.6 | 512.3 | 507.7 | 513.0 | 518.3 | 47% |

^a The current Inventory includes updated vehicle population data based on the MOVES 2014a Model.

^b Pipelines reflect CO₂ emissions from natural gas powered pipelines transporting natural gas

Note: Data from DOE (1993 through 2015) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

Note: In 2015, EPA incorporated the NONROAD2008 model into MOVES2014a. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2 percent) to the 1999 to 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

Note: In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in this year's inventory and apply to the 1990 to 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

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3.3. Methodology for Estimating Emissions from Commercial Aircraft Jet Fuel Consumption

IPCC Tier 3B Method: Commercial aircraft jet fuel burn and carbon dioxide (CO₂) emissions estimates were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 2000 through 2014 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

International Bunkers: The IPCC guidelines define international aviation (International Bunkers) as emissions from flights that depart from one country and arrive in a different country. Bunker fuel emissions estimates for commercial aircraft were developed for this report for 2000 through 2014 using the same radar-informed data modeled with AEDT. Since this process builds estimates from flight-specific information, the emissions estimates for commercial aircraft can include emissions associated with the U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands). However, to allow for the alignment of emissions estimates for commercial aircraft with other data that is provided without the U.S. Territories, this annex includes emissions estimates for commercial aircraft both with and without the U.S. Territories included.

Time Series and Analysis Update: The FAA incrementally improves the consistency, robustness, and fidelity of the CO₂ emissions modeling for commercial aircraft, which is the basis of the Tier 3B inventories presented in this report. While the FAA does not anticipate significant changes to the AEDT model in the future, recommended improvements are limited by budget and time constraints, as well as data availability. For instance, previous reports included reported annual CO₂ emission estimates for 2000 through 2005 that were modeled using the FAA's System for assessing Aviation's Global Emissions (SAGE). That tool and its capabilities were significantly improved after it was incorporated and evolved into AEDT. For this report, the AEDT model was used to generate annual CO₂ emission estimates for 2000, 2005, 2010, 2011, 2012, 2013 and 2014 only. The reported annual CO₂ emissions values for 2001 through 2004 were estimated from the previously reported SAGE data. Likewise, CO₂ emissions values for 2006 through 2009 were estimated by interpolation to preserve trends from past reports.

Commercial aircraft radar data sets are not available for years prior to 2000. Instead, the FAA applied a Tier3B methodology by developing Official Airline Guide (OAG) schedule-informed estimates modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. The ratios between the OAG schedule-informed and the radar-informed inventories for the years 2000 and 2010 were applied to the 1990 OAG scheduled-informed inventory to generate the best possible CO₂ inventory estimate for commercial aircraft in 1990. The resultant 1990 CO₂ inventory served as the reference for generating the additional 1991-1999 emissions estimates, which were established using previously available trends.

Notes on the 1990 CO₂ Emissions Inventory for Commercial Aircraft: There are uncertainties associated with the modeled 1990 data that do not exist for the modeled 2000 to 2014 data. Radar-based data is not available for 1990. The OAG schedule information generally includes fewer carriers than radar information, and this will result in a different fleet mix, and in turn, different CO₂ emissions than would be quantified using a radar-based data set. For this reason, the FAA adjusted the OAG-informed schedule for 1990 with a ratio based on radar-informed information. In addition, radar trajectories are also generally longer than great circle trajectories. While the 1990 fuel burn data was adjusted to address these differences, it inherently adds greater uncertainty to the revised 1990 commercial aircraft CO₂ emissions as compared to data from 2000 forward. Also, the revised 1990 CO₂ emissions inventory now reflects only commercial aircraft jet fuel consumption, while previous reports may have aggregated jet fuel sales data from non-commercial aircraft into this category. Thus, it would be inappropriate to compare 1990 to future years for other than qualitative purposes.

The 1990 commercial aircraft CO₂ emissions estimate is approximately 5 percent lower than the 2014 CO₂ emissions estimate. It is important to note that the distance flown increased by more than 40 percent over this 25-year period

and that fuel burn and aviation activity trends over the past two decades indicate significant improvements in commercial aviation's ability to provide increased service levels while using less fuel.⁵⁷

Methane Emissions: Contributions of methane (CH₄) emissions from commercial aircraft are reported as zero. Years of scientific measurement campaigns conducted at the exhaust exit plane of commercial aircraft gas turbine engines have repeatedly indicated that CH₄ emissions are consumed over the full mission flight envelope (Santoni et al. 2011). As a result, the U.S. EPA published that "...methane is no longer considered to be an emission from aircraft gas turbine engines burning Jet A at higher power settings and is, in fact, consumed in net at these higher powers."⁵⁸ In accordance with the following statements in the 2006 IPCC Guidelines (IPCC 2006), the FAA does not calculate CH₄ emissions for either the domestic or international bunker commercial aircraft jet fuel emissions inventories. "*Methane (CH₄) may be emitted by gas turbines during idle and by older technology engines, but recent data suggest that little or no CH₄ is emitted by modern engines.*" "*Current scientific understanding does not allow other gases (e.g., N₂O and CH₄) to be included in calculation of cruise emissions.*" (IPCC 1999).

Results: For each inventory calendar year the graph and table below include four jet fuel burn values. These values are comprised of domestic and international fuel burn totals for the U.S. 50 States and the U.S. 50 States + Territories. Data are presented for domestic defined as jet fuel burn from any commercial aircraft flight departing and landing in the U.S. 50 States and for the U.S. 50 States + Territories. The data presented as international is respective of the two different domestic definitions, and represents flights departing from the specified domestic area and landing anywhere in the world outside of that area.

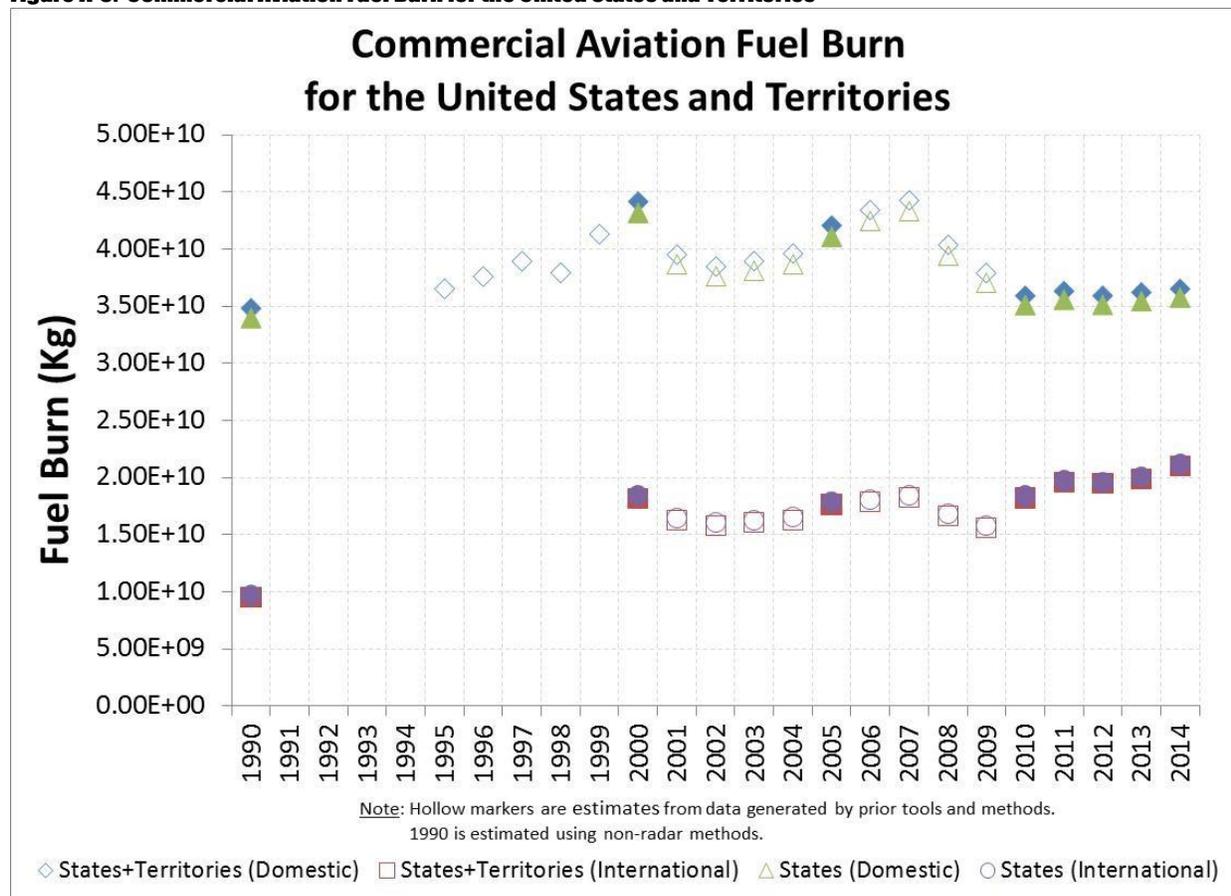
Note that the graph and table present less fuel burn for the international U.S. 50 States + Territories than for the international U.S. 50 States. This is because the flights between the 50 states and U.S. Territories are "international" when only the 50 states are defined as domestic, but they are "domestic" for the U.S. 50 States + Territories definition.

⁵⁷ Additional information on the AEDT modeling process is available at:

http://www.faa.gov/about/office_org/headquarters_offices/apl/research/models/

⁵⁸ Recommended Best Practice for Quantifying Speciated Organic Gas Emissions from Aircraft Equipped with Turbofan, Turbojet and Turboprop Engines, EPA-420-R-09-901, May 27, 2009. See <<http://www.epa.gov/otaq/aviation.html>>.

Figure A-5: Commercial Aviation Fuel Burn for the United States and Territories



Note: Hollow markers are estimates from data generated by prior tools and methods. 1990 is estimated using non-radar methods.

Table A-119: Commercial Aviation Fuel Burn for the United States and Territories

| Year | Region | Distance Flown (nmi) | Fuel Burn (M Gallon) | Fuel Burn (Tbtu) | Fuel Burn (Kg) | CO ₂ (MMT) |
|-------|---|----------------------|----------------------|------------------|----------------|-----------------------|
| 1990 | Domestic U.S. 50 States and U.S. Territories | 4,057,195,988 | 11,568 | 1,562 | 34,820,800,463 | 109.9 |
| | International U.S. 50 States and U.S. Territories | 599,486,893 | 3,155 | 426 | 9,497,397,919 | 30.0 |
| | Domestic U.S. 50 States | 3,984,482,217 | 11,287 | 1,524 | 33,972,832,399 | 107.2 |
| | International U.S. 50 States | 617,671,849 | 3,228 | 436 | 9,714,974,766 | 30.7 |
| 1995* | Domestic U.S. 50 States and U.S. Territories | N/A | 12,136 | 1,638 | 36,528,990,675 | 115.2 |
| 1996* | Domestic U.S. 50 States and U.S. Territories | N/A | 12,492 | 1,686 | 37,600,624,534 | 118.6 |
| 1997* | Domestic U.S. 50 States and U.S. Territories | N/A | 12,937 | 1,747 | 38,940,896,854 | 122.9 |
| 1998* | Domestic U.S. 50 States and U.S. Territories | N/A | 12,601 | 1,701 | 37,930,582,643 | 119.7 |
| 1999* | Domestic U.S. 50 States and U.S. Territories | N/A | 13,726 | 1,853 | 41,314,843,250 | 130.3 |
| 2000 | Domestic U.S. 50 States and U.S. Territories | 5,994,679,944 | 14,672 | 1,981 | 44,161,841,348 | 139.3 |
| | International U.S. 50 States and U.S. Territories | 1,309,565,963 | 6,040 | 815 | 18,181,535,058 | 57.4 |
| | Domestic U.S. 50 States | 5,891,481,028 | 14,349 | 1,937 | 43,191,000,202 | 136.3 |
| | International U.S. 50 States | 1,331,784,289 | 6,117 | 826 | 18,412,169,613 | 58.1 |
| 2001* | Domestic U.S. 50 States and U.S. Territories | 5,360,977,447 | 13,121 | 1,771 | 39,493,457,147 | 124.6 |
| | International U.S. 50 States and U.S. Territories | 1,171,130,679 | 5,402 | 729 | 16,259,550,186 | 51.3 |
| | Domestic U.S. 50 States | 5,268,687,772 | 12,832 | 1,732 | 38,625,244,409 | 121.9 |
| | International U.S. 50 States | 1,191,000,288 | 5,470 | 739 | 16,465,804,174 | 51.9 |
| 2002* | Domestic U.S. 50 States and U.S. Territories | 5,219,345,344 | 12,774 | 1,725 | 38,450,076,259 | 121.3 |
| | International U.S. 50 States and U.S. Territories | 1,140,190,481 | 5,259 | 710 | 15,829,987,794 | 49.9 |

| | | | | | | |
|-------|---|---------------|--------|-------|----------------|-------|
| | Domestic U.S. 50 States | 5,129,493,877 | 12,493 | 1,687 | 37,604,800,905 | 118.6 |
| | International U.S. 50 States | 1,159,535,153 | 5,326 | 719 | 16,030,792,741 | 50.6 |
| 2003* | Domestic U.S. 50 States and U.S. Territories | 5,288,138,079 | 12,942 | 1,747 | 38,956,861,262 | 122.9 |
| | International U.S. 50 States and U.S. Territories | 1,155,218,577 | 5,328 | 719 | 16,038,632,384 | 50.6 |
| | Domestic U.S. 50 States | 5,197,102,340 | 12,658 | 1,709 | 38,100,444,893 | 120.2 |
| | International U.S. 50 States | 1,174,818,219 | 5,396 | 728 | 16,242,084,008 | 51.2 |
| 2004* | Domestic U.S. 50 States and U.S. Territories | 5,371,498,689 | 13,146 | 1,775 | 39,570,965,441 | 124.8 |
| | International U.S. 50 States and U.S. Territories | 1,173,429,093 | 5,412 | 731 | 16,291,460,535 | 51.4 |
| | Domestic U.S. 50 States | 5,279,027,890 | 12,857 | 1,736 | 38,701,048,784 | 122.1 |
| | International U.S. 50 States | 1,193,337,698 | 5,481 | 740 | 16,498,119,309 | 52.1 |
| 2005 | Domestic U.S. 50 States and U.S. Territories | 6,476,007,697 | 13,976 | 1,887 | 42,067,562,737 | 132.7 |
| | International U.S. 50 States and U.S. Territories | 1,373,543,928 | 5,858 | 791 | 17,633,508,081 | 55.6 |
| | Domestic U.S. 50 States | 6,370,544,998 | 13,654 | 1,843 | 41,098,359,387 | 129.7 |
| | International U.S. 50 States | 1,397,051,323 | 5,936 | 801 | 17,868,972,965 | 56.4 |
| 2006* | Domestic U.S. 50 States and U.S. Territories | 5,894,323,482 | 14,426 | 1,948 | 43,422,531,461 | 137.0 |
| | International U.S. 50 States and U.S. Territories | 1,287,642,623 | 5,939 | 802 | 17,877,159,421 | 56.4 |
| | Domestic U.S. 50 States | 5,792,852,211 | 14,109 | 1,905 | 42,467,943,091 | 134.0 |
| | International U.S. 50 States | 1,309,488,994 | 6,015 | 812 | 18,103,932,940 | 57.1 |
| 2007* | Domestic U.S. 50 States and U.S. Territories | 6,009,247,818 | 14,707 | 1,986 | 44,269,160,525 | 139.7 |
| | International U.S. 50 States and U.S. Territories | 1,312,748,383 | 6,055 | 817 | 18,225,718,619 | 57.5 |
| | Domestic U.S. 50 States | 5,905,798,114 | 14,384 | 1,942 | 43,295,960,105 | 136.6 |
| | International U.S. 50 States | 1,335,020,703 | 6,132 | 828 | 18,456,913,646 | 58.2 |
| 2008* | Domestic U.S. 50 States and U.S. Territories | 5,475,092,456 | 13,400 | 1,809 | 40,334,124,033 | 127.3 |
| | International U.S. 50 States and U.S. Territories | 1,196,059,638 | 5,517 | 745 | 16,605,654,741 | 52.4 |
| | Domestic U.S. 50 States | 5,380,838,282 | 13,105 | 1,769 | 39,447,430,318 | 124.5 |
| | International U.S. 50 States | 1,216,352,196 | 5,587 | 754 | 16,816,299,099 | 53.1 |
| 2009* | Domestic U.S. 50 States and U.S. Territories | 5,143,268,671 | 12,588 | 1,699 | 37,889,631,668 | 119.5 |
| | International U.S. 50 States and U.S. Territories | 1,123,571,175 | 5,182 | 700 | 15,599,251,424 | 49.2 |
| | Domestic U.S. 50 States | 5,054,726,871 | 12,311 | 1,662 | 37,056,676,966 | 116.9 |
| | International U.S. 50 States | 1,142,633,881 | 5,248 | 709 | 15,797,129,457 | 49.8 |
| 2010 | Domestic U.S. 50 States and U.S. Territories | 5,652,264,576 | 11,931 | 1,611 | 35,912,723,830 | 113.3 |
| | International U.S. 50 States and U.S. Territories | 1,474,839,733 | 6,044 | 816 | 18,192,953,916 | 57.4 |
| | Domestic U.S. 50 States | 5,554,043,585 | 11,667 | 1,575 | 35,116,863,245 | 110.8 |
| | International U.S. 50 States | 1,497,606,695 | 6,113 | 825 | 18,398,996,825 | 58.0 |
| 2011 | Domestic U.S. 50 States and U.S. Territories | 5,767,378,664 | 12,067 | 1,629 | 36,321,170,730 | 114.6 |
| | International U.S. 50 States and U.S. Territories | 1,576,982,962 | 6,496 | 877 | 19,551,631,939 | 61.7 |
| | Domestic U.S. 50 States | 5,673,689,481 | 11,823 | 1,596 | 35,588,754,827 | 112.3 |
| | International U.S. 50 States | 1,596,797,398 | 6,554 | 885 | 19,727,043,614 | 62.2 |
| 2012 | Domestic U.S. 50 States and U.S. Territories | 5,735,605,432 | 11,932 | 1,611 | 35,915,745,616 | 113.3 |
| | International U.S. 50 States and U.S. Territories | 1,619,012,587 | 6,464 | 873 | 19,457,378,739 | 61.4 |
| | Domestic U.S. 50 States | 5,636,910,529 | 11,672 | 1,576 | 35,132,961,140 | 110.8 |
| | International U.S. 50 States | 1,637,917,110 | 6,507 | 879 | 19,587,140,347 | 61.8 |
| 2013 | Domestic U.S. 50 States and U.S. Territories | 5,808,034,123 | 12,031 | 1,624 | 36,212,974,471 | 114.3 |
| | International U.S. 50 States and U.S. Territories | 1,641,151,400 | 6,611 | 892 | 19,898,871,458 | 62.8 |
| | Domestic U.S. 50 States | 5,708,807,315 | 11,780 | 1,590 | 35,458,690,595 | 111.9 |
| | International U.S. 50 States | 1,661,167,498 | 6,657 | 899 | 20,036,865,038 | 63.2 |
| 2014 | Domestic U.S. 50 States and U.S. Territories | 5,825,999,388 | 12,131 | 1,638 | 36,514,970,659 | 115.2 |
| | International U.S. 50 States and U.S. Territories | 1,724,559,209 | 6,980 | 942 | 21,008,818,741 | 66.3 |
| | Domestic U.S. 50 States | 5,725,819,482 | 11,882 | 1,604 | 35,764,791,774 | 112.8 |
| | International U.S. 50 States | 1,745,315,059 | 7,027 | 949 | 21,152,418,387 | 66.7 |

*Estimates for these years were derived from previously reported tools and methods

3.4. Methodology for Estimating CH₄ Emissions from Coal Mining

The methodology for estimating CH₄ emissions from coal mining consists of two steps:

- **Estimate emissions from underground mines.** These emissions have two sources: ventilation systems and degasification systems. They are estimated on a mine-by-mine basis, then summed to determine total CH₄ liberated. The CH₄ recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- **Estimate CH₄ emissions from surface mines and post-mining activities.** This step does not use mine-specific data; rather, it consists of multiplying coal-basin-specific coal production by coal-basin-specific gas content and an emission factor.

Step 1: Estimate CH₄ Liberated and CH₄ Emitted from Underground Mines

Underground mines generate CH₄ from ventilation systems and from degasification systems. Some mines recover and use the generated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted from underground mines equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from degasification systems, minus CH₄ recovered and used.

Step 1.1: Estimate CH₄ Liberated from Ventilation Systems

All coal mines with detectable CH₄ emissions use ventilation systems to ensure that CH₄ levels remain within safe concentrations. Many coal mines do not have detectable levels of CH₄; others emit several million cubic feet per day (MMCFD) from their ventilation systems. On a quarterly basis, the U.S. Mine Safety and Health Administration (MSHA) measures CH₄ emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of CH₄ in their ventilation air (MSHA 2015).⁵⁹ Based on the four quarterly measurements, MSHA estimates average daily CH₄ liberated at each of these underground mines.

For 1990 through 1999, average daily CH₄ emissions from MSHA were multiplied by the number of days in the year (i.e., coal mine assumed in operation for all four quarters) to determine the annual emissions for each mine. For 2000 through 2014, the average daily CH₄ emissions were multiplied by the number of days corresponding to the number of quarters the mine vent was operating. For example, if the mine vent was operational in one out of the four quarters, the average daily CH₄ emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

Since 2011, the nation's "gassiest" underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH₄ per year (about 14,700 MT CO₂ eq.)—have been required to report to the EPA's GHGRP (EPA 2015).⁶⁰ Mines that report to the GHGRP must report quarterly measurements of CH₄ emissions from ventilation systems to EPA; they have the option of recording their own measurements, or using the measurements taken by MSHA as part of that agency's quarterly safety inspections of all mines in the U.S. with detectable CH₄ concentrations.⁶¹

Since 2013, ventilation emission estimates have been calculated based on both GHGRP data submitted by underground mines that recorded their own measurements, and on quarterly measurement data obtained directly from MSHA for the remaining mines (not MSHA data reported by the mines to the GHGRP).⁶² The quarterly measurements are used to determine the average daily emissions rate for the reporting year quarter. The CH₄ liberated from ventilation systems was estimated by summing the emissions from the GHGRP self-reported mines and emissions based on MSHA quarterly measurements for the remaining mines.

⁵⁹ MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

⁶⁰ Underground coal mines report to EPA under Subpart FF of the GHGRP. In 2014, 128 underground coal mines reported to the program.

⁶¹ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

⁶² EPA has determined that certain mines are having difficulty interpreting the MSHA data so that they report them correctly to the GHGRP. EPA is working with these mines to correct their GHGRP reports, and in the meantime is relying on data obtained directly from MSHA for purposes of the national inventory.

Table A-120: Mine-Specific Data Used to Estimate Ventilation Emissions

| Year | Individual Mine Data Used |
|------|--|
| 1990 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 1991 | 1990 Emissions Factors Used Instead of Mine-Specific Data |
| 1992 | 1990 Emissions Factors Used Instead of Mine-Specific Data |
| 1993 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 1994 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 1995 | All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)* |
| 1996 | All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)* |
| 1997 | All Mines with Detectable Emissions (Assumed to Account for 100% of Total) |
| 1998 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 1999 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2000 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2001 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2002 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2003 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2004 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2005 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2006 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)* |
| 2007 | All Mines with Detectable Emissions (Assumed to Account for 100% of Total) |
| 2008 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)** |
| 2009 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)** |
| 2010 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)** |
| 2011 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)** |
| 2012 | All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)** |
| 2013 | All Mines with Detectable Emissions and GHGRP reported data (Assumed to account for 100% of Total) |
| 2014 | All Mines with Detectable Emissions and GHGRP reported data (Assumed to account for 100% of Total) |

* Factor derived from a complete set of individual mine data collected for 1997.

** Factor derived from a complete set of individual mine data collected for 2007.

Step 1.2: Estimate CH₄ Liberated from Degasification Systems

Coal mines use several types of degasification systems to remove CH₄, including pre-mining vertical and horizontal wells (to recover CH₄ before mining) and post-mining vertical wells and horizontal boreholes (to recover CH₄ during mining of the coal seam). Post-mining gob wells and cross-measure boreholes recover CH₄ from the overburden (i.e., gob area) after mining of the seam (primarily in longwall mines).

Twenty-five mines employed degasification systems in 2014, and the CH₄ liberated through these systems was reported to the EPA's GHGRP (EPA 2015). Sixteen of these mines reported CH₄ recovery and use projects, and the other nine reported emitting CH₄ from degasification systems to the atmosphere. Several of the mines venting CH₄ from degasification systems use a small portion of the gas to fuel gob well blowers or compressors in remote locations where electricity is not available. However, this CH₄ use is not considered to be a formal recovery and use project.

Degasification information reported to the GHGRP by underground coal mines is the primary source of data used to develop estimates of CH₄ liberated from degasification systems. Data reported to the GHGRP were used to estimate CH₄ liberated from degasification systems at 20 of the 25 mines that used degasification systems in 2014.

Degasification volumes for the life of any pre-mining wells are attributed to the mine as emissions in the year in which the well is mined through.⁶³ The GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under subpart FF. Most pre-mining wells drilled from the surface are considered coalbed methane wells and are reported under another subpart of the program (subpart W, "Petroleum and Natural Gas Systems"). As a result, for the 10 mines with degasification systems that include pre-mining wells, GHGRP information was supplemented with historical data from state gas well production databases (GSA 2016; WVGES 2015), as well as with mine-specific information regarding the dates on which pre-mining wells are mined through (JWR 2010; El Paso 2009). For pre-mining wells, the cumulative CH₄ production from the well is totaled using gas sales data, and considered liberated from the mine's degasification system the year in which the well is mined through.

⁶³ A well is "mined through" when coal mining development or the working face intersects the borehole or well.

EPA's GHGRP reports with CH₄ liberated from degasification systems are reviewed for errors in reporting. For some mines, GHGRP data are corrected for the inventory based on expert judgment. Common errors include reporting CH₄ liberated as CH₄ destroyed and vice versa. Other errors include reporting CH₄ destroyed without reporting any CH₄ liberated by degasification systems. In the rare cases where GHGRP data are inaccurate and gas sales data unavailable, estimates of CH₄ liberated are based on historical CH₄ liberation rates.

Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Of the 16 active coal mines with operational CH₄ recovery and use projects in 2014, 14 sold the recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. Uses at other mines include electrical power generation (one mine) and heating mine ventilation air (one mine).

Ten of the 16 mines deployed degasification systems in 2014; for those mines, estimates of CH₄ recovered from the systems were exclusively based on GHGRP data. Based on weekly measurements of gas flow and CH₄ concentrations, the GHGRP summary data for degasification destruction at each mine were added together to estimate the CH₄ recovered and used from degasification systems.

Of the 10 mines with degasification systems in 2014, four intersected pre-mining wells in 2014. GHGRP and supplemental data were used to estimate CH₄ recovered and used at two of these mines, while supplemental data alone were used at the other two mines, that reported as a single entity to the GHGRP. Supplemental information was used for these four mines because estimating CH₄ recovery and use from pre-mining wells requires additional data (not reported under subpart FF of the GHGRP; see discussion in step 1.2 above) to account for the emissions avoided. The supplemental data came from state gas production databases (GSA 2016; WVGES 2015), as well as mine-specific information on the timing of mined-through pre-mining wells (JWR 2010; El Paso 2009). For pre-mining wells, the cumulative CH₄ production from the wells was totaled using gas sales data, and considered to be CH₄ recovered and used from the mine's degasification system the year in which the well is mined through.

EPA's GHGRP reports with CH₄ recovered and used from degasification systems are reviewed for errors in reporting. For some mines, GHGRP data are corrected for the inventory based on expert judgment (see further discussion in Step 1.2). In 2014, GHGRP information was not used to estimate CH₄ recovered and used at two mines because of a lack of mine-provided information used in prior years and GHGRP reporting discrepancies.

In 2014, one mine destroyed a portion of its CH₄ emissions from ventilation systems using thermal oxidation technology. The amount of CH₄ recovered and destroyed by the project was determined through publicly available emission reduction project information (CAR 2015).

Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH₄ emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's *Annual Coal Report* was multiplied by basin-specific gas contents and a 150 percent emission factor (to account for CH₄ from over- and under-burden) to estimate CH₄ emissions (see King 1994; Saghafi 2013). For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a mid-range 32.5 percent emission factor accounting for CH₄ desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data were compiled from AAPG (1984) and USBM (1986). Beginning in 2006, revised data on *in situ* CH₄ content and emissions factors have been used (EPA 1996, 2005).

Step 2.1: Define the Geographic Resolution of the Analysis and Collect Coal Production Data

The first step in estimating CH₄ emissions from surface mining and post-mining activities was to define the geographic resolution of the analysis and to collect coal production data at that level of resolution. The analysis was conducted by coal basin as defined in Table A-121, which presents coal basin definitions by basin and by state.

The Energy Information Administration's *Annual Coal Report* (EIA 2015) includes state- and county-specific underground and surface coal production by year. To calculate production by basin, the state level data were grouped into coal basins using the basin definitions listed in Table A-121. For two states—West Virginia and Kentucky—county-level production data were used for the basin assignments because coal production occurred in geologically distinct coal basins within these states. Table A-122 presents the coal production data aggregated by basin.

Step 2.2: Estimate Emissions Factors for Each Emissions Type

Emission factors for surface-mined coal were developed from the *in situ* CH₄ content of the surface coal in each basin. Based on analyses conducted in Canada and Australia on coals similar to those present in the U.S. (King 1994; Saghafi 2013), the surface mining emission factor used was conservatively estimated to be 150 percent of the *in situ* CH₄ content of the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* CH₄ content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* CH₄ content in the basin. Table A-123 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate CH₄ Emitted

The total amount of CH₄ emitted from surface mines and post-mining activities was calculated by multiplying the coal production in each basin by the appropriate emission factors.

Table A-121 lists each of the major coal mine basins in the United States and the states in which they are located. As shown in Figure A-6, several coal basins span several states. Table A-122 shows annual underground, surface, and total coal production (in short tons) for each coal basin. Table A-123 shows the surface, post-surface, and post-underground emission factors used for estimating CH₄ emissions for each of the categories. Table A-124 presents annual estimates of CH₄ emissions for ventilation and degasification systems, and CH₄ used and emitted by underground coal mines. Table A-125 presents annual estimates of total CH₄ emissions from underground, post-underground, surface, and post-surface activities. Table A-126 provides the total net CH₄ emissions by state.

Table A-121: Coal Basin Definitions by Basin and by State

| Basin | States |
|------------------------------|--|
| Northern Appalachian Basin | Maryland, Ohio, Pennsylvania, West Virginia North |
| Central Appalachian Basin | Kentucky East, Tennessee, Virginia, West Virginia South |
| Warrior Basin | Alabama, Mississippi |
| Illinois Basin | Illinois, Indiana, Kentucky West |
| South West and Rockies Basin | Arizona, California, Colorado, New Mexico, Utah |
| North Great Plains Basin | Montana, North Dakota, Wyoming |
| West Interior Basin | Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas |
| Northwest Basin | Alaska, Washington |
| State | Basin |
| Alabama | Warrior Basin |
| Alaska | Northwest Basin |
| Arizona | South West and Rockies Basin |
| Arkansas | West Interior Basin |
| California | South West and Rockies Basin |
| Colorado | South West and Rockies Basin |
| Illinois | Illinois Basin |
| Indiana | Illinois Basin |
| Iowa | West Interior Basin |
| Kansas | West Interior Basin |
| Kentucky (east) | Central Appalachian Basin |
| Kentucky (west) | Illinois Basin |
| Louisiana | West Interior Basin |
| Maryland | Northern Appalachian Basin |
| Mississippi | Warrior Basin |
| Missouri | West Interior Basin |
| Montana | North Great Plains Basin |
| New Mexico | South West and Rockies Basin |
| North Dakota | North Great Plains Basin |
| Ohio | Northern Appalachian Basin |
| Oklahoma | West Interior Basin |
| Pennsylvania | Northern Appalachian Basin |
| Tennessee | Central Appalachian Basin |
| Texas | West Interior Basin |
| Utah | South West and Rockies Basin |
| Virginia | Central Appalachian Basin |
| Washington | Northwest Basin |
| West Virginia South | Central Appalachian Basin |

West Virginia North
Wyoming

Northern Appalachian Basin
North Great Plains Basin

Figure A-6: Locations of U.S. Coal Basins

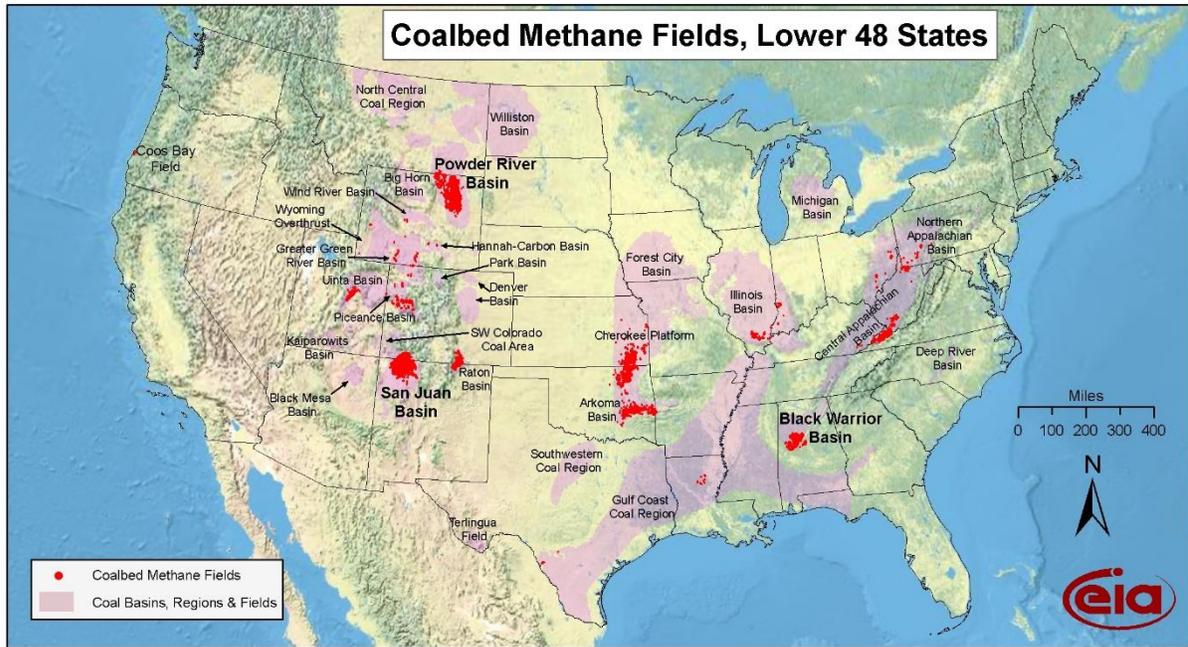


Table A-122: Annual Coal Production (Thousand Short Tons)

| Basin | 1990 | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|----------------|----------------|
| Underground Coal Production | 423,556 | 368,611 | 357,074 | 332,061 | 337,155 | 345,607 | 342,387 | 341,216 | 354,705 |
| N. Appalachia | 103,865 | 111,151 | 105,228 | 99,629 | 103,109 | 105,752 | 103,408 | 104,198 | 116,700 |
| Cent. Appalachia | 198,412 | 123,083 | 114,998 | 98,689 | 96,354 | 94,034 | 78,067 | 70,440 | 64,219 |
| Warrior | 17,531 | 13,295 | 12,281 | 11,505 | 12,513 | 10,879 | 12,570 | 13,391 | 12,516 |
| Illinois | 69,167 | 59,180 | 64,609 | 67,186 | 72,178 | 81,089 | 92,500 | 98,331 | 105,211 |
| S. West/Rockies | 32,754 | 60,865 | 55,781 | 50,416 | 44,368 | 45,139 | 45,052 | 41,232 | 44,302 |
| N. Great Plains | 1,722 | 572 | 3,669 | 4,248 | 8,208 | 8,179 | 10,345 | 13,126 | 11,272 |
| West Interior | 105 | 465 | 508 | 388 | 425 | 535 | 445 | 498 | 485 |
| Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Surface Coal Production | 602,753 | 762,191 | 813,321 | 740,175 | 764,709 | 754,871 | 672,748 | 640,740 | 643,721 |
| N. Appalachia | 60,761 | 28,873 | 30,413 | 26,552 | 26,082 | 26,382 | 21,411 | 19,339 | 17,300 |
| Cent. Appalachia | 94,343 | 112,222 | 118,962 | 97,778 | 89,788 | 90,778 | 69,721 | 57,173 | 52,399 |
| Warrior | 11,413 | 11,599 | 11,172 | 10,731 | 11,406 | 10,939 | 9,705 | 8,695 | 7,584 |
| Illinois | 72,000 | 33,702 | 34,266 | 34,837 | 32,911 | 34,943 | 34,771 | 33,798 | 31,969 |
| S. West/Rockies | 43,863 | 42,756 | 34,283 | 32,167 | 28,889 | 31,432 | 30,475 | 28,968 | 27,564 |
| N. Great Plains | 249,356 | 474,056 | 538,387 | 496,290 | 507,995 | 502,734 | 455,320 | 444,740 | 458,112 |
| West Interior | 64,310 | 52,263 | 44,361 | 39,960 | 46,136 | 55,514 | 49,293 | 46,477 | 47,201 |
| Northwest | 6,707 | 6,720 | 1,477 | 1,860 | 2,151 | 2,149 | 2,052 | 1,550 | 1,502 |
| Total Coal Production | 1,026,309 | 1,130,802 | 1,170,395 | 1,072,236 | 1,101,864 | 1,100,478 | 1,015,135 | 981,956 | 998,426 |
| N. Appalachia | 164,626 | 140,024 | 135,641 | 126,181 | 129,191 | 132,134 | 124,819 | 123,537 | 134,000 |
| Cent. Appalachia | 292,755 | 235,305 | 233,960 | 196,467 | 186,142 | 184,812 | 147,788 | 127,613 | 116,618 |
| Warrior | 28,944 | 24,894 | 23,453 | 22,236 | 23,919 | 21,818 | 22,275 | 22,086 | 20,100 |
| Illinois | 141,167 | 92,882 | 98,875 | 102,023 | 105,089 | 116,032 | 127,271 | 132,129 | 137,180 |
| S. West/Rockies | 76,617 | 103,621 | 90,064 | 82,583 | 73,257 | 76,571 | 75,527 | 70,200 | 71,956 |
| N. Great Plains | 251,078 | 474,628 | 542,056 | 500,538 | 516,203 | 510,913 | 465,665 | 457,866 | 469,384 |
| West Interior | 64,415 | 52,728 | 44,869 | 40,348 | 46,561 | 56,049 | 49,738 | 46,975 | 47,686 |
| Northwest | 6,707 | 6,720 | 1,477 | 1,860 | 2,151 | 2,149 | 2,052 | 1,550 | 1,502 |

Source for 1990–2014 data: EIA (1990 through 2014), *Annual Coal Report*. Table 1. U.S. Department of Energy. Source for 2014 data: spreadsheet for the 2014 *Annual Coal Report*.

Note: Totals may not sum due to independent rounding.

Table A-123: Coal Underground, Surface, and Post-Mining CH₄ Emission Factors (ft³ per Short Ton)

| Basin | Surface Average In Situ Content | Underground Average In Situ Content | Surface Mine Factors | Post-Mining Surface Factors | Post Mining Underground |
|--|------------------------------------|--|-------------------------|--------------------------------|----------------------------|
| Northern Appalachia | 59.5 | 138.4 | 89.3 | 19.3 | 45.0 |
| Central Appalachia (WV) | 24.9 | 136.8 | 37.4 | 8.1 | 44.5 |
| Central Appalachia (VA) | 24.9 | 399.1 | 37.4 | 8.1 | 129.7 |
| Central Appalachia (E KY) | 24.9 | 61.4 | 37.4 | 8.1 | 20.0 |
| Warrior | 30.7 | 266.7 | 46.1 | 10.0 | 86.7 |
| Illinois | 34.3 | 64.3 | 51.5 | 11.1 | 20.9 |
| Rockies (Piceance Basin) | 33.1 | 196.4 | 49.7 | 10.8 | 63.8 |
| Rockies (Uinta Basin) | 16.0 | 99.4 | 24.0 | 5.2 | 32.3 |
| Rockies (San Juan Basin) | 7.3 | 104.8 | 11.0 | 2.4 | 34.1 |
| Rockies (Green River Basin) | 33.1 | 247.2 | 49.7 | 10.8 | 80.3 |
| Rockies (Raton Basin) | 33.1 | 127.9 | 49.7 | 10.8 | 41.6 |
| N. Great Plains (WY, MT) | 20.0 | 15.8 | 30.0 | 6.5 | 5.1 |
| N. Great Plains (ND) | 5.6 | 15.8 | 8.4 | 1.8 | 5.1 |
| West Interior (Forest City, Cherokee Basins) | 34.3 | 64.3 | 51.5 | 11.1 | 20.9 |
| West Interior (Arkoma Basin) | 74.5 | 331.2 | 111.8 | 24.2 | 107.6 |
| West Interior (Gulf Coast Basin) | 11.0 | 127.9 | 16.5 | 3.6 | 41.6 |
| Northwest (AK) | 16.0 | 160.0 | 24.0 | 1.8 | 52.0 |
| Northwest (WA) | 16.0 | 47.3 | 24.0 | 5.2 | 15.4 |

Sources: 1986 USBM Circular 9067, *Results of the Direct Method Determination of the Gas Contents of U.S. Coal Basins*; U.S. DOE Report DOE/METC/83-76, *Methane Recovery from Coalbeds: A Potential Energy Source*; 1986–1988 Gas Research Institute Topical Report, *A Geologic Assessment of Natural Gas from Coal Seams*; 2005 U.S. EPA Draft Report, *Surface Mines Emissions Assessment*.

Table A-124: Underground Coal Mining CH₄ Emissions (Billion Cubic Feet)

| Activity | 1990 | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------------|------------|-----------|------------|------------|------------|------------|-----------|-----------|------------|
| Ventilation Output | 112 | 75 | 100 | 114 | 117 | 97 | 90 | 89 | 89 |
| Adjustment Factor for Mine Data* | 98% | 98% | 99% | 99% | 99% | 99% | 99% | 100% | 100% |
| Adjusted Ventilation Output | 114 | 77 | 101 | 115 | 118 | 98 | 91 | 89 | 89 |
| Degasification System Liberated | 54 | 48 | 49 | 49 | 58 | 48 | 45 | 48 | 48 |
| Total Underground Liberated | 168 | 124 | 150 | 163 | 177 | 147 | 137 | 137 | 136 |
| Recovered & Used | (14) | (37) | (40) | (40) | (49) | (42) | (38) | (41) | (34) |
| Total | 154 | 87 | 110 | 123 | 128 | 104 | 98 | 96 | 102 |

* Refer to Table A-120.

Note: Totals may not sum due to independent rounding.

Table A-125: Total Coal Mining CH₄ Emissions (Billion Cubic Feet)

| Activity | 1990 | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| Underground Mining | 154 | 87 | 110 | 123 | 128 | 104 | 98 | 96 | 102 |
| Surface Mining | 22 | 25 | 27 | 24 | 24 | 24 | 21 | 20 | 20 |
| Post-Mining (Underground) | 19 | 16 | 15 | 14 | 14 | 14 | 14 | 14 | 14 |
| Post-Mining (Surface) | 5 | 5 | 6 | 5 | 5 | 5 | 5 | 4 | 4 |
| Total | 200 | 132 | 157 | 166 | 171 | 148 | 138 | 134 | 140 |

Note: Totals may not sum due to independent rounding.

Table A-126: Total Coal Mining CH₄ Emissions by State (Million Cubic Feet)

| State | 1990 | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| Alabama | 32,097 | 15,789 | 20,992 | 22,119 | 21,377 | 18,530 | 18,129 | 17,486 | 16,301 |
| Alaska | 50 | 42 | 43 | 54 | 63 | 63 | 60 | 45 | 44 |
| Arizona | 151 | 161 | 107 | 100 | 103 | 108 | 100 | 101 | 107 |
| Arkansas | 5 | + | 237 | 119 | 130 | 348 | 391 | 214 | 176 |
| California | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Colorado | 10,187 | 13,441 | 12,871 | 13,999 | 16,470 | 11,187 | 9,305 | 4,838 | 4,038 |
| Illinois | 10,180 | 6,488 | 7,568 | 7,231 | 8,622 | 7,579 | 9,763 | 8,920 | 9,217 |
| Indiana | 2,232 | 3,303 | 5,047 | 5,763 | 5,938 | 6,203 | 7,374 | 6,427 | 7,159 |
| Iowa | 24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kansas | 45 | 11 | 14 | 12 | 8 | 2 | 1 | 1 | 4 |

| State | 1990 | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Kentucky | 10,018 | 6,898 | 9,986 | 12,035 | 12,303 | 10,592 | 7,993 | 8,098 | 8,219 |
| Louisiana | 64 | 84 | 77 | 73 | 79 | 168 | 80 | 56 | 52 |
| Maryland | 474 | 361 | 263 | 219 | 238 | 263 | 197 | 166 | 169 |
| Mississippi | 0 | 199 | 159 | 193 | 224 | 154 | 165 | 200 | 209 |
| Missouri | 166 | 3 | 15 | 28 | 29 | 29 | 26 | 26 | 23 |
| Montana | 1,373 | 1,468 | 1,629 | 1,417 | 1,495 | 1,445 | 1,160 | 1,269 | 1,379 |
| New Mexico | 363 | 2,926 | 3,411 | 3,836 | 3,956 | 4,187 | 2,148 | 2,845 | 2,219 |
| North Dakota | 299 | 306 | 303 | 306 | 296 | 289 | 281 | 282 | 298 |
| Ohio | 4,406 | 3,120 | 3,686 | 4,443 | 3,614 | 3,909 | 3,389 | 3,182 | 3,267 |
| Oklahoma | 226 | 825 | 932 | 624 | 436 | 360 | 499 | 282 | 112 |
| Pennsylvania | 21,864 | 17,904 | 20,684 | 22,939 | 23,372 | 17,708 | 17,773 | 20,953 | 19,803 |
| Tennessee | 276 | 115 | 86 | 69 | 67 | 60 | 35 | 31 | 22 |
| Texas | 1,119 | 922 | 783 | 704 | 823 | 922 | 887 | 854 | 876 |
| Utah | 3,587 | 4,787 | 5,524 | 5,449 | 5,628 | 3,651 | 3,624 | 2,733 | 1,605 |
| Virginia | 46,041 | 8,649 | 9,223 | 8,042 | 9,061 | 8,526 | 6,516 | 8,141 | 12,680 |
| Washington | 146 | 154 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| West Virginia | 48,335 | 29,745 | 36,421 | 40,452 | 40,638 | 35,709 | 33,608 | 32,998 | 38,023 |
| Wyoming | 6,671 | 14,745 | 16,959 | 15,627 | 16,032 | 15,916 | 14,507 | 14,025 | 14,339 |
| Total | 200,399 | 132,481 | 157,112 | 165,854 | 171,000 | 147,908 | 138,012 | 134,173 | 140,343 |

+ Does not exceed 0.5 million cubic feet.

Note: The emission estimates provided above are inclusive of emissions from underground mines, surface mines and post-mining activities. The following states have neither underground nor surface mining and thus report no emissions as a result of coal mining: Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Maine, Massachusetts, Michigan, Minnesota, Nebraska, Nevada, New Hampshire, New Jersey, New York, North Carolina, Oregon, Rhode Island, South Carolina, South Dakota, Vermont, and Wisconsin.

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3.5. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems

The methodology for estimating CH₄ and non-combustion CO₂ emissions from the production, refineries and transportation segments of petroleum systems is generally based on EPA's Greenhouse Gas Reporting Program (GHGRP) data for 2014; the 1999 EPA report, Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999); and the study, Methane Emissions from the U.S. Petroleum Industry (EPA/GRI 1996). Fifty-seven activities that emit CH₄ and thirty-two activities that emit non-combustion CO₂ from petroleum systems were examined from these reports and the GHGRP data. Most of the activities are part of crude oil production field operations, which accounted for approximately 99 percent of total oil industry CH₄ emissions. Crude transportation and refining accounted for the remaining CH₄ emissions of approximately 0.3 and 0.9 percent, respectively. Non-combustion CO₂ emissions were analyzed for production operations and asphalt blowing, flaring, and process vents in refining operations. Non-combustion CO₂ emissions from transportation operations are not included because they are negligible. The following steps were taken to estimate CH₄ and CO₂ emissions from petroleum systems.

Step 1: Calculate Potential Methane (or Net Emissions)

Activity Data

Activity data were taken from the following source: DrillingInfo (2015), the Energy Information Administration annual and monthly reports (EIA 1990 through 2015), (EIA 1995 through 2015a, 2015b), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2015), the Interstate Oil and Gas Compact Commission (IOGCC 2012), the United States Army Corps of Engineers, (1995-2015), and the GHGRP (2010-2014).

For many sources, complete activity data were not available for all years of the time series. In such cases, one of three approaches was employed. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA 1996, and/or GHGRP data. For major equipment, pneumatic controllers, and chemical injection pumps, GHGRP subpart W data were used to develop activity factors (i.e., count per well) that are applied to calculated activity in recent years; to populate earlier years of the time series, linear interpolation is used to connect GHGRP-based estimates with existing estimates in years 1990 to 1995. For hydraulically fractured oil well completions, EPA developed activity data specific to each year of the time series using the date of completion or first reported production available from a data set licensed by DrillingInfo, Inc. For more information on the DrillingInfo data processing, please see Annex 3.6 Methodology for Estimating CH₄ and CO₂ from Natural Gas Systems. In other cases, the activity data were held constant from 1990 through 2014 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. For offshore production, the number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,c).

For petroleum refining activities, 2010 to 2014 emissions were directly obtained from EPA's GHGRP. All refineries have been required to report CH₄ and CO₂ emissions for all major activities since 2010. The national totals of these emissions for each activity were used for the 2010 to 2014 emissions. The national emission totals for each activity were divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors, which were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for each year (EPA 2015d).

The activity data for the total crude transported in the transportation sector is not available. In this case, all the crude oil that was transported was assumed to go to refineries. Therefore, the activity data for the refining sector (i.e., refinery feed in 1000 bbl/year) was used also for the transportation sector. In the few cases where no data were located, oil industry data based on expert judgment was used. In the case of non-combustion CO₂ emission sources, the activity factors are the same as for CH₄ emission sources. In some instances, where 2014 data are not yet available 2013 or prior data has been used as proxy.

Potential methane factors and emission factors

The CH₄ emission factors for the majority of the activities are taken from the 1999 EPA draft report, which contained the most recent and comprehensive determination of CH₄ emission factors for the 57 CH₄-emitting activities in the oil industry at that time. Since the time of this study, practices and technologies have changed. While this study still represents best available data in many cases, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, "potential methane" is

calculated using the data, and then recent data on voluntary and regulatory emission reduction activities (Step 3) is deducted to calculate actual emissions.

For certain CH₄ emissions sources, new data and information allows for net emissions to be calculated directly: Oil well completions with hydraulic fracturing, pneumatic controllers, chemical injection pumps, and refineries. For these sources, EPA used emissions factors that directly reflect recent practice and the use of control technologies. The controlled and uncontrolled emission factors for hydraulically fractured (HF) well completions were developed using data analyzed for the 2015 NSPS OOOOa proposal. The gas engine emission factor is taken from the EPA/GRI 1996b study. For pneumatic controllers, separate estimates are developed for low bleed, high bleed, and intermittent controllers. Chemical injection pumps estimate are calculated with an emission factor developed with GHGRP data, which is based on the previous GRI/EPA factor but takes into account operating hours. The refineries emission factors were also developed from GHGRP data.

Other emission factors that are not based on the 1999 report include oil tank venting and offshore platforms. The oil tank venting emission factor is taken from the API E&P Tank Calc weighted average for API gravity less than 45 API degrees with the distribution of gravities taken from a sample of production data from the HPDI database. Offshore emissions from shallow water and deep water oil platforms are taken from analysis of the Gulf-wide Offshore Activity Data System (GOADS) report (EPA 2015; BOEM 2014). The emission factors were assumed to be representative of emissions from each source type over the period 1990 through 2014, and are used for each year throughout this period.

In general, the CO₂ emission factors were derived from the corresponding source CH₄ emission factors. The amount of CO₂ in the crude oil stream changes as it passes through various equipment in petroleum production operations. As a result, four distinct stages/streams with varying CO₂ contents exist. The four streams that are used to estimate the emissions factors are the associated gas stream separated from crude oil, hydrocarbons flashed out from crude oil (such as in storage tanks), whole crude oil itself when it leaks downstream, and gas emissions from offshore oil platforms. The standard approach used to estimate CO₂ emission factors was to use the existing CH₄ emissions factors and multiply them by a conversion factor, which is the ratio of CO₂ content to methane content for the particular stream. Ratios of CO₂ to CH₄ volume in emissions are presented in Table A-131. The exceptions are the emissions factor for storage tanks, which are estimated using API E&P Tank Calc simulation runs of tank emissions for crude oil of different gravities less than 45 API degrees; emission factors for shallow water and deep water platforms, which are estimated from analysis of the *2011 Gulf-Wide Emission Inventory Study* (BOEM 2014) and the emissions estimates for refineries, which are estimated using the data from U.S. EPA's GHGRP.

Step 2: Compile Reductions Data

The methane emissions calculated in Step 1 above generally represent expected emissions from an activity in the absence of emissions controls (with the exceptions of pneumatic controllers, completions with hydraulic fracturing, etc. as noted above), and do not take into account any use of technologies or practices that reduce emissions. To take into account use of such technologies, data were collected on voluntary reductions. Voluntary reductions included in the Petroleum Sector calculations were those reported to Natural Gas STAR for the following activities: Artificial lift: gas lift, Artificial lift: use compression, Artificial lift: use pumping unit, Consolidate crude oil prod and water storage tanks, Lower heater-treater temperature, Re-inject gas for enhanced oil recovery, Re-inject gas into crude, and Route casing head gas to VRU or compressor.

Industry partners report CH₄ emission reductions by project to the Natural Gas STAR Program. The reductions from the implementation of specific technologies and practices are calculated by the reporting partners using actual measurement data or equipment-specific emission factors. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the Inventory. The technology-specific approach for pneumatic controllers allows net emissions to be calculated directly. Pneumatic controller-related reductions were removed from the Gas STAR reduction data set before it was used to adjust the petroleum segment estimates.

Step 3: Calculate Net Methane and Carbon Dioxide Emissions for Each Activity for Each Year

Annual CH₄ emissions from each of the 57 petroleum system activities and CO₂ emissions from the 32 petroleum system activities were estimated by multiplying the activity data for each year by the corresponding emission factor, except for petroleum refineries segment. Emissions from refineries were obtained directly from the GHGRP data for 2010 through 2014; these four years of data were used to develop emission factors and activity data that are applied for the remainder of the time-series (i.e., 1990 through 2009). These annual emissions for each activity were then summed to estimate the total annual CH₄ and CO₂ emissions, respectively. As a final step, the relevant Natural Gas STAR reductions data is summed for each year and deducted from the total emissions to estimate net CH₄ emissions for the Inventory.

Table A-127, Table A-128, Table A-129, and Table A-132 provide 2014 activity data, emission factors, and emission estimates and Table A-130 and Table A-133 provide a summary of emission estimates for the years 1990, 1995, 2000, and 2005 through 2014. Table A-131 provides the CO₂ content in natural gas for equipment in different crude streams to estimate CO₂ emission factors using CH₄ emission factors.

The tables provide references for emission factors and activity data in footnotes (the lettered footnotes). The tables also provide information on which method was used for supplying activity data for 2014 (the numbered footnotes).

Key to table notations on methods for supplying activity data for 2014 for all tables:

1. Ratios relating other factors for which activity data are available.
2. Activity data for 2014 available from source.
3. Activity data were held constant from 1990 through 2014 based on EPA (1999).
4. 2009, 2010, 2011, 2012, or 2013 activity data are used to determine some or all of the 2014 activity data.

Table A-127: 2014 CH₄ Emissions from Petroleum Production Field Operations

| Activity/Equipment | 2014 EPA Inventory Values | | Emissions (Bcf/yr) | Emissions (kt/yr) |
|---|---|---|-----------------------|----------------------|
| | Emission Factor | Activity Data | | |
| Vented Emissions | | | 128.872 | 2,478.3 |
| Oil Tanks | 7.4 scf of CH ₄ /bbl crude ^a | 2,782 MMbbl/yr (non-stripper wells) ^{b,c,d,1} | 20.575 | 395.7 |
| Pneumatic controllers, High Bleed | 622 scfd CH ₄ /controller ^r | 43,211 No. of high-bleed controllers ^{r,2} | 9.806 | 188.6** |
| Pneumatic controllers, Low Bleed | 23 scfd CH ₄ /controller ^r | 300,940 No. of low-bleed controllers ^{r,2} | 2.510 | 48.3** |
| Pneumatic controllers, Int Bleed | 218 scfd CH ₄ /controller ^r | 868,079 No. of int-bleed controllers ^{r,2} | 69.173 | 1,330.2** |
| Chemical Injection Pumps | 216 scfd CH ₄ /pump ^r | 127,484 No. of pumps ^{r,2} | 10.030 | 192.9 |
| Vessel Blowdowns | 78 scfy CH ₄ /vessel ^h | 502,754 No. of vessels ^{c,g,i,q,1} | 0.039 | 0.8 |
| Compressor Blowdowns | 3,775 scf/yr of CH ₄ /compressor ^h | 2,967 No. of compressors ^{c,g,i,q,1} | 0.011 | 0.2 |
| Compressor Starts | 8,443 scf/yr of CH ₄ /compressor ^h | 2,967 No. of compressors ^{c,g,i,1} | 0.025 | 0.5 |
| Stripper wells | 2,345 scf/yr of CH ₄ /stripper well ^f | 327,674 No. of stripper wells vented ^{f,d,4} | 0.768 | 14.8 |
| Well Completion Venting | 733 scf/completion ^h | 15,753 Oil well completions ^{s,4} | 0.012 | 0.2 |
| Well Workovers | 96 scf CH ₄ /workover ⁱ | 67,370 Oil well workovers ^{g,i,1,4} | 0.006 | 0.1 |
| HF Well Completions, Uncontrolled | 351,146 scf/HF completions ^s | 17,522 HF oil well completions ^{t,2} | 6.153 | 118.3 |
| HF Well Completions, Controlled | 17,557 scf/HF completions ^s | 1,319 HF oil well completions ^{t,2} | 0.023 | 0.4 |
| Pipeline Pigging | 2.4 scfd of CH ₄ /pig station ⁱ | 0 No. of crude pig stations ^{e,3} | 0.000 | 0.0 |
| Offshore Platforms, Shallow water Oil, fugitive, vented and combusted | 16,552 scfd CH ₄ /platform ^q | 1,447 No. of shallow water oil platforms ^{l,4} | 8.739 | 168.1 |
| Offshore Platforms, Deepwater oil, fugitive, vented and combusted | 93,836 scfd CH ₄ /platform ^q | 29 No. of deep water oil platforms ^{l,4} | 1.001 | 19.3 |
| Fugitive Emissions | | | 6.479 | 124.6 |
| Oil Wellheads (heavy crude) | 0.13 scfd/well ^{e,m} | 40,227 No. of hvy. Crude wells ^{d,i,t,1,4} | 0.002 | 0.0* |
| Oil Wellheads (light crude) | 17 scfd/well ^{e,m} | 530,367 No. of lt. crude wells ^{d,i,t,1,4} | 3.219 | 61.9 |
| Separators (heavy crude) | 0.15 scfd CH ₄ /separator ^{e,m} | 38,520 No. of hvy. Crude seps. ^{r,2} | 0.002 | 0.0* |
| Separators (light crude) | 14 scfd CH ₄ /separator ^{e,m} | 350,573 No. of lt. crude seps. ^{r,2} | 1.773 | 34.1 |
| Heater/Treaters (light crude) | 19 scfd CH ₄ /heater ^{e,m} | 113,662 No. of heater treaters ^{r,2} | 0.796 | 15.3 |
| Headers (heavy crude) | 0.08 scfd CH ₄ /header ^{e,m} | 35,647 No. of hvy. Crude hdrs. ^{r,2} | 0.001 | 0.0* |
| Headers (light crude) | 11 scfd CH ₄ /header ^{e,m} | 110,509 No. of lt. crude hdrs. ^{r,2} | 0.438 | 8.4 |
| Floating Roof Tanks | 338,306 tank/yr ^{m,n} | 24 No. of floating roof tanks ^{e,3} | 0.008 | 0.2 |
| Compressors | 100 scfd CH ₄ /compressor ^e | 2,967 No. of compressors ^{c,i,t,1} | 0.108 | 2.1 |
| Large Compressors | 16,360 scfd CH ₄ /compressor ^e | 0 No. of large comprs. ^{e,3} | 0.000 | 0.0 |
| Sales Areas | 41 scf CH ₄ /loading ^e | 2,648,868 Loadings/year ^{c,1} | 0.107 | 2.1 |
| Pipelines | NE scfd of CH ₄ /mile of pipeline | 14,571 Miles of gathering line ^{e,2} | NE | NE |
| Well Drilling | NE scfd of CH ₄ /oil well drilled | 17,774 No. of oil wells drilled ^{c,2} | NE | NE |
| Battery Pumps | 0.24 scfd of CH ₄ /pump ^m | 269,480 No. of battery pumps ^{g,e,1} | 0.024 | 0.5 |
| Combustion Emissions | | | 6.196 | 119.2 |
| Gas Engines | 0.24 scf CH ₄ /HP-hr ^h | 18,694 MMHP-hr ^{c,g,i,1} | 4.487 | 86.3 |

| Activity/Equipment | 2014 EPA Inventory Values | | Emissions (Bcf/yr) | Emissions (kt/yr) |
|----------------------------------|--|--|-----------------------|----------------------|
| | Emission Factor | Activity Data | | |
| Heaters | 0.52 scf CH ₄ /bbl ⁿ | 3,179 MMbbl/yr ^{c,2} | 1.657 | 31.9 |
| Well Drilling | 2,453 scf CH ₄ /well drilled ^m | 17,774 Oil wells drilled ^{c,4} | 0.044 | 0.8 |
| Flares | 20 scf CH ₄ /Mcf flared ⁱ | 452,651 Mcf flared/yr ^{b,c,d,1,4} | 0.009 | 0.2 |
| Process Upset Emissions | | | 0.157 | 3.0 |
| Pressure Relief Valves | 35 scf/yr/PR valve ^h | 265,554 No. of PR valves ^{c,e,1} | 0.009 | 0.2 |
| Well Blowouts Onshore | 2.5 MMscf/blowout ^f | 59 No. of blowouts/yr ^{c,e,1} | 0.148 | 2.8 |
| Voluntary Reductions | | | (1.605) | (30.9) |
| Total Potential Emissions | | | 141.704 | 2,725.1 |
| Total Net Emissions | | | 140.100 | 2,694.2 |

- Zero Emissions

* Emissions are not actually 0, but too small to show at this level of precision.

^a TankCALC

^b EPA / ICF International (1999)

^c Energy Information Administration (EIA) Monthly Energy Review

^d Interstate Oil & Gas Compact Commission (IOGCC) Marginal Wells Report

^e Consensus of Industrial Review Panel

^f Expert Judgment

^g EIA Annual Energy Review

^h Gas Research Institute (GRI) / EPA (1996)

ⁱ Radian (1999)

^j Canadian Association of Petroleum Producers (CAPP) (1992)

^k Adapted from the Minerals Management Service (MMS) Gulfwide Offshore Activities Data System (GOADS) by ICF (2005)

^l Bureau of Ocean Energy Management (BOEM)

^m American Petroleum Institute (API) (1996)

ⁿ EPA, AP 42 Compilation of Air Pollutant Emission Factors

^o Oil and Gas Journal (OGJ) Petroleum Economics Issue

^p BOEM 2011 Gulf-wide Emissions Inventory Study (2014)

^r GHGRP data

^s DrillingInfo data from analysis supporting the NSPS OOOOa proposal

^t DrillingInfo data

Table A-128: 2014 CH₄ Emissions from Petroleum Transportation

| Activity/Equipment | Emission | | Activity Factor Units | Emissions (Bcf/yr) | Emissions (kt/yr) |
|-----------------------------|---|-------|--|-----------------------|----------------------|
| | Factor | Units | | | |
| Vented Emissions | | | | 0.370 | 7.1 |
| Tanks | 0.021 scf CH ₄ /yr/bbl of crude delivered to refineries ^a | | 5,785 MMbbl crude feed/yr ^{b,2} | 0.119 | 2.3 |
| Truck Loading | 0.520 scf CH ₄ /yr/bbl of crude transported by truck ^c | | 152 MMbbl crude trans. By truck ^{d,2} | 0.079 | 1.5 |
| Marine Loading | 2.544 scf CH ₄ /1000 gal crude marine loadings ^c | | 33,954,617 1,000 gal/yr loaded ^{e,1,4} | 0.086 | 1.7 |
| Rail Loading | 0.520 scf CH ₄ /yr/bbl of crude transported by rail ^c | | 133 MMbbl Crude by rail/yr ^{d,2} | 0.069 | 1.3 |
| Pump Station Maintenance | 36.80 scf CH ₄ /station/yr ^f | | 564 No. of pump stations ^{g,1} | 0.000* | 0.0* |
| Pipeline Pigging | 39 scfd of CH ₄ /pig station ^h | | 1,128 No. of pig stations ^{g,1} | 0.016 | 0.3 |
| Fugitive Emissions | | | | 0.050 | 1.0 |
| Pump Stations | 25 scf CH ₄ /mile/yr ^f | | 56,375 No. of miles of crude p/yr ^{g,2} | 0.001 | 0.0* |
| Pipelines | NE scf CH ₄ /bbl crude transported by pipeline ^f | | 9,289 MMbbl crude piped ^{g,2} | NE | NE |
| Floating Roof Tanks | 58,965 scf CH ₄ /floating roof tank/yr ⁱ | | 824 No. of floating roof tanks ³ | 0.049 | 0.9 |
| Combustion Emissions | | | | NE | NE |
| Pump Engine Drivers | 0.24 scf CH ₄ /hp-hr ⁱ | | NE No. of hp-hrs | NE | NE |
| Heaters | 0.521 scf CH ₄ /bbl burned ^k | | NE No. of bbl Burned | NE | NE |
| Total | | | | 0.420 | 8.1 |

* Emissions are not actually 0, but too small to show at this level of precision.

NE - Not estimated for lack of data

^a API (1992)

^b Energy Information Administration (EIA) Petroleum Supply Annual, Volume 1.

^c EPA, AP 42 Compilation of Air Pollutant Emission Factors

^d EIA Refinery Capacity Report

^e EIA Monthly Energy Review
^f Radian (1996)
^g OGJ Petroleum Economics Issue
^h CAPP (1992)
ⁱ API TANK
^j GRI / EPA (1996)
^k EPA / ICF International (1999)

Table A-129: 2014 CH₄ Emissions from Petroleum Refining

| Activity/Equipment | 2014 EPA Inventory Values | | | |
|---------------------------------------|------------------------------------|---|--------------------|-------------------|
| | Emission Factor | Activity Factor | Emissions (Bcf/yr) | Emissions (kt/yr) |
| Vented Emissions | | | 0.373 | 7.2 |
| Uncontrolled Blowdowns | 0.000971 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.292 | 5.6 |
| Asphalt Blowing | 0.000049 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.015 | 0.3 |
| Process Vents | 0.000215 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.065 | 1.2 |
| CEMS | 0.000006 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.002 | 0.0* |
| Fugitive Emissions | | | 0.234 | 4.5 |
| Equipment Leaks | 0.000457 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.137 | 2.6 |
| Storage Tanks | 0.000237 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.071 | 1.4 |
| Wastewater Treating | 0.00798 lb VOC/bbl ^{b,c} | 5,784,637 Mbbbl/year refinery feed ^a | 0.011 | 0.2 |
| Cooling Towers | 0.010 lb VOC/bbl ^{b,c} | 5,784,637 Mbbbl/year refinery feed ^a | 0.014 | 0.3 |
| Loading Operations | 0.000002 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.001 | 0.0* |
| Combustion Emissions | | | 0.614 | 11.8 |
| Catalytic Cracking, Coking, Reforming | 0.000248 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.075 | 1.4 |
| Flares | 0.001611 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.485 | 9.3 |
| Delay Cokers | 0.000178 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.054 | 1.0 |
| Coke Calcining | 0.000005 MT CH ₄ /Mbbld | 5,784,637 Mbbbl/year refinery feed ^a | 0.002 | 0.0* |
| Total | | | 1.221 | 23.5 |

* Emissions are not actually 0, but too small to show at this level of precision.

^a EIA Petroleum Supply Annual, Volume 1.

^b Radian (1996)

^c Assuming methane is 1% of total hydrocarbons (AP-42)

^d GHGRP data

Note: The methodology for year 2014 is to use GHGRP emissions data as-reported. The emission factors in this table were developed for this table by dividing 2014 emissions by 2014 refinery feed rate.

Table A-130: Summary of CH₄ Emissions from Petroleum Systems (kt)

| Activity | 1990 | 1995 | 2000 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Production Field Operations | 1,519 | 1,549 | 1,767 | 2,056 | 2,103 | 2,120 | 2,193 | 2,263 | 2,347 | 2,586 | 2,725 |
| Pneumatic controller venting | 761 | 832 | 1,044 | 1,262 | 1,286 | 1,308 | 1,328 | 1,346 | 1,332 | 1,509 | 1,567 |
| Tank venting | 250 | 226 | 214 | 193 | 185 | 202 | 210 | 220 | 278 | 330 | 396 |
| Combustion & process upsets | 115 | 105 | 95 | 92 | 95 | 95 | 98 | 101 | 108 | 114 | 122 |
| Misc. venting & fugitives | 334 | 332 | 365 | 459 | 482 | 461 | 502 | 540 | 570 | 573 | 578 |
| Wellhead fugitives | 59 | 54 | 48 | 50 | 55 | 53 | 54 | 56 | 59 | 60 | 62 |
| Crude Oil Transportation | 7 | 6 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 7 | 8 |
| Refining | 24 | 25 | 27 | 27 | 26 | 25 | 26 | 28 | 27 | 26 | 23 |
| Voluntary Reductions | (0) | (1) | (17) | (64) | (77) | (67) | (60) | (45) | (45) | (31) | (31) |
| Total Potential Emissions | 1,550 | 1,580 | 1,799 | 2,088 | 2,134 | 2,150 | 2,224 | 2,296 | 2,380 | 2,619 | 2,757 |
| Total Net Emissions | 1,550 | 1,578 | 1,781 | 2,024 | 2,058 | 2,083 | 2,163 | 2,251 | 2,335 | 2,588 | 2,726 |

Note: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table A-131: Ratios of CO₂ to CH₄ Volume in Emissions from Petroleum Production Field Operations

| | Whole Crude, Post-Separator | Associated Gas | Tank Flash Gas | Offshore |
|---|--------------------------------|----------------|----------------|----------|
| Ratio %CO ₂ / %CH ₄ | 0.052 | 0.020 | 0.017 | 0.004 |

Table A-132: 2014 CO₂ Emissions from Petroleum Production Field Operations and Petroleum Refining

| Activity/Equipment | 2014 EPA Inventory Values | | | Emissions (Bcf/yr) | Emissions (kt/yr) |
|---|---|--|--|-----------------------|----------------------|
| | Emission Factor | Activity Factor | | | |
| Vented Emissions | | | | 11.974 | 633.2 |
| Oil Tanks | 3.528 scf of CO ₂ /bbl crude ^a | 2,782 MMbbl/yr (non stripper wells) ^{b,c,d,1,4} | | 9.817 | 519.1 |
| Pneumatic controllers, High Bleed | 12.615 scfd CO ₂ /controller ^q | 43,211 No. of high-bleed controllers ^{q,2} | | 0.199 | 10.5 |
| Pneumatic controllers, Low Bleed | 0.464 scfd CO ₂ /controller ^q | 300,940 No. of low-bleed controllers ^{q,2} | | 0.051 | 2.7 |
| Pneumatic controllers, Int Bleed | 4.430 scfd CO ₂ /controller ^q | 868,079 No. of int-bleed controllers ^{q,2} | | 1.404 | 74.2 |
| Chemical Injection Pumps | 4.374 scfd CO ₂ /pump ^q | 127,484 No. of pumps ^{q,2} | | 0.204 | 10.8 |
| Vessel Blowdowns | 1.583 scfy CO ₂ /vessel ^h scf/yr of | 502,754 No. of vessels ^{c,g,i,1} | | 0.001 | 0.0* |
| Compressor Blowdowns | 77 CO ₂ /compressor ^h scf/yr of | 2,967 No. of compressors ^{c,g,i,1} | | 0.000* | 0.0* |
| Compressor Starts | 171 CO ₂ /compressor ^h scf/yr of CO ₂ /stripper | 2,967 No. of compressors ^{c,g,i,1} | | 0.001 | 0.0* |
| Stripper wells | 48 well ^f | 327,674 No. of stripper wells vented ^{f,1,4} | | 0.016 | 0.8 |
| Well Completion Venting | 14.87 scf/completion ^h | 15,753 Oil well completions ^{c,2} | | 0.000* | 0.0* |
| Well Workovers | 1.95 scf CO ₂ /workover ⁱ | 67,370 Oil well workovers ^{g,i,1} | | 0.000* | 0.0* |
| HF Well Completions, Uncontrolled | 7,125.06 scf/HF completion ^f | 17,522 HF oil well completions ^{s,1} | | 0.125 | 6.6 |
| HF Well Completions, Controlled | 356.25 scf/HF completion ^f | 1,319 HF oil well completions ^{s,1} | | 0.000* | 0.0* |
| Pipeline Pigging | NE scfd of CO ₂ /pig station | 0 No. of crude pig stations | | NE | NE |
| Offshore Platforms, Shallow water Oil, fugitive, vented and combusted | 276 scfd CO ₂ /platform ^k | 1,447 No. of shallow water oil platforms ^{l,4} | | 0.146 | 7.7 |
| Offshore Platforms, Deepwater oil, fugitive, vented and combusted | 1,100 scfd CO ₂ /platform ^k | 29 No. of deep water oil platforms ^{l,4} | | 0.012 | 0.6 |
| Fugitive Emissions | | | | 0.133 | 7.0 |
| Oil Wellheads (heavy crude) | 0.003 scfd/well ^{e,m} | 40,227 No. of hvy. crude wells ^{d,g,i,1,4} | | 0.000* | 0.0* |
| Oil Wellheads (light crude) | 0.337 scfd/well ^{e,m} | 530,367 No. of lt. crude wells ^{d,g,i,1,4} | | 0.065 | 3.5 |
| Separators (heavy crude) | 0.003 scfd CO ₂ /separator ^{e,m} | 38,520 No. of hvy. crude seps. ^{q,2} | | 0.000* | 0.0* |
| Separators (light crude) | 0.281 scfd CO ₂ /separator ^{e,m} | 350,573 No. of lt. crude seps. ^{q,2} | | 0.036 | 1.9 |
| Heater/Treaters (light crude) | 0.319 scfd CO ₂ /heater ^{e,m} | 113,662 No. of heater treaters ^{q,2} | | 0.013 | 0.7 |
| Headers (heavy crude) | 0.002 scfd CO ₂ /header ^{e,m} | 35,647 No. of hvy. crude hdrs. ^{q,2} | | 0.000* | 0.0* |
| Headers (light crude) | 0.220 scfd CO ₂ /header ^{e,m} scf CO ₂ /floating roof | 110,509 No. of lt. crude hdrs. ^{q,2} | | 0.009 | 0.5 |
| Floating Roof Tanks | 17,490 tank/yr ^{m,n} | 24 No. of floating roof tanks ^{e,3} | | 0.000* | 0.0* |
| Compressors | 2.029 scfd CO ₂ /compressor ^e | 2,967 No. of compressors ^{c,g,i,1} | | 0.002 | 0.1 |
| Large Compressors | 332 scfd CO ₂ /compressor ^e | - No. of largecompr. ^{e,3} | | 0.000 | 0.0 |
| Sales Areas | 2.096 scf CO ₂ /loading ^e scfd of CO ₂ /mile of | 2,648,868 Loadings/year ^{c,1} | | 0.006 | 0.3 |
| Pipelines | NE pipeline | 14,571 Miles of gathering line ^{o,2} | | NE | NE |

| Activity/Equipment | 2014 EPA Inventory Values | | | |
|---------------------------------------|--|---|--------------------|-------------------|
| | Emission Factor | Activity Factor | Emissions (Bcf/yr) | Emissions (kt/yr) |
| Well Drilling | scfd of CO ₂ /oil well NE drilled | 17,774 No. of oil wells drilled ^{c,2} | NE | NE |
| Battery Pumps | 0.012 scfd of CO ₂ /pump ^m | 269,480 No. of battery pumps ^{g,e,1} | 0.001 | 0.1 |
| Process Upset Emissions | | | 0.003 | 0.2 |
| Pressure Relief Valves | 1.794 scf/yr/PR valve ^h | 265,554 No. of PR valves ^{c,e,1} | 0.000* | 0.0* |
| Well Blowouts Onshore | 0.051 MMscf/blowout ^e | 59 No. of blowouts/yr ^{c,e,1} | 0.003 | 0.2 |
| Refining Emissions¹ | | | 55.341 | 2,926.7 |
| Asphalt Blowing | 0.020 MT CO ₂ /Mbbbl ^q | 5,784,637 Mbbbl/yearrefineryfeed ^p | 2.187 | 115.6 |
| Flaring | 0.477 MT CO ₂ /Mbbbl ^q | 5,784,637 Mbbbl/year refinery feed ^p | 52.196 | 2,760.4 |
| Process Vents | 0.009 MT CO ₂ /Mbbbl ^q | 5,784,637 Mbbbl/year refinery feed ^p | 0.958 | 50.7 |
| Total | | | 67.451 | 3,567.1 |

* Emissions are not actually 0, but too small to show at this level of precision.

NE - Not estimated for lack of data

^a TankCALC

^b EPA / ICF International (1999)

^c EIA Monthly Energy Review

^d IOGCC Marginal Wells Report

^e Consensus of Industrial Review Panel

^f Expert Judgment

^g EIA Annual Energy Review

^h GRI / EPA (1996)

ⁱ Radian (1996)

^j CAPP (1992)

^k Adapted from the GOADS 2011 Study by ERG (2015)

^l BOEM

^m API (1996)

ⁿ EPA, AP 42 Compilation of Air Pollutant Emission Factors

^o OGJ Petroleum Economics Issue

^p EIA Petroleum Supply Annual, Volume 1

^q GHGRP data

^r Calculated using CH₄ emission factor and CO₂ content of gas.

^s DrillingInfo Data

¹ The methodology for year 2014 is to use GHGRP emissions data as-reported (rather than an EFxAF approach, per se). The emission factors in this table were populated by dividing 2014 emissions by 2014 refinery feed rate.

Note: Energy use CO₂ emissions not estimated to avoid double counting with fossil fuel combustion

Table A-133: Summary of CO₂ Emissions from Petroleum Systems (kt)

| Activity | 1990 | 1995 | 2000 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Production Field Operations | 391 | 362 | 360 | 350 | 343 | 365 | 379 | 395 | 473 | 550 | 640 |
| Pneumatic controller venting | 42 | 46 | 58 | 70 | 72 | 73 | 74 | 75 | 74 | 84 | 87 |
| Tank venting | 328 | 296 | 281 | 253 | 243 | 265 | 276 | 288 | 365 | 432 | 519 |
| Misc. venting & fugitives | 17 | 17 | 18 | 23 | 25 | 24 | 26 | 28 | 30 | 30 | 30 |
| Wellhead fugitives | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Refining | 3,162 | 3,295 | 3,562 | 3,574 | 3,463 | 3,380 | 3,775 | 3,797 | 3,404 | 3,143 | 2,927 |
| Asphalt Blowing | 95 | 99 | 107 | 107 | 104 | 101 | 97 | 84 | 117 | 125 | 116 |
| Flaring | 2,993 | 3,119 | 3,372 | 3,383 | 3,279 | 3,200 | 3,626 | 3,630 | 3,228 | 2,882 | 2,760 |
| Process Vents | 74 | 77 | 83 | 84 | 81 | 79 | 52 | 83 | 58 | 137 | 51 |
| Total | 3,553 | 3,657 | 3,923 | 3,924 | 3,806 | 3,745 | 4,154 | 4,192 | 3,876 | 3,693 | 3,567 |

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3.6. Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems

As described in the main body text on Natural Gas Systems, the Inventory methodology involves the calculation of CH₄ and CO₂ emissions for over 100 emissions sources, and then the summation of emissions for each natural gas sector stage.

Step 1: Calculate Potential Methane (or Net Emissions)

Potential methane factors and emission factors

The primary basis for potential CH₄ factors and emission factors for non-combustion-related CO₂ emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH₄ emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. Since the time of this study, practices and technologies have changed. While this study still represents best available data in many cases, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, “potential methane” is calculated using the data, and then recent data on voluntary and regulatory emission reduction activities (Step 3) is deducted to calculate actual emissions. See Section 3.7 of the main document on Natural Gas Systems for more information.

For certain CH₄ emissions sources, new data and information allows for net emissions to be calculated directly: gas well completions and workovers with hydraulic fracturing, liquids unloading, condensate storage tanks, centrifugal compressors, pneumatic controllers, chemical injection pumps, transmission and storage station fugitives and compressors, M&R stations, and distribution pipeline leaks. For these sources, EPA used emissions factors that directly reflect the use of control technologies. For gas well completions and workovers with hydraulic fracturing, separate emissions estimates were developed for hydraulically fractured completions and workovers that vent, flared hydraulic fracturing completions and workovers, hydraulic fracturing completions and workovers with reduced emissions completions (RECs), and hydraulic fracturing completions and workovers with RECs that flare. For liquids unloading, separate emissions estimates were developed for wells with plunger lifts and wells without plunger lifts. Likewise, for condensate tanks, emissions estimates were developed for tanks with and without control devices. For pneumatic controllers, separate estimates are developed for low bleed, high bleed, and intermittent controllers. Chemical injection pumps estimates are calculated with an emission factor developed with GHGRP data, which is based on the previous GRI/EPA factor but takes into account operating hours.

For potential CH₄ factors and emission factors used in the Inventory, see Table A-134 to Table A-138. Methane compositions from GTI 2001 are adjusted year to year using gross production for National Energy Modeling System (NEMS) oil and gas supply module regions from the EIA. These adjusted region-specific annual CH₄ compositions are presented in Table A-139 (for general sources), Table A-140 (for gas wells without hydraulic fracturing), and Table A-141 (for gas wells with hydraulic fracturing). Therefore, emission factors may vary from year to year due to slight changes in the CH₄ composition between each NEMS oil and gas supply module region.

1990-2014 Inventory updates to emission factors

Summary information for emission factors for sources with updates in this year’s inventory is below. The details are presented in four memoranda addressing production, gathering and boosting, transportation and storage, and distribution (See “Revisions to Natural Gas and Petroleum Production Emissions”, “Revisions to Natural Gas Gathering and Boosting Emissions”, “Revisions to Natural Gas Transmission and Storage Emissions”, and “Revisions to Natural Gas Distribution Emissions” [EPA 2016a through 2016d]).⁶⁴

For the production segment, bleed type-specific (i.e., continuous high bleed, continuous low bleed, and intermittent bleed) emission factors for pneumatic controllers are based on GHGRP data (used for the full time series). Emission factors for gathering and boosting stations based on Marchese et al. are used for the full time series.

For the transmission and storage segment, station-level emission factors for transmission and storage stations and factors for compressors are based on the Zimmerle et al. study and used for 2011 to 2014. Emission factors for transmission and storage pneumatic controllers are from GHGRP and are used for the full time series.

For the distribution segment, emission factors for M&R stations and for emissions per leak for pipeline leaks are from the Lamb et al. study (used for 2011 to 2014). Emission factors for residential customer meters and

⁶⁴ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

commercial/industrial customer meters are from the 2009 GTI study and 2011 Clearstone study and are used for the full time series.

In order to create time series consistency for emission factors between earlier years' estimates (1990 to 1992) that generally rely on data from GRI/EPA 1996 and the most recent years' estimates (2011 to 2014) that were calculated using data from studies or GHGRP, linear interpolation between the data endpoints of 1992 (GRI/EPA) and 2011 (GHGRP) was typically used for calculations. Exceptions to the use of linear interpolation include gathering and boosting stations and residential and commercial/industry customer meters.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc. (DrillingInfo 2015); American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Monthly Energy Review (EIA 2012f, 2012g, 2012h, 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2012c, 2012d, 2012e, 2013a, 2013b, 2013c); the Natural Gas STAR Program annual emissions savings (EPA 2012a, 2013c); Oil and Gas Journal (OGJ 1997–2015); Pipeline and Hazardous Materials Safety Administration (PHMSA 2015); Federal Energy Regulatory Commission (FERC 2014); GHGRP data for natural gas systems (40 CFR 98, subpart W); and other Energy Information Administration publications (EIA 2001, 2004, 2010, 2011, 2012i, 2015); (EPA 1999); Wyoming Oil and Gas Conservation Commission (Wyoming 2015); and the Alabama State Oil and Gas Board (Alabama 2015). Activity data are presented in Table A-134 through Table A-138.

For a few sources, recent direct activity data were not available. For these sources, either 2013 data were used as proxy for 2014 data or a set of industry activity data drivers was developed and was used to update activity data. Drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations. The key activity drivers are presented in Table A-142.

EPA used DI Desktop, a production database maintained by DrillingInfo, Inc. (DrillingInfo 2015), covering U.S. oil and natural gas wells to populate activity data for non-associated gas wells, oil wells (in petroleum systems), gas wells with hydraulic fracturing, and completions with hydraulic fracturing. EPA queried DI Desktop for relevant data on an individual well basis—including location, natural gas and liquids (i.e., oil and condensate) production by year, drill type (e.g., horizontal or vertical), and date of completion or first production. Non-associated gas wells were classified as any well within DI Desktop that had non-zero gas production in a given year, and with a gas-to-oil ratio (GOR) of greater than 100 mcf/bbl in that year. Oil wells were classified as any well that had non-zero liquids production in a given year, and with a GOR of less than or equal to 100 mcf/bbl in that year. Gas wells with hydraulic fracturing were assumed to be the subset of the non-associated gas wells that were horizontally drilled and/or located in an unconventional formation (i.e., shale, tight sands, or coalbed). Unconventional formations were identified based on well basin, reservoir, and field data reported in DI Desktop referenced against a formation type crosswalk developed by EIA (EIA 2012a).

For 1990 through 2010, gas well completions with hydraulic fracturing were identified as a subset of the gas wells with hydraulic fracturing that had a date of completion or first production in the specified year. To calculate workovers for 1990 through 2010, EPA applied a refracture rate of 1 percent (i.e., 1 percent of all wells with hydraulic fracturing are assumed to be refractured in a given year) to the total counts of wells with hydraulic fracturing from the DrillingInfo data. For 2011 through 2014, EPA used GHGRP data for the total number of well completions and workovers. The GHGRP data represents a subset of the national completions and workovers, due to the reporting threshold, and therefore using this data without scaling it up to national level results in an underestimate. However, because EPA's GHGRP counts of completions and workovers were higher than national counts of completions and workovers, obtained using DI Desktop data, EPA directly used the GHGRP data for completions and workovers for 2011 through 2014.

EPA calculated the percentage of gas well completions and workovers with hydraulic fracturing in the each of the four control categories using 2011 through 2014 Subpart W data. EPA assumed 0 percent RECs use from 1990 through 2000, used GHGRP RECs percentage for 2011 through 2014, and then used linear interpolation between the 2000 and 2011 percentages. For flaring, EPA used an assumption of 10 percent (the average of the percent of completions and workovers that were flared in 2011 through 2013 GHGRP data) flaring from 1990 through 2010 to recognize that some flaring has occurred over that time period. For 2011 through 2014, EPA used the GHGRP data on flaring.

Summary information for activity data for sources with updates in this year's inventory is below. The details are presented in four memoranda addressing production, gathering and boosting, transportation and storage, and distribution (see "Revisions to Natural Gas and Petroleum Production Emissions", "Revisions to Natural Gas Gathering and Boosting

Emissions”, “Revisions to Natural Gas Transmission and Storage Emissions”, and “Revisions to Natural Gas Distribution Emissions” [EPA 2016a through 2016d)].⁶⁵

For the production segment, GHGRP-based activity factors (i.e., counts per gas well) were used for the years 2011 to 2014 for in-line heaters, separators, dehydrators, compressors, meters/piping, pneumatic pumps, and pneumatic controllers. In addition, for years 2011 to 2014, bleed type-specific (i.e., continuous high bleed, continuous low bleed, and intermittent bleed) activity data for pneumatic controllers were developed from GHGRP.

For the transmission and storage segment, activity factors (transmission stations; storage stations per storage field) are based on Zimmerle et al. study and applied for 2011 to 2014, reciprocating and centrifugal compressor activity data and compressor seal types (i.e., wet versus dry seals) are based on GHGRP and Zimmerle et al. study data for 2011-2014, and activity factors (i.e., controllers per station) for transmission and storage pneumatic controllers based on GHGRP and Zimmerle et al. study for 2011 to 2014.

For the distribution segment, activity factors for M&R stations for 2011 to 2014 are based on GHGRP and Lamb et al. study. Activity data for meters are from EIA for the full time series. Activity data for pipeline blowdowns and mishaps/dig-ins are from PHMSA for the full time series.

For sources where new activity data was determined to be applicable for only recent years of the time series, in order to create time series consistency for activity data between earlier years’ estimates (1990 to 1992) that generally rely on data from GRI/EPA 1996 and the most recent years’ estimates (2011 to 2014) that were calculated using data from studies or GHGRP, linear interpolation between the data endpoints of 1992 (GRI/EPA) and 2011 (GHGRP) was typically used for calculations. Exceptions to the use of linear interpolation include gathering and boosting stations and residential and commercial/industry customer meters.

Step 2: Compile Reductions Data

The emissions calculated in Step 1 above represent expected emissions from an activity in the absence of emissions controls (with the exceptions of emission sources that use a “net” approach such as pneumatic controllers, gas well completions and workovers with hydraulic fracturing, liquids unloading, centrifugal compressors, condensate tanks, distribution M&R stations, distribution pipelines, etc. as noted above), and do not take into account any use of technologies or practices that reduce emissions. To take into account use of such technologies, data were collected on voluntary and regulatory reductions. Voluntary reductions included in the Inventory were those reported to Gas STAR for activities such as replacing a high bleed pneumatic controllers with a low bleed controller and replacing wet seals with dry seals at reciprocating compressors. Regulatory actions reducing emissions include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks.

Voluntary reductions

Industry partners report CH₄ emission reductions by project to the Natural Gas STAR Program. The reductions from the implementation of specific technologies and practices (e.g., vapor recovery units,) are calculated by the reporting partners using actual measurement data or equipment-specific emission factors. Natural Gas STAR Partners do not report reductions when they are required due to regulation. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the Inventory. In general, the Inventory uses aggregated Gas STAR reductions by natural gas system stage (i.e., production, processing, transmission and storage, and distribution). However, aggregate emissions reductions data by Gas STAR technology are provided for several sources, as shown in Table A-143. For those sources, EPA has also used data on potential emissions, and the Gas STAR data on reductions, to calculate net emissions, as shown in Table A-149 (along with other sources calculated with net emission factors). Many of the activities reported to Gas STAR are cross-cutting and apply to more than one emissions source and therefore cannot be assigned to one emissions source, but instead are included in the “other” category. For Inventory sources with emission factors that already take into account the use of control technologies (i.e., “net” emission sources) Natural Gas STAR reported reductions for those activities are not incorporated into the Inventory, as this would double count reductions. CH₄ emission reductions from the Natural Gas STAR Program are summarized in Table A-143.

For sources where net factor approaches are used, the use of data from the GHGRP and recent studies to revise certain emission factors as discussed above obviated the need to apply Gas STAR reductions data for these sources (i.e., the calculated emissions were already net emissions, instead of potential emissions).

⁶⁵ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

There are significant Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 18 MMT CO₂ eq. of CH₄ in year 2014). As many sources in production are now calculated with net factor approaches, to address potential double-counting of reductions, a scaling factor was applied to the “other voluntary reductions” to reduce this reported amount based an estimate of the fraction of those reductions that occur in the sources that are now calculated using net emissions approaches. This fraction was developed by dividing the net emissions from sources with net approaches, by the total production segment emissions (without deducting the Gas STAR reductions). The result for 2014, is that around 50 percent of the reductions were estimated to occur in sources for which net emissions are now calculated, which yields an adjusted other reduction number of 9 MMT CO₂ Eq.

Federal regulations.

The 1990 Clean Air Act (CAA) sets limits on the amount of hazardous air pollutants (HAPs) that can be emitted in the United States. The NESHAP regulations set the standards to limit emissions of HAPs. The emission sources are required to use the Maximum Achievable Control Technology (MACT), giving the operators flexibility to choose the type of control measure(s) to implement. In regards to the oil and natural gas industry, the NESHAP regulation addresses HAPs from the oil and natural gas production sectors and the natural gas transmission and storage sectors of the industry. Though the regulation deals specifically with HAPs reductions, methane emissions are also incidentally reduced.

The NESHAP regulation requires that glycol dehydration unit vents and storage tanks that have HAP emissions and exceed a gas throughput and liquids throughput threshold, respectively, be connected to a closed loop emission control system that reduces emissions by 95 percent. Also, gas processing plants exceeding the threshold natural gas throughput limit are required to routinely implement Leak Detection and Repair (LDAR) programs. The emissions reductions achieved as a result of NESHAP regulations were calculated using data provided in the Federal Register Background Information Document (BID) for this regulation. The BID provides the levels of control measures in place before the enactment of regulation. The emissions reductions were estimated by analyzing the portion of the industry without control measures already in place that would be impacted by the regulation. CH₄ emission reductions from federal regulations, such as NESHAP, are summarized in Table A-144. In addition to the NESHAP applicable to natural gas, the Inventory reflects the 2012 New Source Performance Standards (NSPS) subpart OOOO for oil and gas, through the use of a net factor approach that captures shifts to lower emitting technologies. By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific methane emission factors for each category, EPA is implicitly accounting for subpart OOOO reductions from hydraulically fractured gas wells. This is also the case for high bleed pneumatic controllers in the production segment.

Step 3: Calculate Net Methane and Carbon Dioxide Emissions for Each Activity for Each Year

Annual CH₄ emissions and CO₂ emissions for each source were estimated by multiplying the activity data for each year by the corresponding emission factor. These annual emissions for each activity were then summed to estimate the total annual CH₄ and CO₂ emissions, respectively. As a final step, the relevant Natural Gas STAR reductions data from each segment is summed for each year and deducted from the total emissions to estimate net CH₄ emissions for the Inventory.

The same procedure for estimating CH₄ emissions holds true for estimating non-energy related CO₂ emissions, except the emission estimates are not adjusted for reductions due to the Natural Gas STAR program or regulations.

Produced natural gas is composed of primarily CH₄, but as shown in Table A-150, the natural gas contains, in some cases, as much as 8 percent CO₂. The same vented and fugitive natural gas that led to CH₄ emissions also contains a certain volume of CO₂. Accordingly, the CO₂ emissions for each sector can be estimated using the same activity data for these vented and fugitive sources. The emission factors used to estimate CH₄ were also used to calculate non-combustion CO₂ emissions. The Gas Technology Institute’s (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH₄ emission factors into non-combustion related CO₂ emission factors. Additional information about CO₂ content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO₂ emission factors. For the CO₂ content used to develop CO₂ emission factors from CH₄ potential factors, see Table A-150. The detailed source emission estimates for CH₄ and CO₂ from the production sector are presented in Table A-145 and Table A-154, respectively.

In the processing sector, the CO₂ content of the natural gas remains the same as the CO₂ content in the production sector for the equipment upstream of the acid gas removal unit because produced natural gas is usually only minimally treated after being produced and then transported to natural gas processing plants via gathering pipelines. The CO₂ content in gas for the remaining equipment that is downstream of the acid gas removal is the same as in pipeline quality gas. The EPA/GRI study estimates the average CH₄ content of natural gas in the processing sector to be 87 percent CH₄. Consequently, the processing sector CO₂ emission factors were developed using CH₄ emission factors, proportioned to

reflect the CO₂ content of either produced natural gas or pipeline quality gas using the same methodology as the production sector. The detailed source emission estimates for CH₄ and CO₂ from the processing sector are presented in Table A-146 and Table A-152, respectively.

For the transmission sector, CO₂ content in natural gas transmission pipelines was estimated for the top 20 transmission pipeline companies in the United States (separate analyses identified the top 20 companies based on gas throughput and total pipeline miles). The weighted average CO₂ content in the transmission pipeline quality gas in both cases—total gas throughput and total miles of pipeline—was estimated to be about 1 percent. To estimate the CO₂ emissions for the transmission sector, the CH₄ emission factors were proportioned from the 93.4 percent CH₄ reported in EPA/GRI (1996) to reflect the 1 percent CO₂ content found in transmission quality natural gas. The detailed source emissions estimates for CH₄ and CO₂ for the transmission sector are presented in Table A-147 and Table A-153, respectively.

The natural gas in the distribution sector of the system has the same characteristics as the natural gas in the transmission sector. The CH₄ content (93.4 percent) and CO₂ content (1 percent) are identical to transmission segment contents due to the absence of any further treatment between sector boundaries. Thus, the CH₄ emissions factors were converted to CO₂ emission factors using the same methodology as discussed for the transmission sector. The detailed source emission estimates for CH₄ and CO₂ for the distribution sector are presented in Table A-148 and Table A-154, respectively.

Three exceptions to this methodology are CO₂ emissions from flares, CO₂ from acid gas removal units, and CO₂ from condensate tanks. In the case of flare emissions, a direct CO₂ emission factor from EIA (1996) was used. This emission factor was applied to the portion of offshore gas that is not vented and all of the gas reported as vented and flared onshore by EIA, including associated gas. The amount of CO₂ emissions from an acid gas unit in a processing plant is equal to the difference in CO₂ concentrations between produced natural gas and pipeline quality gas applied to the throughput of the plant. This methodology was applied to the national gas throughput using national average CO₂ concentrations in produced gas (3.45 percent) and transmission quality gas (1 percent). Data were unavailable to use annual values for CO₂ concentration. For condensate tanks, a series of E&P Tank (EPA 1999) simulations provide the total CO₂ vented per barrel of condensate throughput from fixed roof tank flash gas for condensate gravities of API 45 degree and higher. The ratios of emissions to throughput were used to estimate the CO₂ emission factor for condensate passing through fixed roof tanks.

Table A-134 through Table A-138 display the 2012 activity data, CH₄ emission factors, and calculated potential CH₄ emissions for each stage.

The tables provide references for emission factors and activity data in footnotes (the lettered footnotes). The tables also provide information on which method was used for supplying activity data for 2014 (the numbered footnotes).

Key to table notations on methods for supplying activity data for 2014 for all tables:

1. Ratios relating other factors for which activity data are available.
2. Activity data for 2014 available from source.
3. Activity data were held constant from 1990 through 2014 based on EPA (1999).

Table A-134: 2014 Data and Calculated CH₄ Potential Emissions (Mg) for the Natural Gas Production Stage

| Activity | 2014 EPA Inventory Values | | |
|--|---|--|---|
| | National Activity Data | National Emission Factor or Range of Regional Values (Potential) ^{aa} | Calculated Potential (Mg) ^{bb} |
| Gas Wells | | | |
| Associated Gas Wells | 503,873 wells ^{a,1,cc} | NA ^{dd} | 0.0 |
| Non-associated Gas Wells (less fractured wells) | 205,363 wells ^{a,1} | 7.43-42.49 scfd/well ^b | 17,754.5 |
| Gas Wells with Hydraulic Fracturing | 250,777 wells ^{a,1} | 7.59-42.49 scfd/well ^b | 35,085.1 |
| Well Pad Equipment | | | |
| Heaters | 99,038 heaters ^{c,d,2} | 14.87-67.29 scfd/heater ^b | 23,953.4 |
| Separators | 306,377 separators ^{c,d,2} | 0.94-142.27 scfd/separator ^b | 118,591.2 |
| Dehydrators | 17,126 dehydrators ^{c,d,2} | 23.18-106.25 scfd/dehydrator ^b | 8,417.5 |
| Meters/Piping | 523,885 meters ^{c,d,2} | 9.43-61.68 scfd/meter ^b | 107,173.2 |
| Compressors | 48,518 compressors ^{c,d,2} | 263.85-312.19 scfd/compressor ^b | 96,170.6 |
| Gathering and Boosting | | | |
| Gathering and Boosting Stations* | 4,999 stations ^{e,2} | 53,066 scfd CH ₄ /station ^e | 1,864,870.3 |
| Pipeline Leaks | 431,051 miles ^{f,2} | 52.38-61.97 scfd/mile ^b | 169,701.4 |
| Drilling, Well Completion, and Well Workover | | | |
| Gas Well Completions without Hydraulic | | | |
| Fracturing | 767 completions/year ^g | 707.23-854.65 scf/completion ^b | 11.3 |
| Gas Well Workovers without Hydraulic Fracturing | 8,933 workovers/year ^{a,2} | 2,367.7-2,861.3 scf/workover ^b | 445.8 |
| Hydraulic Fracturing Completions and Workovers that vent* | 1,791 completions and workovers/year ^c | MT/(completion or workover) ^h | 65,940.7 |
| Flared Hydraulic Fracturing Completions and Workovers* | 548 completions and workovers/year ^c | MT/(completion or workover) ^h | 2,690.6 |
| Hydraulic Fracturing Completions and Workovers with RECs* | 1,043 completions and workovers/year ^c | MT/(completion or workover) ^h | 3,379.6 |
| Hydraulic Fracturing Completions and Workovers with RECs that flare* | 1,979 completions and workovers/year ^c | MT/(completion or workover) ^h | 9,653.4 |
| Well Drilling | 18,837 wells ^{i,1} | 2,505.9-2,965.0 scf/well ⁱ | 971.6 |
| Normal Operations | | | |
| Pneumatic Device Vents* | 834,919 controllers ^{c,d,2} | 176.74-209.12 scfd/device ^{c,d} | 1,105,119.0 |
| Pneumatic Device Vents - Low Bleed (LB) | 226,280 controllers ^{c,d,2} | 22.52-26.64 scfd/device ^{c,d} | Aggregated |
| Pneumatic Device Vents - High Bleed (HB) | 29,006 controllers ^{c,d,2} | 612.66-724.91 scfd/device ^{c,d} | Aggregated |
| Pneumatic Device Vents - Intermittent Bleed (IB) | 579,633 controllers ^{c,d,2} | 215.13-254.55 scfd/device ^{c,d} | Aggregated |
| Chemical Injection Pumps* | 83,249 active pumps ^{c,d,2} | 208.89-252.30 scfd/pump ^{c,d} | 128,876.5 |
| Kimray Pumps | 5,012,753 MMscf/yr ^{b,2} | 977.5-1,156.6 scf/MMscf ^b | 100,857.2 |
| Dehydrator Vents | 5,625,985 MMscf/yr ^{b,2} | 271.58-321.34 scf/MMscf ^b | 31,448.3 |
| Condensate Tank Vents | | | |
| Condensate Tanks without Control Devices | 139 MMbbl/yr ^{k,1} | 21.87-302.75 scf/bbl ^l | 253,092.6 |
| Condensate Tanks with Control Devices* | 139 MMbbl/yr ^{k,1} | 4.37-60.55 scf/bbl ^l | 50,618.5 |
| Compressor Exhaust Vented | | | |
| Gas Engines | 51,648 MMHPhr ^{b,2} | 0.237-0.280 scf/HPhr ^b | 249,756.3 |
| Well Clean Ups | | | |
| Liquids Unloading with Plunger Lifts* | 22,477 venting wells ^{a,m,2} | 2,856-1,137,406 scfy/venting well ^m | 112,568.8 |
| Liquids Unloading without Plunger Lifts* | 37,912 venting wells ^{a,m,2} | 77,891-2,002,960 scfy/venting well ^m | 148,075.1 |
| Blowdowns | | | |
| Vessel Blowdowns | 422,542 vessels ^{b,2} | 76.86-90.94 scfy/vessel ^b | 668.5 |
| Pipeline Blowdowns | 431,051 miles (gathering) ^{b,2} | 304.49-360.28 scfy/mile ^b | 2,702.9 |
| Compressor Blowdowns | 48,518 compressors ^{b,2} | 3,719-4,400 scfy/compressor ^b | 3,713.8 |
| Compressor Starts | 48,518 compressors ^{b,2} | 8,320-9,844 scfy/compressor ^b | 8,308.4 |
| Upsets | | | |
| Pressure Relief Valves | 1,015,507 PRV ^{b,2} | 33.50-39.64 scfy/PRV ^b | 700.3 |
| Mishaps | 107,763 miles ^{f,2} | 659.24-780.03 scf/mile ^b | 1,463.0 |
| Produced Water from Coal Bed Methane Wells | | | |
| Black Warrior | 5,480 wells ^o | 0.0023 kt/well ^{o,1} | 12,790.5 |
| Powder River | 20,596,530,150 gal produced water ⁿ | kt/gal water 2.3E-09 drainage ^{n,1} | 47,627.3 |
| Offshore Platforms | | | |
| Shallow Water Gas Platforms (Gulf of Mexico and Pacific) | shallow water gas 1,973 platforms ^{p,3} | 8,899 scfd/platform ^q | 123,460.0 |

| | | | |
|---|---|-----------------------------------|----------|
| Deep Water Gas Platforms (Gulf of Mexico and Pacific) | deep water gas 41 platforms ^{p,3} | 93,836 scfd/platform ^q | 27,105.3 |
|---|---|-----------------------------------|----------|

| | |
|---------------------------------------|----------------|
| Regulatory Reductions (kt) | (91.4) |
| Voluntary Reductions (kt) | (483.2) |
| Total Reductions (kt) | (574.6) |
| Total Potential Emissions (kt) | 4,933.8 |
| Total Net Emissions (kt) | 4,359.2 |

*The values in this table are net emissions for these sources.

^a DI Desktop (2015)

^b EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

^c 2014 GHGRP – Subpart W data

^d EPA (2016a)

^e EPA (2016b)

^f ICF (1996), Estimation of Activity Factors for the Natural Gas Exploration and Production Industry in the U.S.

^g API/ICF Memorandum (1997)

^h 2011-2014 GHGRP – Subpart W data

ⁱ EIA Monthly Energy Review

^j Radian (1992), Global Emissions of Methane Sources

^k EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report

^l EP&P/API Tank Calc runs

^m API/ANGA (2012), Characterizing Pivotal Sources of Methane Emission from Natural Gas Production – Summary and Analysis of API and ANGA Survey

ⁿ Wyoming Oil and Gas Conservation Commission (2015)

^o Alabama State Oil and Gas Board (2015)

^p Bureau of Ocean Energy Management, Regulation and Enforcement (2011)

^q EPA (2015), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Offshore Platform Emissions

^{bb} Totals may not sum due to independent rounding.

^{cc} Emissions from oil wells that produce associated gas are estimated in the Petroleum Systems model. In the Natural Gas Systems model, the oil wells counts are used as a driver only.

^{dd} NA = not applicable (i.e., this data is not applicable for the Natural Gas Systems model).

¹ Activity data for 2014 available from source.

² Ratios relating other factors for which activity data are available.

³ 2013 activity data are used to determine some or all of the 2014 activity.

*The values in this table are net emissions for these sources.

Table A-135: U.S. Activity Data for Hydraulic Fracturing (HF) Completions and Workovers split by 4 categories

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 ^a | 2012 ^a | 2013 ^a | 2014 ^a |
|---|--------------|---------------|---------------|---------------|-------------------|-------------------|-------------------|-------------------|
| HF Completions and Workovers that vent | 3,920 | 10,303 | 5,865 | 5,373 | 4,640 | 3,109 | 1,677 | 1,791 |
| HF Completions and Workovers that flare | 436 | 1,493 | 1,124 | 1,120 | 1,386 | 703 | 835 | 548 |
| HF Completions and Workovers with RECs | 0 | 2,353 | 3,187 | 3,528 | 3,884 | 3,413 | 3,156 | 1,043 |
| HF Completions and Workovers with RECs that flare | 0 | 784 | 1,062 | 1,176 | 1,295 | 1,911 | 2,117 | 1,979 |
| Total | 4,355 | 14,933 | 11,238 | 11,196 | 11,204 | 9,136 | 7,785 | 5,361 |

^a 2011, 2012, 2013, 2014 GHGRP - Subpart W data

Table A-136: 2014 Data and CH₄ Emissions (Mg) for the Natural Gas Processing Stage

| Activity | 2014 EPA Inventory Values | | | | Calculated Potential Emissions (Mg) |
|---------------------------------------|---------------------------|----------------------------|---|------------------------------|-------------------------------------|
| | Activity Data | | Emission Factor (Potential) ^{aa} | | |
| Normal Fugitives | | | | | |
| Plants | 668 | plants ^{a.1} | 7,906 | scfd/plant ^b | 37,126.4 |
| Reciprocating Compressors | 6,020 | compressors ^{c.2} | 11,196 | scfd/compressor ^b | 473,828.9 |
| Centrifugal Compressors (wet seals) | 665 | compressors ^{d.2} | 51,370 | scfd/compressor ^d | 240,031.0 |
| Centrifugal Compressors (dry seals) | 306 | compressors ^{d.2} | 25,189 | scfd/compressor ^d | 54,117.2 |
| Vented and Combusted | | | | | |
| Gas Engines | 43,251 | MMHPhr ^{c.2} | 0.24 | scf/HPhr ^b | 199,922.8 |
| Gas Turbines | 51,283 | MMHPhr ^{c.2} | 0.01 | scf/HPhr ^b | 5,630.0 |
| AGR Vents | 339 | AGRunits ^{b.2} | 6,083 | scfd/AGR ^b | 14,477.9 |
| Kimray Pumps | 1,566,830 | MMscf/yr ^{c.2} | 177.75 | scf/MMscf ^b | 5,364.0 |
| Dehydrator Vents | 14,115,586 | MMscf/yr ^{c.2} | 121.55 | scf/MMscf ^b | 33,045.3 |
| Pneumatic Controllers | 668 | gasplants ^{a.1} | 164,721 | scfy/plant ^b | 2,119.2 |
| Routine Maintenance | | | | | |
| Blowdowns/Venting | 668 | gasplants ^{a.1} | 4,060 | Mscfy/plant ^b | 52,234.7 |
| Regulatory Reductions (kt) | | | | | (17.5) |
| Voluntary Reductions (kt) | | | | | (140.8) |
| Total Reductions (kt) | | | | | (158.3) |
| Total Potential Emissions (kt) | | | | | 1,117.9 |
| Total Net Emissions (kt) | | | | | 959.6 |

^a Oil and Gas Journal^b EPA/GRI (1996), Methane Emissions from the Natural Gas Industry^c ICF (2008), Natural Gas Model Activity Factor Basis Change^d ICF (2010), Emissions from Centrifugal Compressors^{aa} Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). See detailed explanation of methodology above.¹ Activity data for 2014 available from source.² Ratios relating other factors for which activity data are available.

Table A-137: 2014 Data and CH₄ Emissions (Mg) for the Natural Gas Transmission Stage

| Activity | 2014 EPA Inventory Values | | | | Calculated Potential Emissions (Mg) |
|---|---------------------------|--------------------------------------|---|-----------------------------------|-------------------------------------|
| | Activity Data | | Emission Factor (Potential) ^{aa} | | |
| Fugitives | | | | | |
| Pipeline Leaks | 301,748 | miles ^a | 1.55 | scfd/mile ^b | 3,296.3 |
| <i>Compressor Stations (Transmission)*</i> | | | | | |
| Station Total Emissions | 1,834 | stations ^{c,d,2} | 44,459 | scfd/station ^{c,d,bb} | 573,179.2 |
| Station + Compressor Fugitive Emissions | 5,221 | compressors ^{c,d,2} | 9,104 | scfd/station ^{c,d,bb} | 117,370.9 |
| Reciprocating Compressor | 2,173 | compressors ^{c,d,2} | 9,246 | scfd/compressor ^{c,d,bb} | 339,361.9 |
| Centrifugal Compressor (wet seals) | 869 | compressors ^{c,d,2} | 9,673 | scfd/compressor ^{c,d,bb} | 59,092.2 |
| Centrifugal Compressor (dry seals) | 1,304 | compressors ^{c,d,2} | 6,259 | scfd/compressor ^{c,d,bb} | 57,354.2 |
| <i>Compressor Stations (Storage)*</i> | | | | | |
| Station Total Emissions | 356 | stations ^{c,d,2} | 52,604 | scfd/station ^{c,d,bb} | 131,647.9 |
| Station + Compressor Fugitive Emissions | 356 | stations ^{c,d,2} | 10,100 | scfd/station ^{c,d,bb} | 25,276.0 |
| Reciprocating Compressor | 1,520 | compressors ^{c,d,2} | 9,957 | scfd/compressor ^{c,d,bb} | 106,371.9 |
| Wells (Storage) | 19,522 | wells ^{b,2} | 114.50 | scfd/well ^b | 15,714.0 |
| M&R (Trans. Co. Interconnect) | 2,686 | stations ^{e,2} | 3,984 | scfd/station ^b | 75,230.0 |
| M&R (Farm Taps + Direct Sales) | 79,646 | stations ^{e,2} | 31.20 | scfd/station ^b | 17,468.9 |
| Normal Operation | | | | | |
| Dehydrator vents (Transmission) | 1,169,007 | MMscf/yr ^{b,2} | 93.72 | scf/MMscf ^b | 2,110.1 |
| Dehydrator vents (Storage) | 2,169,267 | MMscf/yr ^{b,2} | 117.18 | scf/MMscf ^b | 4,895.8 |
| <i>Compressor Exhaust</i> | | | | | |
| Engines (Transmission) | 53,295 | MMHPhr ^{b,2} | 0.24 | scf/HPhr ^b | 246,351.2 |
| Turbines (Transmission) | 12,717 | MMHPhr ^{b,2} | 0.01 | scf/HPhr ^b | 1,396.1 |
| Engines (Storage) | 5,339 | MMHPhr ^{b,2} | 0.24 | scf/HPhr ^b | 24,677.0 |
| Turbines (Storage) | 1,875 | MMHPhr ^{b,2} | 0.01 | scf/HPhr ^b | 205.9 |
| Generators (Engines) | 2,608 | MMHPhr ^{b,2} | 0.24 | scf/HPhr ^b | 12,055.2 |
| Generators (Turbines) | 31 | MMHPhr ^{b,2} | 0.01 | scf/HPhr ^b | 3.4 |
| <i>Pneumatic Devices Trans + Stor*</i> | | | | | |
| Pneumatic Devices Transmission (High Bleed) | 47,140 | devices ^{c,d,2} | 30,611 | scfy/device ^{c,d,bb} | 27,792.1 |
| (Intermittent Bleed) | 4,129 | devices ^{c,d,2} | 151,969 | scfy/device ^{c,d,bb} | 12,085.2 |
| (Low Bleed) | 39,216 | devices ^{c,d,2} | 19,712 | scfy/device ^{c,d,bb} | 14,888.7 |
| Pneumatic Devices Storage (High Bleed) | 3,795 | devices ^{c,d,2} | 11,196 | scfy/device ^{c,d,bb} | 818.2 |
| (Intermittent Bleed) | 23,964 | devices ^{c,d,2} | 63,622 | scfy/device ^{c,d,bb} | 29,364.5 |
| (Low Bleed) | 8,379 | devices ^{c,d,2} | 147,983 | scfy/device ^{c,d,bb} | 23,882.0 |
| | 13,482 | devices ^{c,d,2} | 19,333 | scfy/device ^{c,d,bb} | 5,020.1 |
| | 2,103 | devices ^{c,d,2} | 11,414 | scfy/device ^{c,d,bb} | 462.3 |
| Routine Maintenance/Upsets | | | | | |
| Pipeline venting | 301,748 | miles ^{a,1} | 31.65 | Mscfy/mile ^b | 183,939.2 |
| <i>Station venting Trans + Storage</i> | | | | | |
| Station Venting Transmission | 1,834 | compressor stations ^{c,d,2} | 4,359 | Mscfy/station ^b | 153,965.5 |
| Station Venting Storage | 356 | compressor stations ^{c,d,2} | 4,359 | Mscfy/station ^b | 29,887.7 |
| LNG Storage | | | | | |
| LNG Stations | 70 | stations ^{f,g,3} | 21,507 | scfd/station ^b | 10,622.8 |
| LNG Reciprocating Compressors | 270 | compressors ^{f,g,3} | 21,116 | scfd/compressor ^b | 40,146.5 |
| LNG Centrifugal Compressors | 64 | compressors ^{f,g,3} | 30,573 | scfd/compressor ^b | 13,766.0 |
| <i>LNG Compressor Exhaust</i> | | | | | |
| LNG Engines | 579 | MMHPhr ^{f,g,3} | 0.24 | scf/HPhr ^b | 2,677.7 |
| LNG Turbines | 113 | MMHPhr ^{f,g,3} | 0.01 | scf/HPhr ^b | 12.4 |
| LNG Station venting | 70 | stations ^{f,g,3} | 4,359 | Mscfy/station ^b | 5,898.6 |
| LNG Import Terminals | | | | | |
| LNG Stations | 8 | stations ^{f,g,3} | 21,507 | scfd/station ^b | 1,270.0 |
| LNG Reciprocating Compressors | 41 | compressors ^{f,g,3} | 21,116 | scfd/compressor ^b | 6,056.5 |
| LNG Centrifugal Compressors | 7 | compressors ^{f,g,3} | 30,573 | scfd/compressor ^b | 1,547.5 |
| <i>LNG Compressor Exhaust</i> | | | | | |
| LNG Engines | 303 | MMHPhr ^{f,g,3} | 0.24 | scf/HPhr ^b | 1,401.7 |

| | | | | | |
|---------------------------------------|----|---------------------------|-------|----------------------------|---------|
| LNG Turbines | 60 | MMHPh ^{f,g,3} | 0.01 | scf/HPh ^b | 6.6 |
| LNG Station venting | 8 | stations ^{f,g,3} | 4,359 | Mscfy/station ^b | 705.2 |
| Regulatory Reductions (kt) | | | | | - |
| Voluntary Reductions (kt) | | | | | (335.0) |
| Total Reductions (kt) | | | | | (335.0) |
| Total Potential Emissions (kt) | | | | | 1,617.3 |
| Total Net Emissions (kt) | | | | | 1,282.3 |

^a Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2014)

^b EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

^c EPA (2016c)

^d 2014 GHGRP – Subpart W data

^e ICF (2008), Natural Gas Model Activity Factor Basis Change

^f ICF (1996), Estimation of Activity Factors for the Natural Gas Exploration and Production Industry in the U.S.

^g EIA (2004), U.S. LNG Markets and Uses

¹ Activity data for 2014 available from source.

² Ratios relating other factors for which activity data are available.

³ 2013 activity data are used to determine some or all of the 2014 activity (to be updated).

^{aa} Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). See detailed explanation of methodology above.

^{bb} Emission factors represent actual emissions and can be used to calculate emissions directly.

*The values in this table are net emissions for these sources.

Table A-138: 2014 Data and CH₄ Emissions (Mg) for the Natural Gas Distribution Stage

| Activity | 2014 EPA Inventory Values | | | | Calculated Potential Emissions (Mg) |
|---------------------------------------|---------------------------|-----------------------------|---|--------------------------------|-------------------------------------|
| | Activity Data | | Emission Factor (Potential) ^{aa} | | |
| Pipeline Leaks* | | | | | |
| Mains—Cast Iron | 29,359 | miles ^{a,1} | 60.09 | Mscf/mile-yr ^{c,bb} | 33,976.2 |
| Mains—Unprotected steel | 58,520 | miles ^{a,1} | 44.72 | Mscf/mile-yr ^{c,bb} | 50,404.7 |
| Mains—Protected steel | 486,432 | miles ^{a,1} | 5.02 | Mscf/mile-yr ^{c,bb} | 47,061.8 |
| Mains—Plastic | 690,029 | miles ^{a,1} | 1.50 | Mscf/mile-yr ^{c,bb} | 19,905.5 |
| Services—Unprotected steel | 3,432,641 | services ^{a,1} | 0.75 | Mscf/service ^{c,bb} | 49,727.5 |
| Services Protected steel | 14,588,827 | services ^{a,1} | 0.07 | Mscf/service ^{c,bb} | 18,896.3 |
| Services—Plastic | 46,755,197 | services ^{a,1} | 0.01 | Mscf/service ^{c,bb} | 12,296.3 |
| Services—Copper | 935,595 | services ^{a,1} | 0.25 | Mscf/service ^b | 4,582.8 |
| Meter/Regulator (City Gates)* | | | | | |
| M&R >300 | 3,952 | stations ^{c,d,2} | 12.70 | scfh/station ^{c,d,bb} | 8,468.2 |
| M&R 100-300 | 14,423 | stations ^{c,d,2} | 5.90 | scfh/station ^{c,d,bb} | 14,356.7 |
| M&R <100 | 7,709 | stations ^{c,d,2} | 4.31 | scfh/station ^b | 5,605.7 |
| Reg >300 | 4,321 | stations ^{c,d,2} | 5.15 | scfh/station ^{c,d,bb} | 3,754.4 |
| R-Vault >300 | 1,501 | stations ^{c,d,2} | 0.30 | scfh/station ^{c,d,bb} | 76.0 |
| Reg 100-300 | 13,071 | stations ^{c,d,2} | 0.85 | scfh/station ^{c,d,bb} | 1,874.6 |
| R-Vault 100-300 | 3,473 | stations ^{c,d,2} | 0.30 | scfh/station ^{c,d,bb} | 175.8 |
| Reg 40-100 | 39,225 | stations ^{c,d,2} | 0.97 | scfh/station ^{c,d,bb} | 6,419.5 |
| R-Vault 40-100 | 20,573 | stations ^{c,d,2} | 0.30 | scfh/station ^{c,d,bb} | 1,041.3 |
| Reg <40 | 16,633 | stations ^{c,d,2} | 0.13 | scfh/station ^b | 373.2 |
| Customer Meters | | | | | |
| Residential | 53,339,363 | Outdoor meters ^e | 77.31 | scfy/meter ^{b,c} | 79,424.1 |
| Commercial/Industry | 5,611,121 | meters ^e | 505.40 | scfy/meter ^{b,c} | 54,619.1 |
| Routine Maintenance | | | | | |
| Pressure Relief Valve Releases | 1,264,340 | milemain ^{a,1} | 0.05 | Mscf/mile ^b | 1,217.6 |
| Pipeline Blowdown | 2,168,588 | miles ^{b,2} | 0.10 | Mscfy/mile ^b | 4,260.2 |
| Upsets | | | | | |
| Mishaps (Dig-ins) | 2,168,588 | miles ^{b,2} | 1.59 | Mscfy/mile ^b | 66,409.5 |
| Regulatory Reductions (kt) | | | | | - |
| Voluntary Reductions (kt) | | | | | (40.8) |
| Total Reductions (kt) | | | | | (40.8) |
| Total Potential Emissions (kt) | | | | | 484.9 |
| Total Net Emissions (kt) | | | | | 444.1 |

^a Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2013)

^b EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

^c EPA (2016d)

^d 2014 GHGRP – Subpart W data

^f EIA (2015d, 2015e, 2015f) – Number of Consumers (Residential, Commercial, and Industrial)

^{aa} Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). See detailed explanation of methodology above.

^{bb} Emission factors represent actual emissions and can be used to calculate emissions directly.

¹ Activity data for 2014 available from source.

² Ratios relating other factors for which activity data are available.

*The values in this table are net emissions for these sources.

Table A-139: U.S. Production Sector CH₄ Content in Natural Gas by NEMS Region (General Sources)

| Year | U.S. Region | | | | | | |
|------|-------------|--------------|----------------|------------|------------|------------|-----------------|
| | North East | Midcontinent | Rocky Mountain | South West | West Coast | Gulf Coast | Lower 48 States |
| 1990 | 84.0% | 78.3% | 67.0% | 64.4% | 75.3% | 79.8% | n/a |
| 1991 | 83.8% | 78.7% | 69.1% | 67.1% | 78.1% | 80.1% | n/a |
| 1992 | 83.5% | 79.1% | 71.4% | 75.4% | 80.8% | 82.7% | n/a |
| 1993 | 82.9% | 79.9% | 73.4% | 76.1% | 83.6% | 84.1% | n/a |
| 1994 | 82.0% | 80.7% | 75.5% | 77.4% | 86.4% | 85.6% | n/a |
| 1995 | 81.5% | 81.6% | 77.6% | 79.0% | 89.1% | 87.2% | n/a |
| 1996 | 81.2% | 82.6% | 80.5% | 80.5% | 91.9% | 88.7% | 84.2% |
| 1997 | 80.3% | 82.5% | 80.4% | 80.5% | 91.9% | 88.6% | 84.1% |
| 1998 | 81.0% | 82.5% | 80.5% | 80.5% | 91.9% | 88.6% | 84.2% |
| 1999 | 80.5% | 82.5% | 80.4% | 80.5% | 91.9% | 88.7% | 84.2% |
| 2000 | 80.8% | 82.5% | 80.2% | 80.5% | 91.9% | 88.7% | 84.0% |
| 2001 | 80.3% | 82.5% | 79.5% | 80.5% | 91.9% | 88.7% | 83.8% |
| 2002 | 80.4% | 82.5% | 79.3% | 80.5% | 91.9% | 88.6% | 83.5% |
| 2003 | 76.4% | 82.6% | 79.1% | 80.5% | 91.9% | 88.6% | 83.2% |
| 2004 | 80.4% | 82.7% | 79.0% | 80.5% | 91.9% | 88.6% | 83.4% |
| 2005 | 80.1% | 82.7% | 79.0% | 80.5% | 91.9% | 88.6% | 83.4% |
| 2006 | 79.5% | 83.0% | 78.9% | 80.5% | 91.9% | 88.6% | 83.4% |
| 2007 | 85.8% | 82.7% | 77.5% | 80.5% | 91.9% | 88.6% | 83.9% |
| 2008 | 86.0% | 82.7% | 77.7% | 80.5% | 91.9% | 88.5% | 83.9% |
| 2009 | 85.1% | 82.7% | 77.5% | 80.5% | 91.9% | 88.5% | 83.6% |
| 2010 | 84.3% | 82.8% | 77.4% | 80.5% | 91.9% | 88.3% | 83.4% |
| 2011 | 85.2% | 82.6% | 77.5% | 80.5% | 91.9% | 88.2% | 83.3% |
| 2012 | 84.8% | 82.5% | 78.2% | 80.5% | 91.9% | 88.2% | 83.0% |
| 2013 | 84.2% | 82.5% | 77.9% | 80.5% | 91.9% | 88.9% | 83.0% |
| 2014 | 84.0% | 82.4% | 77.7% | 80.5% | 91.9% | 88.9% | 82.7% |

Table A-140: U.S. Production Sector CH₄ Content in Natural Gas by NEMS Region (Gas Wells Without Hydraulic Fracturing)

| Year | U.S. Region | | | | | | |
|------|-------------|--------------|----------------|------------|------------|------------|-----------------|
| | North East | Midcontinent | Rocky Mountain | South West | West Coast | Gulf Coast | Lower 48 States |
| 1990 | 84.0% | 78.3% | 67.0% | 64.4% | 75.3% | 79.8% | n/a |
| 1991 | 83.8% | 78.7% | 69.1% | 67.1% | 78.1% | 80.1% | n/a |
| 1992 | 83.5% | 79.1% | 71.4% | 75.4% | 80.8% | 82.7% | n/a |
| 1993 | 82.9% | 79.9% | 73.4% | 76.1% | 83.6% | 84.1% | n/a |
| 1994 | 82.0% | 80.7% | 75.5% | 77.4% | 86.4% | 85.6% | n/a |
| 1995 | 81.5% | 81.6% | 77.6% | 79.0% | 89.1% | 87.2% | n/a |
| 1996 | 81.2% | 82.5% | 79.6% | 80.5% | 91.9% | 88.6% | 84.0% |
| 1997 | 80.5% | 82.5% | 79.5% | 80.5% | 91.9% | 88.6% | 83.9% |
| 1998 | 81.2% | 82.5% | 79.5% | 80.5% | 91.9% | 88.6% | 84.0% |
| 1999 | 80.7% | 82.5% | 79.5% | 80.5% | 91.9% | 88.7% | 83.9% |
| 2000 | 81.0% | 82.5% | 79.2% | 80.5% | 91.9% | 88.7% | 83.8% |
| 2001 | 80.4% | 82.5% | 78.3% | 80.5% | 91.9% | 88.6% | 83.5% |
| 2002 | 80.5% | 82.5% | 78.1% | 80.5% | 91.9% | 88.6% | 83.2% |
| 2003 | 76.5% | 82.6% | 77.9% | 80.5% | 91.9% | 88.6% | 82.9% |
| 2004 | 80.5% | 82.6% | 77.8% | 80.5% | 91.9% | 88.6% | 83.1% |
| 2005 | 80.3% | 82.7% | 77.7% | 80.5% | 91.9% | 88.6% | 83.1% |
| 2006 | 79.6% | 83.0% | 77.7% | 80.5% | 91.9% | 88.6% | 83.1% |
| 2007 | 85.6% | 82.7% | 75.8% | 80.5% | 91.9% | 88.6% | 83.5% |
| 2008 | 85.6% | 82.7% | 76.0% | 80.5% | 91.9% | 88.5% | 83.5% |
| 2009 | 84.7% | 82.7% | 75.8% | 80.5% | 91.9% | 88.5% | 83.2% |
| 2010 | 83.8% | 82.8% | 75.6% | 80.5% | 91.9% | 88.3% | 82.9% |
| 2011 | 85.0% | 82.6% | 75.8% | 80.5% | 91.9% | 88.2% | 82.8% |

| | | | | | | | |
|------|-------|-------|-------|-------|-------|-------|-------|
| 2012 | 84.4% | 82.5% | 76.7% | 80.5% | 91.9% | 88.2% | 82.5% |
| 2013 | 83.9% | 82.5% | 76.3% | 80.5% | 91.9% | 88.9% | 82.4% |
| 2014 | 83.6% | 82.4% | 76.0% | 80.5% | 91.9% | 88.9% | 82.1% |

Table A-141: U.S. Production Sector CH₄ Content in Natural Gas by NEMS Region (Gas Wells With Hydraulic Fracturing)

| Year | U.S. Region | | | | | | |
|------|-------------|--------------|----------------|------------|------------|------------|-----------------|
| | North East | Midcontinent | Rocky Mountain | South West | West Coast | Gulf Coast | Lower 48 States |
| 1990 | 84.0% | 78.3% | 67.0% | 64.4% | 75.3% | 79.8% | n/a |
| 1991 | 83.8% | 78.7% | 69.1% | 67.1% | 78.1% | 80.1% | n/a |
| 1992 | 83.5% | 79.1% | 71.4% | 75.4% | 80.8% | 82.7% | n/a |
| 1993 | 82.9% | 79.9% | 73.4% | 76.1% | 83.6% | 84.1% | n/a |
| 1994 | 82.0% | 80.7% | 75.5% | 77.4% | 86.4% | 85.6% | n/a |
| 1995 | 81.5% | 81.6% | 77.6% | 79.0% | 89.1% | 87.2% | n/a |
| 1996 | 83.2% | 92.6% | 74.4% | 80.5% | 91.9% | 88.7% | 82.1% |
| 1997 | 83.1% | 92.6% | 74.9% | 80.5% | 91.9% | 88.6% | 82.1% |
| 1998 | 83.1% | 92.6% | 75.5% | 80.5% | 91.9% | 88.6% | 82.3% |
| 1999 | 83.1% | 92.6% | 75.3% | 80.5% | 91.9% | 88.7% | 81.9% |
| 2000 | 83.0% | 92.6% | 76.4% | 80.5% | 91.9% | 88.7% | 82.5% |
| 2001 | 83.0% | 92.6% | 78.9% | 80.5% | 91.9% | 88.7% | 83.6% |
| 2002 | 83.0% | 92.6% | 80.5% | 80.5% | 91.9% | 88.6% | 84.4% |
| 2003 | 83.1% | 92.6% | 81.4% | 80.5% | 91.9% | 88.6% | 84.9% |
| 2004 | 83.0% | 92.6% | 81.7% | 80.5% | 91.9% | 88.6% | 85.2% |
| 2005 | 83.0% | 92.6% | 82.0% | 80.5% | 91.9% | 88.6% | 85.3% |
| 2006 | 83.0% | 92.6% | 82.6% | 80.5% | 91.9% | 88.6% | 85.7% |
| 2007 | 83.5% | 92.6% | 86.5% | 80.5% | 91.9% | 88.6% | 88.7% |
| 2008 | 84.1% | 92.6% | 86.3% | 80.5% | 91.9% | 88.5% | 88.4% |
| 2009 | 84.1% | 92.6% | 86.8% | 80.5% | 91.9% | 88.5% | 88.7% |
| 2010 | 84.3% | 92.6% | 86.8% | 80.5% | 91.9% | 88.3% | 89.0% |
| 2011 | 83.6% | 92.6% | 87.9% | 80.5% | 91.9% | 88.2% | 89.4% |
| 2012 | 84.0% | 92.6% | 87.6% | 80.5% | 91.9% | 88.2% | 89.1% |
| 2013 | 83.9% | 92.6% | 88.1% | 80.5% | 91.9% | 88.9% | 89.3% |
| 2014 | 84.2% | 92.6% | 88.8% | 80.5% | 91.9% | 88.9% | 90.0% |

Table A-142: Key Activity Data Drivers

| Variable | Units | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| Transmission Pipelines Length | miles | 291,925 | 300,468 | 304,573 | 304,805 | 305,058 | 303,341 | 302,777 | 301,748 |
| Wells | | | | | | | | | |
| NE—Associated Gas Wells ^{a,1} | # wells | 28,397 | 32,769 | 37,141 | 41,541 | 42,634 | 45,314 | 43,781 | 45,349 |
| NE—Non-associated Gas Wells ^{a,1} | # wells | 64,620 | 128,114 | 148,980 | 155,754 | 158,294 | 158,666 | 158,017 | 160,692 |
| MC—Associated Gas Wells ^{a,1} | # wells | 50,789 | 43,686 | 46,561 | 46,189 | 46,053 | 48,547 | 50,142 | 46,830 |
| MC—Non-associated Gas Wells ^{a,1} | # wells | 62,473 | 85,656 | 101,654 | 101,457 | 102,687 | 101,312 | 99,609 | 100,655 |
| RM—Associated Gas Wells ^{a,1} | # wells | 23,419 | 29,425 | 37,769 | 39,888 | 43,427 | 47,547 | 50,523 | 53,964 |
| RM—Non-associated Gas Wells ^{a,1} | # wells | 22,737 | 61,832 | 79,083 | 78,607 | 79,427 | 78,918 | 76,848 | 75,745 |
| SW—Associated Gas Wells ^{a,1} | # wells | 308,254 | 220,818 | 227,313 | 232,151 | 236,087 | 244,444 | 247,386 | 253,329 |
| SW—Non-associated Gas Wells ^{a,1} | # wells | 32,665 | 42,806 | 48,949 | 49,056 | 49,351 | 48,812 | 48,901 | 49,023 |
| WC—Associated Gas Wells ^{a,1} | # wells | 16,627 | 18,131 | 28,600 | 28,095 | 28,467 | 28,756 | 29,578 | 30,071 |
| WC—Non-associated Gas Wells ^{a,1} | # wells | 2,130 | 2,293 | 2,788 | 2,672 | 2,738 | 2,732 | 2,516 | 2,424 |
| GC—Associated Gas Wells ^{a,1} | # wells | 141,216 | 62,003 | 60,856 | 60,263 | 61,432 | 66,369 | 69,685 | 74,330 |
| GC—Non-associated Gas Wells ^{a,1} | # wells | 34,084 | 53,202 | 67,185 | 69,274 | 70,701 | 70,148 | 68,600 | 67,601 |
| Platforms^{aa} | | | | | | | | | |
| Gulf of Mexico and Pacific OCS Off-shore Platforms ^{b,2} | # platforms | 3,941 | 3,909 | 3,570 | 3,432 | 3,432 | 3,432 | 3,432 | 3,432 |
| GoM and Pacific OCS Deep Water Platforms ^{b,2} | # platforms | 17 | 59 | 68 | 70 | 70 | 70 | 70 | 70 |
| Gas Plants^{c,1} | # gas plants | 761 | 566 | 579 | 585 | 606 | 606 | 650 | 668 |
| Distribution Services | # of services | 47,883,083 | 61,832,574 | 64,498,352 | 64,079,565 | 64,774,921 | 65,057,667 | 65,554,546 | 65,712,260 |
| Steel—Unprotected ^{d,1} | # of services | 7,633,526 | 5,507,356 | 5,221,143 | 4,226,682 | 4,142,891 | 3,917,081 | 3,669,003 | 3,432,641 |
| Steel—Protected ^{d,1} | # of services | 19,781,581 | 16,529,118 | 15,470,934 | 15,324,020 | 15,275,872 | 14,954,692 | 14,753,566 | 14,588,827 |
| Plastic ^{d,1} | # of services | 18,879,865 | 38,549,089 | 42,719,579 | 43,450,479 | 44,299,530 | 45,176,606 | 46,158,870 | 46,755,197 |
| Copper ^{d,1} | # of services | 1,588,111 | 1,247,011 | 1,086,696 | 1,078,384 | 1,056,628 | 1,009,288 | 973,107 | 935,595 |
| Distribution Mains | miles | 944,157 | 1,162,560 | 1,218,148 | 1,228,099 | 1,237,203 | 1,245,694 | 1,253,316 | 1,264,340 |
| Cast Iron ^{d,1} | miles | 58,292 | 39,645 | 35,623 | 34,592 | 33,669 | 32,406 | 30,904 | 29,359 |
| Steel—Unprotected ^{d,1} | miles | 108,941 | 72,458 | 67,758 | 67,443 | 64,981 | 63,703 | 60,619 | 58,520 |
| Steel—Protected ^{d,1} | miles | 465,538 | 490,156 | 488,352 | 488,718 | 488,810 | 487,646 | 486,771 | 486,432 |
| Plastic ^{d,1} | miles | 311,386 | 560,301 | 626,415 | 637,346 | 649,743 | 661,939 | 675,022 | 690,029 |

^a DI Desktop (2015)

^b Bureau of Ocean Energy Management, Regulation and Enforcement (2011)

^c Oil and Gas Journal

^d Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2014)

¹ Activity data for 2014 available from source.

² 2013 activity data are used to determine some or all of the 2014 activity (to be updated).

^{aa} Number of platforms include both oil and gas platforms

Table A-143: CH₄ Reductions Derived from the Natural Gas STAR Program (kt)

| Process | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------------|--------------|----------------|----------------|------------------|----------------|----------------|----------------|----------------|
| Production | (3.5) | (253.8) | (349.1) | (393.9) | (427.6) | (421.4) | (446.7) | (483.2) |
| Pipeline Leaks | (0.0) | (2.4) | - | - | - | - | - | - |
| Gas Engines | (0.0) | (97.9) | (123.1) | (133.3) | (137.2) | (140.0) | (140.5) | (141.0) |
| Compressor Starts | - | (0.2) | (0.4) | (0.5) | (0.5) | (0.5) | (0.5) | (0.5) |
| Other Production | (3.5) | (155.7) | (225.6) | (260.0) | (289.9) | (280.9) | (305.7) | (341.7) |
| Processing | (1.5) | (155.5) | (137.6) | (214.3) | (140.4) | (140.4) | (140.7) | (140.8) |
| Fugitives Reciprocating Compressors | - | - | - | (1.0) | - | - | (0.1) | (0.1) |
| Gas Engines | - | (1.1) | (6.0) | (6.1) | (6.1) | (6.1) | (6.1) | (6.1) |
| AGR Vents | - | - | - | - | - | - | - | - |
| Dehydrator Vents | (1.3) | (2.1) | (9.3) | (9.3) | (9.3) | (9.3) | (9.3) | (9.3) |
| Other Processing | (0.2) | (152.2) | (122.2) | (197.9) | (125.0) | (125.0) | (125.2) | (125.2) |
| Transmission and Storage | - | (496.2) | (379.0) | (433.2) | (341.9) | (375.4) | (331.8) | (335.0) |
| Engines (Transmission) | - | (83.2) | (116.2) | (119.4) | (121.7) | (124.0) | (126.9) | (129.8) |
| Pipeline Vents (Transmission) | - | (124.9) | (88.7) | (128.2) | (58.9) | (100.1) | (59.4) | (59.4) |
| Other Transmission | - | (288.1) | (174.1) | (185.6) | (161.3) | (151.2) | (145.5) | (145.8) |
| Distribution | - | (48.3) | (63.9) | (54.5) | (58.0) | (45.1) | (40.5) | (40.8) |
| Mishaps (Dig-ins) | - | (0.3) | (0.8) | (0.8) | (4.7) | (0.7) | (0.8) | (0.8) |
| Other Distribution | - | (48.0) | (63.1) | (53.7) | (53.3) | (44.4) | (39.6) | (40.0) |
| Total | (5.0) | (953.8) | (929.5) | (1,095.9) | (967.9) | (982.4) | 959.7) | 999.8) |

Table A-144: CH₄ Reductions Derived from Regulations (kt)

| Process | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------------|--------------|---------------|---------------|----------------|---------------|---------------|----------------|----------------|
| Production | NA | (45.9) | (55.1) | (94.3) | (71.7) | (79.6) | (93.6) | (91.4) |
| Dehydrator vents (NESHAP) | NA | (14.0) | (10.9) | (10.5) | (10.3) | (10.2) | (10.1) | (10.1) |
| Condensate tanks (NESHAP) | NA | (31.9) | (44.2) | (83.8) | (61.4) | (69.4) | (83.6) | (81.3) |
| Processing | (0.0) | (12.1) | (13.9) | (14.4) | (15.5) | (16.3) | (16.4) | (17.5) |
| Dehydrator vents (NESHAP) | (0.0) | (12.1) | (13.9) | (14.4) | (15.5) | (16.3) | (16.4) | (17.5) |
| Transmission and Storage | NA | NA | NA | NA | NA | NA | NA | NA |
| Distribution | NA | NA | NA | NA | NA | NA | NA | NA |
| Total | (0.0) | (58.0) | (69.1) | (108.7) | (87.2) | (95.9) | (110.1) | (108.9) |

NA Not applicable

Note: Totals may not sum due to independent rounding.

Table A-145: National CH₄ Potential Emission Estimates from the Natural Gas Production Stage, and Reductions from the Natural Gas STAR Program and Regulations (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|-------|---------|---------|---------|---------|---------|---------|---------|
| Normal Fugitives | | | | | | | | |
| Gas Wells | | | | | | | | |
| Associated Gas Wells | IE | IE | IE | IE | IE | IE | IE | IE |
| Non-associated Gas Wells (less fractured wells) | 12.8 | 17.1 | 18.6 | 18.4 | 18.5 | 18.1 | 17.8 | 17.8 |
| Gas Wells with Hydraulic Fracturing | 7.8 | 25.3 | 34.3 | 34.7 | 35.5 | 35.5 | 35.0 | 35.1 |
| Well Pad Equipment | | | | | | | | |
| Heaters | 13.0 | 21.0 | 23.8 | 24.4 | 24.6 | 24.5 | 24.1 | 24.0 |
| Separators | 42.4 | 95.4 | 119.9 | 120.9 | 122.7 | 122.1 | 120.0 | 118.6 |
| Dehydrators | 14.4 | 12.1 | 9.0 | 8.9 | 8.6 | 8.6 | 8.4 | 8.4 |
| Meters/Piping | 49.4 | 90.2 | 107.4 | 108.8 | 110.4 | 109.8 | 108.0 | 107.2 |
| Compressors | 33.9 | 74.4 | 92.4 | 96.2 | 98.1 | 97.4 | 96.0 | 96.2 |
| Gathering and Boosting | | | | | | | | |
| Gathering and Boosting Stations* | 956.9 | 1,107.2 | 1,364.2 | 1,431.8 | 1,584.0 | 1,697.4 | 1,730.2 | 1,864.9 |
| Pipeline Leaks | 89.8 | 144.9 | 169.7 | 171.1 | 173.2 | 172.4 | 170.2 | 169.7 |
| Vented and Combusted | | | | | | | | |
| Drilling, Well Completion, and Well Workover | | | | | | | | |

| | | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Gas Well Completions without Hydraulic Fracturing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas Well Workovers without Hydraulic Fracturing | 0.3 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.4 | 0.4 |
| Hydraulic Fracturing Completions and Workovers that vent* | 144.3 | 379.4 | 216.0 | 197.8 | 170.9 | 114.5 | 61.7 | 65.9 |
| Flared Hydraulic Fracturing Completions and Workovers* | 2.1 | 7.3 | 5.5 | 5.5 | 6.8 | 3.4 | 4.1 | 2.7 |
| Hydraulic Fracturing Completions and Workovers with RECs* | 0.0 | 7.6 | 10.3 | 11.4 | 12.6 | 11.1 | 10.2 | 3.4 |
| Hydraulic Fracturing Completions and Workovers with RECs that flare* | 0.0 | 3.8 | 5.2 | 5.7 | 6.3 | 9.3 | 10.3 | 9.7 |
| Well Drilling | 0.7 | 1.6 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| <i>Produced Water from Coal Bed Methane</i> | | | | | | | | |
| Powder River | 0.0 | 50.0 | 54.0 | 50.6 | 47.2 | 47.0 | 47.3 | 47.6 |
| Black Warrior | 2.7 | 9.9 | 12.1 | 12.3 | 12.7 | 12.8 | 12.8 | 12.8 |
| Normal Operations | | | | | | | | |
| Pneumatic Controller Vents* | 556.3 | 1,079.3 | 1,261.7 | 1,249.3 | 1,229.7 | 1,245.3 | 1,259.8 | 1,105.1 |
| Low Bleed | 0.0 | 23.0 | 40.0 | 43.5 | 47.0 | 40.7 | 24.5 | 38.3 |
| High Bleed | 335.9 | 483.7 | 469.6 | 436.4 | 398.9 | 352.9 | 193.9 | 133.5 |
| Intermittent Bleed | 220.5 | 572.5 | 752.0 | 769.4 | 783.9 | 851.8 | 1041.4 | 933.3 |
| Chemical Injection Pumps* | 29.2 | 96.0 | 129.5 | 133.4 | 131.5 | 130.6 | 128.7 | 128.9 |
| Kimray Pumps | 166.5 | 139.9 | 109.1 | 105.4 | 102.8 | 102.2 | 100.7 | 100.9 |
| Dehydrator Vents | 51.9 | 43.6 | 34.0 | 32.9 | 32.1 | 31.9 | 31.4 | 31.4 |
| Condensate Tank Vents | | | | | | | | |
| Condensate Tanks without Control Devices | 77.7 | 99.3 | 137.6 | 260.7 | 191.1 | 215.9 | 260.2 | 253.1 |
| Condensate Tanks with Control Devices* | 15.5 | 19.9 | 27.5 | 52.1 | 38.2 | 43.2 | 52.0 | 50.6 |
| Compressor Exhaust Vented | | | | | | | | |
| Gas Engines | 116.9 | 208.5 | 253.0 | 254.3 | 257.4 | 255.3 | 250.9 | 249.8 |
| Well Clean Ups (Liquids Unloading) | | | | | | | | |
| Liquids Unloading - Vent Using Plungers* | 0.0 | 69.2 | 106.6 | 113.2 | 115.0 | 114.1 | 112.1 | 112.6 |
| Liquids Unloading - Vent Without Using Plungers* | 805.9 | 636.9 | 276.2 | 149.0 | 151.6 | 151.0 | 148.4 | 148.1 |
| Blowdowns | | | | | | | | |
| Vessel BD | 0.3 | 0.5 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Pipeline BD | 1.4 | 2.3 | 2.7 | 2.7 | 2.8 | 2.7 | 2.7 | 2.7 |
| Compressor BD | 1.3 | 2.9 | 3.6 | 3.7 | 3.8 | 3.8 | 3.7 | 3.7 |
| Compressor Starts | 2.9 | 6.4 | 8.0 | 8.3 | 8.5 | 8.4 | 8.3 | 8.3 |
| Upsets | | | | | | | | |
| Pressure Relief Valves | 0.3 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Mishaps | 0.8 | 1.2 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Offshore | | | | | | | | |
| Shallow water Gas Platforms (GoM and Pacific) | 134.8 | 149.3 | 129.1 | 123.5 | 123.5 | 123.5 | 123.5 | 123.5 |
| Deepwater Gas Platforms (GoM and Pacific) | 6.2 | 24.1 | 26.4 | 27.1 | 27.1 | 27.1 | 27.1 | 27.1 |
| Regulatory Reductions (kt) | - | (45.9) | (55.1) | (94.3) | (71.7) | (79.6) | (93.6) | (91.4) |
| Voluntary Reductions (kt) | (3.5) | (256.2) | (349.1) | (393.9) | (427.6) | (421.4) | (446.7) | (483.2) |
| Total Reductions (kt) | (3.5) | (302.1) | (404.2) | (488.2) | (499.3) | (501.0) | (540.4) | (574.6) |
| Total Potential Emissions (kt) | 3,338.7 | 4,627.7 | 4,751.9 | 4,818.5 | 4,851.3 | 4,943.1 | 4,969.8 | 4,933.8 |
| Total Net Emissions (kt) | 3,335.1 | 4,325.5 | 4,347.7 | 4,330.4 | 4,352.0 | 4,442.1 | 4,429.4 | 4,359.2 |

IE: Included Elsewhere. These emissions are included in the Petroleum Systems estimates.

*The values in this table are net emissions for these sources.

Note: Totals may not sum due to independent rounding.

Table A-146: Potential CH₄ Emission Estimates from the Natural Gas Processing Plants, and Reductions from the Natural Gas STAR Program and Regulations (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|------|------|------|------|------|------|------|------|
| Normal Fugitives | | | | | | | | |
| Plants | 42.3 | 31.5 | 32.2 | 32.5 | 33.7 | 33.7 | 36.1 | 37.1 |

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------------------|--------------|--------------|--------------|--------------|----------------|----------------|----------------|----------------|
| Reciprocating Compressors | 324.9 | 327.9 | 377.6 | 390.9 | 420.9 | 442.1 | 445.6 | 473.8 |
| Centrifugal Compressors (wet seals) | 240.3 | 229.2 | 232.9 | 233.9 | 236.1 | 237.7 | 237.9 | 240.0 |
| Centrifugal Compressors (dry seals) | - | 6.5 | 22.7 | 27.1 | 36.8 | 43.8 | 44.9 | 54.1 |
| Vented and Combusted | | | | | | | | |
| <i>Compressor Exhaust</i> | | | | | | | | |
| Gas Engines | 137.1 | 138.3 | 159.3 | 164.9 | 177.6 | 186.5 | 188.0 | 199.9 |
| Gas Turbines | 3.9 | 3.9 | 4.5 | 4.6 | 5.0 | 5.3 | 5.3 | 5.6 |
| AGR Vents | 16.5 | 12.3 | 12.5 | 12.7 | 13.1 | 13.1 | 14.1 | 14.5 |
| Kimray Pumps | 3.7 | 3.7 | 4.3 | 4.4 | 4.8 | 5.0 | 5.0 | 5.4 |
| Dehydrator Vents | 22.7 | 22.9 | 26.3 | 27.3 | 29.4 | 30.8 | 31.1 | 33.0 |
| Pneumatic Controllers | 2.4 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 2.1 | 2.1 |
| Routine Maintenance | | | | | | | | |
| Blowdowns/Venting | 59.5 | 44.3 | 45.3 | 45.7 | 47.4 | 47.4 | 50.8 | 52.2 |
| Regulatory Reductions (kt) | - | (12.1) | (13.9) | (14.4) | (15.5) | (16.3) | (16.4) | (17.5) |
| Voluntary Reductions (kt) | (1.5) | (155.5) | (137.6) | (214.3) | (140.4) | (140.4) | (140.7) | (140.8) |
| Total Reductions (kt) | (1.5) | (167.6) | (151.5) | (228.8) | (155.9) | (156.8) | (157.2) | (158.3) |
| Total Potential Emissions (kt) | 853.2 | 822.2 | 919.5 | 946.0 | 1,006.6 | 1,047.3 | 1,060.9 | 1,117.9 |
| Total Net Emissions (kt) | 851.8 | 654.6 | 768.0 | 717.2 | 850.7 | 890.5 | 903.7 | 959.6 |

Note: Totals may not sum due to independent rounding.

Table A-147: Potential CH₄ Emission Estimates from the Natural Gas Transmission and Storage, and Reductions from the Natural Gas STAR Program and Regulations (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|---------|-------|-------|-------|-------|-------|-------|-------|
| Fugitives | | | | | | | | |
| Pipeline Leaks | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| Compressor Stations (Transmission)* | | | | | | | | |
| Station Total Emissions | 1,098.4 | 667.5 | 549.6 | 521.1 | 493.1 | 496.0 | 536.0 | 573.2 |
| Station + Compressor Fugitive Emissions | - | - | - | - | 94.8 | 101.6 | 109.7 | 117.4 |
| Reciprocating Compressor | - | - | - | - | 301.6 | 293.7 | 317.2 | 339.4 |
| Centrifugal Compressor (wet seals) | - | - | - | - | 46.9 | 51.1 | 55.9 | 59.1 |
| Centrifugal Compressor (dry seals) | - | - | - | - | 49.8 | 49.7 | 53.2 | 57.4 |
| Compressor Stations (Storage)* | | | | | | | | |
| Station Total Emissions | 245.6 | 163.9 | 146.0 | 140.9 | 136.5 | 131.0 | 131.6 | 131.6 |
| Station + Compressor Fugitive Emissions | - | - | - | - | - | 25.1 | 25.3 | 25.3 |
| Reciprocating Compressor | - | - | - | - | - | 105.8 | 106.4 | 106.4 |
| Wells (Storage) | 13.6 | 14.9 | 14.8 | 14.8 | 14.6 | 12.8 | 15.1 | 15.7 |
| M&R (Trans. Co. Interconnect) | 72.8 | 74.9 | 75.9 | 76.0 | 76.1 | 75.6 | 75.5 | 75.2 |
| M&R (Farm Taps + Direct Sales) | 16.9 | 17.4 | 17.6 | 17.6 | 17.7 | 17.6 | 17.5 | 17.5 |
| Vented and Combusted | | | | | | | | |
| Normal Operation | | | | | | | | |
| Dehydrator vents (Transmission) | 2.0 | 1.8 | 1.7 | 1.7 | 1.7 | 1.8 | 2.0 | 2.1 |
| Dehydrator vents (Storage) | 4.2 | 4.6 | 4.6 | 4.6 | 4.5 | 4.0 | 4.7 | 4.9 |
| Compressor Exhaust | | | | | | | | |
| Engines (Transmission) | 176.9 | 203.1 | 211.4 | 222.3 | 225.9 | 235.6 | 241.3 | 246.4 |
| Turbines (Transmission) | 1.0 | 1.2 | 1.2 | 1.3 | 1.3 | 1.3 | 1.4 | 1.4 |
| Engines (Storage) | 21.3 | 23.4 | 23.2 | 23.2 | 22.9 | 20.1 | 23.8 | 24.7 |
| Turbines (Storage) | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Generators (Engines) | 8.7 | 9.9 | 10.3 | 10.9 | 11.1 | 11.5 | 11.8 | 12.1 |
| Generators (Turbines) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Pneumatic Devices Trans + Stor* | | | | | | | | |
| Pneumatic Devices Transmission | 213.1 | 73.0 | 42.8 | 36.2 | 30.0 | 21.5 | 26.6 | 27.8 |
| (High Bleed) | - | - | - | - | 19.5 | 10.0 | 11.9 | 12.1 |
| (Intermittent Bleed) | - | - | - | - | 10.0 | 10.8 | 13.9 | 14.9 |
| (Low Bleed) | - | - | - | - | 0.5 | 0.6 | 0.7 | 0.8 |
| Pneumatic Devices Storage | 44.4 | 35.3 | 29.5 | 27.9 | 26.3 | 26.0 | 30.1 | 29.4 |
| (High Bleed) | - | - | - | - | 22.7 | 21.7 | 25.0 | 23.9 |
| (Intermittent Bleed) | - | - | - | - | 3.2 | 3.8 | 4.5 | 5.0 |
| (Low Bleed) | - | - | - | - | 0.4 | 0.4 | 0.6 | 0.5 |
| Routine Maintenance/Upsets | | | | | | | | |
| Pipeline venting | 178.0 | 183.2 | 185.7 | 185.8 | 186.0 | 184.9 | 184.6 | 183.9 |
| Station venting Trans + Storage | | | | | | | | |
| Station Venting Transmission | 145.5 | 131.0 | 126.6 | 125.5 | 124.4 | 133.2 | 143.9 | 154.0 |

| | | | | | | | | |
|---------------------------------------|---------|---------|---------|---------|---------|---------|---------|---------|
| Station Venting Storage | 30.3 | 28.8 | 29.4 | 29.5 | 29.7 | 29.7 | 29.9 | 29.9 |
| LNG Storage | | | | | | | | |
| LNG Stations | 9.2 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 |
| LNG Reciprocating Compressors | 34.5 | 40.1 | 40.1 | 40.1 | 40.1 | 40.1 | 40.1 | 40.1 |
| LNG Centrifugal Compressors | 11.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 |
| LNG Compressor Exhaust | | | | | | | | |
| LNG Engines | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| LNG Turbines | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LNG Station venting | 5.1 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 |
| LNG Import Terminals | | | | | | | | |
| LNG Stations | 0.2 | 0.4 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.3 |
| LNG Reciprocating Compressors | 1.0 | 2.0 | 5.6 | 5.6 | 5.6 | 5.6 | 5.6 | 6.1 |
| LNG Centrifugal Compressors | 0.3 | 0.5 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.5 |
| LNG Compressor Exhaust | | | | | | | | |
| LNG Engines | 1.7 | 12.2 | 8.8 | 8.4 | 6.9 | 3.6 | 2.1 | 1.4 |
| LNG Turbines | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LNG Station venting | 0.1 | 0.2 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 |
| Regulatory Reductions (kt) | - | - | - | - | - | - | - | - |
| Voluntary Reductions (kt) | - | (496.2) | (379.0) | (433.2) | (341.9) | (375.4) | (331.8) | (335.0) |
| Total Reductions (kt) | - | (496.2) | (379.0) | (433.2) | (341.9) | (375.4) | (331.8) | (335.0) |
| Total Potential Emissions (kt) | 2,342.6 | 1,725.9 | 1,564.6 | 1,533.2 | 1,493.8 | 1,491.8 | 1,563.3 | 1,617.3 |
| Total Net Emissions (kt) | 2,342.6 | 1,229.7 | 1,185.7 | 1,100.0 | 1,151.9 | 1,116.4 | 1,231.5 | 1,282.3 |

*The values in this table are net emissions for these sources.

Note: Totals may not sum due to independent rounding.

Table A-14B: Potential CH₄ Emission Estimates from the Natural Gas Distribution Stage, and Reductions from the Natural Gas STAR Program, and Regulations (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------------------|---------|--------|--------|--------|--------|--------|--------|--------|
| Normal Fugitives | | | | | | | | |
| Pipeline Leaks* | | | | | | | | |
| Mains - Cast Iron | 268.0 | 88.9 | 54.1 | 46.3 | 39.0 | 37.5 | 35.8 | 34.0 |
| Mains - Unprotected steel | 231.2 | 91.3 | 67.4 | 62.6 | 56.0 | 54.9 | 52.2 | 50.4 |
| Mains - Protected steel | 27.5 | 41.6 | 45.3 | 46.3 | 47.3 | 47.2 | 47.1 | 47.1 |
| Mains - Plastic | 59.4 | 44.8 | 28.8 | 23.8 | 18.7 | 19.1 | 19.5 | 19.9 |
| Services - Unprotected steel | 250.0 | 111.6 | 85.7 | 65.3 | 60.0 | 56.7 | 53.2 | 49.7 |
| Services Protected steel | 67.2 | 32.4 | 23.5 | 21.5 | 19.8 | 19.4 | 19.1 | 18.9 |
| Services - Plastic | 3.4 | 9.1 | 10.9 | 11.2 | 11.7 | 11.9 | 12.1 | 12.3 |
| Services - Copper | 7.8 | 6.1 | 5.3 | 5.3 | 5.2 | 4.9 | 4.8 | 4.6 |
| Meter/Regulator (City Gates)* | | | | | | | | |
| M&R >300 | 140.6 | 64.9 | 20.2 | 14.4 | 9.4 | 9.4 | 10.1 | 8.5 |
| M&R 100-300 | 272.8 | 123.9 | 37.4 | 25.9 | 15.9 | 15.9 | 17.2 | 14.4 |
| M&R <100 | 6.6 | 8.3 | 5.6 | 5.6 | 6.2 | 6.2 | 6.7 | 5.6 |
| Reg >300 | 138.4 | 59.3 | 15.8 | 9.8 | 4.2 | 4.2 | 4.5 | 3.8 |
| R-Vault >300 | 0.7 | 0.4 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| Reg 100-300 | 104.7 | 43.9 | 11.1 | 6.5 | 2.1 | 2.1 | 2.2 | 1.9 |
| R-Vault 100-300 | 0.2 | 0.4 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 |
| Reg 40-100 | 8.1 | 9.8 | 6.5 | 6.5 | 7.1 | 7.1 | 7.7 | 6.4 |
| R-Vault 40-100 | 0.6 | 2.0 | 1.6 | 1.7 | 1.4 | 1.5 | 1.3 | 1.0 |
| Reg <40 | 0.4 | 0.6 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Customer Meters | | | | | | | | |
| Residential | 58.4 | 75.0 | 77.2 | 77.4 | 77.9 | 78.4 | 78.9 | 79.4 |
| Commercial/Industry | 43.4 | 52.6 | 53.8 | 53.5 | 53.6 | 54.0 | 54.2 | 54.6 |
| Vented | | | | | | | | |
| Routine Maintenance | | | | | | | | |
| Pressure Relief Valve Releases | 0.9 | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| Pipeline Blowdown | 3.0 | 3.9 | 4.1 | 4.1 | 4.2 | 4.2 | 4.2 | 4.3 |
| Upsets | | | | | | | | |
| Mishaps (Dig-ins) | 47.4 | 60.1 | 63.9 | 64.4 | 64.9 | 65.5 | 65.8 | 66.4 |
| Regulatory Reductions (kt) | - | - | - | - | - | - | - | - |
| Voluntary Reductions (kt) | - | (48.3) | (63.9) | (54.5) | (58.0) | (45.1) | (40.5) | (40.8) |
| Total Reductions (kt) | - | (48.3) | (63.9) | (54.5) | (58.0) | (45.1) | (40.5) | (40.8) |
| Total Potential Emissions (kt) | 1,740.7 | 931.9 | 620.2 | 554.1 | 506.5 | 501.9 | 498.5 | 484.9 |

| | | | | | | | | |
|---------------------------------|----------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Total Net Emissions (kt) | 1,740.7 | 883.6 | 556.3 | 499.6 | 448.5 | 456.7 | 458.0 | 444.1 |
|---------------------------------|----------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|

*The values in this table are net emissions for these sources.

Note: Totals may not sum due to independent rounding.

Table A-149: Net Emissions for Select Sources (kt)

| Stage/Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Production | 3,335.1 | 4,325.5 | 4,347.7 | 4,330.4 | 4,352.0 | 4,442.1 | 4,429.4 | 4,359.2 |
| Gathering Stations | 956.9 | 1,107.2 | 1,364.2 | 1,431.8 | 1,584.0 | 1,697.4 | 1,730.2 | 1,864.9 |
| Hydraulic Fracturing Completions and Workovers | 146.5 | 398.2 | 237.0 | 220.5 | 196.6 | 138.3 | 86.4 | 81.7 |
| Liquids Unloading | 805.9 | 706.1 | 382.8 | 262.2 | 266.6 | 265.1 | 260.5 | 260.6 |
| Dehydrator Vents | 51.9 | 29.6 | 23.1 | 22.3 | 21.8 | 21.6 | 21.3 | 21.4 |
| Condensate Tanks | 93.2 | 87.3 | 121.0 | 229.1 | 167.9 | 189.8 | 228.6 | 222.4 |
| Pipeline Leaks | 89.8 | 142.5 | 169.7 | 171.1 | 173.2 | 172.4 | 170.2 | 169.7 |
| Pneumatic Controller Vents | 556.3 | 1,079.3 | 1,261.7 | 1,249.3 | 1,229.7 | 1,245.3 | 1,259.8 | 1,105.1 |
| Chemical Injection Pumps | 29.2 | 96.0 | 129.5 | 133.4 | 131.5 | 130.6 | 128.7 | 128.9 |
| Gas Engines | 116.9 | 110.6 | 130.0 | 120.9 | 120.2 | 115.3 | 110.4 | 108.8 |
| Compressor Starts | 2.9 | 6.2 | 7.6 | 7.8 | 8.0 | 7.9 | 7.8 | 7.8 |
| Other Production | 485.6 | 562.5 | 521.1 | 482.0 | 452.5 | 458.4 | 425.5 | 387.9 |
| Processing | 851.8 | 654.6 | 768.0 | 717.2 | 850.7 | 890.5 | 903.7 | 959.6 |
| Fugitives | | | | | | | | |
| Reciprocating Compressors | 324.9 | 327.9 | 377.6 | 389.9 | 420.9 | 442.1 | 445.4 | 473.7 |
| Gas Engines | 137.1 | 137.2 | 153.3 | 158.9 | 171.5 | 180.4 | 181.9 | 193.8 |
| AGR Vents | 16.5 | 12.3 | 12.5 | 12.7 | 13.1 | 13.1 | 14.1 | 14.5 |
| Dehydrator Vents | 21.3 | 8.6 | 3.1 | 3.5 | 4.5 | 5.2 | 5.3 | 6.2 |
| Other Processing | 351.9 | 168.6 | 221.5 | 152.3 | 240.8 | 249.7 | 257.0 | 271.4 |
| Transmission and Storage | 2,342.6 | 1,229.7 | 1,185.7 | 1,100.0 | 1,151.9 | 1,116.4 | 1,231.5 | 1,282.3 |
| Transmission Stations | 1098.4 | 667.5 | 549.6 | 521.1 | 493.1 | 496.0 | 536.0 | 573.2 |
| Station Fugitives | NA | NA | NA | NA | 94.8 | 101.6 | 109.7 | 117.4 |
| Reciprocating Compressors | NA | NA | NA | NA | 301.6 | 293.7 | 317.2 | 339.4 |
| Centrifugal Compressors (wet seals) | NA | NA | NA | NA | 46.9 | 51.1 | 55.9 | 59.1 |
| Centrifugal compressors (dry seals) | NA | NA | NA | NA | 49.8 | 49.7 | 53.2 | 57.4 |
| Transmission pneumatic controllers | 213.1 | 73.0 | 42.8 | 36.2 | 30.0 | 21.5 | 26.6 | 27.8 |
| Storage stations | 245.6 | 163.9 | 146.0 | 140.9 | 136.5 | 131.0 | 131.6 | 131.6 |
| Station fugitives | NA | NA | NA | NA | NA | 25.1 | 25.3 | 25.3 |
| Reciprocating compressors | NA | NA | NA | NA | NA | 105.8 | 106.4 | 106.4 |
| Storage pneumatic controllers | 44.4 | 35.3 | 29.5 | 27.9 | 26.3 | 26.0 | 30.1 | 29.4 |
| Engines (Transmission) | 176.9 | 119.9 | 95.2 | 102.9 | 104.2 | 111.6 | 114.4 | 116.6 |
| Pipeline Vents (Transmission) | 178.0 | 58.3 | 97.0 | 57.6 | 127.0 | 84.8 | 125.2 | 124.6 |
| Other Transmission and Storage | 386.2 | 111.8 | 225.6 | 213.4 | 234.8 | 245.5 | 267.6 | 279.1 |
| Distribution | 1,740.7 | 883.6 | 556.3 | 499.6 | 448.5 | 456.7 | 458.0 | 444.1 |
| Pipeline Leaks | 914.6 | 425.8 | 320.9 | 282.4 | 257.6 | 251.6 | 243.7 | 236.9 |
| M&R Stations | 673.1 | 313.4 | 99.2 | 71.2 | 47.1 | 47.1 | 50.4 | 42.1 |
| Mishaps (Dig-ins) | 47.4 | 59.8 | 63.1 | 63.6 | 60.3 | 64.7 | 65.0 | 65.6 |
| Other Distribution | 105.6 | 84.6 | 73.1 | 82.4 | 83.5 | 93.3 | 98.9 | 99.5 |
| Total | 8,270.2 | 7,093.5 | 6,857.6 | 6,647.1 | 6,803.1 | 6,905.8 | 7,022.7 | 7,045.2 |

Note: This table presents net emissions for each natural gas system stage, and also presents net emissions for select emissions sources for which disaggregated Gas STAR data and/or regulation reduction data can be matched to an Inventory source category, and sources for which emissions are calculated using net emission factors. In general, the Inventory uses aggregated Gas STAR reductions by natural gas system stage (i.e., production, processing, transmission and storage, and distribution). In some cases, emissions reductions reported to Gas STAR have been matched to potential emissions calculated in the Inventory, to provide a net emissions number for specific emissions sources. Net emission values presented here were calculated by deducting the voluntary reductions (Table A-143) and the regulatory reductions (Table A-144) from the potential emissions values in Table A-145 through Table A-148. Some reported Gas STAR reduction activities are cross-cutting and cover multiple Inventory sources. It is not possible to attribute those reductions to specific Inventory source categories, and they are included in the "Other" category.

Table A-150: U.S. Production Sector CO₂ Content in Natural Gas by NEMS Region and Formation Type for all years

| Formation Types | U.S. Region | | | | | | |
|-------------------|-------------|--------------|------------|------------|----------------|------------|-----------------|
| | North East | Midcontinent | Gulf Coast | South West | Rocky Mountain | West Coast | Lower-48 States |
| Conventional | 0.92% | 0.79% | 2.17% | 3.81% | 7.95% | 0.16% | 3.41% |
| Non-conventional* | 7.42% | 0.31% | 0.23% | NA | 0.64% | NA | 4.83% |
| All types | 3.04% | 0.79% | 2.17% | 3.81% | 7.58% | 0.16% | 3.45% |

Source: GRI-01/0136 GTI's Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. August, 2001

*In GTI, this refers to shale, coal bed methane, and tight geologic formations.

Table A-151: CO₂ Emission Estimates from the Natural Gas Production Stage (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------|-------|-------|-------|-------|-------|-------|-------|
| Normal Fugitives | | | | | | | | |
| Gas Wells | | | | | | | | |
| Associated Gas Wells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Non-associated Gas Wells (less fractured wells) | 1.4 | 1.6 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Gas Wells with Hydraulic Fracturing | 0.4 | 1.2 | 1.4 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Well Pad Equipment | | | | | | | | |
| Heaters | 1.9 | 2.8 | 3.2 | 3.2 | 3.3 | 3.2 | 3.2 | 3.2 |
| Separators | 6.0 | 14.3 | 18.4 | 18.5 | 18.7 | 18.5 | 18.2 | 18.0 |
| Dehydrators | 1.4 | 1.2 | 1.0 | 1.0 | 0.9 | 0.9 | 0.9 | 0.9 |
| Meters/Piping | 6.7 | 12.3 | 14.9 | 15.0 | 15.2 | 15.1 | 14.8 | 14.7 |
| Compressors | 3.1 | 7.7 | 9.8 | 10.1 | 10.3 | 10.3 | 10.1 | 10.1 |
| Gathering and Boosting | | | | | | | | |
| Gathering and Boosting Stations | 88.7 | 135.4 | 167.1 | 171.6 | 182.6 | 192.6 | 194.5 | 207.5 |
| Pipeline Leaks | 9.9 | 16.4 | 19.5 | 19.6 | 19.8 | 19.7 | 19.4 | 19.3 |
| Vented and Combusted | | | | | | | | |
| Drilling and Well Completions | | | | | | | | |
| Gas Well Completions without Hydraulic Fracturing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas Well Completions with Hydraulic Fracturing | 73.6 | 305.5 | 179.9 | 185.0 | 160.8 | 98.6 | 75.0 | 65.8 |
| Well Drilling | 0.1 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Produced Water from Coal Bed Methane | | | | | | | | |
| Powder River | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Black Warrior | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Normal Operations | | | | | | | | |
| Pneumatic Device Vents | 50.3 | 119.2 | 138.4 | 136.4 | 134.0 | 136.2 | 137.4 | 120.0 |
| Chemical Injection Pumps | 2.6 | 10.6 | 14.2 | 14.6 | 14.4 | 14.3 | 14.1 | 14.0 |
| Kimray Pumps | 16.4 | 13.7 | 11.3 | 11.0 | 10.8 | 10.8 | 10.6 | 10.6 |
| Dehydrator Vents | 5.1 | 4.3 | 3.5 | 3.4 | 3.4 | 3.4 | 3.3 | 3.3 |
| Condensate Tank Vents | | | | | | | | |
| Condensate Tanks without Control Devices | 10.3 | 10.3 | 11.6 | 15.7 | 17.2 | 21.0 | 24.9 | 25.4 |
| Condensate Tanks with Control Devices | 2.1 | 2.1 | 2.3 | 3.1 | 3.4 | 4.2 | 5.0 | 5.1 |
| Compressor Exhaust Vented | | | | | | | | |
| Gas Engines | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Well Workovers and Clean Ups | | | | | | | | |
| Gas Well Workovers without Hydraulic Fracturing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| | | | | | | | | |
|---|----------------|----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Gas Well Workovers with Hydraulic Fracturing | 15.3 | 44.3 | 57.1 | 58.3 | 44.1 | 26.1 | 26.1 | 26.1 |
| Well Clean Ups (LP Gas Wells) - Vent Using Plungers | 0.0 | 8.4 | 13.1 | 13.9 | 14.1 | 14.1 | 13.8 | 13.8 |
| Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers | 235.8 | 170.4 | 64.1 | 26.1 | 26.5 | 26.3 | 25.8 | 25.7 |
| Blowdowns | | | | | | | | |
| Vessel BD | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Pipeline BD | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Compressor BD | 0.1 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Compressor Starts | 0.3 | 0.7 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Upsets | | | | | | | | |
| Pressure Relief Valves | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Mishaps | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Flaring Emissions - Onshore | 9,092.7 | 7,193.0 | 9,960.0 | 9,966.9 | 13,084.7 | 12,703.8 | 15,684.1 | 17,628.5 |
| Offshore | | | | | | | | |
| Shallow water Gas Platforms (GoM and Pacific) | 2.5 | 2.8 | 2.4 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| Deepwater Gas Platforms (GoM and Pacific) | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Flaring Emissions - Offshore | 230.4 | 180.7 | 360.3 | 359.3 | 373.7 | 357.1 | 360.3 | 365.2 |
| Total Emissions (kt) | 9,857.4 | 8,260.0 | 11,057.7 | 11,040.8 | 14,145.8 | 13,684.0 | 16,649.3 | 18,585.0 |

^a Energy use CO₂ emissions not estimated to avoid double counting. NE - Not Estimated.

^b Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-152: CO₂ Emission Estimates from the Natural Gas Processing Stage (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Normal Fugitives | | | | | | | | |
| Plants – Before CO ₂ removal | 2.6 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.2 | 2.2 |
| Plants – After CO ₂ removal | 0.6 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 |
| Reciprocating Compressors – Before CO ₂ removal | 19.7 | 19.8 | 22.9 | 23.7 | 25.5 | 26.8 | 27.0 | 28.7 |
| Reciprocating Compressors – After CO ₂ removal | 4.4 | 4.4 | 5.1 | 5.3 | 5.7 | 5.9 | 6.0 | 6.4 |
| Centrifugal Compressors (wet seals) – Before CO ₂ removal | 14.5 | 13.9 | 14.1 | 14.2 | 14.3 | 14.4 | 14.4 | 14.5 |
| Centrifugal Compressors (wet seals) – After CO ₂ removal | 3.2 | 3.1 | 3.1 | 3.1 | 3.2 | 3.2 | 3.2 | 3.2 |
| Centrifugal Compressors (dry seals) – Before CO ₂ removal | - | 0.4 | 1.4 | 1.6 | 2.2 | 2.6 | 2.7 | 3.3 |
| Centrifugal Compressors (dry seals) – After CO ₂ removal | - | 0.1 | 0.3 | 0.4 | 0.5 | 0.6 | 0.6 | 0.7 |
| Vented and Combusted | | | | | | | | |
| Compressor Exhaust | | | | | | | | |
| Gas Engines ^a | NE |
| Gas Turbines ^a | NE |
| AGR Vents | 27,708.2 | 21,694.3 | 21,130.5 | 21,286.7 | 21,403.6 | 21,403.6 | 21,690.3 | 23,643.5 |
| Kimray Pumps | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 |
| Dehydrator Vents | 2.4 | 2.4 | 2.8 | 2.9 | 3.1 | 3.3 | 3.3 | 3.5 |
| Pneumatic Controllers | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Routine Maintenance | | | | | | | | |
| Blowdowns/Venting | 6.4 | 4.7 | 4.8 | 4.9 | 5.1 | 5.1 | 5.4 | 5.6 |
| Total | 27,762.6 | 21,746.1 | 21,188.0 | 21,345.8 | 21,466.3 | 21,468.7 | 21,756.4 | 23,713.0 |

NE – Not Estimated.

^a Energy use CO₂ emissions not estimated to avoid double counting.

Note: Totals may not sum due to independent rounding.

Table A-153: CO₂ Emission Estimates from the Natural Gas Transmission and Storage Stage (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------|------|------|------|------|------|------|------|------|
|----------|------|------|------|------|------|------|------|------|

| | | | | | | | | |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Fugitives | | | | | | | | |
| Pipeline Leaks | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| <i>Compressor Stations (Transmission)</i> | | | | | | | | |
| Station | 31.7 | 19.3 | 15.9 | 15.0 | 14.2 | 14.3 | 15.5 | 16.5 |
| Station + Compressor Fugitive Emissions | - | - | - | - | 2.7 | 2.9 | 3.2 | 3.4 |
| Recip Compressor | - | - | - | - | 8.7 | 8.5 | 9.2 | 9.8 |
| Centrifugal Compressor (wet seals) | - | - | - | - | 1.4 | 1.5 | 1.6 | 1.7 |
| Centrifugal Compressor (dry seals) | - | - | - | - | 1.4 | 1.4 | 1.5 | 1.7 |
| <i>Compressor Stations (Storage)</i> | | | | | | | | |
| Station | 7.1 | 4.7 | 4.2 | 4.1 | 3.9 | 3.8 | 3.8 | 3.8 |
| Station + Compressor Fugitive Emissions | - | - | - | - | - | 0.7 | 0.7 | 0.7 |
| Recip Compressor | - | - | - | - | - | 3.1 | 3.1 | 3.1 |
| Wells (Storage) | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 |
| M&R (Trans. Co. Interconnect) | 2.1 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| M&R (Farm Taps + Direct Sales) | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Vented and Combusted | | | | | | | | |
| <i>Normal Operation</i> | | | | | | | | |
| Dehydrator vents (Transmission) | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Dehydrator vents (Storage) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| <i>Compressor Exhaust</i> | | | | | | | | |
| Engines (Transmission) | NE |
| Turbines (Transmission) | NE |
| Engines (Storage) | NE |
| Turbines (Storage) | NE |
| Generators (Engines) | NE |
| Generators (Turbines) | NE |
| <i>Pneumatic Devices Trans + Stor</i> | | | | | | | | |
| Pneumatic Devices Trans | 6.1 | 2.1 | 1.2 | 1.0 | 0.9 | 0.6 | 0.8 | 0.8 |
| (High Bleed) | - | - | - | - | 0.6 | 0.3 | 0.3 | 0.3 |
| (Intermittent Bleed) | - | - | - | - | 0.3 | 0.3 | 0.4 | 0.4 |
| (Low Bleed) | - | - | - | - | 0.0 | 0.0 | 0.0 | 0.0 |
| Pneumatic Devices Storage | 1.3 | 1.0 | 0.9 | 0.8 | 0.8 | 0.7 | 0.9 | 0.8 |
| (High Bleed) | - | - | - | - | 0.7 | 0.6 | 0.7 | 0.7 |
| (Intermittent Bleed) | - | - | - | - | 0.1 | 0.1 | 0.1 | 0.1 |
| (Low Bleed) | - | - | - | - | 0.0 | 0.0 | 0.0 | 0.0 |
| <i>Routine Maintenance/Upsets</i> | | | | | | | | |
| Pipeline venting | 5.1 | 5.3 | 5.4 | 5.4 | 5.4 | 5.3 | 5.3 | 5.3 |
| <i>Station venting Trans + Storage</i> | | | | | | | | |
| Station Venting Transmission | 4.2 | 3.8 | 3.7 | 3.6 | 3.6 | 3.8 | 4.2 | 4.4 |
| Station Venting Storage | 0.9 | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| LNG Storage | | | | | | | | |
| LNG Stations | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| LNG Reciprocating Compressors | 1.2 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| LNG Centrifugal Compressors | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| <i>LNG Compressor Exhaust</i> | | | | | | | | |
| LNG Engines | NE |
| LNG Turbines | NE |
| LNG Station venting | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| LNG Import Terminals | | | | | | | | |
| LNG Stations | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LNG Reciprocating Compressors | 0.0 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| LNG Centrifugal Compressors | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| <i>LNG Compressor Exhaust</i> | | | | | | | | |
| LNG Engines | NE |
| LNG Turbines | NE |
| LNG Station venting | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Emissions (kt) | 61.7 | 42.8 | 38.1 | 36.8 | 35.6 | 35.5 | 37.3 | 38.7 |

NE - Not Estimated

^a Energy use CO₂ emissions not estimated to avoid double counting.

² Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-154: CO₂ Emission Estimates from the Natural Gas Distribution Stage (kt)

| Activity | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Pipeline Leaks | | | | | | | | |
| Mains—Cast Iron | 7.7 | 2.6 | 1.6 | 1.3 | 1.1 | 1.1 | 1.0 | 1.0 |
| Mains—Unprotected steel | 6.7 | 2.6 | 1.9 | 1.8 | 1.6 | 1.6 | 1.5 | 1.5 |
| Mains—Protected steel | 0.8 | 1.2 | 1.3 | 1.3 | 1.4 | 1.4 | 1.4 | 1.4 |
| Mains—Plastic | 1.7 | 1.3 | 0.8 | 0.7 | 0.5 | 0.6 | 0.6 | 0.6 |
| Total Pipeline Miles | | | | | | | | |
| Services—Unprotected steel | 7.2 | 3.2 | 2.5 | 1.9 | 1.7 | 1.6 | 1.5 | 1.4 |
| Services—Protected steel | 1.9 | 0.9 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.5 |
| Services—Plastic | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 |
| Services—Copper | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| Meter/Regulator (City Gates) | | | | | | | | |
| M&R >300 | 4.1 | 1.9 | 0.6 | 0.4 | 0.3 | 0.3 | 0.3 | 0.2 |
| M&R 100-300 | 7.9 | 3.6 | 1.1 | 0.7 | 0.5 | 0.5 | 0.5 | 0.4 |
| M&R <100 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Reg >300 | 4.0 | 1.7 | 0.5 | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 |
| R-Vault >300 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Reg 100-300 | 3.0 | 1.3 | 0.3 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| R-Vault 100-300 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Reg 40-100 | 0.2 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| R-Vault 40-100 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Reg <40 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Customer Meters | | | | | | | | |
| Residential | 1.7 | 2.2 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 |
| Commercial/Industry | 1.3 | 1.5 | 1.6 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 |
| Routine Maintenance | | | | | | | | |
| Pressure Relief Valve Releases | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Pipeline Blowdown | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Upsets | | | | | | | | |
| Mishaps (Dig-ins) | 1.4 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 |
| Total | 50.2 | 26.9 | 17.9 | 16.0 | 14.6 | 14.5 | 14.4 | 14.0 |

Note: Totals may not sum due to independent rounding.

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3.7. Methodology for Estimating CO₂, N₂O, and CH₄ Emissions from the Incineration of Waste

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic rubber and synthetic fibers in municipal solid waste (MSW), and incineration of tires (which are composed in part of synthetic rubber and C black) in a variety of other combustion facilities (e.g., cement kilns). Incineration of waste also results in emissions of N₂O and CH₄. The methodology for calculating emissions from each of these waste incineration sources is described in this Annex.

CO₂ from Plastics Incineration

In the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014) and *Advancing Sustainable Materials Management: Facts and Figures 2013 – Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2014, the quantity generated, recovered, and discarded for each resin is shown in Table A-155. The data set for 1990 through 2014 is incomplete, and several assumptions were employed to bridge the data gaps. The EPA reports do not provide estimates for individual materials landfilled and incinerated, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and incinerated, total discards were apportioned based on the proportions of landfilling and incineration for the entire U.S. waste stream for each year in the time series according to *Biocycle’s State of Garbage in America* (van Haaren et al. 2010), Themelis and Shin (in press) and Shin (2014). For those years when distribution by resin category was not reported (1990 through 1994), total values were apportioned according to 1995 (the closest year) distribution ratios. Generation and recovery figures for 2002 and 2004 were linearly interpolated between surrounding years’ data.

Table A-155: 2014 Plastics in the Municipal Solid Waste Stream by Resin (kt)

| Waste Pathway | PET | HDPE | PVC | LDPE/ | | PP | PS | Other | Total |
|-------------------------|-------|-------|------|-------|-------|-------|-------|---------------|-------|
| | | | | LLDPE | | | | | |
| Generation | 4,246 | 5,062 | 816 | 6,768 | 6,713 | 2,059 | 3,837 | 29,502 | |
| Recovery | 844 | 517 | 0 | 426 | 36 | 27 | 871 | 2,722 | |
| Discard | 3,402 | 455 | 816 | 6,341 | 6,677 | 2,032 | 2,921 | 26,781 | |
| Landfill | 3,143 | 420 | 754 | 5,859 | 6,170 | 1,878 | 2,699 | 20,924 | |
| Combustion | 259 | 35 | 62 | 482 | 507 | 154 | 222 | 1,721 | |
| Recovery ^a | 20% | 10% | 0% | 6% | 1% | 1% | 23% | 9% | |
| Discard ^a | 80% | 9% | 100% | 94% | 99% | 99% | 76% | 91% | |
| Landfill ^a | 74% | 8% | 92% | 87% | 92% | 91% | 70% | 71% | |
| Combustion ^a | 6% | 1% | 8% | 7% | 8% | 7% | 6% | 6% | |

^a As a percent of waste generation.

Note: Totals may not sum due to independent rounding. Abbreviations: PET (polyethylene terephthalate), HDPE (high density polyethylene), PVC (polyvinyl chloride), LDPE/LLDPE (linear low density polyethylene), PP (polypropylene), PS (polystyrene).

Fossil fuel-based CO₂ emissions were calculated as the product of plastic combusted, C content, and fraction oxidized (see Table A-156). The C content of each of the six types of plastics is listed, with the value for “other plastics” assumed equal to the weighted average of the six categories. The fraction oxidized was assumed to be 98 percent.

Table A-156: 2014 Plastics Incinerated (kt), Carbon Content (%), Fraction Oxidized (%) and Carbon Incinerated (kt)

| Factor | PET | HDPE | PVC | LDPE/ | | PP | PS | Other | Total |
|---|------------|------------|------------|------------|------------|------------|------------|--------------|-------|
| | | | | LLDPE | | | | | |
| Quantity Combusted | 259 | 35 | 62 | 482 | 507 | 154 | 222 | 1,721 | |
| Carbon Content of Resin | 63% | 86% | 38% | 86% | 86% | 92% | 66% | - | |
| Fraction Oxidized | 98% | 98% | 98% | 98% | 98% | 98% | 98% | - | |
| Carbon in Resin Combusted | 158 | 29 | 23 | 405 | 426 | 140 | 143 | 1,325 | |
| Emissions (MMT CO₂ Eq.) | 0.6 | 1.1 | 0.1 | 1.5 | 1.6 | 0.5 | 0.5 | 4.9 | |

^a Weighted average of other plastics produced.

Note: Totals may not sum due to independent rounding.

CO₂ from Incineration of Synthetic Rubber and Carbon Black in Tires

Emissions from tire incineration require two pieces of information: the amount of tires incinerated and the C content of the tires. “2013 U.S. Scrap Tire Management Summary” (RMA 2014a) reports that 2,120 thousand of the 3,667 thousand tons of scrap tires generated in 2013 (approximately 58 percent of generation) were used for fuel purposes. Using

RMA's estimates of average tire composition and weight, the mass of synthetic rubber and C black in scrap tires was determined:

- Synthetic rubber in tires was estimated to be 90 percent C by weight, based on the weighted average C contents of the major elastomers used in new tire consumption.⁶⁶ Table A-157 shows consumption and C content of elastomers used for tires and other products in 2002, the most recent year for which data are available.
- C black is 100 percent C (Aslett Rubber Inc. n.d.).

Multiplying the mass of scrap tires incinerated by the total C content of the synthetic rubber, C black portions of scrap tires, and then by a 98 percent oxidation factor, yielded CO₂ emissions, as shown in Table A-158. The disposal rate of rubber in tires (0.3 MMT C/yr) is smaller than the consumption rate for tires based on summing the elastomers listed in Table A-155 (1.3 MMT/yr); this is due to the fact that much of the rubber is lost through tire wear during the product's lifetime and may also reflect the lag time between consumption and disposal of tires. Tire production and fuel use for 1990 through 2014 were taken from RMA 2006, RMA 2009, RMA 2011; RMA 2014a; where data were not reported, they were linearly interpolated between bracketing years' data or, for the ends of time series, set equal to the closest year with reported data.

In 2009, RMA changed the reporting of scrap tire data from millions of tires to thousands of short tons of scrap tire. As a result, the average weight and percent of the market of light duty and commercial scrap tires was used to convert the previous years from millions of tires to thousands of short tons (STMC 1990 through 1997; RMA 2002 through 2006, 2014b).

Table A-157: Elastomers Consumed in 2002 (kt)

| Elastomer | Consumed | Carbon Content | Carbon Equivalent |
|---------------------------------------|--------------|----------------|-------------------|
| Styrene butadiene rubber solid | 768 | 91% | 700 |
| For Tires | 660 | 91% | 602 |
| For Other Products* | 108 | 91% | 98 |
| Polybutadiene | 583 | 89% | 518 |
| For Tires | 408 | 89% | 363 |
| For Other Products | 175 | 89% | 155 |
| Ethylene Propylene | 301 | 86% | 258 |
| For Tires | 6 | 86% | 5 |
| For Other Products | 295 | 86% | 253 |
| Polychloroprene | 54 | 59% | 32 |
| For Tires | 0 | 59% | 0 |
| For Other Products | 54 | 59% | 32 |
| Nitrile butadiene rubber solid | 84 | 77% | 65 |
| For Tires | 1 | 77% | 1 |
| For Other Products | 83 | 77% | 64 |
| Polyisoprene | 58 | 88% | 51 |
| For Tires | 48 | 88% | 42 |
| For Other Products | 10 | 88% | 9 |
| Others | 367 | 88% | 323 |
| For Tires | 184 | 88% | 161 |
| For Other Products | 184 | 88% | 161 |
| Total | 2,215 | - | 1,950 |
| For Tires | 1,307 | - | 1,174 |

* Used to calculate C content of non-tire rubber products in municipal solid waste.

- Not applicable

Note: Totals may not sum due to independent rounding.

⁶⁶The carbon content of tires (1,174 kt C) divided by the mass of rubber in tires (1,307 kt) equals 90 percent.

Table A-158: Scrap Tire Constituents and CO₂ Emissions from Scrap Tire Incineration in 2014

| Material | Weight of Material (MMT) | Fraction Oxidized | Carbon Content | Emissions (MMT CO ₂ Eq.) |
|------------------|--------------------------|-------------------|----------------|-------------------------------------|
| Synthetic Rubber | 0.3 | 98% | 90% | 1.2 |
| Carbon Black | 0.4 | 98% | 100% | 1.4 |
| Total | 0.7 | - | - | 2.6 |

- Not applicable

CO₂ from Incineration of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO₂ emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber incinerated by an average rubber C content. The amount of rubber discarded in the MSW stream was estimated from generation and recycling data⁶⁷ provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) and unpublished backup data (Schneider 2007). The reports divide rubber found in MSW into three product categories: other durables (not including tires), non-durables (which includes clothing and footwear and other non-durables), and containers and packaging. EPA (2015) did not report rubber found in the product category “containers and packaging;” however, containers and packaging from miscellaneous material types were reported for 2009 through 2014. As a result, EPA assumes that rubber containers and packaging are reported under the “miscellaneous” category; and therefore, the quantity reported for 2009 through 2014 were set equal to the quantity reported for 2008. Since there was negligible recovery for these product types, all the waste generated is considered to be discarded. Similar to the plastics method, discards were apportioned into landfilling and incineration based on their relative proportions, for each year, for the entire U.S. waste stream. The report aggregates rubber and leather in the MSW stream; an assumed synthetic rubber content of 70 percent was assigned to each product type, as shown in Table A-159.⁶⁸ A C content of 85 percent was assigned to synthetic rubber for all product types (based on the weighted average C content of rubber consumed for non-tire uses), and a 98 percent fraction oxidized was assumed.

Table A-159: Rubber and Leather in Municipal Solid Waste in 2014

| Product Type | Incinerated (kt) | Synthetic Rubber (%) | Carbon Content (%) | Fraction Oxidized (%) | Emissions (MMT CO ₂ Eq.) |
|---------------------------------|------------------|----------------------|--------------------|-----------------------|-------------------------------------|
| Durables (not Tires) | 261 | 70% | 85% | 98% | 0.8 |
| Non-Durables | 77 | - | - | - | 0.2 |
| Clothing and Footwear | 59 | 70% | 85% | 98% | 0.2 |
| Other Non-Durables | 18 | 70% | 85% | 98% | 0.1 |
| Containers and Packaging | 2 | 70% | 85% | 98% | 0.0 |
| Total | 341 | - | - | - | 1.1 |

- Not Applicable.

CO₂ from Incineration of Synthetic Fibers

Carbon dioxide emissions from synthetic fibers were estimated as the product of the amount of synthetic fiber discarded annually and the average C content of synthetic fiber. Fiber in the MSW stream was estimated from data provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2015) for textiles. Production data for the synthetic fibers was based on data from the American Chemical Society (FEB 2009). The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table A-160). As with the other materials in the MSW stream, discards were apportioned based on the annually variable proportions of landfilling and incineration for the entire U.S. waste stream, as found in van Haaren et al. (2010), Themelis and Shin (in press), and Shin (2014). It was assumed that approximately 55 percent of the fiber was synthetic in origin, based on information received from the Fiber Economics Bureau (DeZan 2000). An average C content of 70 percent was assigned to synthetic fiber using the production-weighted average of the C contents of the four major fiber types (polyester, nylon, olefin, and acrylic) produced in 1999 (see Table A-161). The equation relating CO₂ emissions to the amount of textiles combusted is shown below.

$$\text{CO}_2 \text{ Emissions from the Incineration of Synthetic Fibers} = \text{Annual Textile Incineration (kt)} \times (\text{Percent of Total Fiber that is Synthetic}) \times (\text{Average C Content of Synthetic Fiber}) \times (44 \text{ g CO}_2 / 12 \text{ g C})$$

⁶⁷ Discards = Generation minus recycling.

⁶⁸ As a sustainably harvested biogenic material, the incineration of leather is assumed to have no net CO₂ emissions.

Table A-160: Synthetic Textiles in MSW (kt)

| Year | Generation | Recovery | Discards | Incineration |
|------|------------|----------|----------|--------------|
| 1990 | 2,884 | 328 | 2,557 | 332 |
| 1995 | 3,674 | 447 | 3,227 | 442 |
| 1996 | 3,832 | 472 | 3,361 | 467 |
| 1997 | 4,090 | 526 | 3,564 | 458 |
| 1998 | 4,269 | 556 | 3,713 | 407 |
| 1999 | 4,498 | 611 | 3,887 | 406 |
| 2000 | 4,706 | 655 | 4,051 | 417 |
| 2001 | 4,870 | 715 | 4,155 | 432 |
| 2002 | 5,123 | 750 | 4,373 | 459 |
| 2003 | 5,297 | 774 | 4,522 | 472 |
| 2004 | 5,451 | 884 | 4,567 | 473 |
| 2005 | 5,714 | 913 | 4,800 | 480 |
| 2006 | 5,893 | 933 | 4,959 | 479 |
| 2007 | 6,041 | 953 | 5,088 | 470 |
| 2008 | 6,305 | 968 | 5,337 | 470 |
| 2009 | 6,424 | 978 | 5,446 | 458 |
| 2010 | 6,508 | 998 | 5,510 | 441 |
| 2011 | 6,513 | 1,003 | 5,510 | 419 |
| 2012 | 7,114 | 1,117 | 5,997 | 456 |
| 2013 | 7,496 | 894 | 6,602 | 502 |
| 2014 | 7,496 | 894 | 6,602 | 502 |

Table A-161: Synthetic Fiber Production in 1999

| Fiber | Production (MMT) | Carbon Content |
|--------------|------------------|----------------|
| Polyester | 1.8 | 63% |
| Nylon | 1.2 | 64% |
| Olefin | 1.4 | 86% |
| Acrylic | 0.1 | 68% |
| Total | 4.5 | 70% |

N₂O and CH₄ from Incineration of Waste

Estimates of N₂O emissions from the incineration of waste in the United States are based on the methodology outlined in the EPA's Compilation of Air Pollutant Emission Factors (EPA 1995) and presented in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015), and unpublished backup data (Schneider 2007). According to this methodology, emissions of N₂O from waste incineration are the product of the mass of waste incinerated, an emission factor of N₂O emitted per unit mass of waste incinerated, and an N₂O emissions control removal efficiency. The mass of waste incinerated was derived from the results of the biannual national survey of Municipal Solid Waste (MSW) Generation and Disposition in the U.S., published in *BioCycle* (van Haaren et al. 2010), Themelis and Shin (in press), and Shin (2014). For waste incineration in the United States, an emission factor of 50 g N₂O/metric ton MSW based on the 2006 IPCC Guidelines and an estimated emissions control removal efficiency of zero percent were used (IPCC 2006). It was assumed that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009, ERC 2009).

Estimates of CH₄ emissions from the incineration of waste in the United States are based on the methodology outlined in IPCC's 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). According to this methodology, emissions of CH₄ from waste incineration are the product of the mass of waste incinerated and an emission factor of CH₄ emitted per unit mass of waste incinerated. Similar to the N₂O emissions methodology, the mass of waste incinerated was derived from the information published in *BioCycle* (van Haaren et al. 2010) for 1990 through 2008. Data for 2011 were derived from information forthcoming in Themelis and Shin (in press) and Shin (2014). For waste incineration in the United States, an emission factor of 0.20 kg CH₄/kt MSW was used based on the 2006 IPCC Guidelines and assuming that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009; ERC 2009). No information was available on the mass of waste incinerated for 2012, 2013, or 2014, so these values were assumed to be equal to the 2011 value.

Despite the differences in methodology and data sources, the two series of references (EPA 2014; van Haaren, Rob, Themelis, N., and Goldstein, N. 2010) provide estimates of total solid waste incinerated that are relatively consistent (see Table A-162).

Table A-162: U.S. Municipal Solid Waste Incinerated, as Reported by EPA and BioCycle (Metric Tons)

| Year | EPA | BioCycle |
|------|-------------------------|-------------------------|
| 1990 | 28,939,680 | 30,632,057 |
| 1995 | 32,241,888 | 29,639,040 |
| 2000 | 30,599,856 | 25,974,978 |
| 2001 | 30,481,920 | 25,942,036 ^a |
| 2002 | 30,255,120 | 25,802,917 |
| 2003 | 30,028,320 | 25,930,542 ^b |
| 2004 | 28,585,872 | 26,037,823 |
| 2005 | 28,685,664 | 25,973,520 ^c |
| 2006 | 28,985,040 | 25,853,401 |
| 2007 | 29,003,184 | 24,788,539 ^d |
| 2008 | 28,622,160 | 23,674,017 |
| 2009 | 26,317,872 | 22,714,122 ^e |
| 2010 | 26,544,672 | 21,741,734 ^e |
| 2011 | 26,544,672 | 20,756,870 |
| 2012 | 26,544,672 | 20,756,870 ^f |
| 2013 | 26,544,672 ^g | 20,756,870 ^f |
| 2014 | 26,544,672 ^g | 20,756,870 ^f |

^a Interpolated between 2000 and 2002 values.

^b Interpolated between 2002 and 2004 values.

^c Interpolated between 2004 and 2006 values.

^d Interpolated between 2006 and 2008 values

^e Interpolated between 2011 and 2008 values

^f Set equal to the 2011 value

^g Set equal to the 2012 value.

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3.8. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military

Bunker fuel emissions estimates for the Department of Defense (DoD) were developed using data generated by the Defense Logistics Agency Energy (DLA Energy) for aviation and naval fuels. DLA Energy prepared a special report based on data in the Fuels Automated System (FAS) for calendar year 2014 fuel sales in the Continental United States (CONUS).⁶⁹ The following steps outline the methodology used for estimating emissions from international bunker fuels used by the U.S. Military.

Step 1: Omit Extra-Territorial Fuel Deliveries

Beginning with the complete FAS data set for each year, the first step in quantifying DoD-related emissions from international bunker fuels was to identify data that would be representative of international bunker fuel consumption as defined by decisions of the UNFCCC (i.e., fuel sold to a vessel, aircraft, or installation within the United States or its territories and used in international maritime or aviation transport). Therefore, fuel data were categorized by the location of fuel delivery in order to identify and omit all international fuel transactions/deliveries (i.e., sales abroad).

Step 2: Allocate JP-8 between Aviation and Land-based Vehicles

As a result of DoD⁷⁰ and NATO⁷¹ policies on implementing the Single Fuel For the Battlefield concept, DoD activities have been increasingly replacing diesel fuel with JP8 (a type of jet fuel) in compression ignition and turbine engines of land-based equipment. Based on this concept and examination of all data describing jet fuel used in land-based vehicles, it was determined that a portion of JP8 consumption should be attributed to ground vehicle use. Based on available Military Service data and expert judgment, a small fraction of the total JP8 use (i.e., between 1.78 and 2.7 times the quantity of diesel fuel used, depending on the Service) was reallocated from the aviation subtotal to a new land-based jet fuel category for 1997 and subsequent years. As a result of this reallocation, the JP8 use reported for aviation was reduced and the total fuel use for land-based equipment increased. DoD's total fuel use did not change.

Table A-163 displays DoD's consumption of transportation fuels, summarized by fuel type, that remain at the completion of Step 1, and reflects the adjustments for jet fuel used in land-based equipment, as described above.

Step 3: Omit Land-Based Fuels

Navy and Air Force land-based fuels (i.e., fuel not used by ships or aircraft) were omitted for the purpose of calculating international bunker fuels. The remaining fuels, listed below, were considered potential DoD international bunker fuels.

- **Aviation:** jet fuels (JP8, JP5, JP4, JAA, JA1, and JAB).
- **Marine:** naval distillate fuel (F76), marine gas oil (MGO), and intermediate fuel oil (IFO).

Step 4: Omit Fuel Transactions Received by Military Services that are not considered to be International Bunker Fuels

Only Navy and Air Force were deemed to be users of military international bunker fuels after sorting the data by Military Service and applying the following assumptions regarding fuel use by Service.

⁶⁹ FAS contains data for 1995 through 2014, but the dataset was not complete for years prior to 1995. Using DLA aviation and marine fuel procurement data, fuel quantities from 1990 to 1994 were estimated based on a back-calculation of the 1995 data in the legacy database, the Defense Fuels Automated Management System (DFAMS). The back-calculation was refined in 1999 to better account for the jet fuel conversion from JP4 to JP8 that occurred within DoD between 1992 and 1995.

⁷⁰ DoD Directive 4140.25-M-V1, Fuel Standardization and Cataloging, 2013; DoD Directive 4140.25, DoD Management Policy for Energy Commodities and Related Services, 2004.

⁷¹ NATO Standard Agreement NATO STANAG 4362, Fuels for Future Ground Equipments Using Compression Ignition or Turbine Engines, 2012.

- Only fuel delivered to a ship, aircraft, or installation in the United States was considered a potential international bunker fuel. Fuel consumed in international aviation or marine transport was included in the bunker fuel estimate of the country where the ship or aircraft was fueled. Fuel consumed entirely within a country's borders was not considered a bunker fuel.
- Based on previous discussions with the Army staff, only an extremely small percentage of Army aviation emissions, and none of Army watercraft emissions, qualified as bunker fuel emissions. The magnitude of these emissions was judged to be insignificant when compared to Air Force and Navy emissions. Based on this research, Army bunker fuel emissions were assumed to be zero.
- Marine Corps aircraft operating while embarked consumed fuel that was reported as delivered to the Navy. Bunker fuel emissions from embarked Marine Corps aircraft were reported in the Navy bunker fuel estimates. Bunker fuel emissions from other Marine Corps operations and training were assumed to be zero.
- Bunker fuel emissions from other DoD and non-DoD activities (i.e., other federal agencies) that purchased fuel from DLA Energy were assumed to be zero.

Step 5: Determine Bunker Fuel Percentages

It was necessary to determine what percent of the aviation and marine fuels were used as international bunker fuels. Military aviation bunkers include international operations (i.e., sorties that originate in the United States and end in a foreign country), operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea (e.g., anti-submarine warfare flights). Methods for quantifying aviation and marine bunker fuel percentages are described below.

- **Aviation:** The Air Force Aviation bunker fuel percentage was determined to be 13.2 percent. A bunker fuel weighted average was calculated based on flying hours by major command. International flights were weighted by an adjustment factor to reflect the fact that they typically last longer than domestic flights. In addition, a fuel use correction factor was used to account for the fact that transport aircraft burn more fuel per hour of flight than most tactical aircraft. This percentage was multiplied by total annual Air Force aviation fuel delivered for U.S. activities, producing an estimate for international bunker fuel consumed by the Air Force.

The Naval Aviation bunker fuel percentage was calculated to be 40.4 percent by using flying hour data from Chief of Naval Operations Flying Hour Projection System Budget for fiscal year 1998 and estimates of bunker fuel percent of flights provided by the fleet. This Naval Aviation bunker fuel percentage was then multiplied by total annual Navy aviation fuel delivered for U.S. activities, yielding total Navy aviation bunker fuel consumed.

- **Marine:** For marine bunkers, fuels consumed while ships were underway were assumed to be bunker fuels. The Navy maritime bunker fuel percentage was determined to be 79 percent because the Navy reported that 79 percent of vessel operations were underway, while the remaining 21 percent of operations occurred in port (i.e., pierside) in the year 2000.⁷²

Table A-164 and Table A-165 display DoD bunker fuel use totals for the Navy and Air Force.

Step 6: Calculate Emissions from International Bunker Fuels

Bunker fuel totals were multiplied by appropriate emission factors to determine greenhouse gas emissions. CO₂ emissions from Aviation Bunkers and distillate Marine Bunkers are the total of military aviation and marine bunker fuels, respectively.

⁷² Note that 79 percent is used because it is based on Navy data, but the percentage of time underway may vary from year-to-year depending on vessel operations. For example, for years prior to 2000, the bunker fuel percentage was 87 percent.

The rows labeled “U.S. Military” and “U.S. Military Naval Fuels” in the tables in the International Bunker Fuels section of the Energy chapter were based on the totals provided in Table A-164 and Table A-165, below. CO₂ emissions from aviation bunkers and distillate marine bunkers are presented in Table A-168, and are based on emissions from fuels tallied in Table A-164 and Table A-165.

Table A-163: Transportation Fuels from Domestic Fuel Deliveries^a (Million Gallons)

| Vehicle Type/Fuel | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Aviation | 4,598.4 | 3,099.9 | 2,664.4 | 2,900.6 | 2,609.8 | 2,615.0 | 2,703.1 | 2,338.1 | 2,092.0 | 2,081.0 | 2,067.8 | 1,814.5 | 1,663.9 | 1,405.0 | 1,449.7 | 1,336.4 | 1,796.2 |
| Total Jet Fuels | 4,598.4 | 3,099.9 | 2,664.4 | 2,900.6 | 2,609.6 | 2,614.9 | 2,703.1 | 2,338.0 | 2,091.9 | 2,080.9 | 2,067.7 | 1,814.3 | 1,663.7 | 1,404.8 | 1,449.5 | 1,336.2 | 1,795.9 |
| JP8 | 285.7 | 2,182.8 | 2,122.7 | 2,326.2 | 2,091.4 | 2,094.3 | 2,126.2 | 1,838.8 | 1,709.3 | 1,618.5 | 1,616.2 | 1,358.2 | 1,100.1 | 882.8 | 865.2 | 718.0 | 546.6 |
| JP5 | 1,025.4 | 691.2 | 472.1 | 503.2 | 442.2 | 409.1 | 433.7 | 421.6 | 325.5 | 376.1 | 362.2 | 361.2 | 399.3 | 372.3 | 362.5 | 316.4 | 311.0 |
| Other Jet Fuels | 3,287.3 | 225.9 | 69.6 | 71.2 | 76.1 | 111.4 | 143.2 | 77.6 | 57.0 | 86.3 | 89.2 | 94.8 | 164.3 | 149.7 | 221.8 | 301.7 | 938.3 |
| Aviation Gasoline | + | + | + | + | 0.1 | 0.1 | + | 0.1 | 0.1 | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.2 | 0.3 |
| Marine | 686.8 | 438.9 | 454.4 | 418.4 | 455.8 | 609.1 | 704.5 | 604.9 | 531.6 | 572.8 | 563.4 | 485.8 | 578.8 | 489.9 | 490.4 | 390.4 | 427.9 |
| Middle Distillate (MGO) | + | + | 48.3 | 33.0 | 41.2 | 88.1 | 71.2 | 54.0 | 45.8 | 45.7 | 55.2 | 56.8 | 48.4 | 37.3 | 52.9 | 40.9 | 62.0 |
| Naval Distillate (F76) | 686.8 | 438.9 | 398.0 | 369.1 | 395.1 | 460.9 | 583.5 | 525.9 | 453.6 | 516.0 | 483.4 | 399.0 | 513.7 | 440.0 | 428.4 | 345.7 | 362.7 |
| Intermediate Fuel Oil (IFO) ^b | + | + | 8.1 | 16.3 | 19.5 | 60.2 | 49.9 | 25.0 | 32.2 | 11.1 | 24.9 | 30.0 | 16.7 | 12.5 | 9.1 | 3.8 | 3.2 |
| Other^c | 717.1 | 310.9 | 248.2 | 109.8 | 211.1 | 221.2 | 170.9 | 205.6 | 107.3 | 169.0 | 173.6 | 206.8 | 224.0 | 208.6 | 193.8 | 180.6 | 190.7 |
| Diesel | 93.0 | 119.9 | 126.6 | 26.6 | 57.7 | 60.8 | 46.4 | 56.8 | 30.6 | 47.3 | 49.1 | 58.3 | 64.1 | 60.9 | 57.9 | 54.9 | 57.5 |
| Gasoline | 624.1 | 191.1 | 74.8 | 24.7 | 27.5 | 26.5 | 19.4 | 24.3 | 11.7 | 19.2 | 19.7 | 25.2 | 25.5 | 22.0 | 19.6 | 16.9 | 16.5 |
| Jet Fuel ^d | + | + | 46.7 | 58.4 | 125.9 | 133.9 | 105.1 | 124.4 | 65.0 | 102.6 | 104.8 | 123.3 | 134.4 | 125.6 | 116.2 | 108.8 | 116.7 |
| Total (Including Bunkers) | 6,002.4 | 3,849.8 | 3,367.0 | 3,428.8 | 3,276.7 | 3,445.3 | 3,578.5 | 3,148.6 | 2,730.9 | 2,822.8 | 2,804.9 | 2,507.1 | 2,466.7 | 2,103.5 | 2,133.9 | 1,907.5 | 2,414.9 |

+ Indicates value does not exceed 0.05 million gallons.

^a Includes fuel distributed in the United States and U.S. Territories.

^b Intermediate fuel oil (IFO 180 and IFO 380) is a blend of distillate and residual fuels. IFO is used by the Military Sealift Command.

^c Prior to 2001, gasoline and diesel fuel totals were estimated using data provided by the Military Services for 1990 and 1996. The 1991 through 1995 data points were interpolated from the Service inventory data. The 1997 through 1999 gasoline and diesel fuel data were initially extrapolated from the 1996 inventory data. Growth factors used for other diesel and gasoline were 5.2 and -21.1 percent, respectively. However, prior diesel fuel estimates from 1997 through 2000 were reduced according to the estimated consumption of jet fuel that is assumed to have replaced the diesel fuel consumption in land-based vehicles. Datasets for other diesel and gasoline consumed by the military in 2000 were estimated based on ground fuels consumption trends. This method produced a result that was more consistent with expected consumption for 2000. Since 2001, other gasoline and diesel fuel totals were generated by DLA Energy.

^d The fraction of jet fuel consumed in land-based vehicles was estimated based on DLA Energy data as well as Military Service and expert judgment.

Note: Totals may not sum due to independent rounding.

Table A-164: Total U.S. Military Aviation Bunker Fuel (Million Gallons)

| Fuel Type/Service | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Jet Fuels | | | | | | | | | | | | | | | | | |
| JP8 | 56.7 | 300.4 | 307.6 | 341.2 | 309.5 | 305.1 | 309.8 | 285.6 | 262.5 | 249.1 | 229.4 | 211.4 | 182.5 | 143.4 | 141.2 | 122.0 | 71.8 |
| Navy | 56.7 | 38.3 | 53.4 | 73.8 | 86.6 | 76.3 | 79.2 | 70.9 | 64.7 | 62.7 | 59.2 | 55.4 | 60.8 | 47.1 | 50.4 | 48.9 | 19.8 |
| Air Force | + | 262.2 | 254.2 | 267.4 | 222.9 | 228.7 | 230.6 | 214.7 | 197.8 | 186.5 | 170.3 | 156.0 | 121.7 | 96.2 | 90.8 | 73.0 | 52.0 |
| JP5 | 370.5 | 249.8 | 160.3 | 169.7 | 158.3 | 146.1 | 157.9 | 160.6 | 125.0 | 144.5 | 139.2 | 137.0 | 152.5 | 144.9 | 141.2 | 124.9 | 121.9 |
| Navy | 365.3 | 246.3 | 155.6 | 163.7 | 153.0 | 141.3 | 153.8 | 156.9 | 122.8 | 141.8 | 136.5 | 133.5 | 149.7 | 143.0 | 139.5 | 123.6 | 120.2 |
| Air Force | 5.3 | 3.5 | 4.7 | 6.1 | 5.3 | 4.9 | 4.1 | 3.7 | 2.3 | 2.7 | 2.6 | 3.5 | 2.8 | 1.8 | 1.7 | 1.3 | 1.6 |
| JP4 | 420.8 | 21.5 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Navy | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + |
| Air Force | 420.8 | 21.5 | + | + | + | + | + | + | + | + | + | + | 0.1 | + | + | + | + |
| JAA | 13.7 | 9.2 | 12.5 | 12.6 | 13.7 | 21.7 | 30.0 | 15.5 | 11.7 | 15.6 | 16.8 | 18.1 | 31.4 | 31.1 | 38.6 | 46.5 | 124.5 |
| Navy | 8.5 | 5.7 | 7.9 | 8.0 | 9.8 | 15.5 | 21.5 | 11.6 | 9.1 | 11.7 | 12.5 | 12.3 | 13.7 | 14.6 | 14.8 | 13.4 | 32.2 |
| Air Force | 5.3 | 3.5 | 4.5 | 4.6 | 3.8 | 6.2 | 8.6 | 3.9 | 2.6 | 3.9 | 4.3 | 5.9 | 17.7 | 16.5 | 23.8 | 33.1 | 92.3 |
| JA1 | + | + | + | 0.1 | 0.6 | 0.2 | 0.5 | 0.5 | 0.4 | 1.1 | 1.0 | 0.6 | 0.3 | (0.5) | (0.3) | 0.6 | 0.3 |
| Navy | + | + | + | + | + | + | + | + | + | 0.1 | 0.1 | 0.1 | 0.1 | (0.5) | (0.3) | 0.6 | + |
| Air Force | + | + | + | 0.1 | 0.6 | 0.2 | 0.5 | 0.5 | 0.4 | 1.0 | 0.8 | 0.5 | 0.1 | + | + | + | 0.3 |
| JAB | + |
| Navy | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + |
| Air Force | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + | + |
| Navy Subtotal | 430.5 | 290.2 | 216.9 | 245.5 | 249.4 | 233.1 | 254.4 | 239.4 | 196.6 | 216.3 | 208.3 | 201.3 | 224.4 | 204.3 | 204.5 | 186.5 | 172.3 |
| Air Force Subtotal | 431.3 | 290.7 | 263.5 | 278.1 | 232.7 | 239.9 | 243.7 | 222.9 | 203.1 | 194.0 | 178.1 | 165.9 | 142.4 | 114.5 | 116.3 | 107.4 | 146.2 |
| Total | 861.8 | 580.9 | 480.4 | 523.6 | 482.1 | 473.0 | 498.1 | 462.3 | 399.7 | 410.3 | 386.3 | 367.2 | 366.7 | 318.8 | 320.8 | 293.9 | 318.5 |

+ Does not exceed 0.05 million gallons.

The negative values in this table represent returned products.

Note: Totals may not sum due to independent rounding.

Table A-165: Total U.S. DoD Maritime Bunker Fuel (Million Gallons)

| Marine Distillates | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Navy – MGO | 0.0 | 0.0 | 23.8 | 22.5 | 27.1 | 63.7 | 56.2 | 38.0 | 33.0 | 31.6 | 40.9 | 39.9 | 32.9 | 25.5 | 36.5 | 32.3 | 43.3 |
| Navy – F76 | 522.4 | 333.8 | 298.6 | 282.6 | 305.6 | 347.8 | 434.4 | 413.1 | 355.9 | 404.1 | 376.9 | 311.4 | 402.2 | 346.6 | 337.9 | 273.1 | 286.2 |
| Navy – IFO | 0.0 | 0.0 | 6.4 | 12.9 | 15.4 | 47.5 | 39.4 | 19.7 | 25.4 | 8.8 | 19.0 | 23.1 | 12.9 | 9.5 | 6.1 | 3.0 | 1.5 |
| Total | 522.4 | 333.8 | 328.8 | 318.0 | 348.2 | 459.0 | 530.0 | 470.7 | 414.3 | 444.4 | 436.7 | 374.4 | 448.0 | 381.5 | 380.6 | 308.5 | 331.0 |

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 million gallons.

Table A-166: Aviation and Marine Carbon Contents (MMT Carbon/QBtu) and Fraction Oxidized

| Mode (Fuel) | Carbon Content Coefficient | Fraction Oxidized |
|---------------------|----------------------------|-------------------|
| Aviation (Jet Fuel) | Variable | 1.00 |
| Marine (Distillate) | 20.17 | 1.00 |
| Marine (Residual) | 20.48 | 1.00 |

Source: EPA (2010) and IPCC (2006).

Table A-167: Annual Variable Carbon Content Coefficient for Jet Fuel (MMT Carbon/QBtu)

| Fuel | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Jet Fuel | 19.40 | 19.34 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 | 19.70 |

Source: EPA (2010)

Table A-168: Total U.S. DoD CO₂ Emissions from Bunker Fuels (MMT CO₂ Eq.)

| Mode | 1990 | 1995 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------|-------------|------------|------------|------------|------------|------------|-------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| Aviation | 8.1 | 5.5 | 4.7 | 5.1 | 4.7 | 4.6 | 4.8 | 4.5 | 3.9 | 4.0 | 3.8 | 3.6 | 3.6 | 3.1 | 3.1 | 2.9 | 3.1 |
| Marine | 5.4 | 3.4 | 3.4 | 3.3 | 3.6 | 4.7 | 5.4 | 4.8 | 4.2 | 4.6 | 4.5 | 3.8 | 4.6 | 3.9 | 3.9 | 3.2 | 3.4 |
| Total | 13.4 | 9.0 | 8.0 | 8.3 | 8.3 | 9.3 | 10.3 | 9.3 | 8.1 | 8.5 | 8.2 | 7.4 | 8.2 | 7.0 | 7.0 | 6.0 | 6.5 |

Note: Totals may not sum due to independent rounding.

References

DLA Energy (2015) Unpublished data from the Defense Fuels Automated Management System (DFAMS). Defense Energy Support Center, Defense Logistics Agency, U.S. Department of Defense. Washington, D.C.

IPCC (2006) *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. The National Greenhouse Gas Inventories Programme, The Intergovernmental Panel on Climate Change. H.S. Eggleston, L. Buendia, K. Miwa, T. Ngara, and K. Tanabe (eds.). Hayama, Kanagawa, Japan.

3.9. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances

Emissions of HFCs and PFCs from the substitution of ozone depleting substances (ODS) are developed using a country-specific modeling approach. The Vintaging Model was developed as a tool for estimating the annual chemical emissions from industrial sectors that have historically used ODS in their products. Under the terms of the Montreal Protocol and the United States Clean Air Act Amendments of 1990, the domestic U.S. consumption of ODS—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—has been drastically reduced, forcing these industrial sectors to transition to more ozone friendly chemicals. As these industries have moved toward ODS alternatives such as hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs), the Vintaging Model has evolved into a tool for estimating the rise in consumption and emissions of these alternatives, and the decline of ODS consumption and emissions.

The Vintaging Model estimates emissions from five ODS substitute end-use sectors: refrigeration and air-conditioning, foams, aerosols, solvents, and fire-extinguishing. Within these sectors, there are more than 60 independently modeled end-uses. The model requires information on the market growth for each of the end-uses, a history of the market transition from ODS to alternatives, and the characteristics of each end-use such as market size or charge sizes and loss rates. As ODS are phased out, a percentage of the market share originally filled by the ODS is allocated to each of its substitutes.

The model, named for its method of tracking the emissions of annual “vintages” of new equipment that enter into service, is a “bottom-up” model. It models the consumption of chemicals based on estimates of the quantity of equipment or products sold, serviced, and retired each year, and the amount of the chemical required to manufacture and/or maintain the equipment. The Vintaging Model makes use of this market information to build an inventory of the in-use stocks of the equipment and ODS and ODS substitute in each of the end-uses. The simulation is considered to be a “business-as-usual” baseline case, and does not incorporate measures to reduce or eliminate the emissions of these gases other than those regulated by U.S. law or otherwise common in the industry. Emissions are estimated by applying annual leak rates, service emission rates, and disposal emission rates to each population of equipment. By aggregating the emission and consumption output from the different end-uses, the model produces estimates of total annual use and emissions of each chemical.

The Vintaging Model synthesizes data from a variety of sources, including data from the ODS Tracking System maintained by the Stratospheric Protection Division, the Greenhouse Gas Reporting Program maintained by the Climate Change Division, and information from submissions to EPA under the Significant New Alternatives Policy (SNAP) program. Published sources include documents prepared by the United Nations Environment Programme (UNEP) Technical Options Committees, reports from the Alternative Fluorocarbons Environmental Acceptability Study (AFEAS), and conference proceedings from the International Conferences on Ozone Protection Technologies and Earth Technologies Forums. EPA also coordinates extensively with numerous trade associations and individual companies. For example, the Alliance for Responsible Atmospheric Policy; the Air-Conditioning, Heating and Refrigeration Institute; the Association of Home Appliance Manufacturers; the American Automobile Manufacturers Association; and many of their member companies have provided valuable information over the years. In some instances the unpublished information that the EPA uses in the model is classified as Confidential Business Information (CBI). The annual emissions inventories of chemicals are aggregated in such a way that CBI cannot be inferred. Full public disclosure of the inputs to the Vintaging Model would jeopardize the security of the CBI that has been entrusted to the EPA.

The following sections discuss the emission equations used in the Vintaging Model for each broad end-use category. These equations are applied separately for each chemical used within each of the different end-uses. In the majority of these end-uses, more than one ODS substitute chemical is used.

In general, the modeled emissions are a function of the amount of chemical consumed in each end-use market. Estimates of the consumption of ODS alternatives can be inferred by determining the transition path of each regulated ODS used in the early 1990s. Using data gleaned from a variety of sources, assessments are made regarding which alternatives have been used, and what fraction of the ODS market in each end-use has been captured by a given alternative. By combining this with estimates of the total end-use market growth, a consumption value can be estimated for each chemical used within each end-use.

Methodology

The Vintaging Model estimates the use and emissions of ODS alternatives by taking the following steps:

1. *Gather historical data.* The Vintaging Model is populated with information on each end-use, taken from published sources and industry experts.

2. *Simulate the implementation of new, non-ODS technologies.* The Vintaging Model uses detailed characterizations of the existing uses of the ODS, as well as data on how the substitutes are replacing the ODS, to simulate the implementation of new technologies that enter the market in compliance with ODS phase-out policies. As part of this simulation, the ODS substitutes are introduced in each of the end-uses over time as seen historically and as needed to comply with the ODS phase-out and other regulations.

3. *Estimate emissions of the ODS substitutes.* The chemical use is estimated from the amount of substitutes that are required each year for the manufacture, installation, use, or servicing of products. The emissions are estimated from the emission profile for each vintage of equipment or product in each end-use. By aggregating the emissions from each vintage, a time profile of emissions from each end-use is developed.

Each set of end-uses is discussed in more detail in the following sections.

Refrigeration and Air-Conditioning

For refrigeration and air conditioning products, emission calculations are split into two categories: emissions during equipment lifetime, which arise from annual leakage and service losses, and disposal emissions, which occur at the time of discard. Two separate steps are required to calculate the lifetime emissions from leakage and service, and the emissions resulting from disposal of the equipment. For any given year, these lifetime emissions (for existing equipment) and disposal emissions (from discarded equipment) are summed to calculate the total emissions from refrigeration and air-conditioning. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates.

Step 1: Calculate lifetime emissions

Emissions from any piece of equipment include both the amount of chemical leaked during equipment operation and the amount emitted during service. Emissions from leakage and servicing can be expressed as follows:

$$Es_j = (l_a + l_s) \times \sum_{i=1}^k Qc_{j-i+1} \quad \text{for } i = 1 \rightarrow k$$

where:

| | | |
|-------|---|--|
| Es | = | Emissions from Equipment Serviced. Emissions in year j from normal leakage and servicing (including recharging) of equipment. |
| l_a | = | Annual Leak Rate. Average annual leak rate during normal equipment operation (expressed as a percentage of total chemical charge). |
| l_s | = | Service Leak Rate. Average leakage during equipment servicing (expressed as a percentage of total chemical charge). |
| Qc | = | Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in a given year by weight. |
| I | = | Counter, runs from 1 to lifetime (k). |
| j | = | Year of emission. |
| k | = | Lifetime. The average lifetime of the equipment. |

Step 2: Calculate disposal emissions

The disposal emission equations assume that a certain percentage of the chemical charge will be emitted to the atmosphere when that vintage is discarded. Disposal emissions are thus a function of the quantity of chemical contained in the retiring equipment fleet and the proportion of chemical released at disposal:

$$Ed_j = Qc_{j-k+1} \times [1 - (rm \times rc)]$$

where:

| | | |
|------|---|--|
| Ed | = | Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment. |
| Qc | = | Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in year $j-k+1$, by weight. |

| | | |
|-----------|---|--|
| <i>rm</i> | = | Chemical Remaining. Amount of chemical remaining in equipment at the time of disposal (expressed as a percentage of total chemical charge). |
| <i>rc</i> | = | Chemical Recovery Rate. Amount of chemical that is recovered just prior to disposal (expressed as a percentage of chemical remaining at disposal (<i>rm</i>)). |
| <i>j</i> | = | Year of emission. |
| <i>k</i> | = | Lifetime. The average lifetime of the equipment. |

Step 3: Calculate total emissions

Finally, lifetime and disposal emissions are summed to provide an estimate of total emissions.

$$E_j = Es_j + Ed_j$$

where:

| | | |
|-----------|---|---|
| <i>E</i> | = | Total Emissions. Emissions from refrigeration and air conditioning equipment in year <i>j</i> . |
| <i>Es</i> | = | Emissions from Equipment Serviced. Emissions in year <i>j</i> from leakage and servicing (including recharging) of equipment. |
| <i>Ed</i> | = | Emissions from Equipment Disposed. Emissions in year <i>j</i> from the disposal of equipment. |
| <i>j</i> | = | Year of emission. |

Assumptions

The assumptions used by the Vintaging Model to trace the transition of each type of equipment away from ODS are presented in Table A-169, below. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates. Additionally, the market for each equipment type is assumed to grow independently, according to annual growth rates.

Table A-169: Refrigeration and Air-Conditioning Market Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|--|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| Centrifugal Chillers | | | | | | | | | | | | | |
| CFC-11 | HCFC-123 | 1993 | 1993 | 45% | Unknown | | | | | | | | 1.6% |
| | HCFC-22 | 1991 | 1993 | 16% | HFC-134a | 2000 | 2010 | 100% | None | | | | |
| | HFC-134a | 1992 | 1993 | 39% | None | | | | | | | | |
| CFC-12 | HFC-134a | 1992 | 1994 | 53% | None | | | | | | | | 1.5% |
| | HCFC-22 | 1991 | 1994 | 16% | HFC-134a | 2000 | 2010 | 100% | None | | | | |
| R-500 | HCFC-123 | 1993 | 1994 | 31% | Unknown | | | | | | | | 1.5% |
| | HFC-134a | 1992 | 1994 | 53% | None | | | | | | | | |
| CFC-114 | HCFC-22 | 1991 | 1994 | 16% | HFC-134a | 2000 | 2010 | 100% | None | | | | 1.4% |
| | HCFC-123 | 1993 | 1994 | 31% | Unknown | | | | | | | | |
| | HFC-236fa | 1993 | 1996 | 100% | HFC-134a | 1998 | 2009 | 100% | None | | | | |
| Cold Storage | | | | | | | | | | | | | |
| CFC-12 | HCFC-22 | 1990 | 1993 | 65% | R-404A | 1996 | 2010 | 75% | None | | | | 3.1% |
| | | | | | R-507 | 1996 | 2010 | 25% | None | | | | |
| HCFC-22 | R-404A | 1994 | 1996 | 26% | None | | | | | | | | 3.0% |
| | R-507 | 1994 | 1996 | 9% | None | | | | | | | | |
| | HCFC-22 | 1992 | 1993 | 100% | R-404A | 1996 | 2009 | 8% | None | | | | |
| R-502 | | | | | R-507 | 1996 | 2009 | 3% | None | | | | 2.6% |
| | | | | | R-404A | 2009 | 2010 | 68% | None | | | | |
| | | | | | R-507 | 2009 | 2010 | 23% | None | | | | |
| | | | | | R-404A | 1996 | 2010 | 38% | None | | | | |
| | | | | | R-507 | 1996 | 2010 | 12% | None | | | | |
| | HCFC-22 | 1990 | 1993 | 40% | Non-ODP/GWP | 1996 | 2010 | 50% | None | | | | |
| | R-404A | 1993 | 1996 | 45% | None | | | | | | | | |
| | R-507 | 1994 | 1996 | 15% | None | | | | | | | | |
| Commercial Unitary Air Conditioners (Large) | | | | | | | | | | | | | |
| HCFC-22 | HCFC-22 | 1992 | 1993 | 100% | R-410A | 2001 | 2005 | 5% | None | | | | 1.3% |
| | | | | | R-407C | 2006 | 2009 | 1% | None | | | | |
| | | | | | R-410A | 2006 | 2009 | 9% | None | | | | |
| | | | | | R-407C | 2009 | 2010 | 5% | None | | | | |
| | | | | | R-410A | 2009 | 2010 | 81% | None | | | | |
| Commercial Unitary Air Conditioners (Small) | | | | | | | | | | | | | |
| HCFC-22 | HCFC-22 | 1992 | 1993 | 100% | R-410A | 1996 | 2000 | 3% | None | | | | 1.3% |
| | | | | | R-410A | 2001 | 2005 | 18% | None | | | | |
| | | | | | R-410A | 2006 | 2009 | 8% | None | | | | |
| | | | | | R-410A | 2009 | 2010 | 71% | None | | | | |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|--|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| Dehumidifiers | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 1997 | 1997 | 89% | None | | | | | | | | 1.3% |
| | R-410A | 2007 | 2010 | 11% | None | | | | | | | | |
| Ice Makers | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1993 | 1995 | 25% | None | | | | | | | | 2.1% |
| | R-404A | 1993 | 1995 | 75% | | | | | | | | | |
| Industrial Process Refrigeration | | | | | | | | | | | | | |
| CFC-11 | HCFC-123 | 1992 | 1994 | 70% | Unknown | | | | | | | | 3.2% |
| | HFC-134a | 1992 | 1994 | 15% | None | | | | | | | | |
| CFC-12 | HCFC-22 | 1991 | 1994 | 15% | HFC-134a | 1995 | 2010 | 100% | None | | | | 3.1% |
| | HCFC-22 | 1991 | 1994 | 10% | HFC-134a | 1995 | 2010 | 15% | None | | | | |
| | | | | | R-404A | 1995 | 2010 | 50% | None | | | | |
| | | | | | R-410A | 1999 | 2010 | 20% | None | | | | |
| | | | | | R-507 | 1995 | 2010 | 15% | None | | | | |
| HCFC-22 | HCFC-123 | 1992 | 1994 | 35% | Unknown | | | | | | | | 3.0% |
| | HFC-134a | 1992 | 1994 | 50% | None | | | | | | | | |
| | R-401A | 1995 | 1996 | 5% | HFC-134a | 1997 | 2000 | 100% | None | | | | |
| | HFC-134a | 1995 | 2009 | 2% | None | | | | | | | | |
| | R-404A | 1995 | 2009 | 5% | None | | | | | | | | |
| | R-410A | 1999 | 2009 | 2% | None | | | | | | | | |
| | R-507 | 1995 | 2009 | 2% | None | | | | | | | | |
| | HFC-134a | 2009 | 2010 | 14% | None | | | | | | | | |
| | R-404A | 2009 | 2010 | 45% | None | | | | | | | | |
| R-410A | 2009 | 2010 | 18% | None | | | | | | | | | |
| R-507 | 2009 | 2010 | 14% | None | | | | | | | | | |
| Mobile Air Conditioners (Passenger Cars) | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1992 | 1994 | 100% | HFO-1234yf | 2012 | 2015 | 1% | None | | | | 0.3% |
| | | | | | HFO-1234yf | 2016 | 2021 | 99% | None | | | | |
| Mobile Air Conditioners (Light Duty Trucks) | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1993 | 1994 | 100% | HFO-1234yf | 2012 | 2015 | 1% | None | | | | 1.4% |
| | | | | | HFO-1234yf | 2016 | 2021 | 99% | None | | | | |
| Mobile Air Conditioners (School and Tour Buses) | | | | | | | | | | | | | |
| CFC-12 | HCFC-22 | 1994 | 1995 | 0.5% | HFC-134a | 2006 | 2007 | 100% | None | | | | 0.3% |
| | HFC-134a | 1194 | 1997 | 99.5% | None | | | | | | | | |
| Mobile Air Conditioners (Transit Buses) | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 1995 | 2009 | 100% | None | | | | | | | | 0.3% |
| Mobile Air Conditioners (Trains) | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 2002 | 2009 | 50% | None | | | | | | | | 0.3% |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|--|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| | R-407C | 2002 | 2009 | 50% | None | | | | | | | | |
| Packaged Terminal Air Conditioners and Heat Pumps | | | | | | | | | | | | | |
| HCFC-22 | R-410A | 2006 | 2009 | 10% | None | | | | | | | | 3.0% |
| | R-410A | 2009 | 2010 | 90% | None | | | | | | | | |
| Positive Displacement Chillers | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 2000 | 2009 | 9% | R-407C | 2010 | 2020 | 60% | None | | | | 2.5% |
| | R-407C | 2000 | 2009 | 1% | R-410A | 2010 | 2020 | 40% | None | | | | |
| | HFC-134a | 2009 | 2010 | 81% | R-407C | 2010 | 2020 | 60% | None | 2010 | 2020 | 40% | |
| CFC-12 | HCFC-22 | 1993 | 1993 | 100% | R-407C | 2009 | 2010 | 9% | None | | | | 2.5% |
| | | | | | HFC-134a | 2000 | 2009 | 9% | R-407C | 2010 | 2020 | 60% | |
| | | | | | R-407C | 2000 | 2009 | 1% | R-410A | 2010 | 2020 | 40% | |
| | | | | | HFC-134a | 2009 | 2010 | 81% | R-407C | 2010 | 2020 | 60% | |
| | | | | | R-407C | 2009 | 2010 | 9% | R-410A | 2010 | 2020 | 40% | |
| Refrigerated Appliances | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1994 | 1995 | 100% | None | | | | | | | | 1.7% |
| Residential Unitary Air Conditioners | | | | | | | | | | | | | |
| HCFC-22 | HCFC-22 | 2006 | 2006 | 70% | R-410A | 2007 | 2010 | 29% | None | | | | 1.3% |
| | R-410A | 2000 | 2005 | 5% | R-410A | 2010 | 2010 | 71% | None | | | | |
| | R-410A | 2000 | 2006 | 5% | R-410A | 2006 | 2006 | 100% | None | | | | |
| | R-410A | 2006 | 2006 | 20% | None | | | | | | | | |
| Retail Food (Large; Technology Transition) | | | | | | | | | | | | | |
| DX ¹ | DX | 2001 | 2006 | 67.5% | DX | 2006 | 2015 | 35% | None | | | | 1.7% |
| | | | | | DR ² | 2000 | 2015 | 23% | None | | | | |
| | | | | | SLS ³ | 2000 | 2015 | 15% | None | | | | |
| | DR | 2001 | 2006 | 22.5% | None | | | | | | | | |
| | SLS | 2001 | 2006 | 10% | None | | | | | | | | |
| Retail Food (Large; Refrigerant Transition) | | | | | | | | | | | | | |
| CFC-12 | R-404A | 1995 | 2000 | 17.5% | R-404A | 2000 | 2000 | 3.3% | None | | | | 1.7% |
| R-502 ⁴ | | | | | R-407A | 2011 | 2015 | 63.3% | None | | | | |
| | R-507 | 1995 | 2000 | 7.5% | R-507 | 2001 | 2005 | 70% | R-404A | 2006 | 2010 | 29% | |
| | | | | | R-407A | 2006 | 2010 | 30% | R-407A | 2006 | 2010 | 71% | |
| | HCFC-22 | 1995 | 2000 | 75% | R-404A | 2006 | 2010 | 13.3% | None | 2011 | 2015 | 100% | |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|---|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| | | | | | R-407A | 2001 | 2005 | 1.3% | None | | | | |
| | | | | | R-404A | 2001 | 2005 | 12% | None | | | | |
| | | | | | R-507 | 2001 | 2005 | 6.7% | R-407A | 2011 | 2015 | 100% | |
| | | | | | R-404A | 2006 | 2010 | 34% | R-407A | 2011 | 2015 | 100% | |
| | | | | | R-404A | 2006 | 2010 | 7.3% | None | | | | |
| | | | | | R-407A | 2006 | 2010 | 25.3% | None | | | | |
| Retail Food (Large Condensing Units) | | | | | | | | | | | | | |
| HCFC-22 | R-402A | 1995 | 2005 | 5% | R-404A | 2006 | 2006 | 100% | None | | | | 1.5% |
| | R-404A | 1995 | 2005 | 25% | None | | | | | | | | |
| | R-507 | 1995 | 2005 | 10% | None | | | | | | | | |
| | R-404A | 2008 | 2010 | 45% | None | | | | | | | | |
| | R-507 | 2008 | 2010 | 15% | None | | | | | | | | |
| Retail Food (Small Condensing Units) | | | | | | | | | | | | | |
| HCFC-22 | R-401A | 1995 | 2005 | 6% | HFC-134a | 2006 | 2006 | 100% | None | | | | 1.6% |
| | R-402A | 1995 | 2005 | 4% | HFC-134a | 2006 | 2006 | 100% | None | | | | |
| | HFC-134a | 1993 | 2005 | 30% | | | | | | | | | |
| | R-404A | 1995 | 2005 | 30% | | | | | | | | | |
| | R-404A | 2008 | 2010 | 30% | | | | | | | | | |
| Retail Food (Small) | | | | | | | | | | | | | |
| CFC-12 | HCFC-22 | 1990 | 1993 | 91% | HFC-134a | 1993 | 1995 | 91% | CO ₂ | 2012 | 2015 | 1% | 2.2% |
| | | | | | | | | | Non-ODP/GWP | 2012 | 2015 | 3.7% | |
| | | | | | | | | | CO ₂ | 2016 | 2016 | 11% | |
| | | | | | | | | | Non-ODP/GWP | 2016 | 2016 | 17.3% | |
| | | | | | HFC-134a | 2000 | 2009 | 9% | | | | | |
| | R-404A | 1990 | 1993 | 9% | Non-ODP/GWP | 2016 | 2016 | 30% | | | | | |
| Retail Food (Vending Machines) | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1995 | 1998 | 90% | CO ₂ | 2012 | 2012 | 1% | None | | | | -0.03% |
| | | | | | CO ₂ | 2013 | 2017 | 39% | None | | | | |
| | | | | | Propane | 2014 | 2014 | 1% | None | | | | |
| | | | | | Propane | 2015 | 2015 | 49% | None | | | | |
| | | | | | R-450A | 2019 | 2019 | 5% | None | | | | |
| | | | | | R-513A | 2019 | 2019 | 5% | None | | | | |
| | R-404A | 1995 | 1998 | 10% | R-450A | 2019 | 2019 | 50% | None | | | | |
| | | | | | R-513A | 2019 | 2019 | 50% | None | | | | |
| Transport Refrigeration (Road Transport) | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1993 | 1995 | 10% | None | | | | | | | | 5.5% |
| | R-404A | 1993 | 1995 | 60% | None | | | | | | | | |
| | HCFC-22 | 1993 | 1995 | 30% | R-410A | 2000 | 2003 | 5% | CO ₂ | 2017 | 2021 | 5% | |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|---|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| | | | | | R-404A | 2006 | 2010 | 95% | CO ₂ | 2017 | 2021 | 5% | |
| Transport Refrigeration (Intermodal Containers) | | | | | | | | | | | | | |
| CFC-12 | HFC-134a | 1993 | 1993 | 60% | CO ₂ | 2017 | 2021 | 5% | None | | | | 7.3% |
| | R-404A | 1993 | 1993 | 5% | CO ₂ | 2017 | 2021 | 5% | None | | | | |
| | HCFC-22 | 1993 | 1993 | 35% | HFC-134a | 2000 | 2010 | 10% | CO ₂ | 2017 | 2021 | 5% | |
| Transport Refrigeration (Merchant Fishing Transport) | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 1993 | 1995 | 10% | None | | | | | | | | 5.7% |
| | R-507 | 1994 | 1995 | 10% | None | | | | | | | | |
| | R-404A | 1993 | 1995 | 10% | None | | | | | | | | |
| | HCFC-22 | 1993 | 1995 | 70% | R-407C | 2000 | 2005 | 3% | R-410A | 2005 | 2007 | 100% | |
| | | | | | | R-507 | 2006 | 2010 | 49% | None | | | |
| | | | | | R-404 | 2006 | 2010 | 49% | None | | | | |
| Transport Refrigeration (Reefer Ships) | | | | | | | | | | | | | |
| HCFC-22 | HFC-134a | 1993 | 1995 | 3.3% | None | | | | | | | | 4.2% |
| | R-507 | 1994 | 1995 | 3.3% | None | | | | | | | | |
| | R-404A | 1993 | 1995 | 3.3% | None | | | | | | | | |
| | HCFC-22 | 1993 | 1995 | 90% | HFC-134a | 2006 | 2010 | 25% | None | | | | |
| | | | | | | R-507 | 2006 | 2010 | 25% | None | | | |
| | | | | | R-404A | 2006 | 2010 | 25% | None | | | | |
| | | | | | R-407C | 2006 | 2010 | 25% | None | | | | |
| Transport Refrigeration (Vintage Rail Transport) | | | | | | | | | | | | | |
| CFC-12 | HCFC-22 | 1993 | 1995 | 100% | HFC-134a | 1996 | 2000 | 100% | None | | | | -100% |
| Transport Refrigeration (Modern Rail Transport) | | | | | | | | | | | | | |
| HFC-134a | R-404A | 1999 | 1999 | 50% | None | | | | | | | | 0.3% |
| | HFC-134A | 2005 | 2005 | 50% | None | | | | | | | | |
| Water-Source and Ground-Source Heat Pumps | | | | | | | | | | | | | |
| HCFC-22 | R-407C | 2000 | 2006 | 5% | None | | | | | | | | 1.3% |
| | R-410A | 2000 | 2006 | 5% | None | | | | | | | | |
| | HFC-134a | 2000 | 2009 | 2% | None | | | | | | | | |
| | R-407C | 2006 | 2009 | 2.5% | None | | | | | | | | |
| | R-410A | 2006 | 2009 | 4.5% | None | | | | | | | | |
| | HFC-134a | 2009 | 2010 | 18% | None | | | | | | | | |
| | R-407C | 2009 | 2010 | 22.5% | None | | | | | | | | |
| | R-410A | 2009 | 2010 | 40.5% | None | | | | | | | | |
| Window Units | | | | | | | | | | | | | |
| HCFC-22 | R-410A | 2008 | 2009 | 10% | None | | | | | | | | 4.0% |
| | R-410A | 2009 | 2010 | 90% | None | | | | | | | | |

¹ DX refers to direct expansion systems where the compressors are mounted together in a rack and share suction and discharge refrigeration lines that run throughout the store, feeding refrigerant to the display cases in the sales area.

² DR refers to distributed refrigeration systems that consist of multiple smaller units that are located close to the display cases that they serve such as on the roof above the cases, behind a nearby wall, or on top of or next to the case in the sales area.

³ SLS refers to secondary loop systems wherein a secondary fluid such as glycol or carbon dioxide is cooled by the primary refrigerant in the machine room and then pumped throughout the store to remove heat from the display equipment.

⁴ The CFC-12 large retail food market for new systems transitioned to R-502 from 1998 to 1990, and subsequently transitioned to HCFC-22 from 1990 to 1993. These transitions are not shown in the table in order to provide the HFC transitions in greater detail.

⁵ HCFC-22 for new equipment after 2010 is assumed to be reclaimed material.

Table A-170 presents the average equipment lifetimes and annual HFC emission rates (for servicing and leaks) for each end-use assumed by the Vintaging Model.

Table A-170: Refrigeration and Air-Conditioning Lifetime Assumptions

| End-Use | Lifetime (Years) | HFC Emission Rates (%) |
|----------------------------------|------------------|------------------------|
| Centrifugal Chillers | 20 – 27 | 2.0 – 10.9 |
| Cold Storage | 20 – 25 | 15.0 |
| Commercial Unitary A/C | 15 | 7.9 – 8.6 |
| Dehumidifiers | 11 | 0.5 |
| Ice Makers | 8 | 3.0 |
| Industrial Process Refrigeration | 25 | 3.6 – 12.3 |
| Mobile Air Conditioners | 5 – 16 | 2.3 – 18.0 |
| Positive Displacement Chillers | 20 | 0.5 – 1.5 |
| PTAC/PTHP | 12 | 3.9 |
| Retail Food | 10 – 20 | 1.0 – 25 |
| Refrigerated Appliances | 14 | 0.6 |
| Residential Unitary A/C | 15 | 11.8 |
| Transport Refrigeration | 9 – 40 | 19.4 – 36.4 |
| Water & Ground Source Heat Pumps | 20 | 3.9 |
| Window Units | 12 | 0.6 |

Aerosols

ODSs, HFCs, and many other chemicals are used as propellant aerosols. Pressurized within a container, a nozzle releases the chemical, which allows the product within the can to also be released. Two types of aerosol products are modeled: metered dose inhalers (MDI) and consumer aerosols. In the United States, the use of CFCs in consumer aerosols was banned in 1978, and many products transitioned to hydrocarbons or “not-in-kind” technologies, such as solid deodorants and finger-pump hair sprays. However, MDIs can continue to use CFCs as propellants because their use has been deemed essential. Essential use exemptions granted to the United States under the Montreal Protocol for CFC use in MDIs are limited to the treatment of asthma and chronic obstructive pulmonary disease.

All HFCs and PFCs used in aerosols are assumed to be emitted in the year of manufacture. Since there is currently no aerosol recycling, it is assumed that all of the annual production of aerosol propellants is released to the atmosphere. The following equation describes the emissions from the aerosols sector.

$$E_j = Qc_j$$

where:

- E = Emissions. Total emissions of a specific chemical in year j from use in aerosol products, by weight.
- Qc = Quantity of Chemical. Total quantity of a specific chemical contained in aerosol products sold in year j , by weight.
- j = Year of emission.

Transition Assumptions

Transition assumptions and growth rates for those items that use ODSs or HFCs as propellants, including vital medical devices and specialty consumer products, are presented in Table A-171.

Table A-171: Aerosol Product Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Growth Rate |
|-------------------------------------|----------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| MDIs | | | | | | | | | |
| CFC Mix ^a | HFC-134a | 1997 | 1997 | 6% | None | | | | 0.8% |
| | Non-ODP/GWP | 1998 | 2007 | 7% | None | | | | |
| | CFC Mix ^a | 2000 | 2000 | 87% | HFC-134a | 2002 | 2002 | 34% | |
| | | | | | HFC-134a | 2003 | 2009 | 47% | |
| | | | | | HFC-227ea | 2006 | 2009 | 5% | |
| | | | | | HFC-134a | 2010 | 2011 | 6% | |
| | | | | | HFC-227ea | 2010 | 2011 | 1% | |
| | | | | | HFC-134a | 2011 | 2012 | 3% | |
| | | | | | HFC-227ea | 2011 | 2012 | 0.3% | |
| | | | | | HFC-134a | 2014 | 2014 | 3% | |
| | | | | HFC-227ea | 2014 | 2014 | 0.3% | | |
| Consumer Aerosols (Non-MDIs) | | | | | | | | | |
| NA ^b | HFC-152a | 1990 | 1991 | 50% | None | | | | 2.0% |
| | HFC-134a | 1995 | 1995 | 50% | HFC-152a | 1997 | 1998 | 44% | |
| | | | | | HFC-152a | 2001 | 2005 | 36% | |

^a CFC Mix consists of CFC-11, CFC-12 and CFC-114 and represents the weighted average of several CFCs consumed for essential use in MDIs from 1993 to 2008.

^b Consumer Aerosols transitioned away from ODS prior to 1985, the year in which the Vintaging Model begins. The portion of the market that is now using HFC propellants is modeled.

Solvents

ODSs, HFCs, PFCs and other chemicals are used as solvents to clean items. For example, electronics may need to be cleaned after production to remove any manufacturing process oils or residues left. Solvents are applied by moving the item to be cleaned within a bath or stream of the solvent. Generally, most solvents are assumed to remain in the liquid phase and are not emitted as gas. Thus, emissions are considered “incomplete,” and are a fixed percentage of the amount of solvent consumed in a year. The remainder of the consumed solvent is assumed to be reused or disposed without being released to the atmosphere. The following equation calculates emissions from solvent applications.

$$E_j = l \times Qc_j$$

where:

- E* = Emissions. Total emissions of a specific chemical in year *j* from use in solvent applications, by weight.
- l* = Percent Leakage. The percentage of the total chemical that is leaked to the atmosphere, assumed to be 90 percent.
- Qc* = Quantity of Chemical. Total quantity of a specific chemical sold for use in solvent applications in the year *j*, by weight.
- j* = Year of emission.

Transition Assumptions

The transition assumptions and growth rates used within the Vintaging Model for electronics cleaning, metals cleaning, precision cleaning, and adhesives, coatings and inks, are presented in Table A-172.

Table A-172: Solvent Market Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Growth Rate |
|----------------------------------|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| Adhesives | | | | | | | | | |
| CH ₃ CCl ₃ | Non-ODP/GWP | 1994 | 1995 | 100% | None | | | | 2.0% |
| Electronics | | | | | | | | | |
| CFC-113 | Semi-Aqueous | 1994 | 1995 | 52% | None | | | | 2.0% |
| | HCFC-225ca/cb | 1994 | 1995 | 0.2% | Unknown | | | | |
| | HFC-43-10mee | 1995 | 1996 | 0.7% | None | | | | |
| | HFE-7100 | 1994 | 1995 | 0.7% | None | | | | |
| | nPB | 1992 | 1996 | 5% | None | | | | |
| | Methyl Siloxanes | 1992 | 1996 | 0.8% | None | | | | |
| | No-Clean | 1992 | 1996 | 40% | None | | | | |
| CH ₃ CCl ₃ | Non-ODP/GWP | 1996 | 1997 | 99.8% | None | | | | 2.0% |
| | PFC/PFPE | 1996 | 1997 | 0.2% | Non-ODP/GWP | 2000 | 2003 | 90% | |
| | | | | | Non-ODP/GWP | 2005 | 2009 | 10% | |
| Metals | | | | | | | | | |
| CH ₃ CCl ₃ | Non-ODP/GWP | 1992 | 1996 | 100% | None | | | | 2.0% |
| CFC-113 | Non-ODP/GWP | 1992 | 1996 | 100% | None | | | | 2.0% |
| CCl ₄ | Non-ODP/GWP | 1992 | 1996 | 100% | None | | | | 2.0% |
| Precision | | | | | | | | | |
| CH ₃ CCl ₃ | Non-ODP/GWP | 1995 | 1996 | 99.3% | None | | | | 2.0% |
| | HFC-43-10mee | 1995 | 1996 | 0.6% | None | | | | |
| | PFC/PFPE | 1995 | 1996 | 0.1% | Non-ODP/GWP | 2000 | 2003 | 90% | |
| | | | | | Non-ODP/GWP | 2005 | 2009 | 10% | |
| CFC-113 | Non-ODP/GWP | 1995 | 1996 | 96% | None | | | | 2.0% |
| | HCFC-225ca/cb | 1995 | 1996 | 1% | Unknown | | | | |
| | HFE-7100 | 1995 | 1996 | 3% | None | | | | |

Non-ODP/GWP includes chemicals with zero ODP and low GWP, such as hydrocarbons and ammonia, as well as not-in-kind alternatives such as "no clean" technologies.

Fire Extinguishing

ODSs, HFCs, PFCs and other chemicals are used as fire-extinguishing agents, in both hand-held "streaming" applications as well as in built-up "flooding" equipment similar to water sprinkler systems. Although these systems are generally built to be leak-tight, some leaks do occur and of course emissions occur when the agent is released. Total emissions from fire extinguishing are assumed, in aggregate, to equal a percentage of the total quantity of chemical in operation at a given time. For modeling purposes, it is assumed that fire extinguishing equipment leaks at a constant rate for an average equipment lifetime, as shown in the equation below. In streaming systems, non-halon emissions are assumed to be 3.5 percent of all chemical in use in each year, while in flooding systems 2.5 percent of the installed base of chemical is assumed to leak annually. Halon systems are assumed to leak at higher rates. The equation is applied for a single year, accounting for all fire protection equipment in operation in that year. Each fire protection agent is modeled separately. In the Vintaging Model, streaming applications have a 12-year lifetime and flooding applications have a 20-year lifetime.

$$E_j = r \times \sum Q_{C_{j+i}} \text{ for } i=1 \rightarrow k$$

where:

- E* = Emissions. Total emissions of a specific chemical in year *j* for streaming fire extinguishing equipment, by weight.
- r* = Percent Released. The percentage of the total chemical in operation that is released to the atmosphere.
- Q_c* = Quantity of Chemical. Total amount of a specific chemical used in new fire extinguishing equipment in a given year, *j-i+1*, by weight.
- i* = Counter, runs from 1 to lifetime (*k*).

j = Year of emission.

k = Lifetime. The average lifetime of the equipment.

Transition Assumptions

Transition assumptions and growth rates for these two fire extinguishing types are presented in Table A-173.

Table A-173: Fire Extinguishing Market Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Growth Rate |
|-------------------------|--------------------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| Flooding Agents | | | | | | | | | |
| Halon-1301 | Halon-1301* | 1994 | 1994 | 4% | Unknown | | | | 2.2% |
| | HFC-23 | 1994 | 1999 | 0.2% | None | | | | |
| | HFC-227ea | 1994 | 1999 | 18% | FK-5-1-12 | 2003 | 2010 | 10% | |
| | Non-ODP/GWP | 1994 | 1994 | 46% | HFC-125 | 2001 | 2008 | 10% | |
| | Non-ODP/GWP | 1995 | 2034 | 10% | FK-5-1-12 | 2003 | 2010 | 7% | |
| | Non-ODP/GWP | 1998 | 2027 | 10% | None | | | | |
| | C ₄ F ₁₀ | 1994 | 1999 | 1% | FK-5-1-12 | 2003 | 2003 | 100% | |
| | HFC-125 | 1997 | 2006 | 11% | None | | | | |
| Streaming Agents | | | | | | | | | |
| Halon-1211 | Halon-1211* | 1992 | 1992 | 5% | Unknown | | | | 3.0% |
| | HFC-236fa | 1997 | 1999 | 3% | None | | | | |
| | Halotron | 1994 | 1995 | 0.1% | None | | | | |
| | Halotron | 1996 | 2000 | 5.4% | Non-ODP/GWP | 2020 | 2020 | 56% | |
| | Non-ODP/GWP | 1993 | 1994 | 56% | None | | | | |
| | Non-ODP/GWP | 1995 | 2024 | 20% | None | | | | |
| | Non-ODP/GWP | 1999 | 2018 | 10% | None | | | | |

*Despite the 1994 consumption ban, a small percentage of new halon systems are assumed to continue to be built and filled with stockpiled or recovered supplies.

Foam Blowing

ODSs, HFCs, and other chemicals are used to produce foams, including such items as the foam insulation panels around refrigerators, insulation sprayed on buildings, etc. The chemical is used to create pockets of gas within a substrate, increasing the insulating properties of the item. Foams are given emission profiles depending on the foam type (open cell or closed cell). Open cell foams are assumed to be 100 percent emissive in the year of manufacture. Closed cell foams are assumed to emit a portion of their total HFC content upon manufacture, a portion at a constant rate over the lifetime of the foam, a portion at disposal, and a portion after disposal; these portions vary by end-use.

Step 1: Calculate manufacturing emissions (open-cell and closed-cell foams)

Manufacturing emissions occur in the year of foam manufacture, and are calculated as presented in the following equation.

$$Em_j = lm \times Qc_j$$

where:

Em_j = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

lm = Loss Rate. Percent of original blowing agent emitted during foam manufacture. For open-cell foams, lm is 100%.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

j = Year of emission.

Step 2: Calculate lifetime emissions (closed-cell foams)

Lifetime emissions occur annually from closed-cell foams throughout the lifetime of the foam, as calculated as presented in the following equation.

$$Eu_j = lu \times \sum Qc_{j+i} \text{ for } i=1 \rightarrow k$$

where:

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

lu = Leak Rate. Percent of original blowing agent emitted each year during lifetime use.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 3: Calculate disposal emissions (closed-cell foams)

Disposal emissions occur in the year the foam is disposed, and are calculated as presented in the following equation.

$$Ed_j = ld \times Qc_{j-k}$$

where:

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

ld = Loss Rate. Percent of original blowing agent emitted at disposal.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 4: Calculate post-disposal emissions (closed-cell foams)

Post-disposal emissions occur in the years after the foam is disposed; for example, emissions might occur while the disposed foam is in a landfill. Currently, the only foam type assumed to have post-disposal emissions is polyurethane foam used as domestic refrigerator and freezer insulation, which is expected to continue to emit for 26 years post-disposal, calculated as presented in the following equation.

$$Ep_j = lp \times \sum Qc_{j-m} \text{ for } m=k \rightarrow k + 26$$

where:

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j, by weight.

lp = Leak Rate. Percent of original blowing agent emitted post disposal.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

k = Lifetime. The average lifetime of foam product.

m = Counter. Runs from lifetime (k) to (k+26).

j = Year of emission.

Step 5: Calculate total emissions (open-cell and closed-cell foams)

To calculate total emissions from foams in any given year, emissions from all foam stages must be summed, as presented in the following equation.

$$E_j = Em_j + Eu_j + Ed_j + Ep_j$$

where:

E_j = Total Emissions. Total emissions of a specific chemical in year j , by weight.

Em = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j , by weight.

Assumptions

The Vintaging Model contains thirteen foam types, whose transition assumptions away from ODS and growth rates are presented in Table A-174. The emission profiles of these thirteen foam types are shown in Table A-175.

Table A-174: Foam Blowing Market Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|---|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| Commercial Refrigeration Foam | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1996 | 40% | HFC-245fa | 2002 | 2003 | 80% | None | | | | 6.0% |
| | | | | | Non-ODP/GWP | 2002 | 2003 | 20% | None | | | | |
| | HCFC-142b | 1989 | 1996 | 8% | Non-ODP/GWP | 2009 | 2010 | 80% | None | | | | |
| | HCFC-22 | 1989 | 1996 | 52% | HFC-245fa | 2009 | 2010 | 20% | None | | | | |
| | | | | | Non-ODP/GWP | 2009 | 2010 | 80% | None | | | | |
| | | | | | HFC-245fa | 2009 | 2010 | 20% | None | | | | |
| Flexible PU Foam: Integral Skin Foam | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1990 | 100% | HFC-134a | 1993 | 1996 | 25% | None | | | | 2.0% |
| | | | | | HFC-134a | 1994 | 1996 | 25% | None | | | | |
| | | | | | CO ₂ | 1993 | 1996 | 25% | None | | | | |
| | | | | | CO ₂ | 1994 | 1996 | 25% | None | | | | |
| Flexible PU Foam: Slabstock Foam, Moulded Foam | | | | | | | | | | | | | |
| CFC-11 | Non-ODP/GWP | 1992 | 1992 | 100% | None | | | | | | | | 2.0% |
| Phenolic Foam | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1990 | 100% | Non-ODP/GWP | 1992 | 1992 | 100% | None | | | | 2.0% |
| Polyolefin Foam | | | | | | | | | | | | | |
| CFC-114 | HFC-152a | 1989 | 1993 | 10% | Non-ODP/GWP | 2005 | 2010 | 100% | None | | | | 2.0% |
| | HCFC-142b | 1989 | 1993 | 90% | Non-ODP/GWP | 1994 | 1996 | 100% | None | | | | |
| PU and PIR Rigid: Boardstock | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1993 | 1996 | 100% | Non-ODP/GWP | 2000 | 2003 | 95% | None | | | | 6.0% |
| | | | | | HC/HFC-245fa Blend | 2000 | 2003 | 5% | None | | | | |
| PU Rigid: Domestic Refrigerator and Freezer Insulation | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1993 | 1995 | 100% | HFC-134a | 1996 | 2001 | 7% | Non-ODP/GWP | 2002 | 2003 | 100% | 0.8% |
| | | | | | HFC-245fa | 2001 | 2003 | 50% | Non-ODP/GWP | 2015 | 2029 | 100% | |
| | | | | | HFC-245fa | 2006 | 2009 | 10% | Non-ODP/GWP | 2015 | 2029 | 100% | |
| | | | | | Non-ODP/GWP | 2002 | 2005 | 10% | None | | | | |
| | | | | | Non-ODP/GWP | 2006 | 2009 | 3% | None | | | | |
| | | | | | Non-ODP/GWP | 2009 | 2014 | 20% | None | | | | |
| PU Rigid: One Component Foam | | | | | | | | | | | | | |
| CFC-12 | HCFC-142b/22 Blend | 1989 | 1996 | 70% | Non-ODP/GWP | 2009 | 2010 | 80% | None | | | | 4.0% |
| | | | | | HFC-134a | 2009 | 2010 | 10% | None | | | | |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|--|--------------------|------------|---|----------------------------|--|--------------------------------------|---|---------------------------------|--|--------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| | HCFC-22 | 1989 | 1996 | 30% | HFC-152a Non-ODP/GWP HFC-134a HFC-152a | 2009 2009 2009 2009 | 2010 2010 2010 2010 | 10% 80% 10% 10% | None None None None | | | | |
| PU Rigid: Other: Slabstock Foam | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1996 | 100% | CO ₂ Non-ODP/GWP HCFC-22 | 1999 2001 2003 | 2003 2003 2003 | 45% 45% 10% | None None Non-ODP/GWP | 2009 | 2010 | 100% | 2.0% |
| PU Rigid: Sandwich Panels: Continuous and Discontinuous | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1996 | 82% | HCFC-22/Water Blend HFC-245fa/CO ₂ Blend Non-ODP/GWP HFC-134a HFC-245fa/CO ₂ Blend | 2001 2002 2001 2002 2009 | 2003 2004 2004 2004 2010 | 20% 20% 40% 20% 40% | HFC-245fa/CO ₂ Blend Non-ODP/GWP None None None | 2009 2009 | 2010 2010 | 50% 50% | 6.0% |
| | HCFC-22 | 1989 | 1996 | 18% | Non-ODP/GWP CO ₂ HFC-134a | 2009 2009 2009 | 2010 2010 2010 | 20% 20% 20% | None None None | | | | |
| PU Rigid: Spray Foam | | | | | | | | | | | | | |
| CFC-11 | HCFC-141b | 1989 | 1996 | 100% | HFC-245fa HFC-245fa/CO ₂ Blend Non-ODP/GWP | 2002 2002 2001 | 2003 2003 2003 | 30% 60% 10% | None None None | | | | 6.0% |
| XPS: Boardstock Foam | | | | | | | | | | | | | |
| CFC-12 | HCFC-142b/22 Blend | 1989 | 1994 | 10% | HFC-134a HFC-152a CO ₂ Non-ODP/GWP | 2009 2009 2009 2009 | 2010 2010 2010 2010 | 70% 10% 10% 10% | None None None None | | | | 2.5% |
| | HCFC-142b | 1989 | 1994 | 90% | HFC-134a HFC-152a CO ₂ Non-ODP/GWP | 2009 2009 2009 2009 | 2010 2010 2010 2010 | 70% 10% 10% 10% | None None None None | | | | |
| XPS: Sheet Foam | | | | | | | | | | | | | |
| CFC-12 | CO ₂ | 1989 | 1994 | 1% | None | | | | | | | | 2.0% |

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|------------------------|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| | Non-ODP/GWP | 1989 | 1994 | 99% | CO ₂ | 1995 | 1999 | 9% | None | | | | |
| | | | | | HFC-152a | 1995 | 1999 | 10% | None | | | | |

Table A-175: Emission Profile for the Foam End-Uses

| Foam End-Use | Loss at Manufacturing (%) | Annual Leakage Rate (%) | Leakage Lifetime (years) | Loss at Disposal (%) | Total ^a (%) |
|---|---------------------------|-------------------------|--------------------------|----------------------|------------------------|
| Flexible PU Foam: Slabstock Foam, Moulded Foam | 100 | 0 | 1 | 0 | 100 |
| Commercial Refrigeration | 6 | 0.25 | 15 | 90.25 | 100 |
| Rigid PU: Spray Foam | 15 | 1.5 | 56 | 1 | 100 |
| Rigid PU: Slabstock and Other | 37.5 | 0.75 | 15 | 51.25 | 100 |
| Phenolic Foam | 23 | 0.875 | 32 | 49 | 100 |
| Polyolefin Foam | 95 | 2.5 | 2 | 0 | 100 |
| Rigid PU: One Component Foam | 100 | 0 | 1 | 0 | 100 |
| XPS: Sheet Foam ^a | 40 | 2 | 25 | 0 | 90 |
| XPS: Boardstock Foam | 25 | 0.75 | 50 | 37.5 | 100 |
| Flexible PU Foam: Integral Skin Foam | 95 | 2.5 | 2 | 0 | 100 |
| Rigid PU: Domestic Refrigerator and Freezer Insulation ^a | 4 | 0.25 | 14 | 40.0 | 47.5 |
| PU and PIR Rigid: Boardstock | 6 | 1 | 50 | 44 | 100 |
| PU Sandwich Panels: Continuous and Discontinuous | 5.5 | 0.5 | 50 | 69.5 | 100 |

PIR (Polyisocyanurate)

PU (Polyurethane)

XPS (Extruded Polystyrene)

^a In general, total emissions from foam end-uses are assumed to be 100 percent, although work is underway to investigate that assumption. In the XPS Sheet/Insulation Board end-use, the source of emission rates and lifetimes did not yield 100 percent emission; it is unclear at this time whether that was intentional. In the Rigid PU Appliance Foam end-use, the source of emission rates and lifetimes did not yield 100 percent emission; the remainder is anticipated to be emitted at a rate of 2.0%/year post-disposal for the next 26 years.

Sterilization

Sterilants kill microorganisms on medical equipment and devices. The principal ODS used in this sector was a blend of 12 percent ethylene oxide (EtO) and 88 percent CFC-12, known as "12/88." In that blend, ethylene oxide sterilizes the equipment and CFC-12 is a diluent solvent to form a non-flammable blend. The sterilization sector is modeled as a single end-use. For sterilization applications, all chemicals that are used in the equipment in any given year are assumed to be emitted in that year, as shown in the following equation.

$$E_j = Qc_j$$

where:

E = Emissions. Total emissions of a specific chemical in year j from use in sterilization equipment, by weight.

Qc = Quantity of Chemical. Total quantity of a specific chemical used in sterilization equipment in year j , by weight.

j = Year of emission.

Assumptions

The Vintaging Model contains one sterilization end-use, whose transition assumptions away from ODS and growth rates are presented in Table A-176.

Table A-176: Sterilization Market Transition Assumptions

| Initial Market Segment | Primary Substitute | | | | Secondary Substitute | | | | Tertiary Substitute | | | | Growth Rate |
|------------------------|--------------------|------------|---|----------------------------|----------------------|------------|---|----------------------------|---------------------|------------|---|----------------------------|-------------|
| | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | Name of Substitute | Start Date | Date of Full Penetration in New Equipment | Maximum Market Penetration | |
| 12/88 | EtO | 1994 | 1995 | 95% | None | | | | | | | | 2.0% |
| | Non-ODP/GWP | 1994 | 1995 | 1% | None | | | | | | | | |
| | HCFC/EtO Blends | 1993 | 1994 | 4% | Non-ODP/GWP | 2010 | 2010 | 100% | None | | | | |

Model Output

By repeating these calculations for each year, the Vintaging Model creates annual profiles of use and emissions for ODS and ODS substitutes. The results can be shown for each year in two ways: 1) on a chemical-by-chemical basis, summed across the end-uses, or 2) on an end-use or sector basis. Values for use and emissions are calculated both in metric tons and in million metric tons of CO₂ equivalents (MMT CO₂ Eq.). The conversion of metric tons of chemical to MMT CO₂ Eq. is accomplished through a linear scaling of tonnage by the global warming potential (GWP) of each chemical.

Throughout its development, the Vintaging Model has undergone annual modifications. As new or more accurate information becomes available, the model is adjusted in such a way that both past and future emission estimates are often altered.

Bank of ODS and ODS Substitutes

The bank of an ODS or an ODS substitute is “the cumulative difference between the chemical that has been consumed in an application or sub-application and that which has already been released” (IPCC 2006). For any given year, the bank is equal to the previous year’s bank, less the chemical in equipment disposed of during the year, plus chemical in new equipment entering the market during that year, less the amount emitted but not replaced, plus the amount added to replace chemical emitted prior to the given year, as shown in the following equation:

$$BC_j = BC_{j-1} - Qd_j + Qp_j + E_e - Q_r$$

where:

| | | |
|--------|---|--|
| BC_j | = | Bank of Chemical. Total bank of a specific chemical in year j , by weight. |
| Qd_j | = | Quantity of Chemical in Equipment Disposed. Total quantity of a specific chemical in equipment disposed of in year j , by weight. |
| Qp_j | = | Quantity of Chemical Penetrating the Market. Total quantity of a specific chemical that is entering the market in year j , by weight. |
| E_e | = | Emissions of Chemical Not Replaced. Total quantity of a specific chemical that is emitted during year j but is not replaced in that year. The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors except foam blowing. |
| Q_r | = | Chemical Replacing Previous Year’s Emissions. Total quantity of a specific chemical that is used to replace emissions that occurred prior to year j . The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors. |
| j | = | Year of emission. |

Table A-177 provides the bank for ODS and ODS substitutes by chemical grouping in metric tons (MT) for 1990 to 2014.

Table A-177. Banks of ODS and ODS Substitutes, 1990-2014 (MT)

| Year | CFC | HCFC | HFC |
|------|---------|-----------|---------|
| 1990 | 699,504 | 281,676 | 872 |
| 1995 | 792,162 | 495,808 | 48,449 |
| 2000 | 667,205 | 921,390 | 181,369 |
| 2001 | 639,001 | 990,934 | 209,791 |
| 2002 | 614,855 | 1,044,303 | 238,162 |
| 2003 | 590,932 | 1,081,093 | 272,302 |
| 2004 | 566,576 | 1,118,737 | 307,974 |
| 2005 | 543,858 | 1,159,977 | 345,872 |
| 2006 | 520,759 | 1,197,172 | 389,652 |
| 2007 | 500,425 | 1,225,447 | 434,729 |
| 2008 | 485,443 | 1,242,579 | 476,428 |
| 2009 | 478,491 | 1,235,393 | 522,965 |
| 2010 | 464,946 | 1,199,995 | 588,726 |
| 2011 | 451,334 | 1,155,064 | 653,741 |
| 2012 | 437,294 | 1,109,688 | 725,821 |
| 2013 | 423,535 | 1,060,341 | 799,683 |
| 2014 | 411,433 | 1,009,123 | 873,569 |

References

IPCC (2006) *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. The National Greenhouse Gas Inventories Programme, The Intergovernmental Panel on Climate Change, H.S. Eggleston, L. Buendia, K. Miwa, T Ngara, and K. Tanabe (eds.). Hayama, Kanagawa, Japan.

Subject: RE: Intermittent-bleed pneumatic controllers
Date: Monday, September 22, 2014 at 8:39:34 AM Eastern Daylight Time
From: Mark D. Smith
To: David McCabe

Yes David. That is correct. We require all controllers to emit less than 6 scf/hr whether the controllers are continuous or intermittent bleed devices.

Mark D. Smith
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Department of Environmental Quality
Air Quality Division
State of Wyoming
122 W. 25th Steet, 2nd Floor East Wing
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From: David McCabe [mailto:dmccabe@catf.us]
Sent: Friday, September 19, 2014 1:19 PM
To: mark.smith1@wyo.gov
Subject: Intermittent-bleed pneumatic controllers

Hi Mark,

Thanks for discussing how the Wyoming Oil and Gas Production Air Permitting Guidance works with me yesterday.

As I understand it, Wyoming's P-BACT permitting requirements do not allow pneumatic controllers at new or modified facilities to emit more than 6 scfh, whether the controllers are continuous-bleed or intermittent bleed. Is that correct?

Best,

David

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CATF is a nonprofit organization dedicated to reducing atmospheric pollution through

research, advocacy, and private sector collaboration.

E-Mail to and from me, in connection with the transaction of public business, is subject to the Wyoming Public Records Act and may be disclosed to third parties.



Howard J. Feldman

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November 30, 2011

Assistant Administrator Regina McCarthy
U.S. Environmental Protection Agency
EPA West (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Attention: Docket ID Number EPA–HQ–OAR–2010–0505

submitted via email to a-and-r-docket@epa.gov

**Ref.: Proposed Rulemaking – Oil and Gas Sector Regulations
Standards of Performance for New Stationary Sources: Oil and Natural Gas
Production and Natural Gas Transmission and Distribution;
National Emission Standards for Hazardous Air Pollutants from Oil and Natural
Gas Production Facilities; and
National Emission Standards for Hazardous Air Pollutants from Natural Gas
Transmission and Storage Facilities
(Docket ID No. EPA-HQ-OAR-2010-0505)**

Assistant Administrator McCarthy:

The American Petroleum Institute (API) is pleased to provide comment on the proposed rulemakings that will modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP) Subparts HH and HHH as a result of EPA's sector-based rulemaking for the oil and natural gas (O&G) industry. API represents more than 480 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports 9.2 million U.S. jobs and 7.7 percent of the U.S. economy, and delivers more than \$86 million a day in revenue to our government. Most of our members will be directly impacted by these proposed regulations.

First, API commends the efforts that your staff has made to learn about the oil and natural gas production industry. With respect to the proposal, we have limited concern with the selected control technologies, which are emission control techniques developed by our industry over many years of operating experience. However, we are concerned about the broad applicability and the one-size-fits-all approach of the proposed rule to regulating an industry that varies greatly in the type, size and complexity of operations.

The following are critical concerns with the proposed rules:

- The proposed rule expands listed categories and applies NSPS to new affected facilities in unique and unprecedented ways that are outside the Agency's authority. There are NSPS sources included in the proposed rule that emit little to no regulated pollutant or are construction-related emissions sources that are temporary (i.e., not routine), neither of which should be included in the rule.
- EPA's schedule will not allow adequate time to review and analyze all stakeholder comments, develop necessary revisions to the rules, and complete internal and interagency reviews. Four months between close of the comment period and promulgation of a final rule is unrealistic and unacceptable for these significant rules impacting an industry as large and vital to the U.S. economy as the oil and gas industry.
- The equipment prescribed to conduct Reduced Emission Completions will simply not be available in time to comply with the current final rule schedule. We believe it will take years to manufacture sufficient specialized equipment and adequately train operators how to safely conduct these operations.
- EPA cost analyses are based on "average model facilities" that do not represent all equipment and compliance costs and, without proper variability analysis to represent the wide variety of operations in the O&G industry, fail to identify when the controls are no longer economic.
- The system of notifications, monitoring, recordkeeping, performance testing and reporting requirements for compliance assurance are overly burdensome for the small and/or temporary affected facilities that EPA is regulating. This is a waste of time and resources for both industry and the EPA.
- EPA has expanded an already conservative risk analysis to include "MACT allowable" emissions and wrongly concluded that additional requirements are needed. The modeling of *actual* emissions under the existing rules indicates that the public is protected with an ample margin of safety.

Therefore, API urges the Agency to:

1. Consult with State air pollution control agency representatives on the expansion of the source category for the new and unique affected facilities as required by CAA §111(f)(3) and re-propose certain new affected source regulations as necessary.
2. Extend the final rule deadline one year to April 5, 2013 to adequately address stakeholder comments.
3. Allow sufficient compliance time (varying from 60 days to at least 2 years) to comply with the equipment specific NSPS requirements following promulgation of the final rule (see technical comments).

4. Revise the economic analyses to include all compliance cost and operational variables. These revised analyses should be used to limit the emission controls applicability to operations where they are economically justifiable.
5. Significantly reduce the compliance assurance complexity and burden by replacing the general provisions notification, recordkeeping and reporting requirements with specific requirements in NSPS, Subpart OOOO. Monitoring and performance testing requirements should be appropriate for small, remote and dispersed sites in the O&G industry.
6. Maintain the existing NESHAP HH and HHH to reflect the low risk posed to the public from these sources.

To facilitate the review of our comments, we have summarized critical issues with the proposed rules in an Executive Summary followed by detailed technical comments. Additionally, we have attached a document with the regulatory language marked up to show how our comments could be accommodated in the regulatory text (Attachment C). Finally, additional attachments are included to document certain points made in our detailed comments.

API remains committed to helping the Agency promulgate a cost effective, clear regulation to reduce the impact of our operations on air quality and look forward to the opportunity to meet and discuss these comments with you and your staff.

We appreciate your consideration of our concerns. If you have any questions, please contact Matt Todd (202-682-8319; todd@api.org) or me.

Sincerely,

/s/

Howard J. Feldman

CC: Bruce Moore, EPA
David Cozzie, EPA
Steve Page, EPA

**API Comments on the Proposed Rulemaking – Oil and Gas
Sector Regulations**

November 30, 2011

**Standards of Performance for New Stationary
Sources: Oil and Natural Gas Production and
Natural Gas Transmission and Distribution;
National Emission Standards for Hazardous Air
Pollutants from Oil and Natural Gas Production
Facilities; and
National Emission Standards for Hazardous Air
Pollutants from Natural Gas Transmission and
Storage Facilities
(Docket ID No. EPA-HQ-OAR-2010-0505)**

Table of Contents

| | |
|---|----|
| EXECUTIVE SUMMARY | 1 |
| INTRODUCTION 1 | |
| GENERAL COMMENTS | 2 |
| 1. EXTENSION OF COMMENT PERIOD AND FINAL RULE DEADLINE..... | 2 |
| 1.1. Extension of Comment Period to 90 Days Remains Insufficient for Adequate Comments..... | 2 |
| 1.2. Insufficient Time for Agency to Review Comments and Revise and Finalize Rule..... | 2 |
| 1.3. Consent Decree Does Not Require Promulgation of Rules for New Affected Facilities..... | 2 |
| 2. EXPANSION OF NSPS SOURCE CATEGORY | 3 |
| 2.1. Current source category does not cover all operations in this industry..... | 3 |
| 2.2. EPA is not Authorized to Arbitrarily Expand a Source Category..... | 4 |
| 2.3. Extremely Small Affected Facilities | 6 |
| 2.4. Temporary Emission Sources (Completions)..... | 7 |
| 3. BOUNDARIES FOR THE OIL AND NATURAL GAS PRODUCTION SECTOR | 8 |
| 3.1. Boundary Between the Production and Transportation Sectors..... | 8 |
| 3.2. Boundary Between the Transportation and Distribution Sectors..... | 10 |
| 4. ECONOMIC ANALYSIS FOR DETERMINING BEST SYSTEM OF EMISSION REDUCTION (BSER)..... | 11 |
| 4.1. Unique Conditions of the Oil and Gas Industry | 12 |
| 4.2. Economic Models and Variability..... | 12 |
| 4.3. Completeness of Cost Estimations of Control Options..... | 13 |
| 4.4. Cost Effectiveness Threshold..... | 14 |
| 5. APPLICABILITY [NSPS OOOO]..... | 15 |
| 5.1. Applicability to Low VOC Natural Gas Streams | 16 |
| 5.2. Applicability to Liquid Streams | 20 |
| 5.3. Applicability Limitation to Sectors | 21 |
| 5.4. Applicability to Wellheads and Reduced Emission Completion Operations | 21 |
| 5.5. Applicability to Sweetening Units | 23 |
| 5.6. Applicability Limitations to Modification and Reconstruction..... | 23 |
| 6. DEFINITIONS [NSPS OOOO]..... | 28 |
| 6.1. Petroleum Product Definitions | 28 |
| 6.2. Low VOC Streams | 29 |
| 6.3. Natural Gas Processing Plant | 29 |
| 6.4. Modification..... | 30 |
| 6.5. Orphaned Definitions | 31 |
| 7. COMPLIANCE DATE..... | 31 |
| 7.1. Congressional Review Act | 31 |
| 7.2. NSPS Effective Date for Completions | 31 |

| | | |
|-------|--|----|
| 7.3. | Manufacturer Compliance..... | 31 |
| 7.4. | Availability of Equipment for Reduced Emissions Completions..... | 32 |
| 7.5. | Adding Control to Existing Tanks..... | 34 |
| 7.6. | Compliance Dates for NESHAP Subparts HH and HHH | 35 |
| 8. | NSPS COMPLIANCE REQUIREMENTS (NOTIFICATION, RECORDKEEPING, REPORTING, MONITORING, PERFORMANCE TESTING, AND THIRD PARTY VERIFICATION). | 37 |
| 8.1. | Excessive Cost Burden..... | 37 |
| 8.2. | Stated Goal Is Inconsistent with Proposed Rule Text and Requirements | 41 |
| 8.3. | Notifications..... | 42 |
| 8.4. | Recordkeeping..... | 43 |
| 8.5. | Reporting..... | 45 |
| 8.6. | Performance Test Methods and Compliance Monitoring Requirements | 51 |
| 8.7. | Use of NESHAP Emission, Monitoring and Performance Testing Standards in NSPS | 61 |
| 8.8. | Third Party Verification | 62 |
| 8.9. | Equipment Specific Notification, Recordkeeping and Reporting Requirements | 63 |
| 9. | COMBUSTION DEVICE REQUIREMENTS | 64 |
| 9.1. | Flares - “Flame Present At All Times” | 64 |
| 9.2. | “Completion Combustion Devices” Are Not Considered Flares | 64 |
| 9.3. | Proper Cite for NSPS Flare Requirements is §60.18(b)..... | 65 |
| 9.4. | Equipment Routing Vapors From Affected Facilities To Process Are Not Considered Control Devices..... | 65 |
| 10. | STARTUP, SHUTDOWN, AND MALFUNCTION PROVISIONS | 66 |
| 10.1. | EPA’s Legal and Technical Analyses of SSM Events are Fundamentally Flawed..... | 66 |
| 10.2. | Notifications and Reports for Malfunctions | 70 |
| 10.3. | EPA Has No Mandate To Impose SSM Requirements in NSPS Rules. | 71 |
| 10.4. | §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] Should Constitute a Work Practice for Compliance..... | 72 |
| 10.5. | Address Weather and System Outage Issues | 72 |
| 10.6. | Provide an Allowance for Reasonable Periods of Maintenance..... | 72 |
| 11. | REVISING THE MACT FLOOR | 73 |
| 12. | CHANGE IN THE PROTOCOL FOR DETERMINING RESIDUAL RISK FOR NESHAP | 74 |
| 12.1. | Lack of Statutory Authority for the Changes | 74 |
| 12.2. | Inappropriateness of the Changes..... | 74 |
| 13. | AFFECT OF PROPOSED REGULATIONS ON STATES | 78 |
| 13.1. | Direct Regulatory Burden to State Environmental Regulatory Agencies. | 78 |
| 13.2. | Minor New Source Review (NSR) Permitting Programs..... | 78 |
| 14. | OFF-SHORE FACILITIES | 79 |
| | TECHNICAL COMMENTS | 80 |
| 15. | WELL COMPLETIONS – NSPS SUBPART OOOO | 80 |

| | | |
|--------|--|-----|
| 15.1. | Legality of Regulation..... | 80 |
| 15.2. | EPA Should Not Prescribe the Equipment Required for Reduced Emissions Completions..... | 81 |
| 15.3. | Need Ability to Combust or Vent..... | 86 |
| 15.4. | Availability of Equipment and Experienced Operators..... | 93 |
| 15.5. | Timing of Requirements..... | 96 |
| 15.6. | Applicability Issues | 98 |
| 15.7. | Multiple Notification Requirements..... | 100 |
| 15.8. | Clearer Definitions | 102 |
| 15.9. | Remove the Requirement to Record the Distance to the Nearest Gathering Line | 105 |
| 15.10. | Emission Rates and Economics Are Unrealistic | 106 |
| 15.11. | Over Estimate of Number Recompletions per Year..... | 108 |
| 16. | STORAGE VESSELS | 109 |
| 16.1. | Applicability..... | 109 |
| 16.2. | Storage Vessel Definition [OOOO & HH]..... | 110 |
| 16.3. | Located in the Oil and Natural Gas Production Source Category..... | 112 |
| 16.4. | Storing Crude Oil or Condensate | 115 |
| 16.5. | Containing the Regulated Pollutant..... | 115 |
| 16.6. | Having Emissions Above a Cost-Effective Threshold [NSPS OOOO] | 116 |
| 16.7. | Compliance Schedule for New Production [NSPS OOOO]..... | 127 |
| 16.8. | Compliance Requirements [NSPS OOOO]..... | 128 |
| 16.9. | Capacity and Vapor Pressure [NSPS OOOO]..... | 133 |
| 16.10. | Infrequent Use [OOOO & HH] | 134 |
| 16.11. | Flare Pilot Flame [OOOO & HH] | 134 |
| 16.12. | Performance Test Methods [OOOO & HH]..... | 134 |
| 16.13. | MACT-Level Requirements for NSPS..... | 135 |
| 16.14. | Floating roof option [OOOO & HH]..... | 135 |
| 16.15. | EPA’s Estimate of the Number of Affected Storage Vessels..... | 136 |
| 16.16. | Permit Limits..... | 136 |
| 17. | PNEUMATIC CONTROLLERS | 137 |
| 17.1. | Problem with High-Bleed/Low-Bleed Classification..... | 138 |
| 17.2. | Definitions | 139 |
| 17.3. | Inconsistent Terminology..... | 141 |
| 17.4. | Pneumatic Controller Affected Facility | 142 |
| 17.5. | Sitewide Applicability by Driver Medium..... | 146 |
| 17.6. | Natural Gas is Not a Valid Surrogate for VOC..... | 148 |
| 17.7. | Administrator’s Approval for Use of High Bleed Pneumatic Controllers | 148 |
| 17.8. | Annual Reporting Requirements for Pneumatic Controllers..... | 148 |
| 17.9. | Recordkeeping..... | 149 |
| 17.10. | Time Extension for Manufacturer’s Guarantee..... | 149 |
| 17.11. | Extend Compliance Date for Pneumatic Controllers by One Year | 150 |
| 18. | COMPRESSORS..... | 150 |

| | | |
|--------|--|-----|
| 18.1. | Does Moving Compressors from One Location to Another Trigger Construction (i.e., Installation)?..... | 150 |
| 18.2. | Applicable Provisions for Compressor Located at an Onshore Natural Gas Process Plant | 152 |
| 18.3. | Rod Packing Change Out | 153 |
| 18.4. | Exclude Reciprocating Compressors in the Transmission and Storage Segment | 155 |
| 18.5. | Reciprocating Compressor Definition..... | 156 |
| 18.6. | Typographical Error | 156 |
| 18.7. | Exclude Centrifugal Compressors in Gathering and Boosting and Transmission Segments ... | 156 |
| 18.8. | Allow for a Wet Seal Option for Centrifugal Compressors | 157 |
| 18.9. | Centrifugal Compressor Definition | 159 |
| 19. | EQUIPMENT LEAKS | 159 |
| 19.1. | Subpart OOOO – Stringency of Subpart VVa Requirements | 160 |
| 19.2. | Subpart OOOO – Alternative Work Practice | 168 |
| 19.3. | Subpart OOOO – Compressors at Natural Gas Processing Plants | 169 |
| 19.4. | Subpart OOOO – Applicability..... | 170 |
| 19.5. | Subpart OOOO – New Delay of Repair Option for On-line Equipment Repair Using Specialized Methods | 176 |
| 19.6. | Subpart OOOO – Work Practice Implementation..... | 177 |
| 19.7. | Subpart OOOO – Equipment Upgrade Implementation | 177 |
| 19.8. | Subpart OOOO – Exceptions in §60.5401 (d) and (e). | 177 |
| 19.9. | Subpart OOOO – Clarifications Sought..... | 178 |
| 19.10. | Subpart HH – Alternative Work Practice..... | 178 |
| 19.11. | Subpart HH – Applicability..... | 178 |
| 19.12. | Subpart HH – Lower Leak Definition for Valves | 179 |
| 19.13. | Subpart HH – Extending Compliance Time..... | 179 |
| 19.14. | Subpart HH – Overlap with Subpart OOOO..... | 179 |
| 20. | GLYCOL DEHYDRATORS [NESHAP HH & HHH]..... | 180 |
| 20.1. | Large Dehydrators – The 0.9 Mg/yr Benzene Alternative Emission Limitation Must Be Retained in both Subpart HH and Subpart HHH..... | 181 |
| 20.2. | 90 Day Compliance Time For Large Dehydrators Is Insufficient If The 0.9 Mg/Yr Benzene Compliance Option Is Removed | 188 |
| 20.3. | Small Dehydrators – The BTEX Emission Limit Is Not Necessary And Should Be Removed 188 | |
| 20.4. | If EPA Moves Forward With Standards for Small Dehydrators, They Must Account for Fundamental Differences in Naturally Occurring Inlet Gas Concentrations and Dehydrator Design | 193 |
| 20.5. | EPA's Proposed Equation Does Not Reflect the MACT Floor Determined..... | 200 |
| 20.6. | Clarification of Terminology..... | 202 |
| 21. | PRODUCED WATER EVAPORATION PONDS | 203 |

TABLES

| | | |
|--|---|-----|
| Table 4-1. | Comparison of EPA Cost Effectiveness Decisions | 15 |
| Table 8-1. | Summary of Recordkeeping and Reporting Requirements of Subpart OOOO | 38 |
| Table 15-1. | Average Compositions of US Shale Gas | 107 |
| Table 15-2. | Average VOC Concentrations of Coal Bed Methane Wells in SW Colorado | 107 |
| Table 16-1 | Variability of Flashing Emissions for Constant Throughput | 119 |
| Table 16-2 | VOC Flash Factors vs. Separator Pressure | 122 |
| Table 16-3 | Cost Effectiveness of Controls Using the TSD Cost Analysis | 123 |
| Table 16-4 | Capital Cost for Enclosed Combustor | 124 |
| Table 16-5 | Cost Effectiveness of Controls Based on the EPA Cost Manual. | 125 |
| Table 16-6 | Throughput Exemption Thresholds vs. Separator Pressure. (corresponding to 12 tpy VOC emissions per tank) | 126 |
| Table 16-7 | Capacity and Vapor Pressure Cutoffs | 133 |
| Table 19-1 | Comparison of VOC Emissions Calculations For Valves From Natural Gas Processing Plants | 161 |
| Table 19-2. | Detailed Data for Valves from Three Natural Gas Processing Units | 162 |
| Table 19-3. | Detailed Data for Connectors from Three Natural Gas Process Facilities | 163 |
| Table for Determining Applicable Value for B | | 175 |
| Table 20-1. | Summary of Glycol Dehydrator Group Criteria and Emission Limitations | 180 |
| Table 20-2. | Hawkins Plant Dehydrator Emissions | 184 |
| Table 20-3. | Cost Effectiveness for Compliance with Proposed Small Dehydrator Emission Limitation at Oil and Gas Production Facilities | 192 |
| Table 20-4. | Application of Subpart HH Proposed Equation 1 for Small Dehydrators to MACT Floor Oil and Natural Gas Production Small Dehydrators | 194 |
| Table 20-5. | Illustration of Sensitivity of the Proposed Subpart HH Proposed Equation 1 for Small Dehydrators to Throughput Rates | 194 |
| Table 20-6. | Summary of EPA's Small Dehydrator Dataset | 197 |
| Table 20-7. | Recommended Subcategories and Standards for Small Dehydrators | 199 |

FIGURES

| | | |
|--------------|---|-----|
| Figure 16-1 | Emissions (lb/bbl) vs. Separator Pressure (psi)..... | 121 |
| Figure 20-1. | Process Flow for Produced Water To Evaporation Basins | 204 |

ATTACHMENTS

| | |
|--------------|---|
| Attachment A | Pre-Proposed Rule Presentations and White Papers by API |
| Attachment B | EPA Data Requested Table |
| Attachment C | Suggested Rule Text Table |
| Attachment D | SMM Coalition Letter |
| Attachment E | Residual Risk Coalition Letter |
| Attachment F | Reservoir Performance for Reduced Emissions Completions |
| Attachment G | Review of the Regulatory Impact Analysis (RIA) for the Well Completions Portion of the Proposed New Source Performance Standards for the Oil and Natural Gas Industry |
| Attachment H | WCI Fuel Gas Metering |
| Attachment I | Applicability Determinations for NSPS D, Da, Db, and Dc |
| Attachment J | Proposed Recordkeeping Requirements for Storage Vessels under NSPS OOOO |
| Attachment K | Pneumatic Controller Technical Review |
| Attachment L | Kimray, Inc. Technical Bulletin Y09201 "Pilot Bleed Rate" |
| Attachment M | <i>Reserved</i> |
| Attachment N | Comments on the EPA Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories |
| Attachment O | Comments on the Risk-Based Proposed Decision to Remove the 0.9 Mg/yr Benzene Alternative for Glycol Dehydrators in the MACT Standards for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories |
| Attachment P | Analysis of Cost Effectiveness for Compliance with Proposed Small Dehydrator Emission Limitation at Oil and Gas Production Facilities |
| Attachment Q | Analysis of Illustration of Impacts of Application of the Proposed Small Dehydrator Emission Limitation Equation for Oil and Gas Production Facilities |
| Attachment R | EPA's Small Dehydrator Data Set |

EXECUTIVE SUMMARY

As detailed in our comments, API has numerous concerns with EPA's proposed rulemaking for the Oil and Gas (O&G) sector. However, the control technologies selected in the proposed O&G New Source Performance Standard (NSPS) and revisions to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) O&G regulations are not what cause the concerns. Instead, API's concerns come from the broad applicability of the proposed rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has supported its regulations using economic studies on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The proposed rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, using unsound legal justification and without consulting with the States as required by the CAA. The system of notifications, monitoring, recordkeeping, performance testing and reporting requirements are more burdensome than justified for the small and/or temporarily affected facilities that EPA is regulating. Finally, API is concerned with the pace of this rulemaking. Seven months between the published proposed rule and promulgating the final rule is an unrealistic schedule for issuing a complex rule with the concerns identified that is supposed to cover an industry as large as the O&G production industry. EPA has only four months to review all the submitted comments, analyze them, make appropriate revisions, and complete the necessary internal and interagency reviews.

Listed below in priority order are API's top issues with the proposed O&G rules. API has included a solution to address the issue raised and the rationale behind the solution, with a reference to the detailed comments.

Natural Gas is Not a Surrogate for Volatile Organic Compounds (VOC) and Regulating Low VOC Natural Gas is not Cost Effective and is Equivalent to Regulating Greenhouse Gases (GHG).

Issue – The proposed rule purports to not regulate GHGs, but rather to regulate emissions of natural gas. Many natural gas streams produced today contain little or no VOCs.

Solution – Restrict final rule applicability to streams that have a minimum VOC content to assure that NSPS are cost effective as required by the Clean Air Act.

Rationale – EPA calculated cost effectiveness based on natural gas that is 18% by weight VOC. The cost effectiveness (in dollars per ton of VOC reduced) approaches infinity as VOC content approaches zero. EPA must economically justify its regulations for not just for the average "model" facility, but for reasonably expected variations.

Economic Analysis of Emission Control Strategies Must Be Representative of Industry's Operations.

Issue – The "average model facilities" that EPA has used in the economic analysis do not represent the great variation seen across the U.S.

Solution – The applicability of the proposed regulations must be narrowed to operations in which the proposed emission control practices can be applied in a cost effective manner.

Rationale – Current economic analyses must include the full variety of conditions (i.e., VOC content) in the O&G industry for all of the costs of compliance with the proposed rule. API found

the cost effectiveness for tanks to vary from \$5,271/ton of VOC to \$1,519,667/ton of VOC (Section 16.6.6., Table 3). See Sections 4 & 5.

Expansion of NSPS Source Category is Arbitrary and is Not Allowed Without Consulting with States.

Issue – 42 USC 7411(f) requires consultation with State Governors air pollution control agencies before expanding the listed categories or promulgating new NSPS.

Solution – EPA should conduct the required consultations with the States with significant the oil and gas transportation and distribution sectors and revise the requirements for reduced emission completions requirements, storage vessels, pneumatic controllers, and compressors in NSPS, Subpart OOOO.

Rationale – The uniqueness of the new affected facilities (very small in cost and/or quantity of emissions or the non-routine, temporary construction nature) being justify consultation with states. States will see a massive increase in permitting burden with little to no environmental benefit. See Section 2.

Compliance Assurance Requirements for NSPS Are Overly Burdensome.

Issue – The notifications, monitoring, recordkeeping, testing and reporting requirements for a major source NESHAP regulation are overly burdensome for NSPS Subpart OOOO.

Solution – Specific O&G industry appropriate notification, recordkeeping, reporting, and performance testing sections requirements should be included in Subpart OOOO.

Rationale – The remote, dispersed and unmanned nature of facilities that lack electrical power, make the requirements logistically impractical, technically difficult and uneconomic. The use of NESHAP compliance requirements for storage vessels is confusing and unjustifiably stringent for NSPS. Comment Section 8.

Availability of Equipment and Experienced Operators for Reduced Emission Completions (REC) Requires Delayed Compliance Date.

Issue – The necessary equipment to comply with the REC requirements is currently not available and will require time to manufacture. Also, industry will have a shortage of experienced contractors or staff for safely doing “reduced emissions completions”.

Solution – Due to the limited availability of appropriate and safe equipment and experienced and trained personnel to perform REC's, API requests that compliance with the reduced emissions completions portion of the rule be delayed for 2 years to allow for manufacturing of equipment and training of operators. During the time period from the effective date to two years after the effective date, only the use of completions combustion devices should be required for reducing emissions.

Rationale - The proposed requirement to implement RECs immediately upon the effective date of the final rule does not constitute “the best system for emission reduction.” Comment Section 15.4

Legality of Reduced Emissions Completions Requirements.

Issue – Flowback immediately following hydraulic fracturing stimulation during well completions is not part of the normal operation of a well but is a construction-related activity that must be

accomplished for a well to begin producing and thereafter engage in normal operations. The proposal to regulate construction-related emissions is a significant and substantive departure in the Agency's prior interpretation and implementation of § 111.

Solution – EPA should remove the requirements for reduced emissions completions from the proposed regulation. If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, EPA should repropose the requirements and include sufficient justification for their departure from not regulating construction-related emissions and present the legal basis for regulating non-routine emissions.

Rationale – EPA's failure to explain why the departure from not regulating construction-related emissions is justified and failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C). Comment Section 15.1.

EPA Should Not Prescribe the Equipment Required for Reduced Emissions Completions (REC).

Issue –API is requesting that the rule not require the use of specific equipment. The final rule should allow options to use other emission reduction techniques, not require routing liquids to a storage vessel, and recognize commercial viability.

Solution – API proposes that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods.

Rationale – Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies and section 111(h) allows work practice standards where "it is not feasible to prescribe or enforce a standard of performance." An underlying presumption of section 111 is that a standard of performance should allow the affected facility flexibility to meet a standard, rather than be required to use specific controls. Comment Section 15.2

Applicability for Storage Vessels [NSPS OOOO & NESHAP HH] Must Be Clarified.

Issue – Both NSPS OOOO and NESHAP HH, as proposed, are unnecessarily vague in specifying the storage vessels to which these rules apply.

Solution – Define storage vessels and specify applicability so as to limit applicability to:

- Storage vessels that are located in the oil and natural gas production sector,
- Which are continuously on site for more than 180 days,
- Storing crude oil or condensate,
- With emissions greater than 12 tpy [NSPS OOOO].

Rationale – EPA has a responsibility to clearly specify the sources to which a given rule applies. See Sections 16.1–16.6.

Allow 90 Days to Implement Storage Vessels [NSPS OOOO] Controls at New Production Sites.

Issue – A period of time is necessary to determine whether a new production site will flow at a rate that will trigger the control requirements for storage vessels, and then an additional period of time is necessary to install those controls.

Solution – Specify that applicability shall be determined on the basis of the first 30 days of production and, for sites that trigger controls for storage vessels, compliance shall be achieved within 60 days thereafter.

Rationale – If EPA fails to specify a reasonable compliance period, then storage vessels would potentially need to be equipped with controls at every new production site – just in case the production characteristics might trigger the control requirements. This would clearly result in installing controls at many sites for which controls would eventually be shown to have been neither required nor cost effective. See Section 16.7.

Control Device Requirements for Storage Vessels [NSPS OOOO & NESHAP HH] Must Be Clarified & Reasonable.

Issue – When vapors are required to be routed to a control device, the proposed requirements for the control device are unreasonably complicated and burdensome. For example, there are more than 50 recordkeeping requirements for storage vessels routed to a control device.

Solution – Revise the requirements for control devices for simplification and for suitability to production field operations, including the following:

- Include the “manufacturer certification” option for performance demonstration in NSPS OOOO (confirm the availability of this NESHAP HH option to NSPS OOOO),
- Specify requirements appropriate to an NSPS rule for VOCs in OOOO, rather than invoking the MACT requirements for HAPs from HH,
- Allow electronic ignition for flares, rather than requiring that a pilot flame is present at all times,
- Specify monitoring requirements that are appropriate for remote facilities that may not have an available power source,
- Limit reporting requirements to semi-annual reporting of exceedances, and
- Simplify the recordkeeping requirements.

Rationale – EPA has a responsibility to specify control requirements that are reasonable for the type of facilities found in a given source category. The proposed rule provisions fail to account for the remoteness of production field facilities, the types of technologies that would be most suitable for these facilities, or the volume of unnecessary paperwork that would be required. See Sections 16.10–16.12.

Regulating Small Sources or Construction Activities Using NSPS Is Not Justified by Cost Effectiveness or Legal Precedent.

Issue – EPA has historically regulated emissions during normal operations of a process unit (i.e., a tank, boiler, gas processing plant, etc.). The proposed rule regulate individual components (e.g., a single pneumatic controller) of a process control system and temporary construction emissions (e.g., hydraulic fracturing flowback emissions requiring REC) that have not previously been regulated by NSPS.

Solution – Subpart OOOO regulations for pneumatic controllers, compressors and REC should be revised so the source categories reflect sources that “contribute significantly” to the endangerment of “human health or the environment.”

Rationale – The NSPS general provisions and compliance assurance requirements proposed are not appropriate for the unique emission sources proposed in Subpart OOOO. See Section 2.

Definitions Do Not Represent the Activities of the Oil and Gas Industry.

Issue – The proposed definitions are inconsistent with the way they are used within the O&G industry activities, leading to confusion of which activities are regulated.

Solution – New definitions and revisions for existing definitions have been suggested that accurately describe O&G activities.

Rationale – A common understanding between the agency and regulatory communities of terms is required for a final rule that is clear and enforceable. See Section 6.

Best System of Emission Reduction Must Be Currently Available To Industry.

Issue – EPA has proposed BSER that is not currently available in sufficient quantities for compliance with the proposed rule (especially REC equipment and combustors).

Solution – EPA should phase in the proposed requirements to provide equipment manufacturers and the O&G industry sufficient time to obtain equipment required.

Rationale – Less than 25% of REC equipment needed to comply with the proposal is available. It will take two to seven years to manufacture the equipment. Sufficient combustors that have been tested by the manufacturer to meet the proposed rule requirements are not currently available. Comment Section 7.

Ability to Combust or Vent During Completions Is Needed.

Issue – Paragraphs 60.5375(a)(1) and (2) require “routing recoverable liquids to storage vessels and routing the recovered gas into a gathering line or collection system” and “all salable quality gas must be routed to the gas gathering line as soon as practicable.” API requests more clarity in the rule to address the many operational and safety constraints to routing all salable gas to gathering line

Solution – API proposes that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods.

Rationale – Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies and section 111(h) allows work practice standards where “it is not feasible to prescribe or enforce a standard of performance.” Comment Section 15.3

Relocation of an Existing Compressor Should Not Trigger NSPS Applicability.

Issue – EPA stating that a compressor is considered to have commenced construction on the date the compressor is installed at the facility.

Solution – Remove the last sentence in the applicability sections for centrifugal and reciprocating compressors.

Rationale – The sentence of concern is inconsistent with historical EPA decisions for other NSPS and Applicability Determination Index determinations. Comment Section 18.1.

Pneumatic Controller Affected Facility Should be Redefined as a Process Unit Affected Facility.

Issue – Pneumatic controllers are numerous, small, component level, and inexpensive pieces of equipment for which minor expenditures for routine maintenance, repair, or replacement may trigger

a reconstruction determination setting up the likelihood for unnecessary onerous recordkeeping and tens or hundreds of wasteful and time consuming annual reports per operator.

Solution – Redefine affected facility to “Continuous bleed gas-driven pneumatically controlled process unit” to include all the component parts of a pneumatic control system at a site. Further limiting to “continuous bleed gas-driven” restricts applicable controllers to only those with a weak stream bleed rate of regulated VOC in accordance with the way EPA correctly defines high and low bleed controllers.

Rationale – EPA uses a process unit approach in LDAR to prevent modification and reconstruction triggers for RMRR of fugitive components such as valves. Also, EPA set precedent for this approach in the preamble discussion of the NSPS Subpart YYY proposal [59 FR 46780, 09/15/94]. See Section 17.4.

Revising the MACT Floor Is Not Authorized by the CAA.

Issue – EPA set the MACT floor in the June 17, 1999 rulemaking. The CAA does not give EPA unfettered authority to revise the MACT floor as it desires.

Solution – EPA should not revise the applicability criteria or the control standards for either storage vessels or triethylene glycol dehydrators.

Rationale – CAA 112(d)(2)-(3) allows EPA to set the MACT floor only once. This MACT floor decision was not challenged or overturned by the Court. Revising this MACT floor due to the successful challenge of another category is both inappropriate and unauthorized by the CAA. CAA 112(d)(6) only authorizes the review of improvements in control technology for the revision of the MACT standard. See Comment Section 11.

Removal of 0.9 Mg/yr Benzene Alternative Emission Limitation is Based on Flawed Analysis.

Issue –For subparts HH and HHH, the EPA proposed to remove the 0.9 Mg/yr benzene alternative emission limitation for large dehydrators. In both subparts, there were errors in the analyses. For example, EPA estimated that the cancer MIR based on MACT allowable emissions was 400-in-1 million for subpart HH. Correction of the analysis results in a cancer MIR that is clearly in the range that EPA considers acceptable.

Solution – EPA must correct the errors in the analysis, which will lead to a different conclusion regarding the 0.9 Mg/yr benzene alternative for large dehydrators.

Rationale – Correction of the errors in the analysis result in risk-based outcomes that do not support EPA's proposed decision to eliminate the 0.9 Mg/yr benzene alternative. See Section 20.

Proposed Standards for Small Dehydrators are Unnecessary.

Issue – EPA identified small dehydrators as unregulated emission sources despite the fact that they are effectively subject to standards. In addition, EPA's proposed standards for both subparts HH and HHH are based on faulty MACT floor analyses.

Solution – Eliminate the proposed requirements for small dehydrators. Alternatively, if EPA elects to promulgate standards for small dehydrators, it must establish subcategories that appropriately account for fundamental differences among small dehydrators in determining the "classes, types, and sizes" of sources to be regulated and determine MACT floors for the subcategories.

Rationale – The dual use of 0.9 Mg/yr benzene as criteria for separating small and large dehydrators and as an emission limitation for large dehydrators effectively creates a situation where all dehydrators are subject to standards. This is consistent with the original MACT floor determination for dehydrators, which did not distinguish between dehydrator subcategories. Therefore, EPA should not promulgate any standards for small dehydrators.

If EPA does elect to move forward with promulgating standards for small dehydrators, EPA must take into account fundamental differences in dehydrators, most importantly the naturally occurring concentration of HAP in the gas stream, create appropriate subcategories, and determine MACT floors for each subcategory. See Section 20.

Equipment Leaks – Lowering the Leak Definition from 10,000 ppm to 500 ppm.

Issue – EPA proposes to lower the leak definition for valves at natural gas processing plants from 10,000 ppm to 500 ppm, which would not lead to any substantial VOC emissions reductions.

Solution – The leak definition for valves at gas plants should remain at 10,000 ppm. In lieu of imposition of 500 ppm leak definition, API recommends the valve LDAR program at gas plants includes the following two elements: 1) once meeting the requirement of no leak detected during monthly monitoring initially, all valves are, and continue to be, monitored on a quarterly basis with no skip periods ; and 2) the owner or operator would identify "chronic leaks" (i.e., valves that leak above 10,000 ppm in three of any consecutive four quarters), and designate these valves for refurbishing or replacement during the next process unit shutdown.

Rationale – EPA overestimated valve control-effectiveness, which is confirmed by the data provided by API member companies. The proposed leak definition for valves would be burdensome without achieving the VOC reduction as claimed by EPA. See Sections 19.1.1 and 19.1.6.

Equipment Leaks – Imposition of a Connector Program.

Issue – EPA proposes to require a leak detection and repair (LDAR) program for connectors at natural gas processing plants, with a leak definition of 500 ppm, while the existing rule only requires auditory, visual and olfactory (AVO) inspections.

Solution – API recommends that no new LDAR program for connectors be imposed at natural gas processing plants, and that connectors continue to be subject to the AVO requirements.

Rationale – EPA overestimated the emissions reduction and underestimated the cost of the proposed connector LDAR program, resulting in an overly inflated cost-effectiveness estimation. See Sections 19.1.2 and 19.1.6.

INTRODUCTION

On August 23, 2011, the US EPA proposed to modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP) Subparts HH and HHH. API has prepared the following detailed comments in response to this proposed sector-based rulemaking for the oil and natural gas (O&G) industry.

API appreciates the efforts that EPA has made to learn about the oil and natural gas production industry (O&G industry) and taking the time to tour production fields and request information on the industry. API was pleased to be able to offer presentations and white papers on various aspects of the O&G industry. Copies of these presentations and white papers have been included in Attachment A for your convenience.

EPA has requested comments on a wide variety of issues. API has tried to supply information on these requests throughout the document. Attachment B is provided to cross reference these request with sections where this information is located. API regrets that time during the comment period was insufficient to gather the type or quantity of information needed to properly answer EPA's questions. However, much of the information is simply not available. Surveys, studies and research would have to be commissioned to provide the information requested. EPA should have commissioned these events during the pre-proposal stage of the rulemaking. EPA simply did not invest the time and resources for a rulemaking of this magnitude.

Finally, EPA has requested during meetings that solutions be provided for the concerns being raised in these comments and that revised regulatory text be suggested to implement these solutions. Attachment C provides revised regulatory text in redline/strikeout format for this purpose with reference to the sections that discuss these revisions. While Attachment C has been prepared as a summary of API's suggested edits to the rule language, the markups shown in these comments should be taken as our preferred position in the event of any differences between these comments and Attachment C.

API remains committed to helping the agency promulgate a cost effective, clear regulation to reduce the impact of our operations on air quality and look forward to the opportunity to meet and discuss these comments soon.

GENERAL COMMENTS

1. EXTENSION OF COMMENT PERIOD AND FINAL RULE DEADLINE

1.1. Extension of Comment Period to 90 Days Remains Insufficient for Adequate Comments

API continues to believe that industry needed a full 120 days to provide an adequate set of comments to a rulemaking as broad, high impact, precedent setting, and complex as these proposed rules. However, API appreciates the additional 30 day extension that EPA provided. API has developed as complete a set of comments as time allowed. Much of the information EPA requested, as well as additional information API wanted to provide, is not included because of time limitations.

1.2. Insufficient Time for Agency to Review Comments and Revise and Finalize Rule

API also continues to believe that the revised final rule deadline of April 3, 2012 needs to be delayed a full year to allow EPA sufficient time to fully review and give reasoned responses to the comments as required by the Administrative Procedures Act (APA). Given the complexity of the issues, the many competing demands on Agency resources, and the time that will be needed to complete interagency review of the draft final rules, the agency is fully justified in extending the final rule promulgation date to February 28, 2013.

1.3. Consent Decree Does Not Require Promulgation of Rules for New Affected Facilities

It is worth noting in this regard that the settlement agreement itself does not dictate that EPA issue a final rule that is commensurate with the scope of the proposed rule. Indeed, EPA's proposal goes well beyond the scope even contemplated by the settlement agreement. With respect to Section 112, the settlement agreement provides that EPA was to propose and shall take final action under Sections 112(d)(6) and 112(f)(2). With respect to Section 111, the settlement agreement provides that EPA shall sign one or a combination of the following for the NSPS Subparts KKK and LLL:

- (a) a proposed rule containing revisions to the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (b) a proposed determination not to revise the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (c) a proposed or final determination not to review the NSPS (in whole or in part) under CAA section 111(b)(1)(B).

For final action, it commits EPA to "sign one or a combination of the following for NSPS Subparts KKK and LLL:

- (a) a final rule containing revisions to the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or

- (b) a final determination not to revise the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (c) a final determination not to review the NSPS (in whole or in part) under CAA section 111(b)(1)(B).”

API believes that many of the proposed rule requirements have been inadequately proposed (especially the expansion of the Oil and Natural Gas Sector and addition of affected facilities) and a supplemental proposal is needed. If EPA cannot extend the comment period and final rule deadline as discussed above, then API recommends that EPA separate the portions of the rule required by the consent decree from the voluntary additions to the rulemaking, so appropriate consideration can be given to these unique provisions.

2. EXPANSION OF NSPS SOURCE CATEGORY

To date, EPA has established only two NSPS for the oil and gas production sector – Subpart KKK, applicable to VOC equipment leaks at gas processing plants, and Subpart LLL, applicable to sulfur dioxide emissions from gas processing plants. In the proposal, EPA would expand its NSPS regulations for the oil and gas production sector to include requirements for numerous additional source types; including completions of hydraulically fractured gas wells, VOC standards for gas-driven pneumatic devices, standards for centrifugal and reciprocating compressors, and tank standards. 76 Fed. Reg. at 52745-52746. These standards would apply throughout the sector, from production wells, to gas processing, to transmission to local distribution systems.

EPA asserts that it is authorized to expand the scope of the current rules because it “believe[s] that the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.*, production, processing, transmission, storage and distribution).” *Id.* at 52745. Alternatively, EPA declares, “To the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b), we hereby modify the category list to include all operations in the oil and natural gas sector.” *Id.* As justification for such a modification, EPA explains only that “Section 111(b) of the CAA gives the EPA broad authority and discretion to list and establish NSPS for a category that, in the Administrator’s judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare” and, pursuant to this authority, “we are modifying the source category list to include any oil and gas operation not covered by the current listing and evaluating emissions from all oil and gas operation at the same time.” *Id.*

EPA is wrong on both counts.

2.1. Current source category does not cover all operations in this industry

As to the scope of the original listing of the “crude oil and natural gas production” source category, EPA made it clear that the category was listed to satisfy CAA § 111(f). 44 Fed. Reg. 49222 (Aug. 21, 1979). Section 111(f) required EPA to create a list of “categories of major stationary sources” that had not been listed as of August 7, 1977 under § 111(b)(1)(A) and to promulgate NSPSs for the listed categories according to a set schedule. EPA explained in the listing rule that its list included “major source categories,” which EPA defined to include “those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant.” *Id.*

While EPA provided no further explanation in its original listing decision as to what facilities it intended to regulate under the “crude oil and natural gas production” source category, there can be no doubt that the category originally included “stationary sources” (*i.e.*, “plants”) that typically have a potential to emit at least 100 tons per year of a regulated pollutant. This communicates two important limitations on the original listing decision. First, EPA was focused on discrete “plants” or “stationary sources.” Second, EPA was focused on large emitting plants or stationary sources.

As a result, the original listing decision cannot reasonably be interpreted to extend to the types of sources EPA seeks to regulate in the proposal. For example, typical production wells do not have the potential to emit major amounts of any regulated pollutant. Thus, they could not reasonably have been considered major-emitting plants at the time of the original listing decision. The same is true for compressors, tanks, and pneumatic devices scattered along gathering and transmission lines. EPA could not plausibly have considered such transportation and distribution sources to be major emitting plants.

Nevertheless, EPA claims that the source category should be construed broadly because, “In the [1979] notice that listed source categories (including Oil and Natural Gas) for promulgation of NSPS, we noted that there were discrepancies between the source category names on the list and those in the background document, and we clarified our intent to address all sources under an industry heading at the same time.” 76 Fed. Reg. at 52745. But, that is not what the Agency said in 1979. Rather, EPA explained in 1979 that the discrepancies were “a result of aggregation of sources which had been subcategorized for size classification and priority ranking analysis in the background document” and that “all source categories under a generic industry heading, such as non-metallic mineral processing, will be evaluated at the same time, although this does not necessarily imply that a single standard would apply to all sources within the listed category.” 44 Fed. Reg. at 49225. Nothing in this explanation suggests that EPA intended to regulate non-major sources under § 111 by “aggregating” them with major sources. In context, EPA was simply saying that categories or subcategories of stationary sources that otherwise met the listing criteria (*i.e.*, plants that typically are major emitting) were sometimes lumped together into a single category for listing purposes. Thus, EPA’s “aggregation” decisions do not lend support to an expansive interpretation of the “crude oil and natural gas production” source category.

It is telling that, when the Agency eventually established NSPS for this source category, it decided to only regulate natural gas processing plants – the closest thing to a major-emitting plant that can be found in this sector. Thus, EPA’s prior actions speak louder than its words in the current proposal.

2.2. EPA is not Authorized to Arbitrarily Expand a Source Category

EPA’s claim that it is authorized to expand the scope of the original source category “to include any oil and gas operation not covered by the current listing and evaluat[e] emissions from all oil and gas operation at the same time” is equally unavailing. EPA is authorized to regulate “a category” of stationary sources under § 111 only if, in the judgment of the Administrator, the category “causes, or significantly contributes to, air pollution which may reasonably be anticipated to endanger public health or welfare.” CAA § 111(b)(1)(A). For now, the “category” of stationary sources that EPA regulates in the oil and gas sector consists of natural gas processing plants. The additional types of

sources that EPA seeks to regulate in the proposal are distinctly different types of stationary sources than gas processing plants. For example, an oil or gas production well is a stationary source, but it clearly is not a processing plant. Similarly, compressors, tanks, and pneumatic devices are stationary sources, but they also are plainly not processing plants. Such sources might be *part* of a gas processing plant (and, therefore, possibly susceptible to regulation as part of a gas processing plant), but if they are not part of a gas processing plant, they constitute a different kind of stationary source.

Thus, EPA is authorized to regulate these additional source types if and only if it: (1) defines a discrete “category” of stationary sources; and (2) determines that emissions from the source category cause or significantly contribute to endangerment to health or the environment. Since EPA has not defined such additional source categories or made such endangerment/contribution findings, EPA is not authorized to “expand” the scope of the “crude oil and natural gas production” source category.

Even if EPA had such authority, it would be arbitrary and unreasonable to expand the source category as proposed. To begin, EPA makes no effort whatsoever to demonstrate that emissions from the additionally-regulated sources cause or contribute to endangerment to health or the environment. Instead, the Agency simply asserts that it may evaluate “emissions from all oil and gas operations at the same time.” 76 Fed. Reg. at 52745. This failure to investigate the key statutory listing criteria is patently arbitrary and plainly violates the § 307(d)(3) requirement to clearly set forth the basis and purpose of the proposal.

In essence, EPA appears to be arguing that, since it determined that certain types of stationary sources within an industry sector cause or significantly contribute to endangerment to health or the environment, it is free thereafter to amend the source category to include all manner of ancillary equipment and operations (regardless of the quantity of emissions) because a teaspoonful of additional emissions contributes to the previously-identified endangerment. This is not a reasonable interpretation of § 111(b)(1)(A) because such an interpretation would bestow virtually unlimited regulatory authority upon EPA – allowing EPA to evade the express listing criteria by creating loose associations of nominally related source types.

The proposal is a case in point. Oil and gas production wells are fundamentally different stationary sources than gas processing plants. Yet, EPA asserts that its long-ago decision to regulate gas processing plants under § 111 somehow enables the Agency to now regulate production wells because the wells are associated with gas processing plants by virtue of being in the same industry sector. Even worse, EPA employs the same rationale to claim authority to regulate pneumatic devices in the sector – including single devices located anywhere on a pipeline and not necessarily associated with a “plant” or “stationary source.” Guilt by association is not a reasonable interpretation of the Act and does not satisfy EPA’s threshold obligation to clearly define a category of stationary source and show that emissions from that category of sources causes or significantly contributes to endangerment to health or the environment.

Lastly, CAA § 111(f)(3) requires EPA to “consult with appropriate representatives of the Governors” prior to “promulgating any regulations under this subsection.” As explained above, EPA originally listed the “crude oil and natural gas production” source category pursuant to § 111(f)(3). Thus, EPA has a clear obligation to consult with the Governors and should do so prior to proposing the rule so that the public has an opportunity to know the views of the Governors and submit comments on the

record. EPA's failure to consult with the Governors prior to proposal is a fundamental procedural error.

2.3. Extremely Small Affected Facilities

EPA makes similar errors in asserting that single individual components (such as pneumatic devices, compressors, and tanks) and single activities (such as each well completion) constitute separate "affected facilities" under the rule. *See, e.g.*, 76 Fed. Reg. at 52746 ("We are proposing that each pneumatic device is an affected facility."). The clear purpose of this approach is to expand the universe of "new sources" that will become subject to the final rules. *See, e.g., id.* ("Accordingly, the proposed standards would apply to each newly installed pneumatic device (including replacement of an existing device)."). This proposal to finely parse the definition of affected facility in order to expand applicability of the rules is fundamentally flawed for three distinct reasons.

2.3.1. EPA Has Failed to Explain Legal Authority

First, EPA has completely failed to explain where it finds legal authority for such an approach. The closest that EPA comes is to state that individual pieces of equipment constitute an "apparatus" and to vaguely refer to "the definitions of "affected facility" and "construction" at 40 CFR 60.2." *See, e.g., id.* at 52761. This explanation is indecipherable and, thus, falls far short of EPA's obligation to include in the proposed rule "the major legal interpretations ... underlying the proposed rule." CAA § 307(d)(3)(C).

2.3.2. Affected Facility Must Match the Source Category

More importantly, the proposal is flawed because the statute simply does not confer authority on EPA to define a source category and then define a different "affected facility" for purposes of determining what constitutes a new source. As explained above, the statute unambiguously requires EPA to identify and regulate "categories of stationary sources." CAA § 111(b)(1)(A). Similarly, the statute defines the term "new source" to mean "any stationary source" that is constructed or modified after proposal of an applicable standard. *Id.* at § 111(a)(2). There can be no doubt that the "stationary source(s)" that is identified for listing purposes must be the same "stationary source" used to define what constitutes a new source. In other words, by defining a category of "stationary sources" to be regulated under § 111, EPA unavoidably identifies the "stationary source" that must be used in applying the definition of "new source."

To be sure, § 111 provides EPA with regulatory flexibility – the Agency clearly "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." *Id.* at § 111(b)(2). However, the authority to parse a given category of stationary sources for purposes of standard setting is distinctly different from the asserted authority to redefine what constitutes a "new source" within the given source category. *Asarco Inc. v. EPA*, 578 F.2d 319, 327 n. 24 (D.C. Cir. 1978) ("This language on its face merely allows the Administrator to set different standards for different classes, types, and sizes of sources. It does not give the Administrator authority to rewrite the definition of a stationary source ..."). EPA has flexibility in defining in the first instance the stationary

sources to be regulated, but the act of defining the “stationary sources” fixes the “affected facility” for purposes of determining what constitutes a new source.

2.3.3. EPA Has Failed to Follow Established Criteria

Third, even assuming (for the sake of argument) that EPA has authority to designate portions of stationary sources as “affected facilities” for purposes of determining what constitutes a “new source,” EPA has failed to follow the analytical framework established in prior rules for making such designations. For example, in establishing the NSPS for VOC emissions from synthetic organic chemical manufacturing wastewater, EPA explained that a balancing must be done. A “narrower” definition of affected facility can be favorable because “a broader definition means that replacement equipment is less likely to be regulated under the NSPS.” 59 Fed. Reg. 46780, 46789 (Sept. 12, 1994). On the other hand, a “broader” definition may be appropriate upon consideration of “the relevant statutory factors (technical feasibility, cost, energy, and other environmental factors).” *Id.* In the case of this SOCM rule, EPA selected the process unit as the appropriate affected facility because it “allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards.” *Id.* at 46790. The failure to engage in reasoned assessment according to these established criteria renders the proposed rule arbitrary and capricious and not in accord with the law.

2.4. Temporary Emission Sources (Completions)

Emissions from well completions are fundamentally different than emissions regulated under any existing NSPS. It goes without saying that the purpose of gas wells is to produce natural gas. A well completion is not part of the normal operation of a well, in that completion activities do not continuously occur as a well is producing or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be “recompleted,” this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

To date, EPA has not sought to impose § 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA has actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until “within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.” 40 C.F.R. §60.8(a). Similarly, performance test must be conducted under conditions reflecting “representative performance of the affected facility.” *Id.* at §60.8(c). Periods of source construction and maintenance have never been determined to be “representative” of normal source operation under the NSPS program.

With this as a backdrop, EPA's proposal to set standards for well completions and recompletions is unfounded. To begin, as discussed more fully in Section 15.1 of these comments, production wells

are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and gas production industry (such as natural gas processing plants) that EPA seeks to regulate in the proposed rule. EPA has not previously found and has not proposed to find that emissions from production wells cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate oil and gas production wells under § 111.

In addition, EPA has not explained why it has reversed a decades-long practice under § 111 of regulating only emissions from normal operation of affected facilities and expressly excluding construction-related emissions from regulation. The proposal to regulate construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of § 111. The failure to explain why this departure is justified and the failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C).

3. BOUNDARIES FOR THE OIL AND NATURAL GAS PRODUCTION SECTOR

3.1. Boundary Between the Production and Transportation Sectors

EPA, in the preamble to the proposed rules, presents a description of the oil and natural gas sector that would clearly expand the boundaries of the oil and natural gas production source category from that listed in 1979. The preamble states, "We consider the oil refinery sector separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector" (76 FR 52744, bottom of middle column). This statement would expand the oil and natural gas sector to include all pipeline facilities all the way to the refinery fence, which is almost surely not the intent. Such an expansion of the oil and natural gas sector would overlap with the oil and natural gas pipeline transportation sector, which is already regulated by NESHAP Subparts HHH and EEEE (OLD MACT) and NSPS Subpart Kb.

Having Subpart HH coverage overlap Subparts HHH and EEEE is unreasonable and unlawful because sources are included in two source categories and regulated under two standards. Under the proposal, it would seem some sources currently regulated under subparts HHH and EEEE might no longer be subject to those rules and instead would be subject to subpart HH on the basis that only one NESHAP applies to any individual source. At a minimum, there would be significant confusion and compliance liability over which rules apply to such sources, whether rule applicability has been correctly assigned in the past and whether the MACT floor analyses for Subparts HHH and EEEE inappropriately included sources from the oil and natural gas production source category. At minimum, any change in Subpart HH applicability must be clearly identified in rule language as applying only from the date of proposal, rather than retroactively, and overlaps with Subparts HHH and EEEE must be specifically addressed.

The point of custody transfer where the hydrocarbon liquids enter the transportation industry has always been the demarcation of the end of the production sector and the beginning of the transportation sector. The current definition of custody transfer in Part 63 Subpart HH (below) is typical of the definitions in NSPS Subpart Kb and NESHAP Subparts HHH and EEEE, each of

which describe this point as being where oil or natural gas is transferred from production or producing operations to “pipelines or any other forms of transportation.”

§63.761

Custody transfer means the transfer of hydrocarbon liquids or natural gas: after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Although oil and natural gas are measured at and pass several “accounting transfers” (such as lease accounting for royalty purposes, and gathering and gas plant balance for product loss and shrinkage purposes), products often are not transferred from the production operator until the product is loaded onto trucks or into a pipeline to leave the field. Additionally, using the last point before the oil or natural gas leaves the production field allows the NSPS and NESHAP regulations to use the same regulatory demarcation between the production and transportation sectors, as specified in CAA section 112(c).

As EPA accurately points out, “hydrocarbon liquids can pass through several custody transfer points between the well and the final destination”. However, this is not a good reason to abandon the best point of physical demarcation between production and transportation sectors that the agencies and industry has found. This rulemaking should clearly define which point of custody transfer is intended for this dividing point. API recommends that this dividing point be the last point of custody transfer before the crude oil or condensate leaves the production field and enters the transportation industry. This would most closely match the original intent of the custody transfer definition in the final NSPS Subpart K of March 8, 1974 and the common practice of the oil and natural gas industry.

Furthermore, API feels it is inappropriate to include the natural gas transportation (transmission) sector in NSPS Subpart OOOO for the reasons discussed in Section 5.1 on the low VOC natural gas streams. EPA states that the purpose of this NSPS is to control emissions of VOC and SO₂. However, there is no SO₂ and very little VOC to control in the natural gas stream after the gas processing plant. EPA recognized this when they exempted residue gas (gas after the extraction of NGLs) from the provisions of NSPS Subpart KKK. In addition to inappropriately expanding the source category, including the natural gas transportation sector in NSPS Subpart OOOO ignores this fact and amounts to the “backdoor” regulation of greenhouse gases (GHGs) because methane is the only substance effectively regulated for low VOC natural gas streams.

If EPA feels there is a need to add new requirements for the transportation and distribution sectors, it should revise existing subparts that already apply to them (i.e., NSPS Subpart Kb for tanks) or create a new subpart if necessary. Adding these sectors as part of a review for the production sector inappropriately reduces the opportunity of the transportation and distribution sectors from commenting on the proposed rules.

API requests that EPA define the boundary of the Oil and Natural Gas Production sector as the last point of custody transfer before leaving the production field, as suggested below, and that the title of NSPS Subpart OOOO be edited to delete the reference to the transmission and distribution sectors.

Suggested Rule Text:**Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production,
~~Transmission, and Distribution~~****§60.5365**

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service or in wet gas service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5430

[Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.](#)

These changes would render NSPS OOOO consistent with NESHAP HH and HHH, as those rule were originally promulgated. The rule text adjustments below are necessary to return the proposal language to the original intent.

NESHAP HH

Return to the original language qualifying the affected facility.

§63.760(a)(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point [of custody transfer](#) ~~where hydrocarbon liquids enter either the Organic Liquids Distribution (Non-gasoline) or Petroleum Refineries source categories.~~

NESHAP HHH

No changes are required to NESHAP HHH, in that the proposed revisions leave the “point of custody transfer” qualifier in place.

3.2. Boundary Between the Transportation and Distribution Sectors

API supports the comments of the American Gas Association (AGA) regarding the boundaries for the natural gas distribution sector under Subpart OOOO. As in the case of the production sector, the boundaries of other sectors in our industry are also defined by the point where the hydrocarbons leave one sector and enter another. Natural gas local distribution utilities usually obtain their supply of natural gas from upstream interstate transmission pipelines. Some gas utilities also obtain pipeline

quality dry natural gas directly from local production or from another adjacent gas utility, without an intervening interstate pipeline. The boundary for the distribution sector occurs at the point where custody of the natural gas is transferred from an upstream interstate transmission pipeline or from local production to a local natural gas distribution utility company. Subsequent transfers of custody from one distribution utility to another would mark the boundary between the two utilities, but would occur within the distribution sector.

EPA uses the term “city gate” loosely in Subpart OOOO to indicate the boundary between distribution and upstream sectors, but the agency has not defined the term or proposed a clear definition of the boundary between the natural gas distribution sector and other sectors of the industry. Although EPA added distribution to the *description of the source category* for Subpart OOOO, we understand that EPA did not intend to apply any of the proposed *standards* on the low VOC natural gas streams in natural gas distribution. This makes it essential to define the boundary of natural gas distribution clearly. Using the term “city gate” will not serve this purpose. AGA notes in its comments that the term “city gate” does not have a consistent meaning within the distribution sector. It is used by different gas utilities in different ways to refer to a wide variety of different types of facilities.^A

Suggested Rule Text:

Accordingly, to avoid confusion, we agree with AGA that EPA should replace the term “city gate” with the term “custody transfer station” and should add the following definition to §60.5430:

§60.5430

Custody transfer station means a facility where custody of natural gas is transferred from an interstate transmission pipeline or local producer to a natural gas local distribution utility.

If this change is made, then the term city gate should be replaced wherever it appears in Part 60, Subpart OOOO with the term “custody transfer station.” This would avoid confusion that would otherwise arise from using the term “city gate.”

As noted in section 3.1 above, §60.5365 should be qualified to pertain to “a site prior to the point of custody transfer at which is located.” The definition of custody transfer suggested in section 3.1, would mark the division between production and “pipelines *or any other forms of transportation.*” This is intended to encompass transportation in distribution systems. In combination with the above revision to §60.5365, this would clearly exclude the natural gas distribution sector from the application of Subpart OOOO, which we understand is consistent with EPA’s intent.

4. ECONOMIC ANALYSIS FOR DETERMINING BEST SYSTEM OF EMISSION REDUCTION (BSER)

^A AGA had a similar concern with the Mandatory Greenhouse Gas Reporting Rule for Natural Gas Systems, 75 Fed. Reg. 74,458. In that rulemaking, EPA responded to AGA’s comment on the term “city gate” used in the GHG reporting rule by proposing to delete the term “city gate” and replacing it with a different defined term in its recently proposed technical revisions to 40 C.F.R. Part 98, Subpart W. See 76 Fed. Reg. 56,010, 56,028 (Sept. 9, 2011). See also AGA’s comments on the Subpart W Technical Revisions, filed Oct. 24, 2011 in Docket EPA-OAR-2011-0512.

The Clean Air Act (CAA) requires EPA to set NSPS at the BSER, considering economics, which have been adequately demonstrated. In performing the economic analysis, EPA created a model for each "affected facility" that was used to perform the required economic analysis. These models contain assumptions for a "typical" affected facility within the industry. One of API's primary concerns with the proposed rule centers around the lack of sufficient sensitivity analysis for these model affected facilities with the economic justification for each control strategy that was determined to be BSER.

4.1. Unique Conditions of the Oil and Gas Industry

The O&G industry differs from most other industrial sectors in that the naturally-occurring dynamic reservoir properties control how we produce and manage the oil and natural gas from the reservoir. Most industries purchase their feedstocks to a set specification and have significant control over each step of the process. When the O&G industry finds a petroleum reservoir, the composition of the petroleum, the temperatures, and pressures of the fluids are dictated by the reservoir. These properties start to slowly change as soon as oil and gas begin being withdrawn from the reservoir. The volume of petroleum withdrawn from the well decreases every year (referred to as depletion) as does the pressure it is produced at. The composition of the petroleum changes (e.g. the gas to oil ratio [GOR], the amount of propane, butane, etc. in the gas, the characteristics of the crude oil, etc.) as does the volume and quality of produced water that comes with it. The O&G industry is constantly required to adapt to these changes. New wells must be drilled to replace the loss of production volume as the well depletes. Compressors must be added to compensate for the loss of well pressure, etc.

Additionally, each reservoir has a completely separate set of properties. For example, "conventional wells" of the past might flow oil and/or gas as soon as the well is drilled. Some of these conventional wells produce a very heavy, thick crude oil (a.k.a. black oil or dead oil) that has no associated natural gas at all. Other conventional wells may produce very light hydrocarbon liquids (a.k.a. condensate) along with high amounts of natural gas. While conventional O&G reservoirs are still producing today, the majority of new reservoirs are typically referred to as "non-conventional" since the reservoir characteristics and storage mechanism can be very different from those of conventional reservoirs. Non-conventional wells include formations such as coal bed methane (CBM), tight sands, and shale. Each type of formation may have some similarities, but still can have wide variation. CBM typically are produced at low pressures and contains very high percentage of methane (often as high as 97% by volume) and almost no hydrocarbons heavier than ethane. However some geographic areas of CBM can produce some liquid hydrocarbons. Some tight sands behave like sand stone and can produce significant amounts of heavier hydrocarbons. Shale fields run the gamut from wells that produce nearly 100% methane to wells that produce significant quantities of hydrocarbons that are liquid at stock tank conditions. The definitions of the various types of reservoirs are very broad and the defining characteristics have little to do with the reservoir's potential to emit VOC or HAP.

4.2. Economic Models and Variability

From the conversation above, it is clear that there is no one-size-fits all model to describe the O&G industry. For example, EPA looked at natural gas compositions that had no VOC content at all up to 53 weight % VOC, but selected a single gas composition of 18 weight % VOC to conduct most of the economic analysis on emission control options. When EPA utilizes this analysis to justify

controls, controls on high VOC content gas will actually have much lower cost/ton of VOC than the average, while controls on low or no VOC in the gas will have cost effectiveness that will approach an infinite cost/ton. (See Section 5.1.2 for further details). It is clearly inappropriate to designate an emission control for the reduction of VOC as BSER for a gas that contains no VOC, but this is what EPA has done by utilizing a one-size-fits-all economic strategy.

However, it is not fair to say that EPA did not attempt to set minimum thresholds where controls are cost effective. EPA set two throughput volume thresholds (20 bbl/day for crude oil and 1 bbl/day for condensate) for storage vessels. EPA selected the two throughput thresholds using a flawed study (see Section 16.6.1.) that assumed the emissions rate is dependent upon throughput volume alone. However, as discussed in Section 16 the composition of the hydrocarbon liquid and the temperature and pressure of the production separator also have a significant impact on VOC emissions. In fact, all three of these must be known to determine the VOC flash emissions from a storage vessel. API believes that throughput alone is an inappropriate surrogate to assure that emissions controls are economical, and that only VOC flash emissions calculations can serve this function for the production sector. However, API has suggested an alternative to a throughput threshold that is based on conservative volatile condensate compositions, conservative separator temperature and a range of separator pressures. (See Tables 16-3, 16-4, and 16-5 in Section 16.6 for cost effectiveness calculations).

Each new emission control suffers from this one-size-fits-all economic justification concern. All of the emission controls proposed are occasionally cost effective in selected O&G operations. However, all of the proposed emission control options fail to be cost effective in other O&G operations. A consistent theme of API's comments is that the controls should be applied only in situations where they are economic, so it qualifies as BSER.

4.3. Completeness of Cost Estimations of Control Options

In most cases, the cost estimates that EPA provides for specific pieces of equipment appear reasonable for the central activity. However, in every case the items included in the economic analysis are incomplete and the costs for compliance assurance requirements of the rule are underestimated. Below are listed examples of cost that have been left out or underestimated.

- **Auxiliary Equipment Required for a Complete Control System.** EPA consistently included the primary equipment required for the control option being considered. However, often the cost of auxiliary equipment was overlooked. For example with storage vessels, EPA considered the cost of the control device (flare, combustor or VRU), but did not appear to include the closed vent system required to collect the vapors, assure condensed liquids do not "vapor lock" this very low pressure system, and separate any condensed liquids before it reaches the control device.
- **Monitoring Requirements.** EPA appeared to include some costs for monitoring where required (i.e. storage vessels and LDAR). However, this cost did not appear to consider the remote, dispersed and unmanned nature of the facilities. This is most evident in the CPMS flow monitoring requirements for storage vessels. The data quality standards for CPMS require that personnel be able to monitor the instrumentation on an hourly (or at least daily) basis. Since these sites are unmanned, remote data collection systems would be required that are typically

either totally unavailable or require expansion to meet the requirements. These costs often far exceed the cost of control equipment that data is being provided for. Additionally, the operational personnel that are routinely at production sites are not qualified to perform many of the tasks required by the proposed rule and may be required multiple times a month. Travel time to and from the site is typically averages an hour in each direction from the central office. These costs have not been included in the economic analysis.

- **Notification, Recordkeeping and Reporting Cost.** EPA appears to assume that the data required for notification, recordkeeping and reporting required by the rule is readily available in a central location or in coordination with other routine operations. This is an unrealistic assumption.

4.4. Cost Effectiveness Threshold

When deciding whether emissions controls are economically justified, some measure is required, typically a cost/ton of emissions reduced. EPA has not placed a numeric threshold on the cost/ton of pollutant reduced, preferring to leave that decision up to a case-by-case analysis. However, comparing the cost effectiveness numbers for the control strategies that were determined not to be BSER with those that were accepted as BSER gives a good representation of an appropriate threshold. The cost effectiveness decisions that EPA made in determining regulatory strategies for this proposed rule were extracted from the Technical Support Document (EPA-HQ-OAR-0505-0045). From this table a cost effectiveness of less than \$5,000/ ton of VOC reduced appears to be acceptable.

Table 4-1. Comparison of EPA Cost Effectiveness Decisions

| Emission Source Type | Control Option | VOC Cost Effectiveness (\$/ton) | EPA Decision |
|--|-----------------------|--|---------------------|
| Pneumatic Devices | Low Bleed | \$262 | Accepted |
| Centrifugal Compressors - Production | Dry Seals | \$595 | Accepted |
| Completions/Flowback | REC | \$1,516 | Accepted |
| Pneumatic Devices | Compressed Air | \$2,659 | Accepted |
| Storage Tanks | 95% Control with VRU | \$3,150 | Accepted |
| Equipment Leaks - Processing Plants | VVa LDAR | \$3,352 | Accepted |
| Centrifugal Compressors - Transmission | Dry Seals | \$3,495 | Accepted |
| Reciprocating Compressors - Other | Change Out Seals | \$3,700 | Accepted |
| Centrifugal Compressors - Production | Flare | \$5,300 | Rejected |
| Equipment Leaks - Well pads | VVa LDAR with AWP | \$5,364 | Rejected |
| Equipment Leaks - Gathering Boosting | Component VVa LDAR | \$6,079 | Rejected |
| Equipment Leaks - Well pads | VVa LDAR | \$6,934 | Rejected |
| Equipment Leaks - Gathering Boosting | VVa LDAR | \$8,174 | Rejected |
| Equipment Leaks - Gathering Boosting | VVa LDAR with AWP | \$8,685 | Rejected |
| Equipment Leaks - Well pads | Component VVa LDAR | \$15,063 | Rejected |
| Equipment Leaks - Transmission Storage | VVa LDAR with AWP | \$19,723 | Rejected |
| Equipment Leaks - Transmission Storage | VVa LDAR | \$19,769 | Rejected |
| Equipment Leaks - Transmission Storage | Component VVa LDAR | \$24,762 | Rejected |
| Centrifugal Compressors - Transmission | Flare | \$31,000 | Rejected |
| Reciprocating Compressors - Wellhead | Change Out Seals | \$84,000 | Rejected |

5. APPLICABILITY [NSPS OOOO]

The scope of the regulation should be defined in the applicability §60.5365, so that all stakeholders clearly know what is covered. This regulation like many others has expansion or limitations of the scope included in definitions, paragraph titles and other portions of the rule. API recommends the following changes be made to the applicability section of the rule.

5.1. Applicability to Low VOC Natural Gas Streams

In the summary of the proposed rule, EPA states that it is adding new source performance standards for VOCs. However, there are insufficient conditions in the proposed rule to limit the applicability to streams that have a significant quantity of VOC, resulting in a NSPS regulation that can be interpreted to apply to streams with no VOCs. In this proposed rule, the term “natural gas” is used in the titles of the category, plants and equipment descriptions, as well as a surrogate for VOCs. However, many natural gas streams are mainly methane and have little or no VOC content when it is produced from the reservoir (thus the terms “dry gas” and “coal bed methane” that are common in the industry). EPA has previously stated that it does not intend to regulate GHGs within this rule and thus has not provided the public with an opportunity to comment on the inclusion of methane. Without some minimum applicability threshold for VOCs, EPA is essentially regulating GHGs.

5.1.1. Natural Gas is not an Appropriate Surrogate for VOCs

A common thread running through the virtually all of the Subpart OOOO proposal is that natural gas can appropriately be assumed to have a fixed composition. EPA does recognize that produced gas typically has significantly different characteristics than gas being moved through transmission operations, and thus established different fixed compositions for production (*i.e.*, completions and recompletions) and transmission (*i.e.*, pneumatics, equipment leaks, compressors). See Memorandum from Heather P. Brown, PE, EC/R Inc., to Bruce Moore, EPA/OAQPS/SPPD, Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking (July 28, 2011) (“EC/R Memo”). However, these compositions are the only compositions used for purposes of analyzing the regulatory alternatives and supporting the proposed rule. In addition, EPA would require applicability to effectively be based on these fixed-composition assumptions. In other words, the actual content of the natural gas produced or transmitted at an affected facility has no bearing on applicability of the rule – applicability is based solely on the act of producing, processing, or transporting natural gas.

This approach of assuming geographically, temporally, and geologically fixed compositions of VOCs and other regulated pollutants in natural gas is insupportable and arbitrary. EPA's own analysis demonstrates the problem. Table 7 of the EC/R Memo provides a sensitivity analysis of EPA's gas composition data for gas wells and hydraulically fractured wells (see EC/R Memo, page 10). This table shows that the minimum VOC content in EPA's database is 0 and the maximum is 29.6 volume percent. This means that certain “affected facilities” will be subject to the rule even though the gas they handle contains little or no VOCs, which is the pollutant ostensibly, being regulated by this rule (see Section 5.1.2 for further details

EPA acknowledges that this is a problem. In discussing the proposed standards for well completions, EPA notes that “gas composition” is one of the “variety of factors” that determine “the length of the flowback period and actual volume of emissions.” 76 Fed. Reg. at 52757. As a result, EPA admits that “[t]his variability means there will be some wells which emit more than the estimated emission factor and some wells that emit less.” More to the point, this “heterogeneity in well operations and costs” means that “while RECS may be cost-effective on average, they may not be for all operators.” *Id.* at 52758.

However, EPA fails to take this observation to its logical conclusion – that some wells will emit so little VOC that the proposed standards cannot be justified given that little or no reductions will be achieved in regulated pollutant emissions and the cost effectiveness of the proposed standards would be unreasonably high. Instead, EPA sets up a false choice – that EPA can either “require an operational standard” (such as the proposed REC requirement) or impose a “performance-based standard” (which is not defined, but in context appears to be some sort of numeric emissions limitation). EPA asserts that a performance standard cannot work “because we believe there are no feasible ways for operators to measure emissions with enough certainty to demonstrate compliance with a performance-based standard.” *Id.* Therefore, EPA decided to propose an “operational standard” applicable to all hydraulically fractured natural gas wells.

This makes no sense because EPA obviously has other regulatory alternatives. These include the possibility of setting a lower level VOC cut-off for natural gas that would target the proposed rule only on those who produce, process, or transport gas with more than a specified amount of VOCs (with the cut-off based on consideration of emissions reductions and costs). EPA's failure to consider such other approaches is arbitrary and capricious. And, its proposal to impose requirements that “may be cost-effective on average” but that “may not be [cost effective] for all operators” violates the Agency's obligation to “consider the representativeness of the test data relied upon in the development and justification of its standard.” *National Lime* at 451.

Notably, in the NESHAP part of the proposal, EPA abandons the fixed composition assumption in assessing control requirements for small dehydrators “due to variability of gas throughput and *inlet gas composition*.” *Id.* at 52768 (emphasis added). As a result, this element of the proposed rule is based on facility-specific data of “inlet natural gas BTEX concentration.” *Id.* This further demonstrates that EPA can and should take account of VOC content in determining the applicability of Subpart OOOO.

On a related note, the variability in the composition of natural gas also means that natural gas is not an appropriate surrogate for VOCs under the standard for pneumatic devices. *See id.* at 52800 (proposed §60.5390). The D.C. Circuit has made clear that EPA does have authority to regulate surrogate pollutants, but “only if it is reasonable to do so.” *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) (internal quotes and citations omitted). For the reasons discussed above, applying the pneumatic device standards to any device in natural gas service would cause the standard to apply to many devices that emit little or essentially no VOCs. As a result, natural gas is not an appropriate surrogate for VOCs because applicability of the rule is not reasonably focused on significant sources of VOCs.

Lastly, the proposed rule does – in a limited way – provide for a lower level VOC cutoff. Section 60.5430 defines “equipment” to include only components “in VOC service” and §60.5400 provides that compressors at onshore natural gas processing plants are covered only if they are “in VOC service.” 76 Fed. Reg. at 52809 (proposed definition of “equipment”; 52800 (proposed VOC standards for onshore natural gas processing plants). However, proposed §60.5400(f) requires that “[e]ach piece of equipment is *presumed* to be in VOC service ... unless an owner or operator demonstrates that the piece of equipment is not in VOC service.” *Id.* at 52801 (emphasis added). This presumption can be overcome

only if it is “determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight.” *Id.*

While a lower level VOC cutoff is appropriate and necessary (for the reasons discussed above), EPA is without authority to require that affected equipment and compressors must be assumed to be in VOC service unless it is proven that they are not. NSPSs apply to specified affected sources – in this case, equipment and compressors with the potential to emit VOCs in amounts that justify regulation. It is unreasonable and arbitrary for EPA to declare that equipment or compressors are covered by the rule when it has not been determined that the equipment or compressors handle gas of a composition that EPA has determined warrants regulation.

5.1.2. In VOC Service and In Wet Gas Service

API requests that EPA add a limitation to §60.5365 that this regulation applies only to streams that are “in VOC service” or “in Wet gas service” as discussed further below.

EPA has chosen to use average compositions of natural gas throughout the US and utilized a single average composition with VOC content of 18.28% by wt. to economically justify regulations for LDAR, natural gas compressors, and pneumatic controllers throughout the US (see EPA-HQ-OAR-0505-0084). This “one size fits all” approach ignores the fact that natural gas ranges in VOC content from 52.72% to 0.0% by wt for the gas compositions EPA listed in the docket. In fact the average VOC content for shale gas production, the fastest growing sector of the natural gas industry, is only 2.95% by wt. and the average VOC content is 2.35% by wt. for the natural gas transportation sector. In Attachment G, RIA Review for Completions, Table G-6, API has calculated the cost effectiveness for the compositions EPA included in the docket for determining an “average natural gas stream”. The cost effectiveness (in terms of \$/ton of VOC) was calculated to be \$4,814/ton at 17.95 wt % VOC, \$8,564 at 10.09 wt % VOC and \$16,552/ton at 4.81 wt % VOC. This means that the cost benefit approaches infinite \$/ton of VOC for gas with no VOC content (i.e. coal bed methane [CBM] and some of the shale gas fields). When compared to the other cost effectiveness decisions that EPA made in determining regulatory strategies in the Technical Support Document (EPA-HQ-OAR-0505-0045; see Section 4.4), restricting these regulations to streams “in VOC service”, as recommended below, seems very reasonable.

NSPS Subparts VV and GGG control equipment leaks for streams containing 10% or more VOC by weight, and API continues to believe that 10 % by weight of VOC is an appropriate threshold for the oil and natural gas production sector. However, when EPA promulgated NSPS Subpart KKK in the 1980s, EPA also decided to control streams in “wet gas” service. While historically most streams in “wet gas” service contained significant amounts of VOC, that is not the case today. Today, two “wet gas” streams commonly occur that were infrequent or non-existent when NSPS Subpart KKK was promulgated. The first is streams with high inert gas (carbon dioxide [CO₂] or nitrogen [N₂]) content from enhanced oil recovery gas flood projects. The inert gas content often becomes the majority of the “wet gas” stream and the VOC content becomes negligible. The wet gas is still processed at a natural gas processing plant, to remove the inert gas stream (typically recycled for enhanced oil recovery purposes) and natural gas liquids (NGLs) to make the remaining natural gas

salable. The second is non-conventional natural gas (coal bed methane [CBM], shale gas or tight sands) that may have little VOC content. These new low VOC content streams were not considered in the original Subpart KKK promulgation process.

API recommends that EPA retain consistency between the LDAR programs (i.e., Subparts VV, GGG and KKK). API proposes that EPA add a definition of "in VOC service" to Subpart OOOO, and use that term in the applicability provisions (See Section 19.4.2 for further information).

Suggested Rule Text:

§60.5365

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5400

This section applies to each compressor in VOC service ~~or in wet gas service~~ and the group of all equipment (as defined in §60.5430), except compressors, within a process unit.

* * * * *

(f) You must use the following provision instead of §60.485a(d)(1):

Each piece of equipment is presumed to be in VOC service ~~or in wet gas service~~ unless an owner or operator demonstrates that the piece of equipment is not in VOC service ~~or in wet gas service~~. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. ~~For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process.~~ For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-63, 77, or 93, E168-67, 77, or 92, or E260-73, 91, or 96 (incorporated by reference as specified in §60.17) must be used.

§60.5430

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service ~~or in wet gas service~~, and any device or system required by this subpart.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

However, if EPA continues to believe it is important to regulate “wet gas” streams that are not “in VOC service”, API believes EPA must still set a minimum VOC content and maximum inert gas content for “wet gas”. Without doing so, EPA is ignoring the important part that VOC content in the controlled stream plays in the cost effectiveness of its regulations. API realizes that setting a concentration below the current 10 wt % “in VOC service” threshold is somewhat arbitrary, since this is not considered cost effective as discussed above. However, API proposes that EPA set the wet gas threshold (X) no lower than 5% by weight VOC. Additionally, API recommends EPA exclude “wet gas” that is predominately (i.e. greater than 50 wt %) inert gases. Therefore, API recommends the following:

Alternative Suggested Rule Text:

§60.5365

If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. Paragraphs §60.5365(a)-(e) apply only to affected facilities *in VOC service or in wet gas service.* ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5430

In wet gas service means that a compressor or piece of equipment contains or contacts wet gas. ~~the field gas before the extraction step at a gas processing plant process unit.~~

Wet gas means field gas before the extraction step at a gas processing plant process unit that is >X% VOC by weight. Wet gas does not include gas streams that are >50% by weight inert gases (nitrogen or carbon dioxide).

[API recommends X be equal to or greater than 5]

5.2. Applicability to Liquid Streams

The regulatory analysis on liquid streams in storage vessels has obviously concentrated on crude oil and condensate from production wells, however nothing in this Subpart limits the applicability to these streams. Regulators could easily apply the storage vessel regulations to vessels storing chemicals, vehicle fuels, lubrication oils, produced water, etc.; however these storage vessels have not gone through the economic analysis necessary to justify the applicability of the proposed rule to these services. API requests that applicability of the rule to storage vessels, as specified at

§60.5365(e), be limited to condensate and crude oil liquid streams. See Sections 16.4 and 16.5 for further details.

5.3. Applicability Limitation to Sectors

Applicability paragraphs §60.5365 (d) & (e) for pneumatic controllers and storage vessels have no limitation on the range of facilities to which they apply. Thus, the standards could inappropriately be applied to a fuel tank in a residence, if you ignore the title of the Subpart. Even with that limitation, a pneumatic device on the fuel system of any commercial boiler could be considered to be regulated, since the ending of the distribution sector was never discussed in the proposed rule. API requests that EPA add text to §60.5365 that limits applicability to the oil and natural gas production sector.

5.4. Applicability to Wellheads and Reduced Emission Completion Operations

5.4.1. Affected Facility

EPA's proposal to regulate temporary construction emissions from well completion activities within an NSPS has created problems and confusion within the proposed regulatory text. As discussed in Section 2.4, construction emissions are not part of normal operations and have not been regulated previously within an NSPS. Additionally, the CAA authority for NSPS applies to "any building, structure, facility, or installation." Thus, EPA chose the only stationary physical structure available at the time a well completion is performed as the "affected facility," the wellhead. API is concerned that EPA's choice of the wellhead as the affected facility along with EPA's failure to accurately define the emissions regulated by the proposed rule will lead to confusion within the agency and industry for the life of Subpart OOOO. EPA should first clarify that the affected facility is a natural gas wellhead facility onshore "except for one that does not have flowback immediately following hydraulic fracturing stimulation."

5.4.2. Regulated Emissions

The emissions proposed to be regulated by the proposed rule come from the flowback immediately following hydraulic fracturing stimulation. Such flowback, post hydraulic fracture stimulation may occur in conjunction with new well completion, existing well recompletion, or workovers. However, the proposed rule regulates "each well completion operation with hydraulic fracturing." Well completion, as discussed in Section 15.8, means the process of making a new oil or natural gas well ready for production. It allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics and also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture stimulate and prop open new fractures in lower permeability reservoirs. Flowback is only a portion of the well completion operation with hydraulic fracturing stimulation. Flowback can also occur from a recompletion or workover with hydraulic fracturing stimulation. VOC air emissions only occur when there is gas containing VOCs in the flowback. Well completions, recompletions, and workovers are not directly associated with the emissions being regulated. API believes that well completions,

recompletions, and workovers should only be included in the definition of flowback to prevent confusion of what is being regulated.

5.4.3. Defining Applicability

The applicability of the proposed regulation to “flowback immediately following hydraulic fracturing stimulation at onshore gas wellhead facilities” should be clearly defined in §60.5365(a). Furthermore, as discussed in Section 15.6.1, API believes that the following portion of the text is unnecessary and should be eliminated.

“For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.”

However, API agrees that the text should clarify that other equipment, such as process units, storage vessels, pneumatic controllers, and compressors located at the well site are not affected by hydraulic fracture flowback operations. This text is needed because of the issues discussed in Sections 5.4.1 and 5.4.2 above.

Suggested Rule Text:

§60.5365

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

- (a) [An onshore natural gas wellhead affected facility](#), is a single natural gas well, ~~that has flowback immediately following hydraulic fracturing stimulation.~~ [VOC emissions from flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore is the only activity regulated at this affected facility. For the purposes of this subpart, an existing onshore natural gas wellhead facility is considered modified if it meets the criteria of modification in §60.14. The modification of an existing natural gas wellhead affected facility does not affect the status of other equipment, process units, storage vessels, or pneumatic devices located at the well site.](#)

§60.5430

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and

returning the well to production. [Flowback immediately following hydraulic fracture stimulation may occur in conjunction with a well completion, recompletion, or fracture stimulation of the same zone in an existing well.](#)

5.5. Applicability to Sweetening Units

In several locations of the regulatory text, EPA states clearly that the standard applies to sweetening units located at onshore natural gas processing plants. However, this distinction is not made in the applicability provisions of §60.5365(g). Some examples of where EPA clearly states the standard applies only to sweetening units at onshore natural gas processing plants, include:

- In §60.5405, “What standards apply to sweetening units at onshore natural gas processing plants?”
- In §60.5406, “What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?”
- In §60.5407, “What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?”

Based on the examples above, API reviewed and commented on the proposed rule with the understanding that the requirements for sweetening units apply only to units located at onshore natural gas processing plants. In order to improve clarity on the applicability for sweetening units, API recommends the following revisions:

Suggested Rule Text:

§60.5365

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

5.6. Applicability Limitations to Modification and Reconstruction

EPA needs to clarify the applicability of Subpart OOOO to equipment that could be considered modified or reconstructed. EPA appears to inappropriately apply the modification or reconstruction tests to capture some existing facilities (i.e., recompletions and compressor relocations) for regulation when the General Provisions tests would not have included them and such inclusion is in violation of the Clean Air Act provisions. Other low cost, component level affected facilities (i.e., pneumatic controllers) may technically undergo modifications and reconstruction per the text of the General Provisions, but not fit the intent of the original rulemaking.

API believes that including definition of modification in Subpart OOOO is unnecessary, adds confusion and improperly changes longstanding precedents that reflect the intent of Section 111 of the Clean Air Act. API recommends that the provisions of §60.14 continue to apply to all NSPS regulations, including Subpart OOOO.

Suggested Rule Text:**§60.5430**Preferred Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

5.6.1. Relocated Compressors

The provisions of §60.5365(b) & (c) states that a “compressor is considered to have commenced construction on the date the compressor is installed at the facility.”

This violates, for no apparent reason, the §60.2 definition of “commenced”, which is “Commenced means, with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.” Under this definition, which is long established in Part 60 precedent, construction of a compressor occurs when the contractual obligation has been entered to purchase the compressor or for the project that purchases and installs the compressor.

In addition, this proposed language could be interpreted to mean that a compressor that has been relocated from one location to another is “new” (see Section 18.1). This is directly opposed to the provisions of §60.14(e)(6) that state “The relocation or change in ownership of an existing facility” by itself shall not be considered a modification. This same precedent has been followed in the NESHAP regulations where the relocation of an affected source does not affect the existing status of the source (see Background Information for Promulgated Standards for the final NESHAP General Provisions (EPA-453/R-02-002), page 3-62). Not following this precedent would lead to the illogical result that if an existing engine (regulated by either NSPS Subparts JJJJ or IIII or NESHAP Subpart ZZZZ) and compressor (regulated by the proposed NSPS Subpart OOOO) package was relocated, the engine would still be considered existing, but the compressor would be considered new. Additionally, for a new compressor package, two notices of construction would be required at different times, one for when the engine is ordered as required by Subpart JJJJ, and a second for when the compressor is installed. Other issues arise with the undefined phrase

“installed at the facility”. API requests that the last sentence of both §60.5365(b)&(c) be removed to resolve this issue.

5.6.2. Reduced Emission Completions

The proposed rule would define “modification” to include “each recompletion of a fractured or refractured existing gas well.” 76 Fed. Reg. at 52810 (definition of “modification” in proposed §60.5430). As a result, recompletion of an existing non-affected well would cause Subpart OOOO to apply to that well. This requirement is unfounded and unlawful.

EPA asserts “a completion associated with refracturing performed at an existing well” would be a modification “because a physical change occurs to the existing well resulting in emissions increase during the refracturing and completion operation.” *Id.* at 52745. More specifically, the “physical change, in this case, would be caused by the reperforation of the casing and tubing, along with the refracturing of the wellbore.” *Id.* at 52759. Additionally, the “increased “VOC emissions would occur during the flowback period following the fracturing or refracturing operation.” *Id.* While EPA asserts in the preamble that “a detailed discussion of this determination is presented in the Technical Support Document,” *id.* at 52745, that “detailed discussion” merely consists of the following:

In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. [TSD at 4-27]

This “detailed discussion” adds nothing of substance to EPA’s recap in the preamble.

The term “modification” is defined in § 111(a)(4) to mean “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” Under this definition, a modification occurs only if two things happen: (1) there must be a “physical change or change in the method of operation”; and (2) the change must result in an emissions increase.

In the context of the New Source Review program, the D.C. Circuit has opined that “Congress’s use of the word “any” in defining a “modification” means that all types of “physical changes” are covered.” *New York v. EPA*, 443 F.3d 880, 890 (D.C. Cir. 2006). In addition, the court determined that “the plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.” *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005).

However, the Supreme Court concluded that the § 111 definition of modification – which is

cross referenced in the statutory PSD provisions and, thus, applied in both the NSPS and NSR programs – does not have to have the same meaning under both programs. *Environmental Defense v. Duke Energy Corp.*, 127 S.Ct. 1423, 1434 (2007) (“Nothing in the text or the legislative history of the technical amendments that added the cross-reference to NSPS suggests that Congress had details of regulatory implementation in mind when it imposed PSD requirements on modified sources; the cross-reference alone is certainly no unambiguous congressional code for eliminating the customary agency discretion to resolve questions about a statutory definition by looking to the surroundings of the defined term, where it occurs.”). Thus, EPA has latitude within the context of § 111 to implement different rules regarding modifications – and, indeed, has done so from the inception of the NSPS program in the early 1970s.

In particular, EPA's regulatory definition of “modification” under the NSPS program provides several categories of activities that “shall not, by themselves, be considered modifications under this part.” 40 C.F.R. §60.14(e). Among other things, excluded activities include “maintenance, repair, and replacement which the Administrator determines to be routine for a source category,” and “an increase in production rate that can be accomplished without a capital expenditure.” *Id.* at §60.14(e)(1), (2). The term “capital expenditure” is defined to mean “an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of the Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code.” *Id.* at §60.2. These provisions have been included in the rules since the very beginning of the NSPS program in 1971. They reflect the fact that Congress established the NSPS program for “new” sources. Without these exclusions, even the most minor activities would convert an existing source into a “new source.” The premise behind characterizing these activities as not being “changes” is that they all contemplate that the plant will continue to be operated in a manner consistent with its original design and thus is not a “new” facility.

In addition, EPA has established a method of measuring emissions increases under the NSPS program that differs markedly from the approach used under the NSR program. Under §60.14(b), the emission rate must be expressed as kg/hr of any pollutant to which the standard is applicable. The rule specifies that emissions factors should be used, unless the Administrator determines the use of such factors will not clearly demonstrate that emissions will increase or decrease as a result of a change. In this case, material balances, continuous monitoring data, or manual emissions test may be used. Testing must be conducted under conditions based on representative performance of the facility. And, all operating parameters that may affect emissions must be held constant to the maximum feasible degree.

To be sure, EPA has authority to adopt rule-specific modification provisions that differ from these general provisions. *See, e.g., Id.* at §60.14(f) (“Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provision of this section.”). However, EPA clearly has the burden of explaining how such “special provisions” comport with the statute and why such “special provisions” should be adopted in lieu of the general provisions. EPA has failed in both regards with respect to the Subpart OOOO definition of

“modification.”

EPA fails in the proposal to explain why a recompletion is a physical change that should automatically trigger the application of NSPS Subpart OOOO. EPA merely asserts that it is a modification without any explanation or justification on the record. This assertion is particularly unavailing in light of the longstanding routine maintenance and capital expenditure exclusions from the definition of modification. Routine maintenance, for example, is a multifactor analysis that tries to arrive at a “common sense” finding based on the specific facts of a particular affected facility. In Section 15.11, API estimates that there are 1205 completions per year nationwide. These recompletions can certainly vary in nature, extent and cost and should be assessed individually, rather than automatically assumed to be a modification. This failure to explain, in the first instance, why recompletions can not constitute excluded routine maintenance or production increases achieved without a capital expenditure are arbitrary and capricious and represent a critical failure to provide an adequate explanation of “the major legal interpretations ... underlying the proposed rule.” CAA § 307(d)(3)(C).

EPA also fails to provide a rational explanation as to why a recompletion must, in all cases, result in an emissions increase. First, this, assumes that there are actual emissions associated with a recompletion, which for reasons discussed in other parts of these comments, is not a correct assumption. Second, if there are emissions, there may not be an increase. In fact, the emissions estimates in the TSD show that recompletions should not be expected to cause an emissions increase at all. Table 4-2 of the TSD shows that uncontrolled emissions from “natural gas well completion with hydraulic fracturing” are expected to be 158.55 tons of methane, 23.13 tons of VOC, and 1.68 tons of HAP per event (TSD at 4-7). Table 4-2 also reports emissions estimates for the same pollutants for “natural gas well recompletion with hydraulic fracturing.” Notably, EPA presents information that the emissions estimates for recompletions *are exactly the same* as the estimates for completions; however, they are lower unless a new zone is fractured.

Even more fundamentally, EPA's general provisions require emissions to be measured based on the “representative performance of the facility,” with all relevant operating parameters held constant. In other words, an apples-to-apples comparison must be made of pre- and post-change emission rates. This raises two critical questions EPA has not addressed. First, why are emissions from completions relevant to the emissions analysis when it is clear that emissions from completions are not representative of the performance of the facility? As explained above, for the vast majority of its operating lifetime, the only emissions from a well come from fugitive leaks. The initial completion and periodic recompletions certainly are not representative of normal operations and, therefore, emission rates during these periods should not be used to characterize emissions from the wells.

Second, even if emissions from completions and recompletions are relevant to the NSPS modification analysis, an “apples-to-apples” analysis should be done – *i.e.*, the emission rate during a recompletion should be compared to the emission rate during the initial completion to determine whether the recompletion results in an increase in emission rate. As shown above, because EPA has determined that emissions from recompletions are the same as

emissions from completions, there can be no emissions increase attributed to recompletions. EPA's failure to investigate and explain its departure from these key aspects of the §60.14 definition of "modification" render the proposal arbitrary and violate EPA's obligations under § 307(d)(3)(C).

5.6.3. Leak Detection and Repair (LDAR).

LDAR process units often use the concept of "capital expenditure" to prevent the addition of a few minor components from triggering modification. API believes that EPA needs to clarify the meaning of "capital expenditure" for the purposes of NSPS Subpart OOOO. A detailed discussion of "capital expenditure" can be found in Section 19.4.4.

6. DEFINITIONS [NSPS OOOO]

Confusion has occurred in the past when definitions have been used to both describe the meaning of the term for clarity and additionally limit applicability of the regulation. While this is often convenient and efficient in terms of creating regulatory text, it can cause unintended consequences. The definitions suggested below have attempted to keep the definition restricted to the meaning of the term, if that term is used within industry. Some terms are unique to EPA regulations, such as "in VOC service". In these instances, efforts have made to be consistent with other regulations, to reduce confusion.

6.1. Petroleum Product Definitions

The definitions of "crude oil" and "condensate" should not be based on API Gravity; the difference in these two products is in their origin. Physical properties of the products overlap and are not good indicators of product type. Also, natural gas was an undefined term and should be clarified.

Suggested Rule Text:

§60.5430

Condensate. *Condensate* means a ~~hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in §60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate~~ natural gas liquid recovered from associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60 degrees Fahrenheit.
[Definition from Energy Information Administration glossary]

Crude Oil. *Crude oil* means ~~crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.~~ a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of non-hydrocarbons produced with the oil.
[Definition from Energy Information Administration glossary]

Natural Gas. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. LNG is not considered natural gas, since impurities such as VOCs and HAPs have been removed.

[Basis of definition is NSPS Subpart Da]

6.2. Low VOC Streams

The definitions below should be added or modified as discussed in Section 5.1.2. The "In VOC service" definition is needed, even though it is in the definitions section of NSPS Subpart VVa, because that section of NSPS Subpart VVa is not referenced from Subpart OOOO.

Suggested Rule Text:

§60.5430

In VOC Service. In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

[Copied from NSPS Subpart VVa]

In Wet Gas Service. In wet gas service means that a compressor or piece of equipment contains or contacts ~~wet gas. the field gas before the extraction step at a gas processing plant process unit.~~

Wet Gas. Wet gas means field gas before the extraction step at a gas processing plant process unit that is >X% VOC by weight. Wet gas does not include gas streams that are >50% by weight inert gases (nitrogen or carbon dioxide).

[API recommends X be equal to or greater than 5; see Section 5.1.2]

6.3. Natural Gas Processing Plant

The term "natural gas processing plant" is important to the Equipment Leaks, Acid Gas Recovery, and Pneumatic Controllers Sections. The definition of "natural gas processing plant" should be revised to add "forced" before extraction to clarify which extraction processes are included. See Section 19.4.1 for additional details.

Suggested Rule Text:

§60.5430

Forced Extraction. *Forced extraction of natural gas liquids* means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids or fuel treatment skids.

[based on EPA's proposed definition in *Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule* (76 FR 56050)]

Natural Gas Processing Plant. *Natural gas processing plant (gas plant)* means any processing site engaged in the forced extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

6.4. Modification

EPA should not redefine the term "modification" in Subpart OOOO. The definition of modification in §60.14 of NSPS General Provisions should apply to Subpart OOOO.

It is unnecessary and confusing to include increases in emissions of both VOCs and natural gas in the proposed definition of modification. On 76 FR 52756, EPA states "this proposed rule does not include standards for regulating the GHG emissions." Including natural gas in the definition of modification, without defining it as requested in Section 4.1, will result in regulation of natural gas streams that have little or no VOCs, such as coal bed methane.

As discussed in Section 5.6, EPA should rely on the Part 60 General Provisions for defining modification. However, if EPA chooses to define modification in this subpart, the references to natural gas and recompletions should be removed.

Suggested Rule Text:

§60.5430

Preferred Option:

~~*Modification* means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC ~~or natural gas~~ emitted into the atmosphere by that

facility or which results in the emission of VOC ~~or natural gas~~ into the atmosphere not previously emitted. ~~For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

6.5. Orphaned Definitions

EPA has defined the terms “pneumatic pump”, “plunger lift system”, “reduced emissions completions”, and “reduced emissions recompletion”. None of these terms are used anywhere in the proposed rule. These definitions should be eliminated.

7. COMPLIANCE DATE

The compliance date of the final rules should be delayed because of the following:

7.1. Congressional Review Act

The Congressional Review Act states that a major rule shall become effective 60 days after publication in the Federal Register (see 5 USC 801(a)(3)(A)(i); unless other processes take longer). 5 USC 804(2)(A) states that a major rule is one that has “an annual effect on the economy of \$100,000,000 or more”. EPA states that “this action is an “economically significant regulatory action” because it is likely to have an annual effect on the economy of \$100 million or more (see 76 FR 52794). Thus, the compliance dates of the final rule need to be extended to at least the effective date (60 days after the publication in the Federal Register) to comply with the Congressional Review Act.

7.2. NSPS Effective Date for Completions

42 USC 7411(a)(2) defines new sources as those commencing construction after the proposal date of the performance standard. Currently, the proposed rule triggers compliance on the date of publication of the final rule in the Federal Register. However, an unintended consequence of defining temporary/construction/maintenance activities as affected facilities (see Section 2.4) is that flowback immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore commencing after August 23, 2011 will be defined as new affected facilities, but may be completed before the effective date of the rule. Some regulatory text makes it appear that compliance activities must be completed before the effective date of the rule (i.e., the control requirements of §60.5375 and the notification and recordkeeping requirement of §60.5420(a)(2) and (b)(2) respectively). The rule, of course, cannot impose requirements prior to its effective date. Moreover, it is not possible to impose, upon the effective date of the rule, control measures on activities that have been completed prior to the effective date of the rule.

This retroactive compliance was stated to not be intended by EPA personnel in conference calls and meetings. This intent needs to be made clear in the final rule text. Please see Section 15.5 of the completion section for more details.

7.3. Manufacturer Compliance

The compliance requirements for certain affected facilities (i.e., pneumatic controllers and vapor combustors for controlling storage vessels) are a part of the equipment design that is controlled by

the equipment manufacturer, not the owner/operator. It is difficult for the owner/operator to be assured that he is meeting the requirements of the regulation with the equipment he purchases and installs, unless EPA allows sufficient time for the manufacturer to review the equipment design and label it as complying with the regulatory requirements of this rule.

For example, there are currently few if any manufacturer "guarantees" that continuous bleed pneumatic controllers are "low bleed" as required by proposed §60.5410(d)(3). Additionally, there are few if any continuous bleed pneumatic controllers that are even capable of a bleed rate of less than six scfh under all operating conditions. Variability in operating conditions, such as increases in instrument gas supply pressure, complicates the ability of a manufacturer to guarantee continuous bleed pneumatic controller performance.

NSPS Subpart JJJJ recognized that the manufacturers needed time to design, certify and manufacture equipment, and thus required compliance only for new sources manufactured after given manufacture dates when that equipment could reasonably be available from the manufacturer in quantities to meet the demand.

The same type of allowance provided for in NSPS JJJJ is needed in Subpart OOOO. Thus, while API believes a design verification is more appropriate for pneumatic controllers than a guarantee, we recommend that any equipment design guarantee required for pneumatic controller manufacturers be delayed by two years from the effective date of the rule. For additional discussion of the "guarantee" issue for pneumatics, please refer to Section 17.10.

A similar scenario exists for the option to have the performance test of a control device conducted by the manufacturer. The requirements in NSPS OOOO for storage tank control devices cite the performance test requirements specified in §63.772(e) of NESHAP HH, which include a provision for the performance test to be conducted by the manufacturer as specified in §63.772(h). It will obviously require considerable lead time, however, before such "manufacturer certified" control devices are readily available. We request that the effective date of the storage tank requirements under NSPS OOOO be delayed for 3 years to allow time for the specified control devices to become available.

7.4. Availability of Equipment for Reduced Emissions Completions

The equipment required for Reduced Emission Completions (REC) is not "off the shelf" equipment, but is typically custom built by the owner/operator or service company to meet the anticipated reservoir properties. Additionally, service companies would have to hire and train sufficient personnel to operate the REC equipment to meet the regulatory requirements. EPA should specify a compliance period for implementing the REC requirements that realistically accounts for the limitations on availability of equipment and trained personnel needed for widespread use of REC. Please see Section 15.4 for more detailed information, and for specific recommendations on revisions to the regulatory language. Such a compliance period is well within EPA's authority and, under the circumstances, the REC requirement cannot be justified without it.

By defining each new well as an affected facility, the proposal would cause the requirement to implement RECs to become effective industry-wide upon the effective date of the final rule. As described in Section 15.4, this means that 1,300 sets of equipment would be needed to accommodate

without unreasonable delay the expected number of affected completions. Only 300 sets of equipment currently exist in the industry, which is far short of what would be needed under the proposed rule. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. As a result, as proposed, the REC requirement simply cannot be implemented upon the effective date of the final rule without causing widespread delays in new well development and imposing the substantial business interruption costs associated with such delays.

This means that the proposed requirement to implement RECs immediately upon the effective date of the final rule does not constitute "the best system for emission reduction" (BSER) for three independent reasons. First, § 111(a)(1) requires that BSER must be "achievable." This requirement is not satisfied when the selected control measures (in this case RECs) are not available to a significant portion of affected facilities. Second, § 111(a)(1) requires that BSER must have been "adequately demonstrated." Implicit in this obligation is that the given control measure not only has been shown to be effective in controlling emissions from the given affected facility, but also that it is sufficiently available that it can be obtained and applied by all affected facilities that trigger the control requirement. In this respect, the REC requirement has not been adequately demonstrated. Third, EPA must demonstrate that BSER is cost effective. EPA has failed to account for the costs of delay in obtaining REC equipment, which renders invalid its determination that RECs constitute BSER.

EPA could easily rectify this problem by bifurcating its BSER determination for well completions such that: (1) BSER is no additional control for a period of two years after the effective date of the final rule; and (2) REC constitutes BSER for well completions beginning two years after the effective date of the final rule. Such an approach would require EPA to adopt a "future effective" BSER determination for well completions. EPA has definitively determined that it has such authority under § 111.

Specifically, the so-called "Clean Air Mercury Rule" ("CAMR") was a § 111 standard that implemented mercury control requirements for power plants in two phases. In adopting this rule, EPA provided a detailed explanation as to why it was authorized under the law to do so:

In *Portland Cement Association v. EPA* (486 F.2d 375) (DC Cir. 1973), the Court rejected the argument that the words "adequately demonstrated" in CAA section 111 meant that the relevant technology already must be in existence and that plants now in existence be able to presently meet the proposed standards. Rather, the CAA's requirement that the degree of emission limitation be "adequately demonstrated" means that a plant now in existence must be able to meet the presently-effective standards for existing units, but that insofar as new plants and future requirements are concerned, section 111 authorizes EPA to "look toward what may fairly be projected for the regulated future, rather than the state-of-the-art at present." The court said:

The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry. 478 F.2d at 629. As there, the question of availability is partially dependent on "lead time," the time in which the technology will have to be available. Since the standards here put into effect will control new plants immediately, as opposed to one or two

years in the future, the latitude of projection is correspondingly narrowed. If actual tests are not relied on, but instead a prediction is made, "its validity as applied to this case rests on the reliability of [the] prediction and the nature of [the] assumptions." (citation omitted).

See also *Lignite Energy Council v. EPA*, 198 F.3d 930 (DC Cir. 1999) (section 111 "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present") (quoting *Portland Cement*). These cases address CAA section 111(b) standards for new sources, where achievement of the standards is mandated on a short-term basis....The cases make clear that while a determination about a technology or performance standard's achievability may not be based on "mere speculation or conjecture," a technology or standard that may not necessarily be considered "adequately demonstrated" at present nonetheless can be considered "adequately demonstrated" for a compliance date in the future.

While CAMR was vacated by the D.C. Circuit, the court did not address the CAMR future effective BSER determinations and the court's decision to overturn the rule was not grounded in any concern about these determinations. Thus, EPA's conclusion that it is authorized to make future effective BSER determinations still stands.

Given that EPA has definitively determined that it has authority to under § 111 to establish such future effective BSER determinations, and in light of the record evidence indicating that sufficient REC equipment will not be available upon the effective date of the final rule but can become available within two years after the effective date of the rule, EPA has ample legal and factual justification to defer the REC requirement.

7.5. Adding Control to Existing Tanks

If an exempt affected storage vessel exceeds the exemption level at some point in the future, the regulation should allow for some period of time after exceeding an exemption level to comply with the control requirements. For example, the additional throughput from bringing on a new well to an affected storage vessel may trigger control requirements for a previously exempt tank. Since the throughput exemption is an annual amount, sources might not know if the exemption was lost until the end of the year. An existing affected storage tank that triggers the control requirements after the effective date of the final rule would then have to meet the control requirements as soon as it no longer meets the exemption, which might not be apparent into; the end of the year. In order to avoid any compliance concerns, an owner/operator may be forced to reduce production to ensure the storage vessel continues to meet the exemption or shutdown production until the storage vessel is modified to meet the control requirements.

API therefore recommends EPA include in the final rule a provision to allow time after exceeding an exemption level to implement controls. The time should be sufficient for designing, ordering, and installing the equipment necessary to meet the control requirements. Although this type of scenario would not be a modification, EPA could use a similar approach used in §60.14(g) and allow 180 days to come into compliance with all the applicable standards. For reference, the language used in §60.14(g):

Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

Furthermore, we recommend proposed §60.5395(a)(1) and (2) be clarified to state that the exemptions are based on calendar year annual averages. A calendar year basis is most appropriate because it avoids surprises from fluctuating operations and minimizes burdens by matching the time period used for emission estimating and other reporting, where tank throughput data is needed.

Suggested Rule Text:

§60.5370

- (a) You must be in compliance with the standards of this subpart no later than **60 days after** the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later **except for the provisions of §60.5370(a)(1)-(5) below:**
- (1) Compliance with §60.5375 is required beginning [two years after the effective date]. From the [effective date] until [two years after the effective date] comply only with §60.5375(a)(1)(ii).
 - (2) Compliance with §60.5390 is required beginning [one year after the effective date], except for the following
 - (i) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (ii) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (iii) Compliance with §60.5420(c)(4)(iii) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (3) Compliance with §60.5395 is required beginning [three years after the effective date].
 - (4) If your new or reconstructed process unit equipment is subject to §§60.5400, 60.5401, and 60.5402, you must be in compliance no later than 180 days after startup.
 - (5) If you become subject to §§60.5400, 60.5401 and 60.5402 due to modification under provisions of §60.14, the group of all equipment within that process unit must be in compliance with the work practice provisions of §§60.5400, 60.5401, and 60.5402 of this subpart no later than a year after the modification. If any equipment upgrade is required in order to achieve initial compliance (e.g., pump seal and pressure relief device upgrades), you must complete all equipment upgrades and comply with §§60.5400, 60.5401 and 60.5402 for that equipment no later than three years after the modification.

7.6. Compliance Dates for NESHAP Subparts HH and HHH

NESHAP Subparts HH and HHH have been revised. EPA has made allowances for new compliance dates for specific types of equipment that have new or revised compliance requirements because of the proposed revisions [§63.760(f)(7)-(10)]. However, other proposed revisions do not appear to have new compliance dates associated. This practice may have the unintended consequence that the

new text may be interpreted as having retroactive compliance requirements. The following list illustrates some of these unintended consequences.

7.6.1. Major Source Definition Changes

Changing Subpart HH to include all tanks in lieu of tanks “with the potential of flashing emissions” in the affected source will cause some facilities to become major sources. However, EPA has provided no beginning effective date for this change, has not provided any provisions for existing facilities to come into compliance with the newly applicable regulations, or even adequately made the regulated public aware that they need to recalculate their applicability to major per the new Subpart HH definitions and obtain compliance with major source requirements if necessary. API recommends that, consistent with §63.6(c)(5) of the Part 63 General Provisions, EPA allow such facilities 3 years to obtain compliance with these new requirements. Regulatory text will need to be added to §63.760(f) to add the new compliance time. Regulatory text revisions should also be added in the definitions of “associated equipment” and “major source” to indicate the effective dates of the changes take effect.

LDAR Requirements.

EPA revised the requirements for LDAR monitoring to a leak rate definition of 500 ppm within the text of §63.769(c). In doing so, it is not apparent that regulated facilities have not always been required to meet the 500 ppm leak rate definition. API believes (see Section 19 for further discussion) that EPA must clarify that compliance with the 500 ppm leak rate definition only applies after the compliance date established in this rulemaking.

EPA should allow new or reconstructed facilities 180 days and existing facilities at least a year to implement work practice requirements and 3 years to come into compliance with new requirements requiring investment after the effective date of this rule

7.6.2. SSM Events

The revisions around the SSM events have no start date associated. Without this, agency personnel without the knowledge of the regulatory history could try to enforce the provisions around affirmative defense and SSM events retroactively. If EPA continues with these revisions (see Sections above), regulatory text should be added/revised to make a clear distinction of when these provisions become effective.

7.6.3. Performance Testing

Many of the revisions to the control equipment requirements of §63.771 apply to equipment that is currently required. No provisions have been made to indicate when these requirements were changed. EPA should revise the proposed rule so that the new performance testing requirements apply only to control equipment installed for the purpose of complying with this subpart after the effective date of this rule.

8. NSPS COMPLIANCE REQUIREMENTS (NOTIFICATION, RECORDKEEPING, REPORTING, MONITORING, PERFORMANCE TESTING, AND THIRD PARTY VERIFICATION).

In most instances, EPA has followed the precedent of previous NSPS regulations for the proposed rule. However, this proposed rule is unprecedented in the number of affected facilities it will regulate, the average sizes of the sites, and the remote, dispersed and unmanned nature of these sites. The proposed NSPS imposes considerable administrative burden associated with compliance (permitting, recordkeeping, reporting obligations) including first-time regulation (e.g., triggering minor source NSR "facility" permitting in several states) for minor individual pneumatic controllers.

These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. The proposed NSPS results in unnecessary burden for notifications, monitoring, recordkeeping and reporting without a commensurate benefit.

Implementation concerns, potential rule conflicts (e.g. §60.5 determination of construction or modification, §60.14 modification, §60.15 reconstruction), and issues resulting from selective adoption of the General Provisions (40 CFR 60, Subpart A; see Table 3 of Subpart OOOO) is problematic for the proposed rule and is unnecessarily complicated. API suggests that NSPS Subpart OOOO, Table 3 sections designate that §60.7 – Notifications and Recordkeeping and §60.8 Performance Testing do not apply and that the specific requirements are defined within this final rule.

8.1. Excessive Cost Burden

Defining a very small individual piece of equipment (i.e. component-level) as an affected facility is illogical and defies the common sense definition of "facility". Unnecessary burden for notifications, permitting, reporting and recordkeeping would be introduced without commensurate benefit. For example, regulation by an NSPS has implications under state air quality regulations – e.g., permitting may be mandated. Although Subpart OOOO includes a provision that precludes Title V permitting, many states require permitting of NSPS affected sources. This would incur significant burden from reporting and recordkeeping, and new permitting requirements would result in some states. While EPA may attempt to preclude state rules implementation burdens and costs from consideration, the rule costs incurred from state permit actions are significant, add compliance risk though unnecessary rule complexity, can be estimated, and should not be summarily dismissed, disregarded, or ignored.

In the preamble, EPA "estimate(s) that over 20,000 completions and recompletions annually will be subject to the proposed requirements [76 FR 52747]. These completions and recompletions likely correspond to approximately 100,000 new pneumatic devices, thousands of new storage vessels, and associated new compressors. Each of these will be a new "facility" and the totals provide an indication of the magnitude of the annual industry cost burden for notification, recordkeeping, reporting (initial and on-going annual), permitting, and management activities.

Table 8-1 provides a summary of the myriad of equipment and facility-specific notification, recordkeeping, and reporting requirements and burdens imposed by the proposed rule. This table illustrates the magnitude of effort to track and comply with these requirements and also highlights

potential cost impacts that have not been properly categorized or considered in the cost-benefit portion of the proposed rule.

Table 8-1. Summary of Recordkeeping and Reporting Requirements of Subpart OOOO^B

| Proposed Regulatory Provision | Requirement | Applies to: | Due Date: | Start Date: |
|--------------------------------------|---|---|--|--------------------|
| 60.5420(a)(1) | Submit written notification required in 60.7(a)(1) | Construction of all affected facilities except pneumatic controllers | 30 days after commencement of construction or reconstruction | 8/23/11 |
| | Submit written notification required in 60.7(a)(3) | Startup of all affected facilities except pneumatic controllers | 15 days after initial startup | 8/23/11 |
| | Submit written notification required by 60.7(a)(4) | Physical or operational change that increase emission rates to any affected facility except pneumatic controllers | 60 days prior to the commencement of change or as soon as practicable | 8/23/11 |
| 60.5410(a)(1); 60.5420(a)(2) | Advance notification of well completion operation; commencement date of well completion; lat/long of well. | Gas wellhead completions and recompletions | 30 days <u>prior</u> to commencement of well completion | 8/23/11 |
| 60.5410(a)(2) | Maintain a daily log for completion including compliance with REC and deviations per 60.5375(b) | Gas wellhead completions and recompletions | Daily during completion operations | 8/23/11 |
| 60.5410(a)(3); 60.5420(b)(1)-(2) | Initial annual report for wellhead affected facility (company name and address; list of affected facilities; reporting period; list of well completions; deviations; completion logs) | Gas wellhead affected facilities | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(1) | Annual report (company name and address; list of affected facilities; reporting period) | All affected facilities | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5410(c)(1) | Continuously monitor number of hours of operation | Well completions | Annual reporting | 8/23/11 |

^B Start date associated with each requirement is August 23, 2011 except for compressor rod packing hour tracking under 60.5420(c)(3)(i)-(ii) that starts either the date of FR final rule or previous rod packing replacement, whichever is later.

| Proposed Regulatory Provision | Requirement | Applies to: | Due Date: | Start Date: |
|-------------------------------|---|--|--|-------------|
| 60.5420(b)(2) | For gas wellhead affected facilities, list of well completions, deviations, and completion logs | Gas wellhead affected facilities | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(3) | For centrifugal compressors, documentation that each one is equipped w/ dry seals | Centrifugal compressors | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(4) | For reciprocating compressors, documentation that rod packing is replaced at least every 24,000 hours, cumulative hours of operation as specified | Reciprocating compressors | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(5) | Date, location and mfr specs; reason for high bleeds; documentation that each controller has 0 NG emissions. | Pneumatic controllers installed at PFs | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| | Date, location, mfr specs, mfr guarantee that bleed rate is <6scf/hr, | Pneumatic controllers not installed at PFs | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(6)(i) | For storage vessels with condensate throughput >1 bbl/d and crude oil >21 bbl/d, records required by 63.774(b)(2)-(8) | Storage vessels | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(b)(6)(ii) | For storage vessels with condensate throughput <1 bbl/d and crude oil <21 bbl/d, documentation of throughput | Storage vessels | 1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter | 8/23/11 |
| 60.5420(c) | [60.7(f)] Maintain records of continuous monitoring tests, calibrations, maintenance, etc. | All affected facilities | Maintain records | 8/23/11 |
| 60.5420(c)(1)(i) | Records of each completion operation during the reporting period | Gas wellheads | Maintain records | 8/23/11 |
| 60.5420(c)(1)(ii) | Records of any deviations in completion operation requirements | Gas wellheads | Maintain records | 8/23/11 |
| 60.5420(c)(1)(iii) | Logs for completion operations | Gas wellheads | Maintain records | 8/23/11 |

| Proposed Regulatory Provision | Requirement | Applies to: | Due Date: | Start Date: |
|-------------------------------|--|---------------------------|------------------|---|
| 60.5420(c)(1)(iii)(A) | Location of well, duration of flowback, recovery to sales line, combustion, venting; and reasons for venting | Non-delineation wells | Maintain records | 8/23/11 |
| 60.5420(c)(1)(iii)(B) | For delineation wells, all of the above except for duration of recovery to sales line + record the distance, in miles, to nearest gathering line | Delineation wells | Maintain records | 8/23/11 |
| 60.5420(c)(2) | Maintain records of type of seal system installed | Centrifugal compressors | Maintain records | 8/23/11 |
| 60.5420(c)(3)(i)-(ii) | Maintain records of (i) cumulative hours of operations as specified and (ii) date and time of rod packing replacement | Reciprocating compressors | Maintain records | Date of FR final rule or previous rod packing replacement, whichever is later |
| 60.5420(c)(4)(i) | Date, location, and mfr specs for each installed pneumatic controller | All pneumatics | Maintain records | 8/23/11 |
| 60.5420(c)(4)(ii) | Use of high bleed pneumatic is predicated and why | High bleed pneumatics | Maintain records | 8/23/11 |
| 60.5420(c)(4)(iii) | Mfr's guarantee that emissions are <6scf/hr | Pneumatics not at PFs | Maintain records | 8/23/11 |
| 60.5420(c)(4)(iv) | Documentation of use of only instrument air controllers | Pneumatics at PFs | Maintain records | 8/23/11 |
| 60.5420(c)(5)(i) | For storage vessels with condensate throughput >1 bbl/d and crude oil >21 bbl/d, records required by 63.774(b)(2)-(8) | Storage vessels | Maintain records | 8/23/11 |
| 60.5420(c)(5)(ii) | For storage vessels with condensate throughput <1 bbl/d and crude oil <21 bbl/d, documentation of throughput | Storage vessels | Maintain records | 8/23/11 |
| 60.5421(a) | Comply with requirements of 60.486a | NG Processing plants | Maintain records | 8/23/11 |
| 60.5421(a)(1) | When leak is detected, mark with visible identification until repaired | Pressure relief devices | Maintain records | 8/23/11 |

| Proposed Regulatory Provision | Requirement | Applies to: | Due Date: | Start Date: |
|-------------------------------|--|-------------------------|---|-------------|
| 60.5421(a)(2)(i)-(x) | Record leaks in log including instrument and operator id, date of leak and attempts to repair, repair methods, delay of repair information, signature of o/o who decided repair could not be made w/o process shutdown, expected date of repair, lift of id numbers for equipment designated for no detectable emissions | Pressure relief devices | Maintain records for 2 years | 8/23/11 |
| 60.5422(a) | [Vva] 60.487a(a)-(c)(2)(i)-(iv), (vii) - LDAR requirements for valves, pumps and compressors | Equipment components | 6 mos after startup; semi-annually thereafter | 8/23/11 |
| 60.5422(b) | Number of pressure relief devices in gas/vapor service subject to quarterly monitoring requirements | Pressure relief devices | 6 mos after startup; semi-annually thereafter | 8/23/11 |
| 60.5422(c) | Number of pressure relief devices in gas/vapor service for which leaks were detected and number of devices for which leaks were not repaired | Pressure relief devices | 6 mos after startup; semi-annually thereafter | 8/23/11 |
| 60.5423(a) | Retain records of calculations and measurements of 60.8 performance test | Sweetening units | Retain records for 2 years | 8/23/11 |
| 60.5423(b) | Excess emissions reports for any 24 hour period of excess sulfur emissions | Sweetening units | Semi-annually | 8/23/11 |
| 60.5423(c) | Certify exemption analysis that facility's design capacity is <2 LT/D of H ₂ S | Sweetening units | Retain records for life of facility | 8/23/11 |
| 60.5423(d) | Alternative compliance demonstration for sulfur removal efficiency for facilities with a design capacity <150 LT/D of H ₂ S | Sweetening units | Retain records for life of facility | 8/23/11 |

8.2. Stated Goal Is Inconsistent with Proposed Rule Text and Requirements

EPA's intent to simplify, streamline, and minimize the burden associated with notification, recordkeeping, and reporting has not been translated into rule text that accomplishes the stated goal and objectives. EPA has significantly underestimated the magnitude of the annual industry cost burden for notification, recordkeeping, reporting (initial and on-going annual), permitting, and management activities. For example the rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility.

Based on EPA's estimate of 20,000 completions/recompletions per year, this would result in 80,000 notifications being filed annually.

EPA states in the preamble that they desire to minimize duplication of notification through incorporating KKK and LLL requirements into OOOO.

“In addition, we are proposing to incorporate the requirements in 40 CFR 60, Subpart KKK and 40 CFR 60, Subpart LLL into the new subpart OOOO so that **all requirements applicable to the new and modified facilities would be in one subpart**. This would **simplify and streamline** compliance efforts on the part of the oil and natural gas industry and **could minimize duplication of notification**, recordkeeping and reporting. [emphasis added]” FR Vol. 76, 52746

EPA also provides additional support for their intention to reduce the burden associated with notification and reporting requirements:

“Given the number of these operations, we believe that **notification and reporting must be streamlined** to the extent possible to **minimize undue burden** on owners and operators, as well as **state, local and tribal agencies**.” [emphasis added]” FR Vol. 76, 52747

While we agree with this goal, the overwhelming administrative burden that would be imposed by the proposed rule falls far short of achieving this outcome.

8.3. Notifications

Affected facilities are so small that all notifications should be eliminated or limited to a single notice coincident with the first annual report. The requirements as proposed could literally lead to daily notifications, as activities change.

Newly added rule administrative costs for notifications and compliance management have *not* been included in cost-effectiveness analyses. These exclusions impose a low bias on compliance costs for *all* emission sources. If EPA elects to retain multiple notification requirements, these obligations need to be streamlined into a single year end summary notice and the cost benefit analyses need to be revised to more accurately reflect actual burdens.

Upset notification in HH and OOOO within 2 days and documentation of affirmative defense is unnecessary and burdensome. As proposed, these notifications would be required for the smallest of emission exceedances with no reportable quantity threshold being set. This is contradictory to other EPA reporting rules such as those under CERCLA and EPCRA where reportable quantities are established for unauthorized releases. Requirements for immediate reporting of unauthorized releases of VOCs should be left to the states as they are best equipped to handle any response that might be required as a result of the release. Immediate reporting to the EPA serves no purpose (see Section 10.2.1 for further details).

8.3.1. Well Completions - Multiple Notification Requirements for Well Completions

The rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility which include:

- Post-marked 30 days after construction [§60.7(a)(1)],
- Post-marked 15 days after initial startup [§60.7(a)(3)],
- Post-marked 60 days or as soon as practicable before the changed is commenced [§60.7(a)(4)], and
- 30 days of the commencement of the well completion operation [§60.5410(a)(1) or §60.5420(a)(2)].

Based on EPA's estimate of 20,000 completions/recompletions per year, this would result in 80,000 notifications being filed annually. The necessary additional staff to manage the notification requirements has not been included in the cost-benefit analysis.

API requests that all the §60.7(a) General Provisions notification requirements be eliminated since they are not appropriate for completions operations. The definitions of both "construction" and "initial start-up" do not apply to the flowback and cleanup portions of the well completions operations. Please see Section 15.7 for further discussion on the completions notifications.

8.4. Recordkeeping

Many of the recordkeeping requirements proposed are ambiguous and need further clarification. API requests the following clarifications to the recordkeeping requirements.

Suggested Rule Text:

§60.5420

- (c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section.
- (1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).
- (i) Records identifying by API well number and date flowback ended, each flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facility ~~well completion operation for each gas wellhead affected facility~~ conducted during the reporting period;
- (ii) Record of deviations and reasons for the deviations in cases where ~~well completion operations with flowback immediately following~~ hydraulic fracturing stimulation at natural gas wellhead facilities onshore were not performed in compliance with the requirements specified in §60.5375.
- (iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. ~~You must maintain the records specified in paragraphs (e)(1)(iii)(A) and (e)(1)(iii)(B) of this section. (A)~~ For each flowback immediately following hydraulic

fracturing stimulation at natural gas wellhead facilities onshore ~~gas wellheads affected facility~~ required to comply with the requirements of §60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion including but not limited to wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, and where combustion is not allowed due to fire hazard, conditions that may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. The duration must be specified in hours of time.

~~(B) For each gas wellhead affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.~~

* * * * *

- (4) For each continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~ affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(~~iv~~iii) of this section.
- (i) Records of the date, and location ~~and manufacturer specifications~~ for each gas-driven pneumatic controller installed.
 - (ii) Records of the determination that the use of high bleed gas-driven pneumatic controllers ~~devices~~ is predicated and the reasons why.
 - ~~(iii) If the pneumatic controller affected facility is not located at a natural gas processing plant, r~~Records of the manufacturer's specifications. For low bleed pneumatic controllers, specifications must verify guarantee that the device is designed such that weak stream ~~natural gas~~ emissions are less than 6 standard cubic feet per hour.
 - ~~(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used.~~
- (5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.
- (i) If required to reduce emissions by complying with ~~§63.766, §60.5395(b)~~, maintain the following records ~~specified in §63.774(b)(2) through (8) of this chapter~~.
 - (A) A copy of the operating plan if using §60.5415(e)(1).
 - (B) A copy of manufacturer certification if using §60.5415(e)(2)
 - (C) A record of the measured values of the parameters monitored.
 - (ii) Records of the determination of the throughput, pressure, and emissions using the methods in §60.5395(c) to demonstrate emissions are below 12 TPY. ~~that the annual average condensate throughput is less than 1 barrel per day per storage vessel and~~

~~crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under §60.5395(a)(1) and (a)(2).~~

8.5. Reporting

Proposed compliance assurance approaches, including electronic reporting, should be revised or excluded from the Final Rule.

8.5.1. Annual Report Timing

Annual NSPS Subpart OOOO reports at Title V Permitted facilities should be allowed to be combined and submitted with other Title V reports for the same facility. For non-Title V permitted facilities, the report should be submitted a year and 60 days after final publication of the rule in the federal register to allow for submittal of a single report for multiple facilities versus a year after the anniversary date of the initial startup date.

8.5.2. Exception Reporting

The rule as proposed requires that for every source category you must report all the records gathered. However, it is excessive and burdensome to both industry and the agencies to require reporting of all the records versus just deviations from the rule. Most of the NSPS regulations require only reporting of deviations such as in 40 CFR 60, Subpart J under §60.107(c) or 40 CFR 60, Subpart Kb under §60.115b. Requiring that all the records are reported will result in a great deal of work for industry to prepare the reports and for the agencies to review all the information supplied to find deviations. In order to reduce this unneeded burden on both industry and agencies, API recommends that only deviations be reported in the annual report.

Suggested Rule Text:

§60.5420

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due ~~1 year after the initial startup date for your affected facility or~~ 1 year and 60 days after the date of publication of the final rule in the Federal Register, ~~whichever is later, or with a Title V report the year after~~ publication of the final rule in the Federal Register. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

* * * * *

(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) ~~through and~~ (b)(2)(iii) of this section.

- (i) An identification by API well number and date flowback ended of each flowback immediately following hydraulic fracturing stimulation at natural gas wellhead facilities onshore ~~well completion operation, as defined in §60.5430, for each gas wellhead affected facility~~ conducted during the reporting period;
- (ii) A record of deviations and reasons for the deviations in cases where ~~well completion operations with~~ flowback immediately following hydraulic fracturing stimulation at gas natural wellhead facilities onshore were not performed in compliance with the requirements specified in §60.5375 for each gas well affected facility.
 - ~~(iii) Records specified in §60.5375(b) for each well completion operation that occurred during the reporting period.~~
- (3) For each centrifugal compressor affected facility installed during the reporting period, documentation ~~that if~~ the centrifugal compressor ~~is was not~~ equipped ~~with dry seals as specified in §60.5380(a).~~
- (4) For each reciprocating compressor affected facility, ~~the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.~~
 - ~~(i) The cumulative number of hours of operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.~~
 - ~~(ii) Documentation that if~~ the reciprocating compressor rod packing was due for replacement according to one of the frequencies described in §60.5385(a), but was not replaced as specified ~~before the cumulative number of hours of operation reached 24,000 hours.~~
- (5) For each continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~ affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(~~iv~~iii) of this section.
 - (i) The date, site name, location and quantity of high bleed gas-driven manufacturer specifications for each pneumatic controllers installed.
 - (ii) ~~If applicable, d~~Documentation that the use of high bleed gas-driven pneumatic controllers devices is predicated and the reasons why.
 - (iii) For all low-bleed gas driven controllers installed, a statement certifying that each controller was designed to meet the emissions threshold of less than 6 standard cubic feet per hour. ~~For pneumatic controllers not installed at a natural gas processing plant, the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.~~
 - ~~(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions.~~

- (6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.
- (i) If required to reduce emissions by complying with paragraph §60.5395(a)(1), ~~the records specified in §63.774(b)(2) through (b)(8) of this chapter.~~ the API number of the location of the tank and date of installation.
- (ii) If exempt from §60.5395 in accordance with §60.5395(a), the API number of the location of the exempt tank and date of installation. ~~Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in §60.5395(a)(1) or (a)(2).~~

8.5.3. Electronic Reporting.

8.5.3.1 Electronic or Administrator Reporting Requirements in §63.775(g)

API is opposed to mandatory electronic reporting and supports voluntarily reporting at the operator's discretion. 40 CFR Part 63 Subpart HH, §63.775(g) requires electronic submittal of performance test results to EPA's Central Data Exchange (CDX) after January 1, 2012. API believes electronic reporting should not be mandatory and should only be voluntary. The electronic reporting tool (ERT) is used to electronically create and submit stationary source sampling test plans to regulatory agencies and, after approval, to calculate and submit the test results as an electronic report to the regulatory agency. Paper notification, test plans, and reports may still be required to satisfy individual state requirements. API does not advocate duplicate effort and until state requirements for redundant reporting have been eliminated it is premature to consider mandatory electronic performance test reporting. The added burden for preparing and inputting data into the ERT is cumbersome and the cost has not been adequately addressed.

Additionally, rule language is also unnecessarily vague with respect to test methods that need to be reported to the Electronic Reporting Tool (ERT). Specifically, of the 18 test methods referenced in Subpart HH, only six (6) methods (Methods 1, 2, 3A, 4, 10, and 25A) are compatible with the ERT. API submits that the ERT is still in its infancy and requires additional time to develop the remaining test methods, data elements, and incorporation of alternative emission calculation methodologies that are currently not included in this system. API recommends that the rule language be modified to indicate the following:

- Electronic reporting is voluntary (i.e., not mandatory);
- Test Methods 1, 2, 3A, 4, 10, and 25A are the test methods that can be reported to the ERT voluntarily; and
- Test results are due 90 days after the completion of a test, beginning with tests performed three (3) years after the publication of the final rule.

Reporting under multiple rules for a variety of purposes are likely to result in conflicting data and add a burden on operators to provide detailed emission assumptions and methodologies that are not well suited to rigidly defined data entry fields in electronic database reporting formats. For example, reporting VOC, NMHC, THC, GHGs, and HAP emissions under different programs is likely to result in confusion and misinform the public based on overlapping compounds, test method differences, and emission factor based approaches. Redundant reporting under different rules is unnecessary, burdensome, and not cost effective. For example, many state agencies require an annual emission inventory.

Experience with some existing EPA reporting tools indicate that they do not enhance reporting efficiency and require an inordinate amount of time to enter data, verify data entries, and tailor available data to the prescribed fields. Further, the security measures for data entry involve additional burden through time-consuming responses to multiple security questions for each entry.

Furthermore, based on the timetable associated with the current comment/response cycle for this rule, we do not anticipate that the rule will be finalized by the end of this year. However, §63.775(g) requires electronic submittal of performance test results after January 1, 2012. Given this language, EPA is effectively requesting that the data be submitted prior to the effective date of this rule. API does not believe that this is logical, rational, and strongly advocates a measured review process and an adequate beta test period for any electronic reporting tool, either voluntary or mandated.

EPA should also consider confidential business information or proprietary data limitations as this reporting requirement is reviewed and the cost burden is reassessed. EPA should examine the likely business impact from the disclosure of required data elements before they are reported and potentially subject to public availability. Any electronic reporting would likely burden owners/operators.

8.5.3.2 Requested Comments on Electronic Reporting for NSPS Subpart OOOO (V.D.3.).

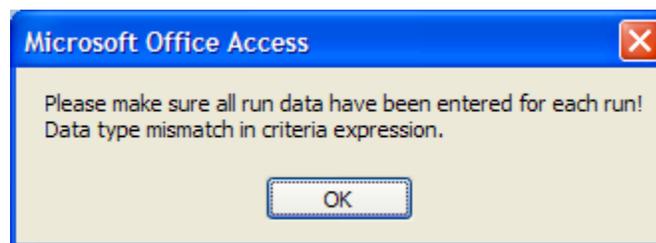
EPA has requested comment on electronic reporting. API believes electronic reporting should not be mandatory and supports only voluntary electronic reporting at the operator's. Electronic reporting is already required for many of these sources in the Mandatory Greenhouse Gas Reporting Rule (40 CFR, Part 98). Reporting conventions associated with VOC, NMHC, THC, and GHG emissions will result in conflicted data and add a burden on operators to provide detailed emission assumptions. Redundant reporting under different rules is unnecessary, burdensome, and not cost effective. If retained, the cost for duplicative reporting requirements should be addressed and justified. Any electronic reporting would burden owners/operators. Furthermore, experience with some existing EPA reporting tools indicate that they do not enhance reporting efficiency. Delays in the final version of the Electronic Greenhouse Gas Reporting Tool (e-GGRT) for the GHG MRR and the e-GGRT system for Subpart W show the difficulty in creating a

tool that is useful to both the EPA and industry. The experience with e-GGRT indicates that a more efficient system needs to be developed before requiring usage by industry. Another difficulty associated with electronic reporting is the reporting of new and/or alternative test methods that are slow to be incorporated into the system. Small companies could also be disproportionately burdened as they typically lack personnel specifically dedicated to environmental management issues.

8.5.4. EPA Should Not Require Use of the Electronic Reporting Tool (ERT)

While EPA continues to make improvements to the Electronic Report Tool (ERT), it still needs much more refinement before it is a useable tool by industry. Outlined below are some of the ongoing concerns with the ERT's ability to allow submittal of accurate, consistent and complete test data. EPA should resolve these issues before requiring its use in a regulatory program.

- a. The range of stack test methods which can be used in the ERT is narrow. Not only does the ERT lack the capability to accommodate all of EPA's test methods, there is only limited provision for use of other state, local or consensus standard methods. In the latest version (v4) EPA incorporated a "custom method" option; however, this is limited to methods which are analogous to EPA Method 5 (using extractive sampling and displacement gas volume meters) or instrumental methods like EPA 3A, 6C, 7E or 10. This feature allows one to enter a custom pollutant, but there is no provision to change the calculations or configure the data inputs to reflect different types of test instrumentation (e.g., for methods that use a rotameter or venturi and time to determine sample volume), different standard temperatures, blank corrections, etc.
- b. ERT has serious functional flaws that can cause calculation, printing and other errors. Error handling is very poor; error messages are not very helpful (e.g., see below), or the program may crash.



- c. Handling of detection limits is not integrated in a manner that would assure appropriate data calculations and data flagging in the test report. Entry of detection limits in comment fields and manual formatting of test data (e.g. [<3.2] for a result below detection limits at a detection limit of 3.2) almost assures that data will not be handled correctly or consistently.
- d. Analytical lab data can only be entered as a single net result for each sample fraction, rather than as individual values for each measured value. This requires testers or laboratories to make an intermediate calculation prior to data entry. For example, gravimetric results generally consist of two weights (tare and final) for each sample

fraction. Each weighing is the result of several replicate weights until the difference between two sequential weighings is less than a certain value (0.5 mg for Method 5). Method 5, for example, does not specify whether the first weight, the second weight or the average of the two weights should be reported, and different testers and labs use different conventions. Thus, there can be a total potential error of as much as 2 mg in the net weight of a Method 5 sample fraction, depending on convention. This can represent a large error compared to sample weights for many modern sources leading to inconsistent results and poor data comparability. As another example, many instances of incorrect intermediate calculations were found in the ICI Boiler and EGU ICRs. For example, many testers failed to correctly handle detection limits when summing values for the five analytical fractions comprising total mercury in EPA Method 29 measurements when some fractions were detected and some undetected. This introduces serious potential data quality issues for mercury measurements by this method. EPA states that one of the benefits of ERT is to improve consistency of results; however, this oversight allows one of the most significant sources of inconsistency to persist.

- e. Some state and local test methods use a different standard temperature than EPA's standard temperature of 20 C (68 F). Standard temperature is hard coded into ERT with no provision for the user to change it, neither in any of the current method templates nor in the custom method option. This limits the use of ERT for local reporting requirements, requiring the tester to prepare separate test reports for WebFIRE and for local use.
- f. Some state and local agencies have different protocols for handling undetected results (e.g., substitution of ½ detection limits or zero for undetected results). As noted above, ERT does not correctly flag undetected results in the test report nor allow for alternative detection limit protocols. Testers would need to prepare separate test reports for local use and WebFIRE use.
- g. There are numerous instances of ambiguous wording and nomenclature in ERT. For example, in Test Plan field 7b, a column is headed "Corrected analyte" and another is "Corrected %". If the intent is to list the diluent indicator (e.g., O₂ or CO₂) and diluent reference concentration, these should say so and the calculations should be handled accordingly.
- h. ERT does not allow for all common diluent corrections. O₂ diluent corrections embedded in ERT only work if the diluent is air. If a combustion source uses O₂ or nitrogen enrichment such that O₂ concentration in the diluent is not 20.9% by volume, the diluent-corrected test result would be incorrect.
- i. The laboratory(ies) performing sample analysis is not identified by name in the test report, unless the tester chooses to do so in a comment field. All organizations involved in the test program should be identified in the report.
- j. There doesn't appear to be a way to handle DGM (dry gas meter) volumes during non-sampling periods, e.g. leak checks.

- k. ERT can handle only three test runs. For some processes it is necessary to make more than three test runs to obtain representative emissions factors.
- l. The number format in the test report is not configurable so that values are reported with an appropriate number of significant digits. This generally gives a highly misleading impression of results precision. For example, the Emissions Summary page uses scientific notation with 3 significant figures (2 decimal places), while the Stack Data Results Summary and Stack Data Results Detail pages use decimal format. In one example, the mass of water gained in the impingers is reported to 11 significant figures (8 decimal places) and all average results are reported to three decimal places, ranging from 2 to 9 significant figures depending on the parameters. The appropriate number of significant figures will vary, depending on specific details of a given test and parameters.
- m. Some document control errors persist e.g. page count for one example test report was incorrect, resulting in last page numbered as "12 of 13".
- n. Data flags and comments entered on the lab data tab (e.g., ADL, BDL, DLL) are not carried forward to the results summary or detailed results report pages, presenting a misleading impression of high data quality.
- o. ERT does not include printing of all primary input data (e.g., point to point run data, lab data with flags and comments, impinger weights, etc.) among the report options. This is a key shortcoming for quality control review and auditing of test reports.
- p. Some formatting issues remain (e.g., in one example several pages of the printed test report had headers but no data).

8.6. Performance Test Methods and Compliance Monitoring Requirements

8.6.1. General

- a. The use of extensive cross referencing to a myriad of other rules and test methodologies renders the requirements in Subpart HH nearly impossible to follow, confusing to the extent that it unnecessarily adds to the compliance burden, and likely to lead to errors and misunderstanding.
- b. The test protocols, requirements, and methodologies specified in the rule are unnecessarily complex, likely not technically achievable in certain instances, and unnecessarily costly.
- c. The requirements for continuous monitoring of parameters to demonstrate continuous compliance are similarly unnecessarily complex, likely not technically achievable in certain instances, and unnecessarily costly.
- d. EPA should redraft the performance testing and continuous compliance monitoring requirements of the rule to:

- i. simplify requirements,
- ii. include only requirements appropriate for the large number and type of dispersed small sources which would be subject to the rule,
- iii. reduce the extensive cross referencing in the testing and monitoring requirements to reduce the confusing nature of the proposed rule and lessen the chance that the confusing construction of the rule will inadvertently lead to non-compliance incidents through misunderstanding, and
- iv. reduce the unnecessary economic burden.

8.6.2. Applicable to Subpart OOOO and Subpart HH/HHH

Requirements for using an enclosed combustion device for HAP or VOC control under NSPS Subpart OOOO or NESHAP Subpart HH or HHH are specified in §63.771.

- a. Paragraph 63.771(d)(1)(i) specifies that an enclosed combustion device must meet one of the following performance criteria:
 - (A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §63.772(e); or
 - (B) Reduces the concentration of either TOC or total HAP in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of §63.772(e); or
 - (C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §63.772(e), operates at a minimum temperature of 760 degrees C.
- b. Operational conditions in the oil and natural gas production sector are very different from those experienced at refineries or chemical plants. Conditions of intermittent, variable and turbulent flow and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API requests:
 - i. The requirement in §63.771(d)(1)(i)(A) should be modified to require reduction of either TOC or HAP emissions by 95% on a volumetric concentration basis using a “carbon balance” methodology for analysis of the exhaust stack effluent from an “enclosed combustion device” being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO₂ and O₂, and 10 for CO should be specified for testing of the stack effluent gas. The CO₂ measured

using Method 3A should be adjusted downward by the latest published atmospheric CO₂ concentration, as reported from the Mauna Loa monitoring site by NOAA’s Earth System Research Laboratory, multiplied by the ratio of O₂ measured in the stack effluent as compared to the ambient O₂ content of 20.8 volume %. (3A measured CO₂ (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O₂ (ppmv)/208,000 (ppmv) ambient O₂ concentration).

Destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(CO_{2c} + CO)/(CO_{2c} + CO + (3 * TOC))$$

where:

CO_{2c} = CO₂ ppmv concentration measured in the stack via method 3A minus the ambient CO₂ ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following table shows this calculation and outcome for an assumed stack effluent composition:

| | | |
|---|---------|--|
| Outlet CO ₂ | 30,000 | Measured Value |
| Outlet CO | 100 | |
| Outlet TOC | 30 | |
| Outlet O ₂ | 150,000 | |
| Ambient O ₂ | 208,000 | |
| Ambient CO ₂ | 388 | |
| Outlet CO _{2c} from combustion | 29,720 | Outlet CO ₂ - ((Ambient CO ₂ X (Outlet O ₂ /Ambient O ₂)) |
| | | |
| Destruction Efficiency | 99.70% | (CO _{2c} + CO)/(CO _{2c} + CO + (3 * TOC)) |

The suggested carbon balance methodology is similar to that described in EPA’s Technical Report “EPA-AA-SDSB-80-05” “Carbon Balance and Volumetric Measurements of Fuel Consumption” used by EPA for vehicle testing and is identical to that described in the UNFCCC CDM methodology found at:

http://cdm.unfccc.int/filestorage/C/6/X/C6XWJCBZSTR2S0SQKE7ZFQYEDIBNPZ/Procedure%20to%20determine%20the%20flare%20efficiency%20based%20on%20the%20flame%20temperature%20in%20an%20enclosed%20flare.pdf?t=bmh8bHYyeTJ0fDAPxze0_d4bXBK2OcnA8D9I and also described on page 630 of the “John Zink Combustion Handbook” available for purchase from Amazon books.

- ii. Modify the requirement in §63.771(d)(1)(i)(B) of the proposed rule to demonstrate that TOC (as propane – method 25A) concentration in the stack exhaust from an enclosed combustion device is less than 200 ppmv corrected to 3% CO₂ in the stack. Using the carbon balance methodology described above a 200 ppmv TOC would correspond to slightly above 98% destruction efficiency which leaves a wide margin between the alternative of 95% destruction efficiency.

As proposed, the rule indicates an alternative control device exhaust concentration requirement of less than 20 ppm corrected to 3 percent oxygen. Typically, combustors have carbon dioxide concentrations of approximately 3% and oxygen concentrations of approximately 16%. 20 ppm corrected to 3 percent oxygen corresponds to an in-stack actual concentration of approximately 5 ppm which would likely correspond to a destruction efficiency approaching 100% (the alternative requirement is 95% destruction). API believes this is a simple mistake and the correct formulation would be corrected to 3 percent CO₂. For the type, small size, and number of sources subject to these requirements API believes a more appropriate formulation would be correction to 3% CO₂. This would be consistent with §§63.772(h)(6)(vi) and 63.772(h)(7)(i)(B), where the proposed rule indicates the concentration limits for the manufacturers of combustors conducting a performance test and specifies an exhaust concentration requirement of being less than 10 ppm corrected to 3 percent carbon dioxide. This appears inconsistent with the 3% oxygen correction stated in §63.771(d)(1)(i)(B), where it outlines the general field performance test requirements. As stated, the manufacturers of combustors would actually have a less restrictive limit than owners conducting a field performance test.

- iii. Modify the requirements in §63.772(h) to conform with the carbon balance test methodologies described above for field performance testing. The ppmv performance criteria stated in §63.772(h)(7)(i)(B) should be modified to 100 ppmv TOC (as propane) corrected to 3% CO₂ which corresponds to ~99% destruction efficiency and provides ample buffer between a manufacturers tests for certification and the required 95% destruction efficiency for field demonstration. As currently constructed, the manufacturers certification testing must show ~ 99.97% destruction which is unreasonable and certainly not supportable from the standpoint of rule cost effectiveness.
- iv. Remove §63.772(h)(7)(i)(C) to eliminate the consideration of CO concentration in the manufacturers certification testing. By imposing a CO concentration, EPA is effectively converting the destruction efficiency testing to combustion efficiency testing which is not required by nor appropriate for the proposed rule.
- v. Eliminate the requirements for measurement of inlet flow to an enclosed combustion device and outlet flow from an enclosed combustion device, as per §63.772(e)(3)(i)(A), or outlet flow from an enclosed combustion device, as per §63.772(e)(3)(i)(A). As described above, these measurements are unnecessary to accurately determine destruction and removal efficiency (DRE) for the control device.

Additionally, requiring Method 2, 2A, 2C, or 2D to determine volumetric inlet flow is not appropriate and likely not technically feasible for accurate measurement. The waste gas inlet stream to an enclosed combustion device being used for control for either a storage tank or a small or large dehydrator will be a low pressure (essentially atmospheric) low flow stream with very low velocity which is almost impossible to measure accurately using any of the specified methods. Rather than attempting to measure such a stream EPA should specify the use of E&P TANK or a process simulation model such as ProSim or HySys to determine the inlet flow and composition of a waste gas stream routed to an enclosed combustion device from a storage tank and GlyCalc 3.0 or higher dehydrator model or a process simulation model such as ProSim or HySys to determine the inlet flow and composition of a waste gas stream routed to an enclosed combustion device from either a small or large dehydrator. The problems with attempting to measure such a stream are more completely described in Attachment H which is incorporated in these comments by reference.

The outlet flow from a typical enclosed combustion device has the same low pressure, low velocity, and difficulty for measurement issues as the waste gas inlet. If EPA insists on a mass balance approach rather than the much simpler and accurate carbon balance approach, API recommends the rule enable the use of Method 2B to calculate outlet flow for the combustion device using the model output information discussed above to calculate inlet flow and composition to the combustion device.

- vi. Eliminate the proposed rule revisions that change the temperature monitoring device accuracy requirements from +/- 2 to +/- 1 percent of the temperature being monitored expressed in degrees C. In the preamble, EPA states:

"we are proposing to revise the temperature monitoring device minimum accuracy criteria ... to better reflect the level of performance that is required of the temperature monitoring devices. We believe that temperature monitoring devices currently used to meet the requirements of the NESHAP can meet the proposed revised criteria without modification."

However, EPA provides no data or analysis to support the need for a more stringent accuracy requirement. At typical incinerator temperatures, any change, in combustion efficiency and emissions caused by a temperature change represented by the difference between 1 and 2 percent accuracy is most likely not detectable. Further, EPA contradicts the need for the rule revision by stating that it believes that current temperature monitoring devices can meet the criteria without modification. If current devices are sufficiently accurate, why is there a need for a new accuracy standard? Absent data and analysis that demonstrate that the new accuracy requirements would provide better emissions control, there is no need to revise the existing accuracy criteria. The primary rule revision effect would be to unnecessarily burden operators to modify internal procedures and recalibrate select devices. Simply because a certain standard of accuracy can be attained is not sufficient to demonstrate that it should be required.

vii. Clarify that the requirements in §63.771(d)(1)(i) for enclosed combustion control devices for "sources except small glycol dehydration units" (i.e., large dehydration units and tanks) is correctly interpreted as:

- Operators may comply with the requirements to reduce HAP emissions in accordance with §§63.771(d)(1)(i) (A), (B), (C), or (D).
- Operators that comply with the requirement to reduce HAP emissions in accordance with §63.771(d)(1)(i)(C) are only required to conduct an initial performance test that demonstrates that the combustion zone profile has a minimum temperature of 760°C. "Uniform" should be deleted from §63.771(d)(1)(i)(C) because uniform is not defined in the rule and the complex interactions of flame zone reactions, mixing, and convective and radiative heat transfer preclude "uniform" combustion zone temperature profiles. Rather, it appears that EPA's intent is that the combustion zone profile must have a minimum temperature of 760°C such that there are no low temperature pathways for HAPs to escape destruction. API recommends the following rule revision:

§63.771

(d)(1)(i)(C) For a control device that can demonstrate a ~~uniform minimum~~ combustion zone temperature of 760°C during the performance test conducted under §63.772(e), ~~operates at a minimum temperature of 760 degrees C.~~

- In addition, the rule appears confused because the requirements for demonstrating "a uniform combustion zone temperature" are not specified in the performance testing section, nor otherwise discussed in the rule. Therefore, API recommends that the following initial performance testing requirements to determine a combustion zone profile be added as §63.772(e)(3)(vii):

§63.772

(e)(3)(vii) To determine compliance with the minimum combustion zone temperature of 760°C specified in §63.771(d)(1)(i)(C), the owner or operator shall profile the combustion zone temperature as follows:

(A) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the measurement sites in the combustion zone.

(B) The gas temperature at each measurement site shall be determined using a temperature monitoring device having a minimum accuracy of ±2 percent of the calibrated range expressed in °C, or ±2.5 °C, whichever is greater.

- Operators that comply with the requirements to reduce HAP emissions in accordance with §63.771(d)(1)(i)(D) are not required to conduct a performance test because this compliance option is an operating standard and does not have a numerical component.

8.6.3. Applicable to Subpart OOOO – Tanks controlled with an enclosed combustion device

- a. Specifying Subpart HH/HHH hazardous air pollutant requirements for testing and performance demonstration of VOC control from tanks is completely inappropriate, unnecessary, and yields unnecessary complexity, confusion, and burden.
- b. API requests that EPA include a separate performance demonstration and monitoring section which is specific to and appropriate for Subpart OOOO rather than simply referring to the requirements in Subpart HH/HHH. This separate performance demonstration and monitoring section should adapt the methodologies described above appropriately for VOC control using enclosed combustion devices. See Section 16.8 for suggested rule text to specify storage tank requirements within Subpart OOOO.

8.6.4. Applicable to Subpart HH/HHH – Dehydrators controlled with an enclosed combustion device

- a. §63.771(f)(1)(i) provides requirements for enclosed combustion control devices for small glycol dehydration units, and lacks compliance options parallel to §63.771(d)(1)(i) (C) and (D).
- b. API requests that compliance options parallel to options §63.771(d)(1)(i) (C) and (D) and appropriate for small dehydrators be added to §63.771(f)(1)(i).
- c. In §63.772(e)(3)(iii)(B)(4) the proposed rule refers to using GRI-GLYCalc 3.0 or higher for determining the mass emission rate of TOC and HAP at the inlet to a control device. It is confusing because it refers to GRI-GLYCalc 3.0 or higher but then later in the same paragraph it refers to EPA Methods 18 and 25A, which of course are testing methods.
- d. API requests that §63.772(e)(3)(iii)(B)(4) be modified to clearly allow use of GRI-GlyCalc to determine the mass emission rate of TOC and HAP at the inlet to a control device.

8.6.5. Other Comments

- a. It is not apparent that ASTM D6420–99 (2004) can be used for HAP measurements. The rule should clarify that ASTM D6420–99 (2004) - in addition to Method 18 in 40 CFR part 60, appendix A and any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A – are applicable for measuring benzene, BTEX, or total HAP emissions from any affected source.
- b. §63.772(f)(3) states: “For inlet gas flow rate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under §63.772(h). However, §63.772(h) only applies to manufacturer performance tested combustion control devices and would not apply to dehydrators that are not equipped with manufacturer performance tested combustion control devices.

- c. §63.772(i)(1) requires the continuous monitoring of the inlet flow rate for manufacturer performance tested combustion control devices. The flowmeter is required to have an accuracy of +/- 2%.

As previously discussed, flowmeters for this type of low pressure low velocity stream application and service are not feasible and demonstration of flow to the enclosed combustion device should rely on appropriate models (E&P TANK or process simulation model for tanks, GlyCalc or process simulation model for dehydrators) to set volumetric operating parameters for conforming with a manufacturers range for a combustion device. For example, a process simulation model may be used to establish a lower and upper limit for oil throughput in a storage tank which corresponds with a manufacturers Btu operating range for a combustion device. An operator could then use their average production rates, as determined by normal production volume accounting methods and frequencies, to ensure they are within this range and demonstrate compliance.

API requests that EPA modify the proposed rule to eliminate continuous flow metering to control devices and enable the use of appropriate models to set limits on normally measured parameters to demonstrate compliance. Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce burden while providing for compliance demonstration and monitoring.

- d. §63.772(i)(2) requires that a pilot flame be present at all times of combustion control device operation. This requirement is not applicable for combustion control devices equipped with electronic ignition systems. For combustion control devices equipped with electronic ignition systems, the rule should add a requirement that these be operational at all times of combustion control device operation.

API recommends the following revision to the rule language:

§63.772

- (i)(2) For combustion control devices equipped with pilot flames, a pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with §63.773(d)(3)(i)(H)(2). For combustion control devices equipped with electronic ignition systems, the electronic ignition systems shall be operational at all times of combustion control device operation.

API recommends the following revision to the rule language:

§63.773

- (d)(3)(i)(H) For a control device model whose model is tested under §63.772(h),²

~~(1) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.~~

~~(2) A~~ heat sensing or UV sensing (fire-eye) monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

- e. §63.772(i)(3) requires monthly visible emissions tests using Method 22 of 40 CFR 60, Appendix A. Monthly testing is excessively burdensome and not needed to assure combustor compliance because continuous monitoring of combustion control ignition is already required and the materials being combusted are inherently combustible.

API recommends that the rule be revised to require testing every six months with an allowance for less frequent testing for units that routinely pass the visible emissions test. For example, for a unit that passes two consecutive emission tests, the next test would be required in 12 months. If EPA insists on retaining the onerous monthly testing requirement, then similar relaxed testing requirements for a compliant unit should be added. For example, for a unit that passes two consecutive monthly tests, the next test would be required in 2 months, and so forth until an annual testing schedule is achieved.

- f. §63.772(i)(4)(iii) requires the replacement of fuel nozzle(s) and burner tubes after one failed visible emissions test. EPA should *not* stipulate specific equipment replacement or maintenance practices that may be unnecessary and wasteful, or possibly not address the problem. The rule should delete these requirements and state that operators must perform maintenance and/or replace equipment as needed to restore combustion control device functionality.
- g. §63.773(b) requires semi-annual inspections of manufacturer performance tested combustion control devices. EPA should *not* stipulate a specific inspection frequency; rather inspection and maintenance practices should be based on manufacturer specifications and requirements as documented in the required inspection and monitoring plan.
- h. §63.773(d)(1)(iii) requires that the owner or operator conduct CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months. EPA should *not* stipulate a specific frequency for CPMS checks and audits. Rather, the appropriate frequency should depend on the monitoring parameters and equipment. API recommends that the frequency of CPMS checks and audits will be documented in the site-specific monitoring plan, and supported by manufacturer recommendations.
- i. §63.773(d)(3)(i)(A) in the redline version of the proposed rule states:

“For a thermal vapor incinerator that demonstrates during the performance test conducted under §63.772(e) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in °C, or ± 2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative in the combustion chamber downstream of the combustion zone temperature.”

This rule passage is poorly written and confusing. It infers that a thermal vapor incinerator performance test that does not demonstrate that combustion zone temperature is an accurate indicator of performance is not required to install a temperature monitoring device. Further, demonstration that “combustion zone temperature is an accurate indicator of performance” would require testing over a range of temperatures and correlating performance with temperature. This is not a performance testing requirement in the proposed rule nor should it be. In addition, the proposed rule does not define or discuss how to determine “a location representative of the combustion zone temperature.” To address these issues, API recommends the following revisions to the Federal Register version of §63.773(d)(3)(i)(A):

§63.773

(d)(3)(i)(A) For a thermal vapor incinerator ~~that demonstrates during the performance test conducted under §63.772(e) that the combustion zone temperature is an accurate indicator of performance~~, a temperature monitoring device equipped with a continuous recorder shall be installed at a location in the combustion chamber downstream of the combustion zone. The monitoring device shall have a minimum accuracy of ~~±12~~ percent of the calibrated range temperature being monitored in degrees C, or ±2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location ~~representative of the combustion zone temperature~~ or downstream temperature measurement during the performance test.

The phrase “or downstream temperature” has been added to the recommended rule text because of the practical considerations associated with measuring combustion zone temperatures. The high temperatures and reactive chemical species rapidly degrade in-situ measurement devices. Equipment properly installed for downstream temperature measurements typically have a much longer operational life and provide an accurate indication of combustion conditions. As long as the compliance temperature is in the same location as the temperature measured during the performance test, that location provides compliance assurance.

- j. §63.773(d)(3)(i)(C) should clarify that a heat sensing monitoring device to indicate continuous ignition of the pilot flame is not required for flares equipped with electronic ignition systems.
- k. For boilers and heaters where the waste gas is not mixed with or used as the primary fuel, to address the temperature sensor location issue previously discussed for thermal vapor incinerators, API recommends the following revisions to the Federal Register version of §63.773(d)(3)(i)(D):

§63.773

(d)(3)(i)(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder shall be installed. The temperature monitoring device shall have a minimum accuracy of ~~±12~~ percent of the

calibrated range ~~temperature being monitored~~ in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature or downstream temperature measurement during the performance test.

- l. The current rule flow meter accuracy requirement of $\pm 10\%$ for regenerative-type carbon adsorption systems should be retained in §63.773(d)(3)(i)(F)(1). EPA has not demonstrated the need for a revised flow meter accuracy requirement including how this revision will improve emission control, nor demonstrated that the additional cost to replace existing equipment and install more accurate flowmeters is justified.
- m. The checks of mechanical connections for leakage required by §63.773(d)(3)(i)(F)(1) should be performed every three months, rather than monthly, in concert with the required visual inspections. Absent moving parts, mechanical connections are extremely slow to develop leaks and more frequent checks add unnecessary labor and recordkeeping burden.

8.6.6. Complete Rewrite Required

API is not attempting to provide a full “mark-up” of the current proposed rule language due to the confusing complexity and extensive cross-referenced manner of its current construction. However, we would certainly be willing to draft, or work with EPA to draft, replacement testing and monitoring requirements and rule text. The replacement requirements must be appropriate for the large number of dispersed small sources subject to the rule with the rule text constructed in a straight forward and non-confusing manner with minimization of the use of cross-references. It is likely that cooperating on this issue will yield better results in a quicker time period.

8.7. Use of NESHAP Emission, Monitoring and Performance Testing Standards in NSPS

The proposed Subpart OOOO would impose a 95% control requirement on affected storage vessels. But, it would do so by incorporating by reference the Subpart HH MACT storage vessel control requirements. *See* 76 Fed. Reg. at 52800 (proposed §60.5395(a)). The preamble and TSD purport that the 95% control requirement is the product of an objective BDT analysis. *See, e.g., id.* at 52763-4; TSD at Section 7. And, EPA proposes that the consistency between the MACT and NSPS storage vessel requirements provides a coincidental opportunity for regulatory streamlining. *See* 76 Fed. Reg. at 52764 (“Because the controls used to achieve the 95-percent HAP reduction are the same as the proposed BSER for VOC reduction for storage vessels (*i.e.*, VRU and flare),” EPA proposes “that storage vessels subject to the requirements of subpart HH are exempt from the proposed NSPS for storage vessel in 40 CFR part 60, subpart OOOO.”).

But, on closer inspection, the storage vessel BDT determination was hard-wired to achieve the same level of control as Subpart HH – undermining the BDT determination and effectively (and unlawfully) extending Subpart HH major source MACT requirements to area source storage tanks. For example, in the BDT analysis, EPA explains that, “We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent.” *Id.* at 52763; *see also* TSD at 7-12. EPA does not explain in the preamble or the TSD why other control efficiencies were

not examined or assessed – it simply begins the BDT analysis with the conclusion that 95-percent control is appropriate.

Having selected its preferred control techniques and control efficiencies, EPA is then forced to back-calculate vessel throughput levels that produce costs satisfying the statutory BDT cost criterion. 76 Fed. Reg. at 52763-4. Yet, this analysis precludes other potentially relevant regulatory alternatives – such as marginally less effective controls that might be applied to a broader range of storage vessels. The Agency's failure to consider other control techniques and other levels of control efficiency that might be achieved by its preferred techniques is arbitrary and capricious.

Even if the same control standard of 95% reduction is selected and economically justified, the more stringent monitoring and performance testing requirements required by the CAA in section 112 for HAPs are not required in section 111 for criteria pollutants. This is discussed in more detail in Sections 16.6 and 16.13 of these comments.

8.8. Third Party Verification

EPA asks for comment on the possibility of requiring affected facilities to provide “third party verification to assure compliance” with well completion requirements. 76 Fed. Reg. at 52750. According to EPA, assuring compliance with these requirements could be “very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers” because “emission sources in the oil and natural gas sector, especially well completions, are widely geographically dispersed (often in very remote locations.” *Id.* A third party verification system could be used to “leverage compliance assurance efforts of the EPA and state, local and tribal agencies” by relieving them “of the burden of receiving thousands of paper or e-mail well completion notifications each year, yet still provide them quick access to the information.” *Id.* EPA also posits that such a system could benefit affected sources, for example by reducing the advance notice for well completions to “much less than 30-days” and eliminating the need for a 2-day follow up notification. *Id.*

There are several problems with this proposal. First, it is not clear what role third party verifiers would play. In part of the discussion of this issue, EPA suggests that the role would be limited to developing and maintaining a “clearinghouse” of information. EPA clearly envisions that such a “clearinghouse” would assist regulators (and the public) by providing easy access to well completion notifications. But, by establishing a clearinghouse, it does not seem that third-party verifiers would do more than the ministerial function of accepting notifications and putting them in an accessible database.

Alternatively, EPA describes the role of third party verifiers as substantive – *i.e.*, “verification of the data collection, compilation and calculations.” In addition, EPA suggests that the scope of third party verification might be extended to required electronic reporting using the ERT. The third party verifiers might assume the task of “review[ing] and verify[ing] that the information submitted to the EPA is truthful, accurate and complete.” *Id.* However, no further details about the scope and authority of the third party verifiers' substantive role is provided. For example, what happens if a third party verifier determines that a calculation error occurred. Would the verifier make the needed correction, or return the notification to the affected facility for correction and resubmission, or

perhaps report a potential violation to EPA? The proposal does not say. Similarly, would third party verifiers make field inspections to verify the information submitted in notifications and/or assess well completions determined not to be subject to Subpart OOOO? Again, the proposal does not say.

This lack of clarity is compounded by the fact that no proposed rule text is provided. As a result, commenters do not have adequate notice of how the third party verification system would work and cannot ascertain whether the regulatory text would faithfully implement the concept. To resolve these problems, EPA must repropose the third party verification requirement before finalizing it.

More fundamentally, EPA has not explained where it finds legal authority to impose a third party verification requirement. To be sure, EPA has broad authority to require such monitoring, recordkeeping, notification, and reporting requirements as are reasonably needed to assure compliance with Part 60 emissions standards. However, there is nothing on the face of the statute (and the statute cannot reasonably be construed as) authorizing EPA to require affected facilities to hire contractors to do EPA's work. EPA freely admits in the proposal that assuring compliance with the well completion requirements would be "very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers." The clear purpose of the third party verification requirement would be for the third party verifiers to relieve this burden. Simply put, EPA does not have authority under the CAA to require affected facilities to hire contractors to do work on behalf of the Agency.

Moreover, such a requirement would run afoul of the Anti-Deficiency Act. A third party verification requirement clearly would circumvent the limited Congressional budget appropriation for EPA enforcement activity. Such circumvention violates the prohibition against authorizing expenditures "exceeding an amount available in an appropriation or fund for the expenditure." 31 U.S.C. § 1341(a)(1)(A).

For these reasons, even with a reproposal, EPA is without authority to impose a third party verification requirement.

8.9. Equipment Specific Notification, Recordkeeping and Reporting Requirements

8.9.1. Storage Vessels Monitoring

Installation and operation of a CPMS on each storage vessel control system is required under §60.5410(e)(4). The CPMS must be installed and operated in accordance with §63.773(d) requirements, which include hourly data collection/measurement and recording. At remote, unmanned locations, the required data collection would be difficult due to the lack of electrical power that would be needed for a continuous data system. Installing electrical generation equipment would be prohibitively expensive given the small size of these emission sources. Therefore, API recommends that the final rule allow manual data collection on a schedule that matches an owner's site visit schedule.

8.9.2. Sweetening Unit Recordkeeping and Reporting

Under §60.5365(g)(3) "Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to

comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §60.5405 through §60.5407 and paragraphs §60.5410(g) and §60.5415(g) of this subpart.”

Although these units are exempt from the standards and monitoring requirements, they remain subject to unnecessary recordkeeping and reporting requirements. API recommends a change to §60.5365(g)(3) as follows: “Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §§60.5405 through §60.5407 and paragraphs §60.5410(g) and §60.5415(g) **and paragraphs §60.5423(a), (b), (d) or (e)** of this subpart.”

9. COMBUSTION DEVICE REQUIREMENTS

9.1. Flares - “Flame Present At All Times”

EPA has deferred to the general design requirement for flares in §60.18 and §63.11 if a flare is to be used as a control device. Since oil and gas operations are not always steady state, flares with continuously lit pilots (24/7) can sometimes unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emissions stream being burned. An example would be a flare installation used as a backup control device when a VRU is used. And in some cases, fuel gas has to be purchased where there is insufficient gas available from the production stream to fuel a flare pilot. EPA can resolve this issue in two ways.

9.1.1. Clarify What is Meant By “Flame Present At All Times”

Please clarify what is meant by “flame present at all times” by adding new regulatory text in §60.5415(i) and §63.769(c)(8) stating that “flame present at all times” in §60.18 and §63.11 refers to a pilot that must only be lit at all times while a VOC or waste stream is being sent to the flare for emissions destruction.

9.1.2. Allow Use of Electronic Flare Ignition Devices

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 303. Presumably this was published because EPA approves of the design and recognizes its benefits and wanted to promote its use in industry. EPA should not lose the benefits of this control technology enhancement by disallowing its use in this rule. With this being an established and preferred technology in Natural Gas STAR, operators should not have to petition EPA for approval under its new control technology provision. See Sections 15.3.8 and 16.11.

9.2. “Completion Combustion Devices” Are Not Considered Flares

Section 60.5375(a)(3) provides that “You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”

EPA appears to have chosen the term “completion combustion device” so that the pit flares, which the preamble states at p. 52758 are not a “traditional flare control device” would not be subject to §60.18. The preamble indicates that this is the case “because of the multiphase slug flow and intermittent nature of the discharge of gas, water and sand over the pit.” As a result, pit flares cannot comply with the technical requirements of this section.

However, Subpart OOOO also includes a definition of flare at §60.5430 which reads as “*Flare* means a thermal oxidation system using an open (without enclosure) flame.” This definition would include pit flares because they use an open flame to oxidize the gas portion of the flowback. Likewise, while pit flares are typically used and may not have been intended to be defined as flares, some operators may choose to use traditional flare devices or be required to do so by state or local rules. These would more clearly be subject to §60.18.

Suggested Rule Text:

§60.5430

Flare means a thermal oxidation system using an open (without enclosure) flame. [Completion combustion devices are not considered flares.](#)

9.3. Proper Cite for NSPS Flare Requirements is §60.18(b)

Subpart OOOO cites the requirements in the Part 60 General Provisions for flares, but the cite given is overly broad. The proper cite is §60.18(b), but the rule more generally cites §60.18.

Suggested Rule Text:

§60.5401

* * * * *

(f) Flares used to comply with this subpart must comply with the requirements of §60.18(b), [except as provided in §60.5415\(i\)\(1\) and \(2\).](#)

§ 60.5415

* * * * *

(i) [Flares used for compliance with this section must comply with §60.18\(b\), except as provided in §60.5415\(i\)\(1\) and \(2\).](#)

(1) [A “flame present at all times” as required in §60.18\(c\)\(2\) means that a pilot must be present at all times while a VOC or waste stream is being sent to the flare for emissions destruction, or](#)

[\(2\) thru the use of an electronic ignition device.](#)

9.4. Equipment Routing Vapors From Affected Facilities To Process Are Not Considered Control Devices

EPA has recognized that many of the emission reductions provided for in this rule may be able to be routed back into the process and sold as natural gas or petroleum products. In Subpart HH, at §63.761, EPA defines a “closed-vent system” such that “If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system.” EPA also included a definition of “routed to a process or route to a process” in the proposed rule text of §60.5430. API requests that EPA add a new provision in §60.5415 to exclude equipment that route the vapors back to the process and meet the definition provided in §60.5430 from being considered as control device or closed vent system for the purposes of this subpart.

Suggested Rule Text:

§60.5415

(j) For the purposes of this subpart if the vapors from the affected facility are routed back to process and meet the definition provided for *routed to process* in §60.5430 then this equipment is not considered a control device or closed vent system.

10. STARTUP, SHUTDOWN, AND MALFUNCTION PROVISIONS

Given that the SSM exemption in Part 63 Subpart A has been vacated by the courts, API supports EPA's edits to Table 2 of NESHAP Subpart HH that render SSM references in the General Provisions not applicable. API also supports EPA's proposal to address malfunctions as distinct from routine operating conditions, but we object to the manner in which EPA proposes to do so. API believes EPA is not authorized to subject malfunction events to an emissions standard for which EPA did not consider the emissions or costs of control associated with malfunctions. API endorses the comments submitted separately from the SSM Coalition on this issue (See Attachment D), particularly with respect to establishing an alternative emissions limitation for malfunctions. We address flaws in EPA's legal analysis below, followed by specific recommendations for a work practice as an alternative emissions limitation for malfunctions. In the comments on a work practice as a standard for malfunctions, Subpart HH references are given first, with Subpart OOOO references in brackets.

10.1. EPA's Legal and Technical Analyses of SSM Events are Fundamentally Flawed

10.1.1. Flawed Analysis of NESHAP SSM

EPA observes in the preamble that the startup, shutdown, and malfunction (“SSM”) provisions contained in the Part 63 General Provisions were vacated by the D.C. Circuit in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) (“*Sierra Club*”). 76 Fed. Reg. at 52787. The Agency then explains that “[w]e are proposing the elimination of the SSM exemption in the two oil and gas NESHAP” and that “[c]onsistent with *Sierra Club v. EPA*, the EPA is proposing to apply the standards in these NESHAP at all times.”

With regard to periods of startup and shutdown, EPA asserts that “operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard.” *Id.* Consequently, “we have not proposed different standards for these periods.” *Id.* As to malfunctions, “EPA has determined that malfunctions should not be viewed as a

distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times.” *Id.* However, EPA does propose to establish “an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions in both of the MACT standards,” which would be available if affected sources can prove by a preponderance of the evidence that qualifying criteria have been met. *Id.* at 52788.

The proposal to eliminate the SSM provisions in the two existing rules is not based on an accurate reading of *Sierra Club*, is not supported by any rational explanation as to why the elimination of the SSM provisions is justified, and is arbitrary and capricious given that EPA fails to provide any analysis of why affected sources reasonably can be expected to meet the emissions limitations and standards that the Agency proposes to apply during periods of SSM.

To begin, EPA's proposal “that the standards in these rules apply at all times” is not, as EPA claims, “[c]onsistent with *Sierra Club v. EPA*.” The decision in that case was grounded in the court's assertion that § 112 requires emissions standards to apply at all times. *Sierra Club* at 1027 (“Congress has required that there must be continuous section 112-compliant standards.”). Based on this, the court held the SSM General Provisions do not comport with § 112 because, in the eyes of the court, the SSM provisions are not “section 112-compliant” emissions standards. *Id.* at 1028 (“Because the general duty is the only standard that applies during SSM events — and accordingly no section 112 standard governs these events — the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously.”). Notably, the court did not hold that EPA is prohibited from setting separate standards for periods of SSM. It simply held that standards for such periods must be developed according to the § 112(d) MACT process.

Thus, the proposal to eliminate the SSM provisions from the two source categories (Subparts HH and HHH) subject to this proposal is not “consistent” with *Sierra Club* because there is nothing in that case that supports the conclusion that vacatur of the Part 63 General Provisions necessarily requires “the established standards in these rules [to] apply at all times.” EPA's flawed legal analysis provides no support for the proposal to eliminate the SSM provisions in the two rules.

This fundamental legal flaw is magnified by the Agency's failure to provide any explanation whatsoever as to why it is appropriate to now apply the existing emissions standards to periods of SSM. For example, EPA made no effort to obtain emissions information from the two source categories for periods of SSM and provides no other evidence or analysis supporting its assertion that it is appropriate to apply the existing standards to periods of SSM. Moreover, EPA fails to investigate the record data developed during the promulgation of the existing standards to assess whether those data are characteristic and representative of emissions during periods of SSM. In short, the Agency simply asserts with no record basis that the existing standards should apply to periods of SSM. This unsupported assertion provides no basis for extending the existing standards to periods of SSM – the failure to seek relevant data, assess existing data, and investigate whether the existing standards should appropriately apply to periods of SSM is facially arbitrary and capricious and provide wholly

inadequate support for the Agency's proposal.

With regard to malfunctions, EPA's proposal to provide an affirmative defense for periods of malfunction is without merit. Comments recently submitted by the "SSM Coalition" on EPA's proposed standards for Sewage Sludge Incinerators explain in detail that: (1) EPA must take malfunctions into account when setting § 112 emissions standards; (2) the proposed affirmative defense is not a permissible substitute for setting emissions standards for periods of malfunction; and (3) the proposed affirmative defense is unreasonable and impracticable. *See* Letter to EPA Docket Center (EPA/DC) from the American Chemistry Council, *et al.*, Comments on Proposed Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Docket ID No. EPA-HQ-OAR-2009-0559, at 6-20 (Nov. 29, 2010). We incorporate these comments by reference.

A further flaw in EPA's reasoning is that it has failed to account for the costs of a standard that does not accommodate malfunctions. To assure continuous compliance, affected facilities have only two choices – install redundant processing and pollution control equipment so that operations can continue during a malfunction, or shut down the affected facility until the malfunction can be rectified. In either case, affected facilities would incur substantial costs directly attributable to the standard that have not been accounted for in the formulation of the rule.

For these reasons, EPA should set aside the proposed affirmative defense for periods of malfunction and, instead, set a work practice standard for such periods.

10.1.2. Flawed analysis of NSPS SSM

Consistent with its proposed approach to the oil and gas NESHAPs, "EPA is proposing standards in [the Part 60] rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction." 76 Fed. Reg. at 52766. EPA claims that it "has taken into account startup and shutdown periods" in the proposed Part 60 standards. *Id.* And, EPA proposes "to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions." *Id.* To qualify for the affirmative defense, an affected source "must prove by a preponderance of the evidence that it has met" specified criteria. *Id.*

With regard to applying the proposed standards to periods of startup and shutdown, EPA has failed to provide record evidence as to how it has "taken into account startup and shutdown periods" in the proposed rules. Thus, EPA's assertion that the standards accommodate emissions during periods of startup and shutdown is unsupported and fundamentally arbitrary. EPA further undermines its position by asserting that "any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim." *Id.* In essence, EPA is trying to remake the law by asserting that its unsupported conclusions will be adopted *unless* commenters prove these unsupported conclusions to be wrong. This cannot be. EPA unambiguously has the obligation to support its proposed standards with substantial evidence

and must include in the proposed rule “the factual data on which the proposed rule is based.” CAA § 307(d)(3)(A). EPA has failed on both counts with regard to its unsupported assertion that the proposed standards should apply to periods of startup and shutdown.

EPA's proposal to provide an affirmative defense for malfunctions is equally flawed. EPA begins its analysis by asserting that it “has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards.” 76 Fed. Reg. at 72766. In support of this assertion, EPA first cites *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1058 (D.C. Cir. 1978) for the proposition that “nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards.” 76 Fed. Reg. at 52766.

Yet, *Weyerhaeuser* is inapposite – it is a Clean Water Act case that has no bearing on EPA's authorities and responsibilities under CAA § 111. More directly relevant cases – those decided under § 111 itself – tell a very different story. As explained in the SSM Coalition's comments (Attachment D), the courts have long recognized that a “technology based standard discards its fundamental premise when it ignores the limits inherent in technology.” *NRDC v. EPA*, 859 F.2d 156, 208 (D.C. Cir. 1988). For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that “‘start-up’ and ‘upset’ conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated.” *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are “necessary to preserve the reasonableness of the standards as a whole.” *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held CAA technology-based standards must be capable of being met “under most adverse circumstances which can reasonably be expected to recur,” such as during periods of SSM. 627 F.2d at 431 n.46. Thus, the relevant case law makes clear that EPA is authorized and obligated to account for periods of malfunction when setting Part 60 standards.

Nevertheless, EPA presses on by arguing that “it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards” because “[t]he ‘application of the best system of emission reduction’ is more appropriately understood to include operating units in such a way as to avoid malfunctions.” 76 Fed. Reg. at 52766. This rationale makes no sense because EPA effectively is defining BDT as an affected facility that does not malfunction. EPA has asserted no record basis for such a determination and could not if it tried because malfunctions are inevitable, notwithstanding best efforts. In any event, as explained above, EPA has failed to estimate and take account of the added costs associated with a rule that requires compliance during malfunctions (*i.e.*, the costs of installing redundant equipment or the business interruption costs of shutting down).

EPA lastly asserts that “even if malfunctions were considered a distinct operating mode, we

believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for affected facilities” because “it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category.” *Id.* Four decades of operating under the existing Part 60 malfunction provision belie this claim. A work practice requiring best efforts to minimize emissions during malfunction events consistent with the application of good air pollution control practices is a tried and true way to “account for the myriad different types of malfunctions that can occur.” EPA’s failure to explain why such an approach cannot continue to be successfully applied represents a critical flaw in its conclusion that standards cannot and should not be developed for malfunction events.

10.2. Notifications and Reports for Malfunctions

Proposed paragraph §63.762(d)(2) [§60.5415(h)(2)] would require a notification of a malfunction to be submitted within 2 business days after the initial occurrence of the malfunction in order to preserve an affirmative defense. This paragraph would additionally require a report within 45 days after the malfunction. These deadlines are arbitrary, unrealistic, and unwarranted.

10.2.1. The Proposed 2-Day Notification is Unrealistic and Unnecessary

The provisions of §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] would specify a 9-step procedure for determining whether a given malfunction event qualifies for the affirmative defense. In most cases, it would not be realistic to complete this determination process within 2 days following the occurrence of the event. Facilities might therefore tend to routinely submit the 2-day notification in order to preserve the potential for an affirmative defense, even in cases which subsequently are determined to not qualify. Furthermore, there is no environmental benefit that would accrue from this notification, and similar provisions in refinery consent decrees do not require it. The result of this unrealistic and unnecessary requirement, then, would be to burden both the facility and the regulatory agency having jurisdiction with the processing of paperwork that has no associated environmental benefit. As proposed, these notifications would be required for the smallest of emission exceedances with no reportable quantity threshold being set. This is contradictory to other EPA reporting rules such as those under CERCLA and EPCRA where reportable quantities are established for unauthorized releases. Requirements for immediate reporting of excess emissions of VOCs should be left to the states as they are best equipped to handle any response that might be required as a result of the release. Immediate reporting to the EPA serves no beneficial purpose. However, if EPA insists on a notification requirement, the rules should allow at least 15 business days following the occurrence of the event for this notification to be submitted.

10.2.2. Malfunction Reports Should Be Submitted with the Semi-Annual Reports

The rule already requires, at §63.775(e) [§60.5423(b)], the submission of excess emissions reports on a semi-annual basis, and EPA has established the semi-annual basis as being appropriate for all compliance-related reporting through numerous rulemakings. In fact, EPA promulgated the Recordkeeping and Reporting Burden Reduction Rule for the

expressed purpose of simplifying and unifying reporting schedules. EPA stated this intent in the preamble to that rule:

“The Agency now believes that the semiannual reporting frequencies contained in recently promulgated NSPS and NESHAP regulations and proposed in this rulemaking for all types of information are generally appropriate. . . EPA sees no reason to retain different reporting frequencies in the NSPS and NESHAP General Provisions compared to the reporting frequencies contained in recently promulgated rules.”^C

As noted by EPA, there is no reason to require a reporting frequency that differs from the semi-annual basis adopted by the agency. It would be contrary to the agency's own assessment of an appropriate reporting frequency to arbitrarily require malfunction reports to be submitted within 30 days.

10.3. EPA Has No Mandate To Impose SSM Requirements in NSPS Rules.

EPA states that “In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods” (see 76FR52766). However, API has found nothing in the Docket to support such a statement for the NSPS Subpart OOOO standards. In particular, the Technical Support Document (EPA-OAQR-0505-0045) does not have any statement about startup, shutdown emissions. The only reference to malfunctions is in a discussion about workovers being performed to address malfunctions of downhole pumps and this type of equipment mechanical malfunction has no emissions to atmosphere. EPA has predominately added work practices (i.e. compressor seal change and RECs). Although an SSM event could potentially cause the owner/operator to exceed the requirements of a work practice, it is unclear how the exceedance of a work practice would be tied to an “emission exceedance”. It is also not clear how an SSM event would cause “emission exceedance” in the case of a design standard such as the proposed requirements for pneumatic controllers. Finally, even though the sulfur recovery standard is an emission standard, it is simply a strengthening of the standard promulgated in the mid-1980s. No consideration of SSM events was found in the Technical Support Document as discussed above.

EPA has no mandate by the Court to cover periods of SSM in NSPS emission standards. In fact, EPA would have an obligation to show that covering such SSM periods within the NSPS emission standard was cost effective. Simply stating that SSM events have been considered is insufficient. By definition, SSM events have emissions in excess to the standard. API has not found any instance where EPA has defined what the SSM events are, the emission associated with the event, the control required obtain the emission standard and the cost effectiveness of requiring that control. The Clean Air Act (CAA) does not contain any provision allowing EPA to ignore cost effectiveness when setting NSPS and SSM events are no different. For these reasons, API recommend that EPA remove all references to SSM provisions from NSPS Subpart OOOO. If EPA continues to impose the emission standards at all times (including during SSM events), EPA must identify the SSM events, the controls required to maintain the emission standard and justify the cost impact of including the emission standard during the SSM event.

^C 61 Federal Register 47840-47852, September 11, 1996; page 47844, first two columns.

10.4. §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] Should Constitute a Work Practice for Compliance

For the reasons set forth in the comments above on the legal analysis, the steps specified in §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] should be specified as a work practice for compliance in the event of a malfunction, rather than being specified as a basis for an affirmative defense. In the preamble to the proposed rulemaking, EPA presents numerous reasons for not accounting for malfunctions in the setting of emission standards for routine operating conditions, yet proposes to apply these emission standards to malfunction events. This is logically inconsistent and statutorily inappropriate. If the standards are to apply to malfunction events, then the emissions and costs of control associated with malfunction events should have been included in the evaluation of the standards. As explained by EPA, however, not only was this not done – it would not be feasible to do so.

On the one hand, then, EPA is obligated to set standards that are “achievable” under section 112(d)(2) of the Clean Air Act. On the other hand, it is not feasible to develop an emission standard that governs malfunction periods. This scenario is expressly addressed in section 112(h) of the Clean Air Act, which allows EPA to set work practice standards for situations where “it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . .” Malfunctions fit within the situations described in the definition of “not feasible to prescribe or enforce an emission standard” as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Consequently, EPA should set work practice requirements to address periods of malfunction. The steps set forth in §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] would constitute an appropriate work practice standard for malfunctions, in which case the notifications specified in §63.762(d)(2) [§60.5415(h)(2)] should be replaced by a semi-annual reporting requirement.

10.5. Address Weather and System Outage Issues

Excess emissions can result from weather conditions or gathering system/processing plant outages that are beyond the control of the operator. Many well sites are remotely located and most are unmanned facilities. Inspection and maintenance visits occur on average anywhere from weekly to twice per month, depending on the location and time of year. In some areas, winter weather makes it difficult to visit sites causing extended periods between site visits. Although telemetry is often utilized for new production well sites to optimize the need for operator attention, weather conditions can affect not only the control device (flare flameout) but can also affect telemetry which would catch and report such discrepancies. System outages to the gathering system, gas treating plants, or gas processing plants occur infrequently but can occur several times during the year. These outages immediately result in a stop in production. Wells that are equipped to automatically shut down, do so. However, most wells must be visited manually in order to shut in the well and associated equipment. Once the system is restored and open to production flow, operators must begin the process of visiting the wells to open them back to production and restore associated operating equipment and control devices. EPA should specify how they would consider weather and “system” outages that are beyond the control of the upstream operator in a malfunction work practice.

10.6. Provide an Allowance for Reasonable Periods of Maintenance

EPA should provide an allowance for a reasonable period of routine maintenance for the control device. Proper operation of a control device includes periodic routine maintenance, and manufacturers of control devices typically recommend preventive maintenance on a semi-annual basis. EPA has stipulated in other rulemakings^D that standards do not apply during planned routine maintenance, other than a work practice standard that such periods shall not exceed 240 hours per year and records must be maintained to document such periods.

11. REVISING THE MACT FLOOR

Once EPA establishes a MACT standard for a particular source category, the Agency has the authority under § 112(d)(6) to “review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years.” In other words, EPA does not have unfettered discretion to revisit a prior MACT determination once that determination has been issued. Rather, EPA may revise a prior determination only “as necessary” according to explicit statutory criteria. *Cf. New Jersey v. EPA*, 517 F.3d 574, 582 (D.C. Cir. 2008) (Thus, EPA can point to no persuasive evidence suggesting that [the statute’s] plain text is ambiguous. It is therefore bound by [the statute] because “for [] EPA to avoid a literal interpretation at *Chevron* step one, it must show either that, as a matter of historical fact, Congress did not mean what it appears to have said, or that, as a matter of logic and statutory structure, it almost surely could not have meant it,” *Engine Mfrs. Ass’n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996), showings EPA has failed to make.”).

In the proposal, EPA explains that, “Pursuant to CAA sections 112(d)(2) and (3), we are proposing MACT standards for subcategories of glycol dehydrators for which standards were not previously developed.” 76 Fed. Reg. at 52746. Similarly, EPA states that, “We are also proposing MACT standards for storage vessels that are currently not regulated under the Oil and Natural Gas Production NESHAP.” *Id.* These statements make it clear that EPA is not invoking § 112(d)(6) as the authority for the new proposed standards – indeed, the preamble provides no analysis of “developments in practices, processes, and control technologies” to justify the proposed standards, as would be required if EPA were relying on § 112(d)(6). And, there is no mention of § 112(d)(6) in relation to the proposed new standards. EPA unambiguously drives home this point – “For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we are proposing no revision to the existing NESHAP pursuant to section 112(d)(6) of the CAA.” 76 Fed. Reg. at 52747. Instead, the Agency is invoking §§ 112(d)(2) and (3) directly, as if MACT standards for these source categories do not already exist.

EPA does not have such authority. As explained above, once EPA makes a MACT determination for a particular category, § 112(d)(6) provides the only authority for the Agency to later review and possibly revise the determination. Section 112(d)(6) expressly authorizes EPA to review existing determinations and provides specific criteria to guide and constrain the review. The existence of this express authority forecloses the Agency’s ability to directly invoke §§ 112(d)(2) and (3) for a given source category when a MACT determination has already been issued for the source category.

Notably, even if the Agency had invoked § 112(d)(6) as authority for revising the existing MACT standards, it still would not have authority to regulate the emissions points for which standards were not established in the first round of MACT rulemaking. Prior MACT determinations may be revised only “as necessary (taking into account developments in practices, processes, and control technologies).” Perceived “gaps” in the

^D Examples of regulatory provisions for maintenance of the control device include §60.102a(f)(3) and §63.119(e)(3) & (4).

original MACT determinations are not “practices, processes, and control technologies” that are properly within the scope of a § 112(d)(6) review.

In any event, it is not a reasonable exercise of authority to establish new emissions limitations under existing MACT standards when there is no significant risk associated with emissions from sources in the given source category. As explained in Section 20 of these comments, the available data overwhelmingly show that the current standards protect public health with an ample margin of safety. Establishing new standards under these circumstances is patently unreasonable and cannot be justified under § 112(d)(6) because the so-called regulatory “gaps” in the current rules clearly are not contributing to unacceptable risk. This is regulation for the sake of regulation and, as such, contradicts Congress’s clear intent that an ample margin of safety is an appropriate stopping point for emissions limitations under § 112.

12. CHANGE IN THE PROTOCOL FOR DETERMINING RESIDUAL RISK FOR NESHAP

As noted in the Federal Register (FR) announcement, EPA is required under section 112(f) of the Clean Air Act (CAA) to evaluate the risk to public health that remains after implementation of the technology-based national emission standards for hazardous air pollutants (MACT standards). EPA proposes, in this rulemaking, to change the manner in which this “residual risk” is evaluated. API has several concerns with respect to these proposed changes. Please see Attachment E which contains the Residual Risk Coalition letter commenting on this issue.

12.1. Lack of Statutory Authority for the Changes

As EPA notes, the process that the agency has followed for residual risk evaluations was established in accordance with a protocol mandated by the CAA, including preparation and submission to Congress of the methods to be employed. These methods include the two-step process described in the FR announcement. The first step in this process is to determine whether the maximum individual lifetime cancer risk (MIR) exceeds a presumptive limit of approximately 1-in-10 thousand. When the MIR is determined to be below this limit, the residual risk is deemed to be acceptable and the analysis moves to the second step. The second step, for situations in which the MIR is above 1-in-1 million, is to determine whether the standard provides an “ample margin of safety” to protect human health. EPA has established certain metrics for the determination of ample margin of safety through both the agency’s report to Congress and an extensive history of subsequent rulemaking.

API believes that EPA lacks statutory authority to make significant and substantive changes unilaterally to this procedure that has been established in accordance with CAA mandates, vetted with Congress, and ratified by precedent. There has been no indication from Congress or experience which indicates that the established procedure for evaluating residual risk has failed to be protective of human health. API objects to arbitrary changes which are unnecessary and unauthorized, and which needlessly add further uncertainty and complexity to a process that is already unduly burdensome.

12.2. Inappropriateness of the Changes

The new measures which EPA proposes to apply to the determination of acceptable risk and ample margin of safety are inappropriate. These new measures include:

- “total facility” consideration; consideration of risk from the total facility (facility-wide risk), rather than from only the portion of the facility subject to the rule,
- “demographic” consideration; consideration of risk across selected social, demographic, and economic groups within the population living near the facility, and
- “allowable emissions” consideration; consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard (versus the actual emissions from the facility).

Each of these considerations is discussed below and in Attachment E.

12.2.1. The “Total Facility” Approach to Conducting Risk Assessment Exceeds EPA’s Authority Under §112(f)

EPA explains in the proposal that, “To put the source category risks in context, we also examined the risks from the entire ‘facility,’ where the facility includes all HAP-emitting operations within a contiguous area and under common control.” 76 Fed. Reg. 52774. Because the CAA requires residual risk determinations to be conducted on a category by category basis, EPA does not have authority to consider the combined emissions from entire facilities when making a § 112(f) risk assessment for a given source category.

Section 112(f)(2)(A) unambiguously requires EPA, within 8 years after adopting a MACT standard for a given source category or subcategory, to “promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health.” Section 112(f)(2)(A) further dictates that, “Emissions standards promulgated under this subsection shall provide an ample margin of safety to protect public health.” It is not reasonable to construe these provisions as authorizing EPA to consider emissions from entire facilities in conducting risk assessments and potentially revising the underlying rule for the simple reason that the Congress clearly envisioned that full implementation of the MACT program would take longer than 8 years. Consequently, it would be impossible for EPA to fulfill its unambiguous obligation for § 112(f) standards to protect public health with an ample margin of safety in cases where facilities contain sources in a category where the 8 year deadline for conducting the § 112(f) risk review precedes the adoption of MACT standards for other sources at the facilities.

This is not mere hypothetical conjecture. The standards under review in this proposal provide a case in point. Certain of the facilities containing sources affected by one of the standards under review in this proposal also contain industrial boilers that will be subject to the MACT standard for industrial boilers. As a result, EPA currently is without authority to conduct a § 112(f) risk assessment for co-located industrial boilers because those boilers are not yet subject to a MACT standard due to the stay of the final rule. Thus, it is impossible for EPA to assure an ample margin of safety from total facility emissions for sources affected by the standards covered by this proposal. This demonstrates why the statute cannot be interpreted to allow consideration of emissions from entire facilities when conducting a § 112(f) risk review.

In addition, § 112(f)(2)(A) further provides that, “If standards promulgated pursuant to subsection (d) of this section and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to *emissions from a source in the category or subcategory* to less than one in one million, the Administrator shall promulgate standards under this subsection for such source category” (emphasis added). This provision unambiguously requires the § 112(f) risk assessment to be focused exclusively on “emissions from a source in the category or subcategory.” For this reason alone, EPA does not have authority to consider emissions from any sources other than those in the source category or subcategory under review at that time.

12.2.2. Demographics May Not be Considered in Conducting Risk Assessments Under §112(f).

EPA explains that, “To examine the potential for any environmental justice (EJ) issues that might be associated with each source category, we performed a demographic analysis of population risk.” 76 Fed. Reg. at 52774. Although EPA conducted an “environmental justice” assessment for the two rules covered by this proposal, EPA determined that those analyses do not provide a basis for imposing additional control measures in order to assure an ample margin of safety.

Because the term “public health” cannot reasonably be interpreted to include consideration of environmental justice in the § 112(f) context, EPA’s proposal to consider demographic analyses in conducting risk reviews under § 112(f) is not a proper exercise of Agency authority. Section 112(f)(2)(A) expressly instructs EPA to impose additional emissions controls if needed to provide an ample margin of safety “to protect public health.” The term “public health” is not defined in § 112 or in EPA’s Part 63 regulations.

In the context of EPA’s national ambient air quality program (“NAAQS”), the Supreme Court has observed that the “primary definition of the term” should be applied – *i.e.*, public health means “the health of the public.” *Whitman v. American Trucking Associations, Inc.*, 531 U.S. 457, 465 (2001). This conclusion emphasizes that the scope of the term “public health” should be dictated by the meaning of the word “public.” In relevant part, Websters Free Dictionary defines the adjective “public” to mean “of, relating to, or affecting all of the people or the whole area of a nation or state” and “of or relating to people in general.” These definitions emphasize that the word “public” should be construed expansively as describing the people as a whole, and not particular demographic segments.

EPA’s established approach to assessing potential impacts on public health under the NAAQS program is consistent with this meaning. EPA reasonably interprets the term “public health” to include consideration not only of potential impacts to the population as a whole, but also to sensitive subpopulations – recognizing that the objective is to protect the group rather than any particular individual in the group. *See, e.g.*, 71 Fed. Reg., 61144, 61145 fn. 2 (Oct. 17, 2006). But, sensitive subpopulations are identified according to their particular health-based sensitivities (*e.g.*, asthmatics) rather than demographic classifications

unrelated to particular health-based sensitivities (e.g., population without a high school diploma).

With this backdrop, it is not reasonable to construe the term “public health” as used in § 112(f) as allowing consideration of demographic classifications that bear no relationship to the potential health effects presented by the HAPs at issue for the given source category or subcategory. EPA’s proposal would unreasonably inject racial, ethnic, and other policy considerations into a program designed to provide protection for the public at large. For example, EPA suggests that the population without a high school diploma should receive extra scrutiny, yet does not afford the same scrutiny to other reasonably definable educational groups, such as those with a high school diploma, those with college degrees, and those with advanced degrees. There is simply no principled way to identify and define those groups that should receive extra scrutiny from those that do not. In short, EPA’s approach would inappropriately cause arbitrary policy and political considerations to trump objective scientific analysis. This is patently unreasonable and, as such, is not a supportable interpretation of § 112(f).

12.2.3. EPA Fails to Provide a Rational Basis for Using Allowable Emissions in Conducting Risk Assessments Under §112(f).

EPA uses the term “MACT allowable” emissions in the preamble to mean “the highest emission level that could be emitted by the facility without violating the MACT standards.” 76 Fed. Reg. at 52770. The Agency asserts that considering MACT allowable emissions in determining residual risk under § 112(f) “is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards.” *Id.* Without further explanation as to why it might be appropriate to determine and apply MACT allowable emissions in § 112(f) risk assessments, the Agency goes on to explain that it developed a ratio method of estimating MACT allowable emissions and applied these ratios in the risk assessment. Based on this analysis, EPA proposes to find that the “risks are unacceptable” under the current Subpart HH “due to MACT-allowable emissions” and, therefore, EPA proposes “to eliminate the 0.9 Mg/yr compliance alternative for dehydrators.” *Id.* at 52780.

EPA cannot lawfully use MACT allowable emissions in the proposed risk assessments and residual risk determinations because the Agency has failed to provide any reasoned explanation for why risk assessments based on actual emissions estimates are inadequate. It is noteworthy that § 112(f)(1)(A) required EPA to report to Congress on “methods of calculating the risk to public health *remaining, or likely to remain*, from sources subject to regulation under this section after the application of standards under subsection (d) of this section” (emphasis added). Section 112(f)(1)(B) required EPA also to report on “the *actual health effects* with respect to persons living in the vicinity of” affected sources” (emphasis added). These requirements clearly signal that Congress expected EPA to focus on actual risk and not hypothetical risk in implementing the requirements of § 112(f). Thus, it is not reasonable in the first instance for EPA to construe § 112(f) as authorizing the Agency to conduct risk assessments based on hypothetical “MACT allowable” emissions.

Moreover, the Agency's risk assessment methodology already is rife with conservative assumptions. For example, health benchmarks, such as acute reference doses, typically incorporate two to three orders of magnitude of conservatism to account for uncertainties, such as the extrapolation of animal toxicity testing data to humans. Similarly, the dispersion models used to predict off-site ambient HAP concentrations attributable to emissions from affected sources incorporate numerous conservative assumptions to simplify the analysis of highly complex factors, such as meteorology and atmospheric chemistry. In addition, risk assessments assume exposure to the most exposed individual on a continuous basis for an entire lifetime.

In light of the conservatism that already is inherent to EPA's risk assessment methodology, it makes no sense to apply yet another layer of conservatism – this time based on the hypothetical assumption that affected sources should be expected to emit more than the actual data indicate – to § 112(f) risk assessments. EPA has provided no data or analyses indicating that its current methodology results in negative bias. EPA has provided no data demonstrating that affected sources actually do emit at levels significantly higher than the actual data show for any significant period of time. In short, EPA's proposal to use hypothetical emissions levels in § 112(f) risk assessments is justified on nothing more than the bald assertion that sources *might* emit at these higher levels. The failure to provide a reasoned explanation as to why this approach is justified and the failure to provide any record evidence supporting the use of MACT allowable emissions render this proposal insupportable under the law.

13. AFFECT OF PROPOSED REGULATIONS ON STATES

13.1. Direct Regulatory Burden to State Environmental Regulatory Agencies.

The proposed rule will add tens of thousands of affected facilities annually. These affected facilities will result in a flood of notifications for new affected facilities that will each result in the submittal of annual reports, primarily into the State air pollution control agency. For this reason, API believes that consultation with the “appropriate representatives of the Governors and of State air pollution control agencies” of oil and natural gas producing states, as required by 42 USC 7411(f), is particularly important. The experience of these agencies is necessary to insure that only the notification and report information that is most beneficial to the agency is required to be submitted. API believes that the notification and recordkeeping requirements included in the proposed rule will flood the agencies with paperwork and effectively hide the useful information. API has made recommendation for the reduction of compliance assurance documentation below. However, EPA needs to recognize that these burdens are not only shouldered by industry, but the regulatory agencies as well.

13.2. Minor New Source Review (NSR) Permitting Programs

As discussed in Section 2, the proposed rule regulates affected facilities (i.e., individual pneumatic controllers and compressors, as well as RECs) that have not typically been regulated in an NSPS or NESHAP regulation in the past. Many states have developed minor source NSR permitting programs that go far beyond the requirements of the PSD (Prevention of Significant Deterioration) NSR or Title V Operating permitting programs. These programs typically have annual mass

emission thresholds similar to those included in the recent Tribal Lands FIP for Minor Sources (76 FR 38747, July 1, 2011; see Table 1, 76 FR 38792-3 for thresholds). However, some states also have an overriding requirement to permit facilities that contain NSPS or NESHAP affected facilities. This could result in a constant stream of permit revisions for very minor equipment activity (i.e., routine change out of equipment that occurs frequently). This unintended consequence of the proposed rule will bring a great burden to states that have this type of requirements and the O&G industry that operates within them for no environmental benefit. The NSPS/NESHAP programs are self implementing, thus do not require a permit to codify their requirements to make them enforceable. We recognize that EPA has already stated that the proposed regulation will not trigger Title V permitting requirements but we recommend that EPA expand this to include a recommendation in the preamble that "NSPS/NESHAP applicability alone should not trigger minor source NSR permitting requirements". We realize that such a statement will not bind the States, but it will be helpful in addressing this issue with the States

14. OFF-SHORE FACILITIES

API has found no evidence in the docket that EPA has considered the impact of the proposed rules on the offshore facilities that are under the EPA's jurisdiction for air quality issues. Offshore operations have unique and significant issues that directly impact the cost of compliance such as space on the platform for emission control equipment, weight allowance for additional equipment on the platform, remoteness of the platform, etc. Because of the unique circumstances around drilling and producing from offshore platforms and exploration vessels, complying with requirements designed for onshore activities is much more difficult and the costs are significantly higher when applying those same requirements to offshore facilities. For example, performing reduced emission completions on a new well completed on an existing offshore platform would most likely require a special separate installation to accommodate the additional REC equipment. The space on an offshore rig or platform is limited and designed to hold the equipment normally associated with drilling or necessary to manage the fluids expected during production. In addition, any recovered gas not meeting sales quality and capable of being flared, would be controlled using an existing flare typically designed as an emergency or safety control device. The flares used offshore are not designed to meet the §60.18 requirements. In Alaska, the vessels used for exploration are often foreign owned and operated and many times not designed to meet EPA stationary source standards. If the NSPS apply to offshore activities, drilling and subsequent production in Alaska will be significantly delayed until exploration rigs meeting the NSPS can be secured and moved to Alaska. With specific consideration of these issues for each of the standards EPA has proposed, API believes that the cost benefit requirement of the NSPS has not been satisfied. It is inappropriate for EPA to apply these standards to offshore facilities because of omission. API request that EPA specifically exempt offshore operations from the new standards it has proposed, as it has previously done in Subparts LLL and KKK.

TECHNICAL COMMENTS

15. WELL COMPLETIONS – NSPS SUBPART OOOO

API and its member companies are fully supportive of EPA's goals of minimizing VOC emissions from flowback immediately following hydraulic fracturing stimulation and have been among the earliest companies to adopt reduced such measures. Reduced emissions completions make sense in many scenarios, though not all. However, API does not support the manner in which EPA is proposing to regulate reduced emissions completions as discussed below in Section 15.1. Also, if EPA chooses to proceed in regulating reduced emissions completions, several issues must be addressed, as discussed in the rest of Section 15.

15.1. Legality of Regulation

Emissions from flow back immediately following hydraulic fracturing stimulation during well completions are fundamentally different than emissions regulated under any existing NSPS. It goes without saying that the purpose of gas wells is to produce natural gas. A well completion is not part of the normal operation of a well, in that completion activities do not continuously occur as a well is producing or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be "recompleted," this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

To date, EPA has not sought to impose § 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA has actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until "within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility." 40 C.F.R. §60.8(a). Similarly, performance test must be conducted under conditions reflecting "representative performance of the affected facility." *Id.* at §60.8(c). Periods of source construction and maintenance have never been determined to be "representative" of normal source operation under the NSPS program.

With this as a backdrop, EPA's proposal to set standards for well completions and recompletions is unfounded. To begin, as discussed more fully in Section 2 of these comments, production wells are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and gas production industry (such as natural gas processing plants) that EPA seeks to regulate in the proposed rule. EPA has not previously found and has not proposed to find that emissions from flowback immediately following hydraulic fracturing stimulation cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate flow back immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore under § 111.

In addition, EPA has not explained why it has reversed a decades-long practice under § 111 of regulating only emissions from normal operation of affected facilities and expressly excluding construction-related emissions from regulation. The proposal to regulate construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of § 111. The failure to explain why this departure is justified and the failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C). EPA should remove the requirements for reduced emissions completions from the proposed regulation. If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, EPA should repropose the requirements and include sufficient justification for their departure from not regulating construction-related emissions and present the legal basis for regulating non-routine emissions, under § 111, as discussed in Section 2. Furthermore, there are several issues that EPA needs to address which are discussed in the remainder of Section 15.

15.2. EPA Should Not Prescribe the Equipment Required for Reduced Emissions Completions

If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, API is concerned with the prescriptive nature of the rule proposal for gas wellhead affected facilities. Section 60.5375(a) establishes three separate and prescriptive work practices, each of which must be followed in order to comply with the rule:

- Minimization of venting and routing recovered gases to the gas gathering line
- Use of specified equipment to maximize resource recovery^E and minimize releases to the environment
- Direction of flowback emissions that cannot be sent to a gathering line to a completion combustion device

Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies:

CAA section 111(b)(5) "Except as otherwise authorized under subsection (h), nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."

Section 111(h) allows work practice standards where "it is not feasible to prescribe or enforce a standard of performance," API concurs that it is not feasible to prescribe a standard of performance for gas wellhead.

However, an underlying presumption of section 111 is that a standard of performance should allow the affected facility flexibility to meet a standard, rather than be required to use specific controls. Likewise, the NSPS rules are directed at criteria pollutants, which for the gas wellhead affected

^E The maximization of resource recovery is not a proper subject of regulation in a New Source Performance Standard under the Clean Air Act. Such considerations are appropriate only under RCRA.

facilities are VOCs. For this reason, we propose that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods. This proposed rule text also reflects the complexity of completions and the variability of conditions that can be encountered in natural reservoirs. If EPA chooses to regulate flowback immediately following hydraulic fracturing stimulation, API proposes that EPA adopt a management system approach to well completions rather than trying to specify methods that may work well in one well or region, but be wholly unsuited in another. EPA has used this approach in many rules, such as Part 68, but has also used this approach in NSPS Ja for flares.

15.2.1. The Rule Should Not Specify Use of Specific Equipment

Paragraph 60.5375(a)(2) states that “You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations”. Any one of these pieces of equipment may not be necessary for any given flowback and cleanout operation, or not necessary for the entire time, so it is not appropriate to mandate it. Industry should be allowed to determine what equipment is required to safely minimize emissions.

15.2.2. The Rule Needs To Be Expanded To Allow For Use of Other Emission Reduction Techniques

Currently the proposed rule presumes a very simplistic understanding of completions - that all wells are simply flowed back using the reservoir energy to pits or flowback tanks. As structured, the rule precludes the use of other completion techniques which may be necessary to clean out a well and which may have equally low emissions in comparison to reduced emission completions. For instance reverse circulation completions have been utilized in a number of areas/wells with good success and low emissions. Reverse circulation completions have been presented in several Natural Gas STAR workshops and should not be ignored or precluded by the rule as proposed. In the future, new completion techniques and options may be developed which adequately clean-up the reservoir while providing for reduced emissions when compared to an uncontrolled “normal” flow-back. The rule, as proposed, would stifle this innovation and effectively preclude progress in better reservoir clean-up and reduced emissions.

15.2.3. The Rule Should Not Require Routing Liquids to a Storage Vessel

Sometimes flowback contains sands and other injection fluids that can damage storage vessels and make the condensate not salable; therefore, some of the flowback may get sent to a pit versus a storage vessel. The ability to flowback to a pit should be allowed.

15.2.4. The Rule Should Recognize Commercial Viability

The rule should recognize that installation of a collection line, to enable gas sales and REC's, prior to drilling or completing a well is only justifiable from an economic and surface disturbance/habitat disturbance perspective when the probability of a commercially successful well is almost assured. This is typical only for well developed areas with very well-known reservoir extent and productivity where the new wells are “in-fill” between existing wells. Although EPA attempted to deal with this uncertainty by excluding

exploration and delineation wells from the REC requirements the exclusion is not broad enough. API requests that EPA broaden this exclusion to include any well which the owner determines does not have a very high probability of success. The operator would be required to document their evaluation of wells probability of commercial success.

Suggested Rule Text: In order to address these concerns and others in later sections of these comments, API proposes two options. The preferred option would be to require the development and implementation of a management plan of how you will minimize VOC emissions associated with flowback immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore instead of requiring specific equipment. The alternative option that API is proposing to replace requiring specific equipment would be to “*Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. When the well head pressure (in absolute units) immediately following perforation is four times the static sales meter pressure then the operator is obligated to flow the well to an available sales line or document the reasons for failing to flow to sales.*” This would specify when it would even be feasible when gas can be routed to the sales line which is discussed further in Section 15.3.2.

Preferred Option:

§60.5375

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

- (a) Except as provided in paragraph (f) of this section, for flowback immediately following ~~with~~ hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) ~~through and~~ (a)(32) of this section.
- (1) You must minimize the VOC emissions associated ~~with venting of hydrocarbon fluids and gas over the duration of~~ with flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, utilizing one or more of the following options routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system:
- (i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator.
- (ii) Capture and route VOC emissions associated with flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore that cannot be directed to the gathering line to a completion combustion device except when conditions may result in a fire hazard, conditions may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion

devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to §60.18.

(iii) Other method that minimizes VOC emissions associated with flowback immediately following hydraulic fracture stimulation.

~~(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.~~ Develop and implement a management plan for each basin for how you will minimize VOC emissions associated with flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facilities onshore utilizing the options in §60.5375(a)(1). The plan must include:

(i) Methods and techniques to enhance direction of gas during the flowback immediately following hydraulic fracturing to the natural gas gathering system.

(ii) Equipment to be used.

(iii) Operating procedures

(iv) Definition of roles and responsibilities for implementation of the plan.

(v) Review of the effectiveness of the plan in minimizing VOC emissions every 2 years.

~~(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.~~

(b) You must maintain a log records for each well completion operation at each gas wellhead affected facility. ~~The log must be completed~~ on a daily basis and must contain the information records specified in §60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by §60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by §60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

- (f) For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(~~3~~)(1)(ii) of this section. ~~You must also maintain records specified in §60.5420(e)(1)(iii) for wildcat or delineation wells.~~
- (g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing at a natural gas wellhead facility onshore that ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f)

Alternative Option:

§60.5375

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

- (a) Except as provided in paragraph (f) of this section, for ~~flowback of each well completion operation with~~ immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) ~~through (a)(3)~~ of this section.
- (1) You must minimize the VOC emissions associated ~~with venting of hydrocarbon fluids and gas over the duration of~~ flowback duration of immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, utilizing one or more of the following ~~options: by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.~~
- (i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. When the well head pressure (in absolute units) immediately following perforation is four times the static sales meter pressure then the operator is obligated to flow the well to an available sales line or document the reasons for failing to flow to sales.
- (ii) Capture and route flowback emissions that cannot be directed to the gathering line to a completion combustion device except when conditions may result in a fire hazard, or explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to §60.18. For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, reduce emissions by

using a completion combustion device when not precluded by one of the conditions described above.

(iii) Other methods that minimize VOC emissions associated with flowback immediately following hydraulic fracture stimulation.

~~(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.~~

~~(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.~~

- (b) You must maintain a log records for each well completion operation at each gas wellhead affected facility. ~~The log must be completed~~ on a daily basis and must contain the information records specified in §60.5420(c)(1)(iii).
- (c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by §60.5410.
- (d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by §60.5415.
- (e) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.
- (f) For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(~~3~~) (1)(ii) of this section. ~~You must also maintain records specified in §60.5420(c)(1)(iii) for wildcat or delineation wells.~~
- (g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f).

15.3. Need Ability to Combust or Vent

Paragraphs 60.5375(a)(1) and (2) require “routing recoverable liquids to storage vessels and routing the recovered gas into a gathering line or collection system” and “all salable quality gas must be routed to the gas gathering line as soon as practicable.” API appreciates that EPA is trying to provide flexibility in the proposed rule language, but additional clarity is needed in the rule to

address the many operational and safety constraints to routing all salable gas to gathering line. There are several operational and safety constraints that limit the ability to meet these requirements. These constraints include but are not limited to:

15.3.1. Lack of Availability of a Natural Gas Gathering Line and Production Equipment

Unless a well's probability of commercial productivity is almost assured, natural gas gathering lines and production equipment may not be installed prior to completion and it is unreasonable and not cost effective to require that they be installed to enable REC's. This limits the "footprint" as well as the financial risk associated with a well that may never produce. Non-producing wells are known as "dry holes". According to the US Energy Information Administration (EIA), in 2010 8.9% of total wells drilled were dry holes^F and approximately 39.2% of total exploration wells drilled were dry holes^G. Commercial viability of the well must be considered when requiring to route gas to a natural gas gathering line. The Wyoming Department of Environmental Quality "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance" revised March 2010^H only applied to concentrated development areas and the Jonah Pinedale Development Area of Wyoming, not to smaller development areas where reservoir extent, productivity, compositions, and pressures are not well established. Furthermore, in these concentrated development areas current development is "in-fill" drilling where the probability of success is almost assured, there is already sufficient natural gas production to justify the installation of a natural gas gathering line and the main gas gathering line/system is already in place. Permitting, designing, and installing a natural gas gathering system (including pipelines, compression, gas plant) takes a great amount of time and money. Sufficient natural gas production in the area is required to justify the cost and burden for permitting, designing, and building the natural gas gathering system. Companies may drill multiple wells prior to determining whether an area can be economically produced and justify the investment necessary. An exemption from sending natural gas to a natural gas gathering line should be extended to wells where commercial viability is not assured prior to installation of equipment and pipelines.

Before natural gas production can be sent to natural gas gathering line, all of following must be done:

- **A natural gas gathering line/system must be permitted, installed and operational in the area.** Permits are required for right-of-way, installation, compressor site air quality, etc. for the natural gas gathering line/system before it is installed which take much longer than getting a permit to drill a well. Designing and installing a natural gas gathering system (including a pipelines, compression, gas plant to send the gas to, etc) takes considerable time and money. Furthermore, designing and installing a gas

^F <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0407>

^G <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0406>

^H Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

gathering line depends on having enough natural gas production to justify the exceptional cost and burden for the gas gathering system.

- **A contractual right to flow into the gas gathering system with the company that owns the gathering line.** In most cases the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added.
- **Acquire necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system.** Permits and right-of-way are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary right-of-way can be difficult and require a court decision.
- **The natural gas must meet the specifications of the natural gas gathering line.** Contracts with the gathering company include specifications for entering the gas gathering line including concentrations of inert gases such as carbon dioxide or nitrogen, and H₂S. Carbon dioxide and nitrogen are often used to energize well stimulations to assist with flowback and cleanup. The carbon dioxide and nitrogen flowback and can not be routed to the pipeline because they make the gas not salable. The natural gas gathering system operator ultimately controls when an operator can send gas to sales.
- **There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well and not choke it.** This has been discussed in further detail under Section 15.3.2 below and Attachment F (Reservoir Performance) which is incorporated in these comments by reference.
- **The natural gas gathering line must be operational at the time of the completion.** Natural gas gathering lines can be down for a multitude of reasons including but not limited compressor maintenance or repair, line maintenance, line inspection, the gas plant being shut down, etc.

Furthermore, there are many reasons to complete a well and flowback without a natural gas gathering line or production equipment in place including but not limited to:

- **Avoiding lease jeopardy by establishing production in paying quantities.** Mineral leases contain expiration clauses tied to specific milestones to encourage the development of a lease hold in a timely fashion. One of the typical milestones is performance of a well completion. If the date is missed, the lease expires, causing the rights owner not only to lose the cost of the lease, but the investment in assessing the lease and preparing to drill it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to unavailability of REC equipment create an additional risk that the operator could fail to live up to steps in the contract and negate the contract causing the operator to lose their rights to the minerals.

- **Waiting for the necessary permits for installing the pipeline or the production equipment.** For major sources and minor sources in some states or on Tribal land, a permit for installing the production equipment must be obtained prior to construction of the source. Due to lease requirements, the well may have to be drilled within a certain time period as discussed above. If the air permit for collection system compression or the well site (if required) has not been obtained in time, the well could have to be drilled due to performance provisions in the lease agreement before the production equipment can be constructed. Furthermore, permits are needed to install the pipeline to connect to the natural gas gathering system. Time for approval of permits depends on the agency reviewing them and is out of the control of the company owning the well.
- **Not knowing the composition of gas limiting ability to design the production equipment or pipeline.** In some areas, the production equipment and pipeline are not installed until the composition of the gas is known in order to design the equipment to handle the gas and condensate, particularly for sour gas fields where the level of H₂S is critical for the design requirements. This is particularly significant in areas where the reservoir and properties are not well known and delineated.
- **Getting the surface rights for installing production equipment.** In many cases the owners of the mineral rights are different from the surface rights; therefore, surface rights must be obtained for construction of a pad to drill a well and subsequently install the production equipment. These surface rights are size/area limited and in many cases not sufficient to have in place both the completions equipment and the production equipment at the same time so companies wait to install the production equipment until after the drilling and completions equipment are gone. This also limits the “footprint” of surface disturbance to the area.

API requests that any well that does not have production equipment or a natural gas gathering line reasonably available based on when the well is flowed back should be able to be treated the same as a delineation or wildcat well under the rule and be able to combust or vent the natural gas. At a minimum, we would appreciate concurrence that the issued discussed above are conditions in which routing to a sales line are not practicable.

15.3.2. Pipeline Pressure

When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure and maintain adequate velocity to clean-up the well and reservoir. Any time this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline. This allows clean up of the well bore and is critical to minimize the potential for formation damage. It is possible that sensitive zones can lose productivity due to increased clean-up time required if back pressure is added to the well because of the line pressures. Once a fracture stimulation is pumped, flowback and cleanup must proceed regardless of sufficient pressure to enable sales or severe and permanent reservoir damage is likely. Adding compression to overcome line pressure on low energy wells has been tried several times and found to be not feasible for technical reasons. Furthermore it adds additional emissions for engines to power the compressors while greatly increasing the cost.

The Colorado Oil and Gas Commission requirements under 805(b)(3) are written to apply only to “on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater.” Based on conversations with industry and agency participants in the rule making, the threshold of 500 psig was based on ensuring the reservoir pressure was high enough to overcome the line pressure, clean out the well, and not choke the well based on the reservoir and line pressures within Colorado. Based on the wide range of variability across the US in reservoir and line pressures, setting a specific pressure threshold would be difficult. API recommends that any well whose reservoir pressure (measured at the wellhead immediately after perforation) is less than 4 times (in absolute units) line pressure measured at the flow meter would be exempt from any requirement to flow to sales during the flowback period. Please see Attachment F (Reservoir Performance) which is incorporated into these comments by reference for additional information.

15.3.3. Drilling Fracture Plugs and Running Tubing

Nitrogen may be added to the fluid stream when drilling fracture plugs to help assist flowback and debris removal. The nitrogen content prevents the gas from meeting pipeline specifications and may render the gas unable to support combustion. A well must be flowed while drilling out plugs to remove cuttings/debris and prevent “pack off” around the tubing which is likely to result in stuck tubing. Flow may be sent to a pit or flow-back tank and atmospheric pressure rather than sales to reduce back pressure to enable fracture-plug debris and sand to be more efficiently removed from the well. Furthermore, higher back pressures which may occur if “pack off” around the tubing occurs, may result in cross flow from high pressure zones to low pressure zones, which results in the inefficient cleanup of low pressure zones and may cause irreparable formation damage.

15.3.4. Hydrates and Maintenance

Pressure drops across a flow-back choke can initiate hydrate formation. The additional equipment and piping associated with flareless completions creates an even greater opportunity for hydrates (which form at elevated temperatures while the stream is at elevated pressure). Hydrate formation can plug the pipeline, wellhead equipment, or production equipment. If any of the components must be taken out of service, the well may be routed to the flare until the hydrate problems are solved and the system is back on line. Cold weather operations need additional flexibility to flare to prevent hydrates during clean-up operations.

15.3.5. Depressuring High Pressure Wells

Routing initial flow from a high pressured well to the sales line can create a safety issue. When there is a large difference between the well pressure and the sales line pressure, the decrease in pressure results in a significant temperature drop. This cold gas stream can cause the equipment to freeze up. Initial well flow after drilling or shut-in will be flared until the gas is warm enough to be routed to sales safely. Some companies require the use of a line heater to prevent freezing and choking the well.

15.3.6. Exempt Appraisal Wells from Going to Sales.

The proposed Subpart OOOO does not require reduced emissions completions for “wildcat” and “delineation” wells because such wells are “generally not in close proximity to a gathering line.” 78 FR 52745. These two terms are defined as follows:

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists

These terms probably work reasonably well in conventional oil and gas reservoirs to define the early stages in field development where a gathering system would not be expected to be present.

However, unconventional reservoirs such as shale gas reservoirs present different issues in determining whether infrastructure investment in gathering systems is appropriate. The issue is related to understanding well performance and ultimate well recovery. The decline of wells in unconventional reservoirs is not as well understood and most of the 'new' shale plays have only limited production history. It often takes several wells and significant production history before enough production data exists to properly characterize the well and area potential. Aside from the lesser degree of production history, shale plays have two other characteristics that may delay infrastructure investment:

- Horizontal wells are more costly to drill and prepare than typical conventional wells, so that good production history is important to determine if more wells are economically viable
- Shale reservoirs often have gradual gradients from oil to gas. Oil remains more valuable as a commodity than natural gas, so that one function of field appraisal is to find the economically viable areas of a shale reservoir, not its technical geologic boundary

API recommends adding “Appraisal wells” as a third category of well that is exempt from the REC requirements of §60.5375(a). The suggested definition shown below has been drawn from definitions used by the Energy Information Agency and other federal agencies such as the USGS and SEC.¹

Because the term “proved reserve” has an important regulatory and financial reporting meaning, companies have a very strong incentive to accurately report areas and amounts of proved reserves.

We believe this additional definition better reflects the universe of wells for which a gas gathering system will not be available. It also avoids a potential “chicken before the egg” problem where a shale play appraisal well system is effectively compelled to install a

¹ http://www.eia.gov/dnav/ng/TblDefs/ng_enr_shalegas_tbldef2.asp

gathering line system before the wells are determined to be economically viable, in order to assure compliance with NSPS Subpart OOOO.

Suggested Rule Text:

§60.5430

Appraisal well means a well drilled in an area where the reservoir has not been classified for that area as containing proved reserves of natural gas.

Proved reserves of natural gas are reserves which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas -- oil and/or gas -- water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

15.3.7. Allow for Venting Versus Flaring

The rule allows for venting in “conditions that may result in a fire hazard or explosion.” However, there are also times when the gas may not be burnable due to low BTU content from use of nitrogen or CO₂ in the fracturing operation which would require venting. Also, there are areas of the country that do not allow for the use of a combustion device due to fire hazard such as San Juan County, CO or areas where burn bans are put in place.

15.3.8. Allow For Electronic Igniters

The rule currently requires a completion combustion device with a “reliable continuous ignition device.” In many cases electronic igniters are used instead of a continuous ignition device. API requests that the rule be modified to explicitly allow the use of electronic igniters. (See Section 9.1.2 of general comments for more details.)

15.3.9. Completion Combustion Device Not Subject to §60.18

Section 60.5375(a)(3) provides that “You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”

EPA appears to have chosen the term “completion combustion device” so that the pit flares, which the preamble states at p. 52758 are not a “traditional flare control device” would not be subject to §60.18. The preamble indicates that this is the case “because of the multiphase

slug flow and intermittent nature of the discharge of gas, water and sand over the pit.” As a result, pit flares cannot comply with the technical requirements of this section.

However, Subpart OOOO also includes a definition of flare at §60.5430 which reads as “*Flare* means a thermal oxidation system using an open (without enclosure) flame.” This definition would include pit flares because they use an open flame to oxidize the gas portion of the flowback. While pit flares are often used, some operators may choose to use temporary portable “field flare” flare devices or be required to do so by state or local rules. These temporary portable “field flares” may or may not be capable of meeting the full requirements of §60.18 and API requests that they receive the same exclusion from the requirements of §60.18 that are afforded to pit flares.

Suggested Rule Text:

§60.5430

Flare means a thermal oxidation system using an open (without enclosure) flame. [A completion combustion device is not a flare.](#)

Suggested Rule Text: Please see suggested rule text for §60.5375 under Section 15.2.

15.4. Availability of Equipment and Experienced Operators

Paragraph 60.5370(a) requires that “You must be in compliance with the standards of this subpart no later than the date of publication of the final rule in the Federal Register or upon startup, whichever is later.” EPA is required to complete the final rules by February 28, 2012 which is the deadline established in the consent decree EPA negotiated with WildEarth Guardians and San Juan Citizens Alliance. Obtaining the necessary equipment and experienced staff for reduced emissions completions (REC) is a significant issue as discussed below. The processes and equipment used for doing reduced emissions completions have taken industry over 10 years to develop and vary greatly depending on the reservoir type, gas composition, hydraulic fracturing medium used, etc. Currently most of the larger operators are employing REC where it makes economic sense; however, the majority of smaller and independent operators are not currently doing REC. As written, every gas well hydraulically fractured would require REC as discussed further in Attachment G (RIA Review), which is incorporated into these comments by reference.

Due to the limited availability of appropriate and safe equipment and experienced and trained personnel to perform REC's, API requests that compliance with the reduced emissions completions portion of the rule, except for routing gas to a completion combustion device, be delayed for 2 years to allow for manufacturing of equipment and training of operators. This delayed compliance date is necessary to ensure the implementation of safe equipment and practices and enable the ability of companies to comply with the proposed requirements. Under 40 CFR 60 Subpart A, Ja, AA, JJJ, and KKKK, EPA allowed for an effective date for compliance with the rule after the final rule was published in the federal register. The Wyoming Department of Environmental Quality allowed over a year from the time their “Oil and Gas Production Facilities Chapter 6, Section 2 Permitting

Guidance" revised March 2010^J was approved until permits were issued for reduced emissions completions to give all companies time to acquire the needed equipment and train operators on doing the completions for only part (concentrated development areas and the Jonah Pinedale Development Area) of the State of Wyoming. With the nationwide coverage of Subpart OOO the magnitude of the gap between current availability and necessary equipment and experienced personnel will be much larger and a longer delay will be required.

15.4.1. Availability of Equipment

With implementation of the rule required so quickly after the rule is finalized, equipment will not be available to meet these requirements. There is already a shortage of the specialty equipment required due to the recent WYDEQ BACT Policy and the expansion of the rule to all of the US will make this shortage unmanageable. It will take a significant amount of time for the vessel/equipment manufacturers to expand their capacity to manufacture adequate equipment which meets API and pressure-vessel code specifications in the quantities required to comply with the rule. Maintaining the current aggressive rule implementation schedule will force one of two outcomes:

- (1) The pace of drilling of new wells and recompletion of existing wells will be sharply reduced which will result in job losses, supply disruption, higher natural gas prices, and higher electricity prices.
- (2) In order to comply, companies will be forced to use or quickly manufacture/modify equipment which may not meet fabrication codes and standards and could be less safe to use.

In short, the current schedule contemplated by the rule is very likely to unnecessarily create unsafe conditions and operations or supply disruptions and job losses.

Today there is something on the order of 300 sets of REC equipment in existence. This equipment has the ability to process approximately 4,000 wells a year. To allow 20,000 wells to flow to sales in a year would require about 1,300 additional sets of equipment. This equipment is fairly specialized, the shops licensed to make it are limited, and some of the components require a long lead time. It should be expected with today's demand for other pressure vessels that it will be on the order of one year before the first set of additional equipment can be delivered. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. For this reason, API also requests that the applicability be further limited and that the specific equipment not be specified as discussed further below. As discussed in Section 7.4, if the equipment is not available it does not constitute "the best system of emission reduction."

A related problem with meeting the equipment demand is the availability of capital to fund the necessary new equipment given the current economic conditions and credit availability. Manufacture of a single set of high-pressure code compliant REC equipment is expected to

^J Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

cost about \$467,000 per set. With the estimated 1,300 additional sets necessary this implies a capital investment in excess of \$600 MM to manufacture the equipment. The majority of the pressure vessel manufacturers are not large companies and will likely not commit the capital and effort to expanding the equipment base until the rule is finalized and detailed requirements are known. Even when the rule is finalized, detailed requirements known, and manufacturers chose to construct additional equipment they may not be able to access the funding required. This could further extend the time required for the necessary suite of equipment to be manufactured and deployed.

The current flowback language requires that this equipment must be available prior to stimulation even if it is known that the reservoir pressure/energy, pipeline pressure, and prior well behavior in an area preclude or make highly unlikely that a well can flow to sales. Requiring equipment on site even when it is known that REC's cannot be reasonably accomplished will unnecessarily exacerbate the equipment and personnel shortage problems with zero benefit while imposing unnecessary costs on the operators and ultimately the public. This unnecessary requirement will exacerbate the likely reduced well activity with the consequent job loss, lowering of gas supply, and raising of natural gas and electricity prices.

An additional potential economic harm is the requirements included in mineral leases. If the spud date of a well is delayed by very many months due to equipment availability, then there is a real risk that companies can find themselves in violation of leasing agreements that allow those agreements to be cancelled by the mineral owner. This "lease jeopardy" situation is a real danger in oil & gas operations and production companies take special pains to avoid it where possible. Requirements of REC will create a real risk that companies will lose leases that otherwise would have represented substantial value.

15.4.2. Availability of Experienced Operators

An additional significant concern with requiring implementation of the rule so quickly after the rule is finalized is that industry will have a shortage of experienced contractors or staff for complying with §60.5375(a) or doing "reduced emissions completions". Reduced emissions completions are very complicated and involve many safety issues/concerns with unique risks. The high pressure flow rates of fluids and sand can be quite dangerous. Inexperienced staff will not have adequate knowledge to properly manage the unique risks and prevent incidents from occurring. Industry will not have time to adequately train contractors or staff on how to safely do "reduced emissions completions" which again is likely to create unsafe conditions and operations.

Suggested Rule Text:**§60.5370**

- (a) You must be in compliance with the standards of this subpart no later than 60 days after the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later: ~~except for the provisions of §60.5370(a)(1)-(5) below:~~
- (1) Compliance with §60.5375 is required beginning [two years after the effective date]. From the [effective date] until [two years after the effective date] comply only with §60.5375(a)(1)(ii).

15.5. Timing of Requirements

EPA has stated during conference calls on the rule and at a meeting with API that it was EPA's intent that well completions at gas wellhead affected facilities commenced after the August 23, 2011 proposal date for NSPS OOOO where the completion was commenced before the effective date of the final NSPS OOOO ("Proposal Period Wells") did not require compliance with the emissions control requirements of §60.5375(a). This appears to be consistent with section 111(e) of the Clean Air Act, which reads as follows:

(e) After the effective date of standards of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source.

If the completion work is commenced before the effective date of the final rule, the owner or operator of an affected natural gas wellhead facility will not be operating the well in violation of the requirements of §60.5375 (or other provisions of Subpart OOOO that apply) after the effective date of the final rule. Thus, the requirements of Subpart OOOO do not apply to Proposal Period Wells. However, the applicability section of the rule is written as follows:

§60.5365 Am I subject to this subpart? If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart.

This can be read to require that Proposal Period Wells comply with the emissions control requirements of §60.5375. This concern is magnified by the recordkeeping requirements in §60.5420(c).

§60.5420 (c) Recordkeeping requirements. You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

- (1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).
- (i) Records identifying each well completion operation for each gas wellhead affected facility conducted during the reporting period;

- (ii) Record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.
- (iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section.

In particular, subparagraph §60.5420(c)(ii) appears to state that it is a “deviation” (i.e. a violation of Subpart OOOO) if Proposal Period Wells are not completed in accordance with the requirements specified in §60.5375(a)

To clarify the applicability of Subpart OOOO to Proposal Period Wells, API recommends that Section §60.5375 be amended to add a new paragraph (g):

Suggested Rule Text:

§60.5375

(g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f).

Most of the recordkeeping provisions applicable to gas wellhead affected facilities are tailored to documentation of compliance with §60.5375(a). We are suggesting recordkeeping requirements for Proposal Period Wells which require documenting that the well is not required to comply with emissions control requirements in §60.5375(a). We have also suggested that owners and operators have until two years after publication of the final rule in the federal register or worst case 60 days after publication of the final rule in the federal register to comply with these reporting and recordkeeping obligations, so that owners and operators have a reasonable compliance period to provide these notifications and ensure that proper exemption documentation relating to Proposal Period Wells is in place after the effective date.

API believes that neither section 111(e) (set forth above) nor section 111(a)(2)^K prevent EPA from allowing Proposal Period Wells additional time after the effective date of NSPS OOOO to comply with reporting, recordkeeping and notification requirements^L. That is because these requirements are not standards of performance as that term is defined in section 111:

Section 111(a) For purposes of this section:

^K (2) The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

^L This comment is not intended to suggest that EPA lacks authority under Section 111 as a general matter to allow for compliance dates after the effective date of an NSPS rule. Other sections of API's comments discuss other requirements for which API believes additional time should be allowed for compliance after the effective date of NSPS OOOO.

- (1) *The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction.*

Thus, it is only the standard for emissions of air pollutants that is referenced in section 111(e). Reporting, recordkeeping and notification requirements are not, therefore, standards of performance so that section 111(e) need not be read to require compliance with these requirements on the effective date of NSPS OOOO. This appears to a distinction already recognized by EPA as general matter, since EPA already allows time after the effective date of rules to submit reports and notifications for other new sources.

15.6. Applicability Issues

Further clarity is needed in various parts of the rule text as to where reduced emissions completions applies.

15.6.1. §60.5365(a)

As discussed in Section 5.6.2 (modification) of the comments, §60.5365 states, “For the purposes of this subpart, a well completion operation refracturing that occurs at a natural gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the natural gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.” First, this general section is the wrong location for this text. It only adds confusion. At a minimum, it needs to be moved to §60.5365(a) which discusses the affected source. More importantly, it adds to the confusion of what the affected source is or should be. As discussed in Section 5.4.1, the affected source has been defined as the wellhead, when the emissions being regulated are emissions from the flowback immediately following hydraulic fracture stimulation. API believes that this contradiction will lead to decades of confusion and disagreements by regulators and industry alike. API believes that this contradiction must be eliminated by the consultation and supplemental proposal previously discussed. However, if EPA refuses to do so, then EPA should clarify its intent through a series of definitions and regulatory text revisions that makes its intent much more clear than does the proposed rule.

Currently, there is no time limit placed on “following” hydraulic fracturing or refracturing. Thus, as written, once a well has been hydraulically fractured, any subsequent well work could be subject to the reduced emissions completions requirements. Furthermore, it does not limit the applicability to the flowback immediately following hydraulic fracturing at a natural gas wellhead facility onshore. Also, EPA mistakenly states that the rule applies “before” August 23, 2011.

Suggested Rule Text: See suggested rule text for §60.5365 under Section 5.4.3

15.6.2. §60.5375

Under §60.5375, it states that “for each well completion operation with hydraulic fracturing” the operational procedures of reduced emissions completions applies. However, as with §60.5365, there is no time limit placed on “with hydraulic fracturing or refracturing” and could be interpreted that any subsequent well work could be subject to reduced emissions completions. Also, it does not limit the applicability to the flowback immediately following hydraulic fracturing. Furthermore, “gas wellhead” is never mentioned which could be interpreted that all hydraulically fractured wells, gas and oil, would be subject to these requirements.

Suggested Rule Text: See suggested rule text for §60.5375 under Section 15.2.4.

15.6.3. Definition of Modification

As discussed earlier in the comments, a “modification” should apply to flowback of a recompletion immediately following hydraulic fracturing that has a reasonable expectation to be greater than the original completion. Wells that are recompleted within the same reservoir/zone that was previously hydrofractured will necessarily have fewer emissions than previously experienced due to the depletion of reservoir pressure. However, a well that is recompleted in new reservoir may have more or less emission than in original completion operations. By including recompletion in the definition of modifications, EPA has exceeded the intent of the CAA. The definition of modification should remain under §60.14. However, if EPA chooses to define modification in this subpart, the recompletions portion of the definition of modification should be removed.

Suggested Rule Text:

§60.5430

Preferred Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

15.6.4. Gas Wellhead Applicability Only

Based on EPA's discussion in Section 4 of the Technical Support Document, it appears the EPA's intent is to require reduced emissions completions only for natural gas wells. However, the rule needs to include "natural gas" versus "gas" throughout as API has proposed for clarity. API supports that EPA applied reduced emissions completions only to natural gas wellhead facilities and excluded oil wellhead facilities and other types of gas wells which have little or no VOC emissions. As shown on page 4-13 on Table 4.4 "Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions" of the Technical Support Document, there are only 134 TPY of VOCs emissions from oil well completions and recompletions for the entire U.S., which is not worth regulating.

15.6.5. Offshore Applicability.

Based on the Technical Support Document and preamble for the proposed rule, it was clear that EPA did not assess the feasibility and cost for doing reduced emissions completions offshore. Without a pipeline being available nor space for the specified reduced emission completions equipment, it is not feasible to do REC offshore. Furthermore, many offshore rigs are often foreign flagged and will not necessarily be designed to accommodate or achieve US regulatory requirements. Therefore, API request that reduced emissions completions only apply to onshore facilities.

Suggested Rule Text : See suggested rule text for §60.5365 under Section 5.4.3, for §60.5375(a) under Section 15.2.4, and for the definition of a modification under Section 15.6.3 above.

15.7. Multiple Notification Requirements

The rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility which include:

- Post-marked 30 days after construction [§60.7(a)(1)],
- Post-marked 15 days after initial startup [§60.7(a)(3)],
- Post-marked 60 days or as soon as practicable before the changed is commenced [§60.7(a)(4)], and
- 30 days of the commencement of the well completion operation [§60.5410(a)(1) or §60.5420(a)(2)].

Furthermore, EPA requested comment on a "follow-up notification one or two days before an impending completion via telephone or by electronic means" which would mean five notifications for every completion operation. EPA predicted 20,000 hydraulic fracturing and refracturing events per year resulting in greater than 100,000 notifications per year. These multiple notifications will be excessively burdensome on both the Administrator and industry with no benefit to air quality. Industry would need full time employees to just do all these notification and re-notifications. EPA

solicited many comments on the notifications for completions on pages 52749-52750 of the Federal Register. In response to EPA's questions, API proposes the following changes.

15.7.1. Remove Subpart A Notifications

API requests that all the §60.7(a) notifications be removed since they are not appropriate for completions operations. The definitions of both "construction" and "initial start-up" do not apply to the flowback immediately following hydraulic fracturing. The flowback is a temporary operation that lasts only "3-10 days" as discussed in the preamble. Furthermore, predicting 60 days in advance of doing a completion operation is not possible. Even drilling of the well would not necessarily have even been started 60 days prior to the completion operation so predicting when the completions event would begin is even more difficult to predict. The timing for the flowback portion of the completions operation depends on the drilling schedule, availability of the drilling equipment, the time to drill the well, the schedule for the completion, the availability of the equipment for casing the well and running tubing, the schedule for casing the well and running tubing, the schedule for fracturing, the availability of the hydraulic fracturing equipment, the time to fracture the well, the number of fracture stages (individual or multi-stage), etc.

15.7.2. Remove the Notification to EPA 30 Days Prior to a Well Completion Operation or Change as Proposed

Paragraph 60.5420(a)(2) requires that you must submit a notification to the Administrator within 30 days of the commencement of the well completion operation. The notification must include the date of commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983." Based on the preamble and discussions with EPA, it is API's understanding that the intent was that notification be given to EPA 30 days prior to the doing a completion so that the Administrator could attend. Predicting a completion 30 days prior to its occurrence is extremely difficult as discussed above. In many cases the well may not have begun to be drilled. The actual date of the flowback depends on a multitude of factors as discussed above. EPA acknowledged this issue in the preamble stating "We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance" (pg. 52749-52750 of the FR). API requests that this notification requirement either be removed or reduced to a monthly report of the well completions scheduled to occur during the upcoming month. The notification could provide the tentative scheduled date for the start of the flowback immediately following hydraulic fracturing that will occur in the following month. The Administrator could contact the company with questions to request or more up-to-date timing of the flowback operations if needed. This would minimize the burden for reporting for each flowback operation for operators and give the Administrator a plan of the operations for the month ahead. Follow-up notification two days in advance seems excessive. With operations lasting 3-10 days, this should allow the Administrator sufficient time to attend part of the flowback operation.

Suggested Rule Text:

§60.5410

- (a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.
- (1) You have notified the Administrator monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month in which you have one or more hydraulic fractures scheduled, including within 30 days of the commencement of the well completion operation, the tentative scheduled start date of the well flowback and commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

§60.5420

- (a) You must submit the notifications required ~~in §60.7(a)(1), (a)(3) and (a)(4), and~~ according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in §60.5365. ~~For the purposes of this subpart, a workover that occurs after August 23, 2011-2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under §60.7(a)(4).~~

* * * * *

- (2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month in which you have one or more hydraulic fractures scheduled~~within 30 days of the commencement of the well completion operation~~. The notification must include the tentative scheduled start date of the well flowback and commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

15.8. Clearer Definitions

The definitions for gas well, crude oil, well completions, well completions operation, and hydraulic fracturing in the rule are unclear and inconsistent with common industry understanding. Also, the definition of flowback should be edited as discussed in Section 5.4.2, and a definition should be added for well recompletion.

15.8.1. Definition of Gas Well

The definition of a gas well is unclear. “*Gas well means a well, the principal production of which at the mouth of the well is gas.*” The phrase “mouth of the well” is not a term used or defined in the industry, by the EIA, or commonly understood. For consistency with 40 CFR 98 Subpart W of the GHG Mandatory Reporting Rule and the EIA definition of a “gas well”, API recommends using the definition of a gas well from 40 CFR 98.238 (which is based on the EIA definition) of “*Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.*”

Suggested Rule Text:

§60.5430

Gas well means a well, ~~the principal production of which at the mouth of the well is gas.~~ completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

15.8.2. Definition of Crude Oil

The definition of crude oil that EPA uses in the proposed rule conflicts with the definition of crude oil used in the Greenhouse Gas Mandatory Reporting Rule 40 CFR 98 Subpart W, by the EIA, and most states. The API gravity is not known for a well at the time a well is completed; therefore, with the definition of a gas well including crude oil and the definition of a gas well determining applicability for REC, the definition of crude oil should not contain an API gravity. API, therefore, recommends that EPA use the definition of crude oil from the EIA^M. This definition is also consistent with the definition of crude oil used in the Greenhouse Gas Mandatory Reporting Rule 40 CFR 98 Subpart W.

Suggested Rule Text:

§60.5430

Crude oil means ~~crude petroleum oil any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.~~ a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of non-hydrocarbons produced with the oil.

^M http://www.eia.gov/dnav/pet/TblDefs/pet_crd_pres_tbldef2.asp

15.8.3. Definition of Well Completions

Under §60.5430 a well completion is defined as “the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment.” Flowback of the well after hydraulic fracturing is potentially part of a well completion but a well completion may involve other activities such as perforating the production casing, stimulating the reservoir, and installing wellbore equipment such as tubing, packers, or liquid-lift tools.

API suggests the following definitions for well completion and well completion operations:

Suggested Rule Text:

§60.5430

Well Completions means the process ~~that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment~~ of making a new oil or natural gas well ready for production. It allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics and also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture stimulate and prop open new fractures in lower permeability reservoirs.

Well Completion Operation means any well completion ~~or well workover~~ occurring at a gas wellhead affected facility onshore.

15.8.4. Definition of Hydraulic Fracturing

The definition used for hydraulic fracturing is inconsistent with standard industry understanding. API recommends the following definition that is based on the definition of hydraulic fracturing in the Schlumberger Oilfield Glossary^N.

Suggested Rule Text:

§60.5430

Hydraulic fracturing means ~~process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that~~

^N <http://www.glossary.oilfield.slb.com/>

~~involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers~~ [a stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a fracture\(s\) to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.](#)

15.8.5. Definition of Flowback

As discussed in Section 5.4.2, to help prevent confusion of what is being regulated under §§60.5365(a) and 60.5375, API recommends that discussions of well completions and recompletions should only be included in the definition of flowback to prevent confusion of what is being regulated.

Suggested Rule Text:

§60.5430

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. [Flowback immediately following hydraulic fracture stimulation may occur in conjunction with a well completion, well recompletion, or fracture stimulation of the same zone in an existing well.](#)

15.8.6. Add Definition for Well Recompletion

The current proposed rule does not define *well recompletion*. This term has been included in the suggested revisions to the rule text. Therefore, API suggests the following definition for well recompletion be added to the proposed rule text.

Suggested Rule Text:

§60.5430

[Well Recompletion means completing a well again. See the definition of well completion.](#)

15.9. Remove the Requirement to Record the Distance to the Nearest Gathering Line

Paragraph 60.5420(c)(1)(iii)(B) requires that “For each gas wellhead affected facility required to comply with the requirements of §60.5375(f) “you must record the distance, in miles, of the nearest gathering line.” This could take an excessive amount of work to determine and provides no benefit to air quality. Before natural gas production can be sent to natural gas gathering line, all of following must be done as discussed in more detail under Section 15.3.1:

- A natural gas gathering line system must be permitted, installed and operational in the area a reasonable distance from the well.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must be in place.
- The necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system must be obtained.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well against the pipeline pressure without lowering the flow and velocity to the point where the well will not adequately clean-up.
- The natural gas gathering line and system must be operational at the time of the completion.

Suggested Rule Text:**§60.5420**

~~(c)(1)(iii)(B) For each gas wellhead-affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.~~

15.10. Emission Rates and Economics Are Unrealistic

Based on API's analysis, the data presented by the EPA for the cost effectiveness of reduced emissions completions does not take in account great variability of the VOC content of the gas, the flow rate of the gas, equipment needed for reduced emissions completions, etc. to adequately address requiring reduced emissions completions for all hydraulically fractured wells. Due to the vast variability, determining a threshold for cost effective reduced emissions completions is extremely difficult. EPA has looked at small subset of wells for the RIA which does not fully represent the diversity of wells across the US that are hydraulic fractured. Please see Attachment G (RIA Review) for more details. API estimates that the average cost per ton of VOCs without sales is \$33,748 versus EPA's estimate of \$1,516 and cost per ton of VOCs with sales is \$27,579 versus EPA's net gain of \$99. The overall cost to the industry for doing REC in 2015 would be \$782.6 Million versus EPA's benefit estimate of \$20.2 million.

15.10.1.EPA's Overestimate of Completions Emissions

In the preamble EPA stated "we estimate that uncontrolled well completion emissions for a hydraulically fractured gas well are approximately 23 tons of VOC, where emissions for a conventional gas well completion are around 0.12 tons VOC." Many of the formations currently being developed have very low concentrations of VOCs in the gas, particularly for some shale gas and coal bed methane formations.

An article published in *Oil & Gas Journal* March 9, 2009 titled "Compositional variety complicated processing plans for US shale gas" written by Keith A Bullin and Peter E Kroushop both of Bryan Research and Engineering had a series of tables that are summarized below:

Table 15-1. Average Compositions of US Shale Gas

| Area | C1 | C2 | C3+ | CO2 | N2 |
|---------------------------|-------|-------|------|------|------|
| Barnett Average | 86.8% | 6.7% | 2.0% | 1.7% | 2.9% |
| Marcellus Average | 85.2% | 11.3% | 2.9% | 0.4% | 0.3% |
| Fayetteville Average | 97.3% | 1.0% | 0.0% | 1.0% | 0.7% |
| New Albany Average | 89.9% | 1.1% | 1.1% | 7.9% | 0.0% |
| Haynesville Shale Average | 95.0% | 0.1% | 0.0% | 4.8% | 0.1% |
| Shale Gas Average | 90.8% | 4.0% | 1.2% | 3.1% | 0.8% |

One API member furnished an average VOC content for coal bed methane wells (1,190 analyses) in the SW Colorado (Durango area) San Juan Basin area which indicates the following composition:

Table 15-2. Average VOC Concentrations of Coal Bed Methane Wells in SW Colorado

| | C1 | C2 | C3 | IC4 | NC4 | IC5 | NC5 | C6 | CO2 | N2 |
|-----------------|--------|-------|-------|-------|-------|-------|-------|-------|--------|-------|
| Mole % | 94.694 | 0.332 | 0.062 | 0.010 | 0.009 | 0.002 | 0.001 | 0.002 | 4.330 | 0.280 |
| Weight % | 87.694 | 0.576 | 0.159 | 0.034 | 0.031 | 0.009 | 0.006 | 0.010 | 11.027 | 0.453 |

As these data illustrate, the variability of VOC content is broad and EPA's assumption of "average" VOC content is both high and does not reflect many of the producing areas. Consequently, EPA's analysis of cost per ton of VOC emissions controlled is both high and does not reflect the reality of gas compositions. For example, a 3 day flow-back period for a well with the Durango area average composition and EPA's assumed flow-back volume of ~9,175 mscf of gas would reduce VOC emissions by about 900 lbs at an EPA estimated risked cost of \$33,237 (~\$72,500 per ton) with no condensate recovery and a more likely maximum recovery of ~70%. With a 70% recovery the VOC reduction would be ~ 0.36 tons with an EPA estimated cost of \$33,237 and a total product sales revenue of ~ \$25,692 or a net cost of ~\$21,163/ton of VOC reduced which is clearly economically unreasonable. Given that API's analysis predicts sharply higher costs, lower overall volumes, and lower (<90%) recovery than EPA's estimate the costs of applying REC's to a well in the Durango area would approach \$500,000 per ton.

API requests that the final regulation include an applicability cut-off of 10% VOC by weight as discussed in Section 5.1.2. Actual data shows emissions range from 0 to 156 tons per flowback depending on the volume of the gas in the flowback, the VOC concentration, etc. (see Attachment G (RIA Review) for more details). However, the average emissions for shale gas wells are only 5.334 Tons of VOC per flowback. As the Tons of VOCs per

flowback drops to zero, the cost for doing reduced emissions completions per ton goes to infinity.

15.10.2. Cost of “Reduced Emissions Completions”

The estimated cost per well to do reduced emissions completions ranges from ~\$30,000 - \$200,000 per well according to an API survey depending on whether equipment is rented or owned, the equipment required, the time need for having the equipment on site, etc. (see Attachment G for details). In the preamble, EPA stated that, “Typical well completions last between 3 and 10 days and costs of performing REC are projected to be between \$700 and \$6,500 per day, including a cost of approximately \$3,523 per completion event for the pit flaring equipment.” This grossly underestimates the cost. The cost estimate per day in the RIA is reasonably close to the numbers reported in the API survey reported in Attachment G, but the RIA assumes that the equipment rental begins the very first day that it is needed and ends the last day of the flowback. This is unrealistic. The manpower and equipment required for completion events represent valuable resources that are in short supply. It is not normal practice to have stimulation equipment and personnel waiting for equipment installation. The respondents to the survey place the elapsed time for REC rental at 30 days more or less. So, for \$5,000/day a 30 day rental represents a \$150,000 outlay. Further, work around an active well site is very expensive. The respondents in the API survey estimated that mobilization/demobilization and operations of REC equipment adds approximately \$30,000 to the cost of the flowback. API estimates that a REC evolution to sales would add \$180,000 to the cost of the well. For low VOC wells, this additional cost represents a cost effectiveness that can be hundreds of thousands of dollars per ton. On CBM wells and those shale gas wells with very low VOC, the cost effectiveness can approach infinity. Production companies may have economic incentives to flow the well back to sales, but those incentives do not include a cost-effectiveness of VOC emission avoidance. A detailed economic analysis will be submitted later; however, the preliminary results indicate that the cost is much higher than EPA estimated.

15.11. Over Estimate of Number Re Completions per Year

In the TSD, EPA states that “10 percent of the wells being re-fractured annually (as previously assumed in Subpart W’s Technical Supporting Document³). From anecdotal information, API understands that this 10% re-fracture frequency per year was originally from work underlying the National Inventory and was developed based on one paper which evaluated the post re-stimulation performance of five (5) wells in the Barnett shale area which was then extrapolated to the population of unconventional wells nationwide. Obviously relying on extrapolation of somewhat unrelated information on five (5) wells in one area and one formation to the nationwide population of unconventional wells is completely unsupportable. API requests that EPA fully and completely explain the derivation of the 10% re-stimulation frequency per year rather than simply referencing the technical support document for Subpart W which simply makes the 10% assumption with no explanation or backup information. As the largest single reduction category in the proposed rule, this explanation is necessary to reasonably support EPA’s analysis.

According to a 1996 study by the Gas Research Institute (GRI)^O, only 2-3% of wells are refractured. This study found that only 15% of the well populations are potentially high potential restimulation candidates which should be subjected to additional analysis. Another study done in 1999 that was presented in a paper at a Society of Petroleum Engineers conference^P, showed that further analysis must be done to determine whether these 15% would actually benefit from restimulation. This paper presented an analysis of some 300 tight sand wells which had originally been hydraulic fracture stimulated, high-graded the top 15% of candidate wells for further evaluation and ultimately reduced the wells recommended for restimulation to five (5) of which 2 had been restimulated at the time the paper was written. In other words, only a small number (~2% of the total wells) of the top 15% candidate wells would actually be economic to restimulate anytime in their life. Other developing information suggests the percentage of wells refractured annually is less than 1%. Applying a 1% re-stimulation rate per year rather than a 10% would reduce the projected number of affected units to ~1,205 rather than 12,050 (90% reduction) and reduce the emissions reductions by the same magnitude.

16. STORAGE VESSELS

16.1. Applicability

There is considerable ambiguity under both Subpart OOOO and Subpart HH as to the population of storage vessels to which these rules are intended to apply. API requests EPA clarify that the boundaries listed below apply to the storage vessel provisions. Each of these issues is discussed more fully in the paragraphs that follow.

- **Storage vessel properly defined.** That is, defined as stationary vessels constructed of non-earthen materials, and which are distinct from process tanks.
- **Located in the oil and gas production source category.** That is, located upstream of the point of custody transfer between the production field and the liquid distribution pipeline.
- **Storing crude oil or condensate.** That is, storing only produced petroleum liquids.
- **Containing the regulated pollutant.** That is, storing liquids from which the regulated pollutant is emitted at greater than de minimis levels.
- **Having emissions above a cost-effective threshold.** That is, regulating emissions only for those storage vessels for which the controls would be above a cost-effective threshold under Subpart OOOO.

^O Reeves, S.R.: "Assessment of Technology Barriers and Potential Benefits of Restimulation R&D for Natural Gas Wells", Final Report, GRI- 96/0267, July, 1996.

^P Reeves, S.R., Hill, D.G., Tiner, R.L, Bastian, P.A, Conway, M.W. and Mohaghegh, S.: "Restimulation of Tight Gas Sand Wells in the Rocky Mountain Region", SPE 55627, Proceedings of the SPE Rocky Mountain Regional Meeting, Gillette, May 15-19, 1999.

16.2. Storage Vessel Definition [OOOO & HH]

The term “storage tank” or “storage vessel” should be defined in a manner that is consistent with other rules, while acknowledging the particular scenarios unique to the oil and gas production sector. Existing EPA regulations establish several features that distinguish a storage vessel (tank):

- The function of a storage vessel is storage, which distinguishes storage vessels from process vessels or tanks.
- A storage vessel is stationary, which distinguishes storage vessels from containers, vessels attached to mobile vehicles, and other vessels that are placed temporarily.
- A storage vessel is constructed of non-earthen materials, which distinguishes storage vessels from surface impoundments and underground caverns.

16.2.1. Process Tank

Activities identified as process functions in other regulations include:

- Reactions and blending.^Q
- Collection of material discharged from a process prior to transfer to other equipment within the process or to a storage vessel.^R
- Surge control.^S
- Bottoms receiver.^T
- Knock-out.^U

16.2.2. Stationary

The stationary aspect of a storage vessel is typically addressed by EPA in terms of whether or not it is reasonably portable. One issue in the consideration of portability is the size of the vessel, which is sometimes addressed by EPA in regulations pertaining to storage vessels.

Another criterion specified by EPA in several regulations is that “vessels permanently attached to motor vehicles” are not storage vessels, and EPA has issued a determination^V that this exemption extends to tanks “equipped with a permanently attached wheel assembly and a truck hitch.” This renders most so-called frac tanks, Baker tanks, ISO tanks, *etc.* exempt from the storage tank provisions when this form of definition is used.

API recognizes, however, that such tanks sometimes become effectively “stationary” in oil and gas production operations, and that it may be appropriate to apply a time limitation to

^Q From the definition of a Process Tank, 40 CFR 60.111b, added to Subpart Kb Standards of Performance for Volatile Organic Liquid Storage Vessels with the October 15, 2003 rule amendments.

^R Ibid.

^S Ibid.

^T Ibid.

^U From the preamble to the October 15, 2003 amendments to Subpart Kb (68 FR 59328).

^V U. S. Environmental Protection Agency, letter from George T. Czerniak to Ken Comey, Flint Hills Resources L.P., September 2, 2004.

this exemption. We therefore suggest that storage vessels should be deemed stationary if they remain at a given site for more than 180 consecutive days, consistent with the period of time allowed under §60.14(g) to achieve compliance after a modification. As a point of comparison, the definition of non-road engines in 40 CFR 89.2 states:

“(2)(iii) the engine otherwise included in paragraph (1)(iii) of this definition remains or will remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph does not apply to an engine after the engine is removed from the location.”

Given this precedent for the term stationary to not apply until a source has remained in place for at least 12 consecutive months, API's request that stationary not apply to a storage tank at an oil and gas production site until it remains in place for only 180 days is a modest and reasonable request.

Finally, cost effectiveness of the proposed control measures has been evaluated under the assumption that storage vessels remain in place for the useful life of the control equipment, and thus the control costs are amortized over a period of years. The cost per ton of emission reductions would obviously be much higher if the controls were applied to a tank that is only on site temporarily, in that the total cost of controls would be applied to emission reductions achieved over only 180 days, rather than over a period of years. It is clear, then, that a cost-effectiveness analysis for permanent storage tanks would not be valid for temporary storage tanks, and thus the control requirements for permanent storage tanks are not justified for temporary storage tanks.

16.2.3. Non-earthen

This is self-explanatory. Certain EPA regulations add the phrase “such as wood, concrete, steel, fiberglass, or plastic”^W as a parenthetical explanatory clause.

Suggested Rule Text:

We request that the following definition of “storage vessel” be used in both OOOO and HH:

§60.5430 and §63.761

[Storage vessel or Tank means a stationary unit that is constructed primarily of nonearthen materials \(such as wood, concrete, steel, fiberglass, or plastic\) which provide structural support](#)

^W U.S. Environmental Protection Agency, “National Emission Standards for Storage Vessels (Tanks)–Control Level 2,” 40 CFR Part 63, Subpart WW.

and is designed to hold an accumulation of liquids or other materials. Storage vessel or Tank does not include:

(1) Vessels with a design capacity less than or equal to 472 barrels^X storing a volatile organic liquid with maximum true vapor pressure less than 11.1 psia.

(2) Process tanks, including vessels used for a process function such as reactions, blending, or separation, vessels such as sumps used to collect discharged material such that it can be transferred to a process or to storage, vessels used for surge control, and vessels used as knockouts,

(3) Vessels storing wastewater,

(4) Pressure vessels designed to operate without emissions to the atmosphere,

(5) Subsurface caverns and porous rock reservoirs, and

(6) Vessels that do not remain at a given site for more than 180 consecutive days.

16.3. Located in the Oil and Natural Gas Production Source Category

As discussed in Section 3, there is unnecessary ambiguity in the applicability of the proposed rules with respect to storage vessels. The rules need to clearly specify the boundaries of the source category, identify the affected facilities within that source category, and specify which of the affected facilities are subject to the control requirements. Part 60 Subpart Kb and Part 63 Subparts HH, HHH, and EEEE each describe the boundary between the oil and natural gas production sector and the transportation sector as being where oil or natural gas is transferred from production or producing operations to “pipelines or any other forms of transportation.”

It is evident that the oil and natural gas production sector has been historically understood as being distinct from the transportation sector, but Subpart OOOO fails to delineate the sector to which the storage vessel provisions apply. Furthermore, EPA has proposed removing the distinction of “prior to custody transfer” from NESHAP HH, thereby unnecessarily obscuring the boundaries that had been previously established. These ambiguities should be addressed by restoring the source category boundaries to the manner in which they have been historically understood.

16.3.1. NSPS OOOO – Storage Tank Location

While the Subpart OOOO provisions for several types of emission points specify the locations at which the rule applies (e.g., applicability to compressors is specified as being between the well head and the city gate, both of which are defined terms), the applicability section contains no such language to stipulate boundaries for the storage vessel provisions.

^X A capacity threshold of 75 cubic meters (472 barrels) is specified in 40 CFR Part 63 Subpart BBBBBB—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR Part 63 Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), and 40 CFR Part 60 Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

In fact, the provisions simply specify that they apply to storage vessels, with no discussion of what industry sector the storage vessels may be located in.

Paragraph §60.5395(b) addresses overlap of Subpart OOOO with Subpart HH, and the definition of a storage vessel makes reference to a well site, so it might be inferred that applicability of the rule is limited to the production field, but the language is simply not clear. The definition of a storage vessel in Subpart OOOO limits the applicability for storage vessels that are not manifolded together to those located at a single well site. But there is no such qualifier for storage vessels that are manifolded together. Furthermore, the terms “manifolded together” and “single well site” are not defined, and their meaning is not evident.

API requests that EPA clarify the population of storage vessels to which NSPS OOOO is applicable as those located in the production field, prior to the point of custody transfer to the liquids distribution system. This may be accomplished by:

- Replacing the definition of “storage vessel” with the language suggested above (see below for mark-up of EPA’s proposed rule language), and
- Clearly specifying the intended applicability of the storage vessel provisions in the description of the affected facility, at §60.5365(e). This paragraph should specify that applicability is to storage vessels located prior to the point of custody transfer to pipelines or other forms of transportation.

Suggested Rule Text:

§60.5430

Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.

Storage vessel or Tank means a stationary ~~vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy.~~ unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials.
Storage vessel or Tank does not include:

(1) Vessels with a design capacity less than or equal to 472 barrels storing a volatile organic liquid with maximum true vapor pressure less than 11.1 psia.

(2) Process tanks, including vessels used for a process function such as reactions, blending, or separation, vessels such as sumps used to collect discharged material such that it can be transferred to a process or to storage, vessels used for surge control, and vessels used as knockouts.

- [\(3\) Vessels storing wastewater,](#)
- [\(4\) Pressure vessels designed to operate without emissions to the atmosphere,](#)
- [\(5\) Subsurface caverns and porous rock reservoirs, and](#)
- [\(6\) Vessels that do not remain at a given site for more than 180 consecutive days.](#)

§60.5365

* * * * *

- (e) A storage vessel affected facility, which is defined as a single storage vessel [storing condensate or crude oil and located prior to the point of custody transfer.](#)

16.3.2. NESHAP HH – Storage Tank Location

As noted above, the original version of Subpart HH specifies that applicability is limited to storage vessels located prior to the point of custody transfer to pipelines or other forms of transportation. The proposed revisions to §63.760(a)(2), however, would remove that point of demarcation, and instead specify that the rule applies to facilities “prior to the point where hydrocarbon liquids enter either the Organic Liquids Distribution (Nongasoline) or Petroleum Refineries source categories.” While this wording has the apparent intent of preserving the boundary between the production field and the liquids distribution system, the reference becomes circular in that the Organic Liquids Distribution MACT rule (Part 63 Subpart EEEE) specifies that it excludes facilities subject to Part 63 Subpart HH (see §63.2334(c)(1)). Thus the revisions to Subpart HH would result in each rule excluding the affected facilities of the other, but neither rule defining the boundary between the source categories. In order to preserve a specified boundary, the wording of §63.760(a)(2) should continue to specify the point of custody transfer as the demarcation between the production field and transportation sectors. Further clarity would be achieved by replacing the former definition of “custody transfer” with the suggestion shown below (as suggested for NSPS OOOO above).

Suggested Rule Text:

§63.761

[Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.](#)

§63.760

- (a)(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer ~~where hydrocarbon liquids enter either the Organic Liquids Distribution (Non gasoline) or Petroleum Refineries source categories.~~

16.4. Storing Crude Oil or Condensate

API believes that EPA intends the storage vessel requirements to apply only to tanks storing crude oil or condensate, but this intent is not adequately specified in the regulations.

16.4.1. NSPS OOOO – Crude Oil and Condensate

It seems, from the preamble, that EPA intends for these rules to apply only to tanks storing crude oil or condensate. However, the rules do not expressly specify the stored liquids to which the rules are applicable. On the one hand, one might infer from §60.5395(a) that Subpart OOOO applies only to tanks storing crude oil or condensate. On the other hand, the language could be construed to extend applicability to any storage vessel storing any liquid whatsoever, unless the vessel is storing crude oil or condensate and the throughput is below the specified cutoffs (in that the language does not address the situation if the vessel is storing something other than crude oil or condensate). API requests clarification that the storage vessel provisions of Subpart OOOO are applicable only to tanks storing crude oil or condensate.

Suggested Rule Text: See suggested rule text for §60.5365(e) under Section 16.3.1.

16.4.2. NESHAP HH – Crude Oil and Condensate

The MACT Floor memo for Subpart HH, in the discussion of storage tanks, indicates that the EPA survey was representative of “tanks that have the potential for air emissions to occur.” It then states, “Significant HAP emissions can occur due to flashing, and due to breathing and working losses from tanks containing volatile organic liquids such as condensates or volatile oils.”^Y The “volatile oil” produced in the oil and natural gas production source category is, of course, crude oil. It seems readily evident, then, that the storage vessels in this source category are those located in the production field which store condensate or crude oil. API requests clarification that the storage vessel provisions of Subpart HH are applicable only to tanks storing crude oil or condensate.

Suggested Rule Text:

§63.760

(b)(1)(ii) Each storage vessel [storing condensate or crude oil and located prior to the point of custody transfer](#);

16.5. Containing the Regulated Pollutant

EPA's authority to extend applicability of a regulation to a given facility is predicated on that facility being reasonably considered a source of the regulated pollutant. EPA has recognized this by use of the term “in VOC service” with respect to NSPS regulations, and “in organic HAP service” or “in

^Y Memorandum from G. Fitzsimons and G. Viconovic, EC/R, to M. Smith, EPA, “Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category,” September 23, 1997, page 9, section 3.2, third paragraph.

VHAP service” for NESHAP regulations. This is not a matter of requesting an exemption for facilities that are sources of the regulated pollutant, but rather it is a matter of recognizing that below certain *de minimis* thresholds of concentration, a facility is not reasonably deemed a source of that pollutant and thus is not part of the source category.

16.5.1. In VOC Service [NSPS OOOO]

Subpart OOOO, at §60.5400(f), specifies “For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight.” The same statutory authority applies to other types of emission sources as to “equipment,” and thus this requirement of being “in VOC service” should qualify applicability of the rule to every type of emission source. We note, however, that this qualifier would be moot if EPA were to clarify that Subpart OOOO is applicable only to storage vessels storing crude oil or condensate, in that those liquids would always exceed the 10% threshold.

16.5.2. In VHAP Service [NESHAP HH]

Similarly, Subpart HH defines the term “in VHAP service” as involving a total volatile HAP concentration equal to or greater than 10% by weight. Subpart HH presently applies this term only to ancillary equipment and compressors. API requests that this term also be applied in the determination of applicability of Subpart HH to storage vessels, in that EPA is not required to regulate *de minimis* sources of HAPs.

Revision of the rule language to clarify that the rule is applicable to storage vessels that are “in VHAP service” would ensure that applicability of the rule is practicable and effective. As with the issue of “in VOC service” noted above, however, this comment on “in VHAP service” would likely be rendered moot if EPA were to clarify that Subpart HH is applicable only to storage vessels storing crude oil or condensate.

16.6. Having Emissions Above a Cost-Effective Threshold [NSPS OOOO]

EPA has proposed thresholds for applicability of the Subpart OOOO storage vessel provisions on the basis of cost effectiveness. However, both the use of throughput as a surrogate for VOC emissions and EPA's cost-effectiveness analysis are flawed. Also, while we endorse the concept of limiting applicability to tanks that emit more than 10 tpy, we believe that this limit should be specified in the storage vessel provisions rather than in the definitions, and the limit should be 12 tpy (as documented below).

16.6.1. EPA's Emission Rate versus Throughput is Not Credible.

In the preamble VI.B.4.d, EPA states that the emission factors used to establish thresholds for requiring storage vessel controls are from a Texas Environmental Research Consortium (TERC) study. This study H051c, *VOC Emissions from Oil and Condensate Storage Tanks*, calculated emission factors based on observations made during three summer months in 2006 of 11 crude oil tanks and 22 condensate tanks in East Texas. The report calculated an

emission rate as a function of throughput of 33.3 lb/bbl +/- 24.3 lb/bbl for the condensate tanks and 1.6 lb/bbl +/- 1.6 lb/bbl for the crude oil tanks.

We believe the methodology used in the report is flawed for the following reasons.^Z

- A. It is obvious that gross errors in measurements occurred for tank battery #25. Both the reported vent gas molecular weight of 89 and the VOC fraction of 0.99 are impossible values for gas flashed from condensate at a natural gas production site. The calculated VOC flash emissions of 215 lb/bbl would require that 82% of the condensate flashed when reduced in pressure from 200 psig. This is not possible at this separator pressure. Rejecting this data point and recalculating the average VOC emissions from the remaining tank batteries would give a factor of 24.2 lb/bbl, 73% of 33.3 lb/bbl.
- B. For tank battery #17, the calculated VOC flash emissions of 145 lb/bbl would require that 55% of the condensate flashed when reduced in pressure from 200 psig. This is not possible at this separator pressure. Since the other measured data for the vented gas (molecular weight of 36.6 and VOC fraction of 0.65) are reasonable, the error is most likely due to the low condensate production rate of 2 bbl/day used in the calculations. Rejecting this data point and recalculating the average VOC flash emissions from the remaining 19 tank batteries would give a factor of 17.8 lb/bbl, 53% of 33.3 lb/bbl.
- C. Throughput was not accurately determined, because the researchers did not follow their experimental design. Section B1 (Experimental Design), states "VOC emission rates will be measured by sampling the tank vent gas for compositional analysis and measuring the vent gas flow rate. Measurements of separator gas vented to the atmosphere will also be made. The concentration of each C1-C6 gas component in the sample, plus benzene, toluene, ethyl benzene, xylene (BTEX) and other C6+ VOC will be multiplied by the flow rate (averaged over 24-hours) to produce measurements of mass emission rates for each of the reported gas constituents and other C6+ VOC in units of pounds per hour. The mass emission rates will then be divided by the number of barrels produced during the 24-hour flow measurement period to produce emission factors in units of pounds per barrel. Critical measurements for this approach include the following:
 - Vent gas composition;
 - Vent gas flow rate; and
 - Oil or condensate production rate"

On the same page, when discussing selection of well sites to be tested, one of the stated criteria is that "The oil or condensate production rate is at least 2 barrels per day."

^Z The comments in this section are taken in large part from various comments submitted by Dr. Ed Ireland, Executive Director of the Barnett Shale Energy Education Council (BSEEC) to the Texas Commission on Environmental Quality (TCEQ) regarding various regulatory proceedings.

Lastly, Section B5 (Quality Control) states “The greatest source of uncertainty in the calculated emission factors is likely to be the estimation of oil or condensate produced over the sampling period. The accuracy of the emission factors derived from these tests will be limited to how accurately the production volumes can be determined during the sampling episode. While such production information is readily available on a monthly or annual basis from the Texas Railroad Commission, accurate production data over a 24-hour period is generally not available (emphasis added), and will have to be estimated from reading the tank level gauges (if present), manually gauging the tank level, or from production meters at the site if available. The specific methods and instruments used to estimate daily throughput will be recorded in the field sampling log; however, the sensitivities of these devices to oil or condensate throughput over 24-hours is unknown.”

1. Obtaining data from a well site that is producing only 2 barrels of condensate per day is very inaccurate when the goal is to calculate VOC emissions based on a 24-hr test period. Using emissions data based on this low amount of production lends itself to large sampling errors that can result in large variability in reported numbers (which is exactly what occurred). In addition, page 1 of Section B2 (Sampling and Measurement Methods), states that “The liquid production rates will be determined during the test period either by reading the level gage on the tanks (if present at the site), or by manually gauging the tanks. The manual tank readings will be adjusted to account for any unloading of the tanks into tank trucks during the test.”

The smallest capacity storage tank found in the report was 300 barrels. Even if one assumes a tank height of 20 feet (most likely the height would be 12 feet), the storage capacity of the tank would be around 15 bbl per foot. To gauge a 24-hr production rate of 2 barrels would mean taking two measurements to obtain a difference of about 1 ½ inches. For a tank height of 12 feet, measurement of a difference of 1 inch would be necessary. In addition, all of the sites had at least two tanks. Therefore, to measure 2 barrels of production would take two measurements to obtain a difference of 1/2 to 3/4 of an inch. It is easy to see that this technique would lead to large errors in assumed condensate production rate, and in fact, it appears that the researchers abandoned this concept at some point (see Item 2).

2. Our greatest concern is with the methodology used to estimate condensate production rates for the 24-hr test periods. Evidently, the researchers rightly determined that an accurate measurement of condensate production during the test periods from tank gauging was not feasible based on the concerns described above. It appears that, in place of measured condensate production, the researchers substituted 2005 daily average condensate production numbers for each tested site obtained from the RRC database (footnote “f” for Table 3-3 on page 3-4 “Daily average condensate production for 2005 from www.rrc.state.tx.us/interactive_data.html”). Using daily average condensate production numbers from a historical database, for which only monthly and yearly totals are reported, to calculate a VOC emissions factor from actual 24-hr test data for a specific tank battery can introduce large errors in the calculation of the flash VOC emissions factor as evidenced by the results from tank battery #17.

- D. Excluding tank batteries with a throughput of 2 bbl/day or less would give average VOC flash emissions of 14.9 lb/bbl. This is more in line with the results from the CDPHE study (cited in Section 1.2 of the report), which gave a range of 10.0 to 13.7 lb/bbl for different condensate producing regions, and with the simulation results discussed below

16.6.2. Variability of Flashing Emissions

A database that is more representative of nationwide emission rates from production field tanks than the data in the TERC study is available from the Geographical Database Option of the E&P TANK^{AA} program. For the 103 geographic sites across the U.S. for which E&P TANK results were tabulated in the Geographical Database Option, the average emission rate for condensate tanks (if condensate is defined as API gravity of 40 degrees or greater) is 11.4 lb/bbl and for crude oil tanks 1.1 lb/bbl. But, even with this larger sample, the variability in emissions per throughput barrel is large.

Under d. NSPS for Storage Vessels on page 52763 of the preamble, EPA correctly states “Flash losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing dissolved gases and a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the greater the flash emissions will occur in the storage stage. Temperature of the liquid also influences the amount of flash emissions. The amount of liquid entering the tank during a given time, commonly known as throughput, also affects the emissions rate, with higher throughput tanks having higher annual emissions, given that other parameters are the same.” However, EPA did not mention the other very important parameter, the volatility of the liquid, which can be indicated by API gravity but is more accurately a function of the composition of the high pressure separator liquid.

Flashing emissions determined using the E&P TANK low pressure oil option with a pressurized liquid sample are summarized in Table 16-1 for 7 sites in Texas and Louisiana. This table shows that, among sites with the same throughput, VOC emissions vary by three orders of magnitude (from 0.072 lb/bbl to 20.72 lb/bbl). This clearly establishes that throughput correlates very poorly to emissions.

Table 16-1 Variability of Flashing Emissions for Constant Throughput

| Location | API Gravity | Throughput (bbl/day) | Pressure (psi) | Temperature (°F) | GOR | VOC Emissions (lb/bbl) |
|------------------|-------------|----------------------|----------------|------------------|------|------------------------|
| Robertson Co. TX | 36 | 1 | 42 | 60 | 22.1 | 3.504 |
| Shelby Co. TX | 53 | 1 | 40 | 75 | 3.5 | 0.072 |

^{AA} American Petroleum Institute, “Production Tank Emissions Model - A Program For Estimating Emissions From Hydrocarbon Production Tanks - E&P TANK VERSION 2.0,” API Publication 4697.

| | | | | | | |
|-------------------------|----|---|-------|------|-------|--------|
| Panola Co. TX | 45 | 1 | 76 | 90 | 14.5 | 1.224 |
| Claiborne Parish, LA | 62 | 1 | 160 | 75 | 113.4 | 16.584 |
| La Salle Parish, LA | 32 | 1 | 47 | 114 | 0.5 | 0.528 |
| Upsher Co. TX | 56 | 1 | 230 | 60 | 203.9 | 20.760 |
| Rusk Co. TX | 47 | 1 | 108 | 98 | 13.2 | 2.664 |
| Average | 49 | 1 | 141.5 | 81.5 | 71.3 | 6.237 |

16.6.3. Specify an Applicability Threshold for Storage Tanks Based on Estimated Emissions

Given the variability of emissions as a function of site-specific conditions, we request that the rule specify an emissions threshold for storage tanks, and allow facilities to perform emissions estimates to determine whether a given storage tank is subject to the control requirements of the rule. As indicated by both EPA^{BB} and TCEQ^{CC}, appropriate methods of estimating flashing emissions include process simulation software and E&P TANK.

16.6.4. Allow Use of Default Emission Rates as a Function of Throughput and Separator Pressure

As an alternative to a site-specific estimate of flashing emissions, the rule should allow an estimate of flashing emissions to be obtained from a table that accounts for both throughput and separator pressure.

Figure 16-1 shows a graph of flashing emissions (in lb/bbl) as a function of separator pressure (in psi). This graph shows emissions estimated from three simulation methods. The results labeled "API Flash Factor" were obtained using ProMax^{DD} (includes two very volatile high API gravity condensates), the results labeled "TX & LA sites" were obtained using E&P TANK, and the results labeled "Anadarko well" were obtained using HYSYS^{EE}. For comparison, the TERC study average (33.3 lb/bbl) and the average of the E&P TANK Geographical Database Option with simulated results for 103 wells nationwide (11.4 lb/bbl) are also shown.

The TERC estimate is greater than the simulation results for any level of pressure, which

^{BB} STAPPA/ALAPCO/EPA, "Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations," Emission Inventory Improvement Program, Volume II: Chapter 10, September 1999.

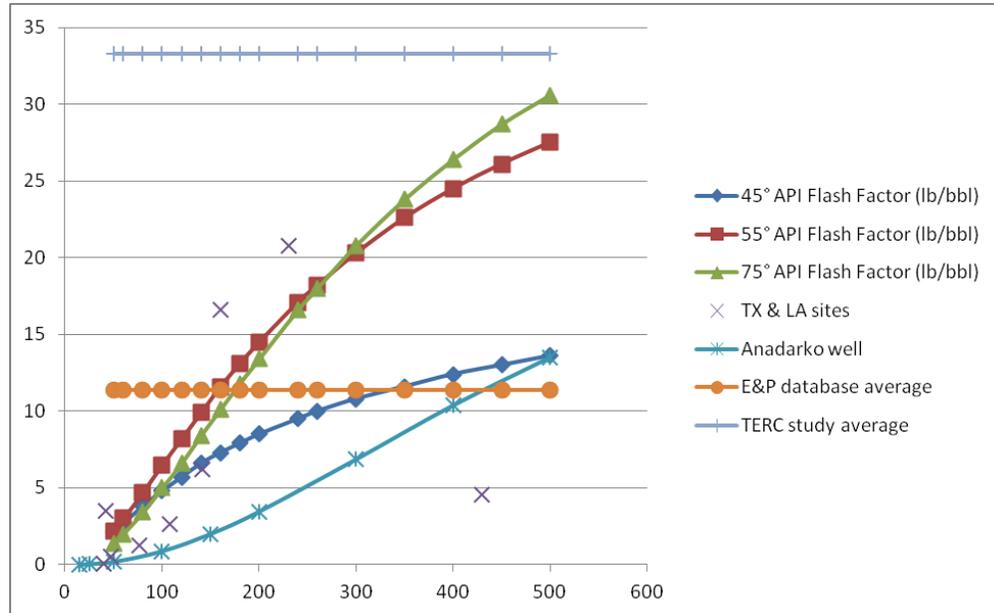
^{CC} Texas Commission on Environmental Quality, Air Permits Division, "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites," Air Permit Reference Guide APDG 5942, v2, September 2009.

^{DD} ProMax, Bryan Research & Engineering, Inc.

^{EE} AspenTech HYSYS 2006.5, Aspen Technology, Inc.

further suggests that it is not a credible value. However, as noted previously, a value of 14.9 lb/bbl is obtained from the TERC study when the most problematic data are removed from the data set. This value appears to be much more in line with simulation results using site-specific data. Also, the average value of 11.4 lb/bbl from the E&P TANK database falls reasonably within the simulation results. But the evident variability as a function of pressure shows that a simple average is not an appropriate indicator of flashing emissions.

Figure 16-1 Emissions (lb/bbl) vs. Separator Pressure (psi)



A throughput-based factor for estimating flashing emissions should be expressed as a function of pressure drop, rather than applying a simple average value as a function of throughput. This could be done by means of a lookup table.

The results of the ProMax simulations for the volatile condensates graphed in Figure 16-1 are tabulated in Table 16-2, along with results from a 38° API Gravity crude oil, showing the relationship between emissions, throughput, and separator pressure at multiple levels of API Gravity. In the simulations, the last separator temperature was set at 60°F, which is conservative since a higher temperature (which is typical for most sites with a heater-treater) lowers the amount of VOC flashed at the storage tank. Table 16-2 shows that emissions are highly influenced by pressure and, to a lesser extent, by API Gravity.

It is evident from Table 16-2 that an applicability threshold based on throughput should also account for separator pressure.

Table 16-2 VOC Flash Factors vs. Separator Pressure

| Separator Pressure (psig) | 38° API Crude Oil Flash Factor (lb/bbl) | 45° API Condensate Flash Factor (lb/bbl) | 55° API Condensate Flash Factor (lb/bbl) | 75° API Condensate Flash Factor (lb/bbl) |
|---------------------------|---|--|--|--|
| 10 | 0.2 | 0.2 | 0.1 | 0.1 |
| 20 | 0.5 | 0.5 | 0.4 | 0.3 |
| 30 | 0.9 | 1.0 | 0.9 | 0.6 |
| 40 | 1.3 | 1.6 | 1.5 | 0.9 |
| 50 | 1.7 | 2.1 | 2.2 | 1.4 |
| 60 | 2.1 | 2.7 | 3.0 | 2.0 |
| 80 | 2.8 | 3.8 | 4.7 | 3.4 |
| 100 | 3.4 | 4.8 | 6.5 | 5.0 |
| 120 | 4.0 | 5.7 | 8.2 | 6.6 |
| 140 | 4.4 | 6.6 | 9.9 | 8.4 |
| 160 | 4.8 | 7.3 | 11.6 | 10.1 |
| 180 | 5.2 | 7.9 | 13.1 | 11.8 |
| 200 | 5.5 | 8.5 | 14.5 | 13.4 |
| 240 | 6.1 | 9.5 | 17.1 | 16.6 |
| 260 | 6.3 | 10.0 | 18.2 | 18.0 |
| 300 | 6.7 | 10.8 | 20.3 | 20.8 |
| 350 | 7.2 | 11.6 | 22.6 | 23.8 |
| 400 | 7.6 | 12.4 | 24.5 | 26.4 |
| 450 | 7.9 | 13.0 | 26.1 | 28.7 |
| 500 | 8.3 | 13.6 | 27.5 | 30.6 |

16.6.5. Basis for Determining Throughput

Under §60.5410(e)(5)(i), EPA requires "You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications." Flow of condensate from a production separator to a storage vessel is intermittent and short duration. Every flow meter has a "latency period" that provides unreliable data for some period of time after flow begins. This unreliable period of time can range from a few seconds to several minutes depending on the technology. The "short duration" part of the equation is compounded by the latency period. It is frequent for a common technology like a turbine meter to over-range (i.e., spin faster than the magnetic revolution counter can count) for several seconds when it first opens in dump service. Often, by the time it has slowed to begin reporting reasonable values, the dump is beginning to close. It is common for either a turbine meter or a magnetic meter in dump service to report values that are 5-10 times higher than sales volumes that are eventually reported to accounting systems. There is no technology that will allow a 1 bbl/day condensate stream (or a 20 bbl/day oil stream for that matter) to accurately record flow volume into a storage

tank. API strongly recommends that the preferred method of quantifying liquid hydrocarbons throughput in the regulation be changed to “based on Lease Automatic Custody Transfer (LACT) meter, haul records (run tickets), sales tickets, or other sales documentation to show the amount transferred to a truck or liquids pipeline.” See Attachment H for background on technical issues pertaining to metering.

16.6.6. Variability of Cost Effectiveness

Using EPA's estimated annual cost for controls of \$18,983 and 95% control effectiveness, the cost effectiveness of controls for the sites shown in Table 16-1 is shown in Table 16-3. Table 16-3 shows that, when emissions are determined for a throughput of 1 bbl/day of condensate on a site-specific basis, the cost of controls varies from about \$5,300 to over \$1.5 million per ton. These costs are much higher than EPA's estimate of \$3,228/ton given in EPA's background technical support document (TSD) Table 7-10, because these costs are based on site-specific emission estimates rather than on a flawed study purporting to determine an average emissions rate as a function of throughput, which itself is an inaccurate indicator of emissions.

Table 16-3 Cost Effectiveness of Controls Using the TSD Cost Analysis.

| Location | API Gravity | Throughput (bbl/day) | Pressure (psi) | Temperature (°F) | VOC Emissions (ton/ yr) | Emission Reductions (ton/ yr) | Annual Cost (\$/yr) | Cost Effectiveness (\$/ton) |
|----------------------|-------------|----------------------|----------------|------------------|-------------------------|-------------------------------|---------------------|-----------------------------|
| Robertson Co. TX | 36 | 1 | 42 | 60 | 0.6399 | 0.6079 | \$18,983 | \$ 31,226 |
| Shelby Co. TX | 53 | 1 | 40 | 75 | 0.0131 | 0.0124 | \$18,983 | \$1,519,667 |
| Panola Co. TX | 45 | 1 | 76 | 90 | 0.2235 | 0.2123 | \$18,983 | \$ 89,392 |
| Claiborne Parish, LA | 62 | 1 | 160 | 75 | 3.0287 | 2.8773 | \$18,983 | \$ 6,598 |
| La Salle Parish, LA | 32 | 1 | 47 | 114 | 0.0964 | 0.0916 | \$18,983 | \$ 207,227 |
| Upsher Co. TX | 56 | 1 | 230 | 60 | 3.7913 | 3.6017 | \$18,983 | \$ 5,271 |
| Rusk Co. TX | 47 | 1 | 108 | 98 | 0.4865 | 0.4622 | \$18,983 | \$ 41,072 |
| Average | 49 | 1 | 141.5 | 81.5 | 1.1390 | 1.0821 | \$18,983 | \$ 17,543 |

16.6.7. Corrected Cost Analysis

As noted above, the TSD used an annual cost of \$18,983 for controlling a tank. This cost, however, is inconsistent with the EPA Air Pollution Control Cost Manual^{FF} (EPA Cost Manual), which addresses enclosed combustors in Section 3.2. Using the method prescribed in the EPA Cost Manual, the annual cost of controls is \$55,207, as detailed below. This cost

^{FF} U.S. Environmental Protection Agency, “EPA Air Pollution Control Cost Manual,” EPA/452/B-02-001, Sixth Edition, January 2002. <http://www.epa.gov/ttn/catc/dir1/cs3-2ch1.pdf>

is conservative in that it includes no costs for data management required by the proposed rule, and it does not adjust for inflation since calendar year 2000.

Table 16-4 Capital Cost for Enclosed Combustor

| <u>Item</u> | | | <u>Cost</u> |
|---|---|---------------|--------------------|
| Direct Costs | | | |
| Purchased equipment costs | | | |
| | Combustor | | 14,102 |
| | Auxiliary equipment (includes knock-out drum and piping) | | 828 |
| | Sum = A | | 14,929 |
| | Instrumentation = | 0.10 A | 1,493 |
| | Sales taxes = | 0.03 A | 448 |
| | Freight = | 0.05 A | 746 |
| | Purchased equipment cost = B | | 17,617 |
| Direct installation costs | | | |
| | Foundation & supports = | 0.12 B | 2,114 |
| | Handling & erection = | 0.40 B | 7,047 |
| | Electrical = | 0.01 B | 176 |
| | Piping = | 0.02 B | 352 |
| | Insulation = | 0.01 B | 176 |
| | Painting = | 0.01 B | 176 |
| | Direct installation cost | 0.57 B | 10,042 |
| | Site preparation | | 0 |
| | Facilities and buildings | | 0 |
| | Total direct cost | | 27,658 |
| Indirect Costs (installation) | | | |
| | Engineering | 0.10 B | 1,762 |
| | Construction & field expenses | 0.10 B | 1,762 |
| | Contractor fees | 0.10 B | 1,762 |
| | Start-up | 0.01 B | 176 |
| | Performance test | 0.01 B | 176 |
| | Contingencies | 0.03 B | 529 |
| | Total indirect cost | 0.35 B | 6,166 |
| | Total Capital Cost = C | | 33,824 |
| Annual Cost for Enclosed Combustor | | | |
| <u>Item</u> | | | <u>Cost</u> |
| Direct Annual Costs, DC | | | |
| | Operating Labor | 630 hr/yr | |
| | | | <u>hourly cost</u> |
| | | | \$ 15.64 |
| | Supervisor = 0.15(operating labor) | | 9,853 |
| | Operating materials | | 1,478 |
| | | | 0 |
| | Maintenance labor | 547.5 hr/yr | |
| | | | \$ 17.21 |
| | Maintenance material = maintenance labor | | 9,422 |
| | Electricity | | 9,422 |
| | | | 0 |
| | Purge gas \$ 3.03 /Msfc | 0 Msfc/yr | 0 |
| | Pilot gas \$ 3.03 /Msfc | 613.2 Msfc/yr | 1,858 |

| | | | |
|--|--------------------|--------------|---------------|
| Steam | \$ 4.65 /1000 lb | 0 1000 lb/yr | 0 |
| Total direct cost | | | 32,034 |
| Indirect Annual Costs, IC | | | |
| Overhead | 0.6 (labor + matl) | | 18,106 |
| Administrative costs | 0.02 C | | 676 |
| Property tax | 0.01 C | | 338 |
| Insurance | 0.01 C | | 338 |
| Capital recovery = CRF(total capital cost) | | | 3,714 |
| Total indirect cost | | | 23,173 |
| Total Annual Cost | | | 55,207 |

Table 16-5 presents a cost effectiveness analysis using the annual cost of \$55,207 determined from the EPA Cost Manual, and a control effectiveness of 95%.

Table 16-5 Cost Effectiveness of Controls Based on the EPA Cost Manual.

| Uncontrolled Emissions (tons/yr) | Emission Reductions (tons/yr) | Annual Cost (\$/yr) | Cost Effectiveness (\$/ton) |
|----------------------------------|-------------------------------|---------------------|-----------------------------|
| 3 | 2.85 | \$55,207 | \$19,371 |
| 6 | 5.70 | \$55,207 | \$ 9,685 |
| 8 | 7.60 | \$55,207 | \$ 7,264 |
| 10 | 9.50 | \$55,207 | \$ 5,811 |
| 11 | 10.45 | \$55,207 | \$ 5,283 |
| 12 | 11.40 | \$55,207 | \$ 4,843 |
| 15 | 14.25 | \$55,207 | \$ 3,874 |
| 20 | 19.00 | \$55,207 | \$ 2,906 |

16.6.8. Requested Emissions Threshold

EPA concluded in the TSD that a cost of \$5,300 per ton was not cost effective. On this basis, Table 16-5 shows that a threshold of 11 tpy would not be cost effective, but a threshold of 12 tpy would be cost effective. API therefore requests a level of 12 tpy of VOC emissions as the threshold above which controls are required for a storage vessel under NSPS OOOO.

EPA proposed throughput thresholds pegged to 6 tpy of emissions in the storage tank provisions of §60.5395(a), as well as a 10 tpy emissions threshold in the definition of a storage vessel at §60.5430. These thresholds do not determine whether or not a given structure is a storage vessel, but rather they are criteria for determining whether a given storage vessel is subject to the control requirements of the rule. As such, the more appropriate location for them in the rule is at §60.5395, rather than in the definitions. API therefore requests that EPA move the emissions threshold from the storage vessel definition at §60.5430 to the storage vessel standard at §60.5395, and specify a threshold of 12 tpy.

16.6.9. Look-up Table Alternative

As we noted above, the regulations should specify that the owner or operator may estimate emissions to determine whether a given storage vessel would exceed the 12 tpy threshold, using E&P TANK or other process simulation software to account for flashing emissions. The rule should also include a look-up table as an alternative approach to determining applicability.

Despite EPA's recognition of severable variables affecting the rate of VOC flash emissions, the agency chose a single VOC flash emissions factor of 33 lb/bbl for condensate and 1.6 lb/bbl for crude oil. Our previous comments demonstrate that the emission factors for condensate are based on faulty test data and data analysis, as well as the faulty premise that flashing emissions can be reasonably predicted as a simple function of throughput.

We agree that a throughput exemption threshold is convenient for operators in many situations; however, a "one-size-fits-all" throughput number is not appropriate due to the many variables that can affect emissions. Of those variables, last separator pressure and throughput are the most important. We therefore suggest a look-up table that is a function of these two variables as an alternative to estimating emissions to evaluate the applicability threshold.

The VOC flash factors from Table 16-2 may be converted to throughput thresholds corresponding to an emissions threshold of 12 tpy as follows:

$$Q = 12.00 \text{ tpy} * 2,000 \text{ lb/ton} * 1/365 \text{ d/yr} * 1/FF = 65.75/FF$$

where:

Q is the throughput, in barrels per day, and

FF is the flash factor, in pounds per barrel.

Using this approach, the flash factors from Table 16-2 have been converted to an applicability look-up table in Table 16-6. The flash factors given for condensate in Table 16-6 are based on the worst case at each level of separator pressure from the condensate cases given in Table 16-2. The flash factors given for crude oil in Table 16-6 are based on the 38° API Gravity crude oil from Table 16-2. In that 38° API Gravity is a very light crude oil, it is expected that these factors are conservative (*i.e.*, likely to overestimate VOC emissions for heavier crude oils). We request that EPA include this look-up table in NSPS OOOO as an alternative to estimating emissions to determine applicability.

**Table 16-6 Throughput Exemption Thresholds vs. Separator Pressure.
(corresponding to 12 tpy VOC emissions per tank)**

| Separator Pressure (psig) | Crude Oil Throughput Threshold (bbl/day) | Condensate Throughput Threshold (bbl/day) |
|---------------------------|--|---|
| 10 | 330 | 330 |
| 20 | 130 | 130 |

| | | |
|-----|-----|------|
| 30 | 73 | 66 |
| 40 | 50 | 41 |
| 50 | 39 | 30 |
| 60 | 31 | 22 |
| 80 | 23 | 14 |
| 100 | 19 | 10.0 |
| 120 | 16 | 8.0 |
| 140 | 15 | 6.6 |
| 160 | 14 | 5.7 |
| 180 | 13 | 5.0 |
| 200 | 12 | 4.5 |
| 240 | 11 | 3.8 |
| 260 | 10 | 3.6 |
| 300 | 10 | 3.2 |
| 350 | 9.0 | 2.8 |
| 400 | 8.7 | 2.5 |
| 450 | 8.3 | 2.3 |
| 500 | 8.0 | 2.1 |

16.6.10. Allowance for Production Decline.

In that oil field production declines over time, storage vessels that initially emit more than 12 tpy may eventually fall below 12 tpy of emissions. EPA should specify that controls are no longer required after a storage vessel no longer emits more than 8 TPY similar to the WYDEQ Best Available Control Technology (BACT) Policy^{GG}. EPA has allowed boilers that are derated below 100 TPY to no longer be subject to NSPS Subparts D, Da, Db, and Dc. Attachment I contains applicability determinations given by EPA allowing boilers to no longer be subject to NSPS D, Da, Db, and Dc. Furthermore, the cost effectiveness analysis above shows that controls at 8 tpy are not cost effective.

16.7. Compliance Schedule for New Production [NSPS OOOO]

The rule should allow time to evaluate the throughput, pressure, and emissions before the control must be installed and then time to install the control. For instance WYDEQ bases control on the first 30 days of production multiplied by a decline factor, and then control must be installed 60 days later.^{HH} WYDEQ allows the use of the first 30 days production multiplied by a decline factor for determining applicability of the rule because it is very difficult to predict the actual production for a well before the well is producing. This method gives operators a chance to estimate what the annual

^{GG} Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

^{HH} Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

production and emissions could be and then allows time to install a control if the emissions were to exceed the specified threshold.

16.8. Compliance Requirements [NSPS OOOO]

Suggested Rule Text:

§60.5365

If you are the owner or operator of a site prior to the point of custody transfer at which is located one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. Paragraphs §60.5365(a)-(e) apply only to affected facilities in VOC service. ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

* * * * *

- (e) A storage vessel affected facility, which is defined as a single storage vessel storing condensate or crude oil and located prior to the point of custody transfer.

§60.5395

You must comply with the standards in paragraphs (a) through (eg) of this section for each storage vessel affected facility.

- (a) You must comply with the standards for storage vessels storing condensate or crude oil specified in ~~40 CFR part 63, subpart HH, §63.766(b) and (c) paragraph (b) of this section,~~ except as specified in paragraph (bd) of this section. ~~Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section.~~ Storage vessels with annual average VOC emissions less than 12 tons per year, estimated according to paragraph (c)(3) of this section, are exempt. A storage vessel that has been subject to this standard becomes exempt when the uncontrolled emissions of VOC drop below an annual average of 8 tons per year.

~~(1) The annual average condensate throughput is less than 1.5 barrel per day per storage vessel.~~

~~(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel.~~

- (b) Within 90 days of the first date of production the owner or operator shall equip the affected storage vessel closed vent system and control device meeting the following specifications:

(1) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions.

(2) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.

(c) The annual average daily throughput and pressure and the annual emissions for a new well shall be determined as follows:

(1) First 30 days of throughput after the first date of production divided by 30 times the average decline factor for the reservoir based on Lease Automatic Custody Transfer (LACT) meter, haul records (run tickets), sales tickets, or other sales documentation to show the amount transferred to a truck or liquids pipeline.

(2) Pressure of separator prior to the tank averaged over the first 30 days after the first date of production.

(3) Calculated using either methods (i) or (ii) using the average annual throughput calculated under (c)(1) and the average pressure calculated under (c)(2) for demonstrating compliance with (a)(1):

(i) E&P TANK or an appropriate flashing model.

(ii) Interpolating from the table below:

| <u>Separator Pressure (psig)</u> | <u>Crude Oil Throughput Threshold (bbl/day)</u> | <u>Condensate Throughput Threshold (bbl/day)</u> |
|----------------------------------|---|--|
| <u>10</u> | <u>330</u> | <u>330</u> |
| <u>20</u> | <u>130</u> | <u>130</u> |
| <u>30</u> | <u>73</u> | <u>66</u> |
| <u>40</u> | <u>50</u> | <u>41</u> |
| <u>50</u> | <u>39</u> | <u>30</u> |
| <u>60</u> | <u>31</u> | <u>22</u> |
| <u>80</u> | <u>23</u> | <u>14</u> |
| <u>100</u> | <u>19</u> | <u>10.0</u> |
| <u>120</u> | <u>16</u> | <u>8.0</u> |
| <u>140</u> | <u>15</u> | <u>6.6</u> |
| <u>160</u> | <u>14</u> | <u>5.7</u> |
| <u>180</u> | <u>13</u> | <u>5.0</u> |
| <u>200</u> | <u>12</u> | <u>4.5</u> |
| <u>240</u> | <u>11</u> | <u>3.8</u> |
| <u>260</u> | <u>10</u> | <u>3.6</u> |
| <u>300</u> | <u>10</u> | <u>3.2</u> |
| <u>350</u> | <u>9.0</u> | <u>2.8</u> |
| <u>400</u> | <u>8.7</u> | <u>2.5</u> |
| <u>450</u> | <u>8.3</u> | <u>2.3</u> |
| <u>500</u> | <u>8.0</u> | <u>2.1</u> |

- (bd) This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 63, subpart HH, §63.766(b)(1) or (2).
- (ee) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by §60.5410.
- (df) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by §60.5415.
- (eg) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

§60.5410

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in §60.5420(b).

* * * * *

- (e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1) through (e)(7) of this section.
 - (1) You have equipped the storage vessel with a closed vent system ~~that meets the requirements of §63.771(e) connected to a~~ and a control device that meets the conditions specified in ~~§63.771(d)~~ §60.5395(b).
 - ~~(2) You have conducted an initial performance test as required in §63.772(e) within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in §63.772(f).~~
 - ~~(3) You have conducted the initial inspections required in §63.773(e)~~
 - ~~(4) You have installed and operated continuous parameter monitoring systems in accordance with §63.773(d)~~
 - ~~(5) If you are exempt from the standards of §60.5395 according to §60.5395(a)(1) or (a)(2), you have determined the condensate or crude oil throughput, pressure, and emissions according to §60.5395(c), as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank.~~
 - ~~(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications.~~
 - ~~(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput.~~

(63) You have submitted the information in paragraphs (e)(1) through (e)(5) of this section in the initial annual report for your storage vessel affected facility as required in §60.5420(b).

§60.5415

* * * * *

(e) ~~For each storage vessel affected facility, continuous compliance is demonstrated according to 40 CFR part 63, subpart HH, §63.772(f).~~ The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.5395(b) shall meet the requirements of either (1) or (2) below.

(1) Develop and maintain an operating plan containing the information listed below and operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (2)(i) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) A control device that has been certified by the manufacture with a performance test to demonstrate the device meets the requirements of §60.5395(b) and parameters limits needed to meet the requirements of §60.5395(b) to measure. Monitor the parameters of the control device to demonstrate the control device is operating within the parameter limits specified by the manufacture.

§60.5420

* * * * *

(b) **Reporting requirements.** You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year

after the date of publication of the final rule in the Federal Register, whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

* * * * *

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

- (i) If required to reduce emissions by complying with paragraph §60.5395(ab), ~~the records specified in 40 CFR part 63, subpart §63.774(b)(2) through (b)(8) the API number of the location of the tank and date of installation.~~
- (ii) ~~If exempt from §60.5395 in accordance with §60.5395(a), the API number of the location of the exempt tank and date of installation. Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in §60.5395(a)(1) or (a)(2).~~

(c) **Recordkeeping requirements.** You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

* * * * *

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

- (i) If required to reduce emissions by complying with ~~§63.766~~ §60.5395(b), maintain the following records ~~specified in §63.774(b)(2) through (8) of this chapter.:~~

(A) A copy of the operating plan if using §60.5415(e)(1).

(B) A copy of manufacturer certification if using §60.5415(e)(2)

(C) A record of the measured values of the parameters monitored.

- (ii) Records of the determination of the throughput, pressure, and emissions using the methods in §60.5395(c) to demonstrate emissions are below 12 TPY. ~~that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under §60.5395(a)(1) and (a)(2).~~

§60.5430

Condensate means a ~~hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in §60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate.~~ natural gas liquid recovered from

associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60 degrees Fahrenheit.

First Date of Production means the date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production from initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.

Alternative Rule Text (if EPA insists on citing to Subpart HH):

The requirements in NSPS OOOO for storage tank control devices cite the performance test requirements specified in §63.772(e) of NESHAP HH, which include a provision for the performance test to be conducted by the manufacturer as specified in §63.772(h). While the intent appears to allow the manufacturer’s certification specified in §63.772(h) for NSPS OOOO, it would be helpful if NSPS OOOO were to explicitly say so. API requests that EPA clarify this intent by editing §60.5410 to read as follows:

§60.5410

(e)(2) You have conducted an initial performance test as required in §63.772(e) of this chapter, or you have a copy of the performance test results for a performance test conducted by the manufacturer as specified in §63.772(h), within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in §63.772(f).

16.9. Capacity and Vapor Pressure [NSPS OOOO]

Every EPA regulation with provisions for storage vessels has capacity and vapor pressure thresholds below which the specified control measures are not required – even rules for the storage of gasoline and benzene. It is certainly unreasonable, then, to not have capacity and vapor pressure cutoffs for vessels storing crude oil and condensate. The cutoffs in NSPS Subpart Kb have already been determined by EPA as appropriate for storage vessels, and thus would seem appropriate for NSPS OOOO as well. However, we recognize that the oil production sector has the unique situation of potential for flash emissions, and thus it would be reasonable to remove the minimum capacity threshold in Subpart Kb when applying these thresholds to Subpart OOOO. The Subpart Kb cutoffs are presented in Table 16-7, with suggested adjustment for Subpart OOOO.

Table 16-7 Capacity and Vapor Pressure Cutoffs

| Subpart Kb | Subpart OOOO |
|---|---|
| Controls are not required if a storage vessel has: | Controls are not required if a storage vessel has: |
| a capacity of less than 75 m ³ (472 bbl) regardless of the vapor pressure; | a capacity of less than 75 m ³ (472 bbl) And true vapor pressure less than 11.1 psia |

| | | |
|--|-----|--|
| or | | |
| a capacity of less than 151 m ³ (950 bbl) | and | true vapor pressure less than 4.0 psia; |
| or | | |
| a capacity greater than 151 m ³ (950 bbl) | and | true vapor pressure less than 0.75 psia; |

| | | |
|--|-----|--|
| or | | |
| a capacity of less than 151 m ³ (950 bbl) | and | true vapor pressure less than 4.0 psia; |
| or | | |
| a capacity greater than 151 m ³ (950 bbl) | and | true vapor pressure less than 0.75 psia; |

16.10. Infrequent Use [OOOO & HH]

EPA’s capacity and vapor pressure thresholds are based on emissions that would be expected if these tanks were in continuous operation. However, tanks such as blowdown tanks, emergency tanks, and dehydrator drip tanks are used only infrequently. EPA should specify a threshold for storage vessels in infrequent use, and specify a work practice for such tanks. There is precedent for this in the Gasoline Distribution area source rule. EPA must allow for open-top blow down tanks. A well cannot be blown down to a closed top tank. The conventional set up is to route the gas associated with a blow down to the produced water tank to allow for entrained liquid to be contained during the event. Knocking out this entrained liquid will be a critical step in flaring this stream as well. However, the tanks are only rated to around 10-12 oz with thief hatch seals set at approximately 6 oz of pressure to protect tank integrity. The majority of tanks in the field are not designed to take the back pressures anticipated by the piping changes. These tanks are typically “atmospheric” tanks/vessels designed to operate at pressures not exceeding 15 psig (per mechanical design codes defined by the American Society of Mechanical Engineers). The relief valves and seals are designed and operate accordingly. Piping system for the combustion device will provide too much back pressure during a blow down event and the safety devices will vent the tanks as they should.

The EPA needs to recognize that implementation of this requirement is far more complicated than connecting up existing tanks to combustors. The entire tank system would need to be evaluated and possibly replaced with a “code stamped” pressure vessel/tank and appropriately sized and designed safety valves, hatches, and gas piping. Accordingly, the EPA needs to fully recognize the associated costs which are substantially more. Furthermore, infrequently used tanks such as blowdown tanks, emergency tanks, and dehydrator drip tanks were not considered in EPA’s cost effectiveness analysis.

16.11. Flare Pilot Flame [OOOO & HH]

The requirement in §60.18(c)(2) and §63.11(b)(5) for a flare to be operated “with a flame present at all times,” referenced by NSPS OOOO [§60.5401(f)] and NESHAP HH [§63.771(d)(1)(iii)] respectively, is not appropriate in light of current technology. This issue is discussed in more detail in Section 9.1 of the general comments.

16.12. Performance Test Methods [OOOO & HH]

See Section 8.6 of the general comments for API’s recommendations with respect to performance tests.

16.13. MACT-Level Requirements for NSPS

EPA has referenced the full MACT requirements in NESHAP HH for NSPS OOOO, rather than craft cost-effective requirements tailored for storage tanks with relatively low annual VOC emissions and generally located in remote areas. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for NSPS OOOO. This is illustrated in the cost discussion above, where annual costs determined from EPA's Cost Manual are shown to be nearly 3 times the cost that EPA presented in the TSD. Furthermore, NSPS OOOO applies to dispersed locations that do not have electricity or automation, and with limited remote transmitting unit (RTU) space. Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH, it is not appropriate to arbitrarily invoke requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for an NSPS regulation for the control of volatile organic compounds (VOCs). See Section 8.7 of these comments.

Examples of the inappropriateness of invoking MACT requirements for NSPS include but are not limited to:

- **§63.773(d) Control Device Monitoring requirements [Continuous Parameter Monitoring System (CPMS)].** EPA did not include the cost for installing, maintaining, and operating a CPMS. Most affected storage tanks will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work can not be performed by lease operators during normal inspection visits.
- **§63.772 Test Methods, Compliance Procedures, Compliance Demonstrations.** EPA should reference test methods specific to VOCs. Many of the methods reference HAPs or comparison of a performance test to a HAP emission limit. This causes confusion in understanding how to apply the requirements to a VOC standard. EPA should reference test methods, compliance procedures, and compliance demonstrations that are specific to VOCs and the type of control device being used to control VOCs.
- **§63.774(b)(2) through (8) Recordkeeping Requirements.** The proposed recordkeeping requirements result in more than 56 different records to be maintained for a single tank (see Attachment J). These overwhelming and burdensome recordkeeping requirements are unreasonable and unjustified.

16.14. Floating roof option [OOOO & HH]

Other regulations governing storage tanks allow floating roofs as an alternative to routing vapor to a control device. Consideration should be given to providing a floating roof control option under these rules. While floating roofs are not viable for tanks with the potential for flash emissions or for very small tanks, they may be suitable for larger production field tanks storing stabilized crude oil, and

thereby avoid roof fitting leak tightness requirements. API requests that EPA revise both NSPS OOOO and NESHAP HH to specify that a storage vessel storing a volatile organic liquid with a maximum true vapor pressure of less than 11.1 psia may be equipped with a floating roof, in lieu of routing vapors to a control device. We suggest that EPA specify the floating roof requirements in the same manner as in Table 1 of the Gasoline Distribution area source rule.ⁱⁱ

16.15. EPA's Estimate of the Number of Affected Storage Vessels

See FR page 52789, Preamble VIII.A. EPA predicts that a very small fraction of the production field tank population will be affected by this rulemaking. While we have not yet evaluated these numbers, we believe for the reasons stated below that the total cost impact of the rule will be dramatically greater than projected by EPA.

16.15.1.NESHAP HH

The proposed changes to the definition of an affected facility will likely cause some existing sites that were not previously major sources to become major sources, due to the expansion of emission points that EPA proposes to include in the major source determination. Tanks at these facilities would then become subject to NESHAP HH controls, but EPA does not appear to have taken these tanks into account when evaluating the impact of the proposed rule revisions.

16.15.2.NSPS OOOO

EPA apparently evaluated the existing well population, which is dominated by old wells that have declined to very low production rates (sometimes known as stripper or marginal wells), and assumed that the production rates of these stripper wells would be characteristic of new wells. On this basis, EPA assumed that very few new wells would have sufficient flow to trigger applicability for storage tanks under NSPS OOOO. This is a fundamentally flawed assumption, in that companies do not purposely drill low producing wells. New wells would not be drilled unless there was an expectation of flow significantly greater than EPA's proposed throughput thresholds, and thus virtually all new wells would likely trigger NSPS OOOO applicability for the associated storage tanks.

16.16. Permit Limits

Under the MACT rules, a facility can avoid major source status if it has federally enforceable permit conditions that preclude emitting above the major source threshold (i.e., synthetic minor status). Similarly, if EPA sets an emissions-based applicability threshold for tanks under NSPS OOOO, the rule should specify that legally effective PTE limits (such as those issued through state minor NSR permits) are one means that may be used to manage applicability of the rule. EPA has ample legal authority to define the applicability of an NSPS. Such an approach would be a reasonable exercise of that authority. In addition, such an approach would be consistent with similar approaches taken in prior NSPSs. For example, the NSPS for Bulk Gasoline Terminals applies to facilities with a throughput greater than 75,700 liters/day. The gasoline throughput of a facility "shall be the

ⁱⁱ 40 CFR Part 63 Subpart BBBB—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.” 40 C.F.R. § 60.501 (definition of “bulk gasoline terminal”).

17. PNEUMATIC CONTROLLERS

API supports the use of intermittent vent, electro-pneumatic, and low bleed pneumatic controllers where feasible, however, certain key language in the proposal is unclear with regard to applicability, is unnecessarily restrictive, and creates burdensome, and needless recordkeeping and reporting requirements.

API supports comments regarding pneumatic controllers provided to EPA by the Gas Processors Association (GPA). We are in agreement that the only regulated sources should be high bleed gas-driven pneumatic controllers. We would add that EPA should only regulate high bleed gas-driven controllers in VOC service as we argue numerous times throughout this comment document for affected facilities with natural gas emissions. As well, limiting regulation to controllers in VOC service would markedly reduce the recordkeeping and reporting burden in the proposal.

Before continuing review of our comments and suggested rule text changes API recommends that EPA reviewers read the pneumatic controller technical paper in Attachment K and Kimray, Inc.'s technical bulletin Y09201 “Pilot Bleed Rate” in Attachment L^{JJ}. Both of these papers are excellent references that clarify the terminology and technology of pneumatic controllers.

From our review of the preamble, proposal, TSD, and Natural Gas STAR documentation, EPA appears to have an inconsistent understanding of the design and operation of pneumatics. For example, in the preamble EPA incorrectly states: “(1) Continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure and gas is vented at a steady state rate; (2) actuating/intermittent devices (high or low-bleed) perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow...” indicating that both high and low bleed controllers can be either continuous or intermittent vent. However, in the proposed rule language and TSD, EPA correctly categorizes high and low bleed controllers as continuous bleed controllers only. The result of this inconsistency is an affected facility that effectively includes all pneumatic controllers when intermittent vent controllers are considered neither high nor low bleed, but rather no-bleed controllers that have no weak stream vent. As a result, intermittent vent controllers are not defined in the proposal, but should be exempted from this rulemaking. A fundamental and consistent understanding of pneumatic terminology, design, and operation is essential to providing an effective regulatory framework that works for both industry and EPA alike.

API provides suggested changes to proposed rule language in Attachment C that limits requirements to continuous bleed gas-driven controllers, clarifies both intent and compliance requirements, and simplifies the recordkeeping and reporting requirements. The underlying premise of our comments is that this rule needs to be clearly limited to “continuous bleed gas-driven pneumatic controllers,” but grouped as pneumatically controlled process unit affected facilities. Additionally, pneumatic controllers driven by compressed air, or other medium that does not contain VOC, cannot be affected facilities since there are no regulated emissions associated with them. In no other NSPS subpart do definitions of affected facilities include those with no regulated emissions. The following discussion explains in detail the issues and recommendations identified by API.

^{JJ} <http://kimray.com/LinkClick.aspx?fileticket=WvoYfx11%2f6E%3d&tabid=215&mid=811>

17.1. Problem with High-Bleed/Low-Bleed Classification

The proposed rule sets a threshold of 6 SCF/hr to classify continuous “high bleed” and “low bleed” controllers and EPA seeks to regulate both. There is no discussion in the proposed rule or in the TSD that explains how this threshold was derived. Instead, there is only a footnote on page 5-3 in the TSD that says this classification originated from a PG&E/GRI report in 1990, titled “Unaccounted for Gas Project Summary Volume” that EPA adopted for a 1993 report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. EPA has failed to include this 1990 PG&E report in the docket. API, via email to EPA staff, also requested background documentation addressing how the 6 scfh threshold was derived. No reply was received. Without needed documentation being made available, API is unable to review and comment on the validity of this threshold classification.

From the 1993 congressional report, this 6 scfh threshold carried forward into EPA's definition of a low bleed controller for the Natural Gas STAR (NGS) program. However, NGS was a voluntary program. The 6 scfh dividing line for low bleed/high bleed became an acceptable threshold by EPA declaration that wasn't subjected to the needed scrutiny required for rulemaking and regulatory compliance obligations. Using this threshold declared by EPA fiat since 1993 in a non-regulatory environment does not satisfactorily justify its use in rulemaking. Not being able to review the 1990 PG&E report, API has no way of knowing under what conditions bleed rates for continuous bleed controllers were determined to set this threshold.

EPA has set a performance standard without making available its own independent BSER technical review for continuous bleed pneumatic controllers. In addition to not having access to the 1990 PG&E report, the TSD data is incomplete, and does not include details of the data collected from their vendor surveys. API has asked for this data in emails to EPA staff, but did not receive a response to this request. With this data unavailable for review, API cannot conduct its own quality assurance analysis (QA) of the data and comment on the results.

Concurrent with an incomplete demonstration of BSER, without the needed background documentation in the docket, EPA has not “adequately demonstrated” that less than 6 scfh bleed rate is practically “achievable” as BDT for continuous bleed controllers as required by CAA §111(a)(1). The issues with BSER and BDT can be remedied by re-proposing these requirements with inclusion of the necessary background documentation placed in the docket.

Without the appropriate technical documentation available for stakeholder review and comment, API is not supportive of the 6 scfh threshold for continuous high bleed controllers. API believes the 6 scfh threshold is too low for defining the high bleed/low bleed boundary for continuous bleed pneumatic controllers. Only a few models advertised as continuous low bleed controllers operating at < 6 scfh are available in the marketplace. And those that advertise low bleed rates, base it on operating at a low supply gas pressure such as 20 psi or less though the devices are designed for and frequently operate at higher pressures. Guarantees of a constant low bleed rate of < 6 scfh are not reasonable as operating variables in the field dictate controller bleed rates. These variables can include dependence on a supply pressure required by the actuator that is higher than that advertised by a manufacturer for low bleed controller performance.

As pointed out in the technical paper in Attachment K, a 6 scfh dividing line between high bleed and low bleed will effectively mean most operators will choose between continuous high bleed and intermittent vent controllers that are no-bleed, which should be considered a desirable outcome. The reason for this is that most continuous bleed controllers will require a pilot orifice so small, that reliability of the controller will be an issue. Plugging of the orifice will be a major concern as will controller response time. Also, if the controller is part of a pneumatic system where the valve actuator requires a higher pressure to operate than the advertised supply pressure for low bleed rate performance, the "low bleed" controller operating at a lower pressure than required could very well result in sluggish end-device performance and increase the risk of liquid spills and uncontrolled gas releases. Since intermittent vent controllers have no continuous bleed rate, in most cases where feasible, this will be the choice for operators that do not want to be subject to the requirements for high bleed controllers and want to be exempt from the rule.

From the TSD, EPA recognizes there are intermittent vent pneumatic controllers that are no-bleed. EPA correctly refers to snap acting controllers as no-bleed, and acknowledges that intermittent vent rates are dependent on valve actuation volume and frequency which cannot be regulated. Hence, snap acting controllers appear to be exempt from the rule. However, as illustrated in the API technical paper in Attachment K and EPA's 1996 report "Methane Emissions from the Natural Gas Industry," Vol. 12^{KK}, throttling controllers can also be intermittent vent. Likewise, continuous bleed controllers can also be converted to intermittent vent no bleed controllers by replacing the pilot valve with a Mizer type no-bleed pilot. As with snap acting controllers, all other intermittent vent controllers should be exempt from the rule.

17.2. Definitions

The subject of pneumatic controllers is highly technical and has been the province of a very narrow subset of industry experts. Unfortunately, key terminology and definitions have never been standardized which adds complexity to this rulemaking. Consequently, one of the results of this problem has led to inadequate definitions in the proposal. For example, the proposed definition of pneumatic controller in Subpart OOOO is "Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature". A more appropriate definition would be "Pneumatic controller means an instrument that is able to sense the state of a process variable and send a pressure signal to an end device to affect a change in that process variable". With EPA's proposed definition, an incorrect conclusion can be made that the end-device such as a control valve that actually maintains the process condition or variable is being regulated instead of the controller. API is recommending language for definitions needing clarity which apply to pneumatic controllers and recommending definitions for additional terms not currently in the proposal.

17.2.1. Revised Definitions

For clarity API recommends EPA's proposed definitions for pneumatic controllers be revised to read as follows:

^{KK} U.S. Environmental Protection Agency, "Methane Emissions from the Natural Gas Industry – Volume 12: Pneumatic Devices," EPA/600/R-96-0801, June 1996.

§60.5430

Pneumatic controller means an ~~automated~~ instrument that is able to sense the state of a process variable and send a pressure signal to an end device to affect a change in that process variable.~~used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature.~~

Gas-driven pneumatic controller means a pneumatic controller that directs a signal to an end device using pressurized natural gas.~~powered by pressurized natural gas.~~

Non gas-driven pneumatic controller ~~device~~ means a pneumatic controller that directs a signal to an end device in a medium other than natural gas. The signal can include compressed air, electric power, or hydraulic power. ~~means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~

Low-bleed pneumatic controller means a continuous bleed pneumatic controller which controls pressurized gas that has the ability to vent the weak stream to the atmosphere at a rate equal to or less than six standard cubic feet per hour.~~automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.~~

High-bleed pneumatic controller means a continuous bleed pneumatic controller which controls pressurized gas that has the ability to vent the weak stream to the atmosphere at a rate greater than six standard cubic feet per hour.~~automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.~~

The definition changes API proposes remove ambiguity, and help clarify the rule. These changes in definition are especially important to the rule text revisions API recommends in Attachment C. In particular, API's revisions add "weak stream" to the definitions of low and high bleed controllers. Weak stream is added as a new definition in the next section, but this is a critically important term to unambiguously distinguish which stream in a continuous bleed controller is being regulated. Our recommended rule text revisions are based on use of these definition revisions.

17.2.2. New Definitions

In addition to revising existing proposed definitions, API recommends five new definitions to help with rule clarity and recommendations to rule text. The list of terms API recommends to be defined are:

§60.5430

Continuous bleed pneumatic controller means a pneumatic controller that does not have a mechanical barrier between the pressure source and the end device and controls the signal to the end device by adjusting the magnitude of the flow rate of the bleed gas to the atmosphere (weak stream) through an adjustable port.

Intermittent vent pneumatic controller means a pneumatic controller that has an internal mechanical barrier between the source of gas pressure and the end device. In response to an input signal, these devices will shut the vent and open the mechanical barrier to send gas pressure to the end device. When the input signal has been satisfied it shuts the mechanical barrier and opens a vent to remove pressure from the end device.

Weak stream means the stream of gas that is vented when the end device is “at rest” in its idle position (e.g., when the end device is shut on a pressure-to-open system).

Pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate the flow, pressure, or temperature of gas and liquids located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, pressure regulators, pneumatic controllers, valve actuators, and valves.

Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, continuous bleed gas-driven pneumatic controllers, valve actuators, and valves.

Again, these new terms are important to the rule text changes API is recommending. The “continuous bleed pneumatic controller and “continuous bleed gas-driven pneumatically controlled process unit” are new terms vitally important to API’s recommendation for changes in §60.5365(d) for the affected facility discussed below in section 17.4. “Weak stream” requires definition because in the rule text revisions in Attachment C, API frequently recommends use of this term to clearly define which controller vent stream is being regulated. “Weak stream” is also used in suggested rule text changes for pneumatic controllers. As recommended previously, EPA may refer to the technical paper in Attachment K, for a more detailed discussion of the “weak stream” and “intermittent vent pneumatic controller”.

17.3. Inconsistent Terminology

Another problem with definitions and the proposal in general is inconsistent terminology when referring to pneumatic controllers. The terms “pneumatic device” and “pneumatic controller” are used interchangeably throughout the proposal. Examples are the definitions of “high bleed pneumatic devices” and “low bleed pneumatic controller”. API recommends that all instances of the

term "pneumatic device" be replaced with "pneumatic controller". Pneumatic device is a general nonspecific term, and even though it is meant to be synonymous with pneumatic controller, it could create uncertainty with regard to applicability.

17.4. Pneumatic Controller Affected Facility

From both the discussion of pneumatic controllers in Section 5.0 of the Technical Support Document (TSD) and the definitions provided in Subpart OOOO §60.5430 for high bleed and low bleed controllers, EPA clearly shows that the rulemaking was intended to apply to "continuous bleed" pneumatic controllers in natural gas service. From Section 5.1 of the TSD, EPA states: "Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in Section 5.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation." The continuously bleeding stream referred to both in the preceding quote from the TSD and in the proposed definitions for high and low bleed controllers is also known as the "weak stream". API agrees if pneumatic controllers are to be regulated, it is only the weak stream that should be regulated.

Additionally, pneumatic controllers are small, component level, and inexpensive pieces of equipment for which minor expenditures for routine maintenance, repair, or replacement (RMRR) may trigger a reconstruction determination. Consequently, the pneumatic controller affected facility definition needs to be redefined as a process unit to address the collection of all equipment used to pneumatically control an end device such as a valve using continuous bleed gas-driven pneumatic controllers in VOC service.

17.4.1. Include Continuous Bleed Only

As alluded to in this section's introduction, due to inaccuracies in the discussion of pneumatic controller design and operation in the preamble, and the nonspecific definition of a pneumatic controller affected facility in §60.5365(d), a high level of confusion exists over EPA's intention of what is meant by a "pneumatic controller affected facility". Snap acting and other intermittent vent controllers have no weak stream that continuously bleeds, and as EPA correctly points out in the TSD, the intermittent vent rate is dependent on the necessary cycling frequency of the controller. Consequently, a narrower, more specific definition of pneumatic controller affected facility that limits applicability to continuous bleed controllers is needed to clarify both EPA's intent and the type of controller being regulated.

17.4.2. Include Gas-Driven Only

In addition, the proposed rule includes all pneumatic controllers regardless of the medium used to drive the controller. As EPA correctly points out in the proposal, compressed air or "instrument air" or other inert gas is frequently used as the driver for pneumatic controllers. However, since neither air nor inert gas driven controllers produce regulated emissions, these controllers should not be affected facilities.

As in other NSPS Subparts for source categories, a method of documented applicability determination can be employed by operators. Subpart Kb for example, defines applicability

based on the design capacity of the tank and vapor pressure of the fluid being stored. Equivalently, one of the design criteria for pneumatic controllers at a site is the medium used to drive the controller. Since compressed air and inert gas drivers have no regulated emissions, a design to operate controllers without using a natural gas driver should exempt these controllers as affected facilities. As a result, in addition to narrowing the affected facility to continuous bleed controllers, the affected facility needs to be further limited to a natural gas-driven pneumatic controller in VOC service.

17.4.3. Modification/Reconstruction Must Not Apply to Individual Controllers

As discussed in Section 2.3, pneumatic controllers are an unprecedented small affected source. In fact, a pneumatic controller is not even a piece of operating equipment on its own, but only a component that sends a control signal to another piece of equipment. The concept of reconstruction was developed to trigger when "the Administrator will consider, on a case-by-case basis, technical and economic parameters in determining 'whether a substantial portion of a facility has been replaced'" (see 39 FR 36946). The types of affected facilities being considered in the 1970's when this concept was developed were large boilers, tanks, and waste incinerators. The "50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility" [§60.15(b)(1)] threshold for reconstruction did not consider affected facilities where the "entirely new facility" would cost just a few hundred to a few thousand dollars. In fact, pneumatic controllers would have been only one small component of an affected source being regulated until this rulemaking.

API believes that neither modification, reconstruction, nor the total replacement of a pneumatic controller should be subject to the provisions of NSPS OOOO. At most, only the installation of a new pneumatic controller on a newly constructed process unit should be regulated. API recommends that §60.5365(d) be revised to group all equipment used for gas-driven pneumatically controlled valves into a single "continuous bleed gas-driven pneumatically controlled process unit." This removes the individual pneumatic controller as an affected facility, and more appropriately treats it as a component of a process unit. If EPA refuses to group pneumatic controllers within a process unit, then EPA should explicitly exempt pneumatic controllers from having to undergo modification and reconstruction determinations as a result of RMRR.

To illustrate this point, consider the following example. It is determined that a single existing low bleed controller installed sometime before this rule was proposed, requires pilot replacement because of problems with plugging. With a larger orifice pilot, the bleed rate increases slightly. This change causes an insignificant increase in emissions, but is still a modification. This simple repair now has to be documented and reported in an annual report, even though it still meets the criteria for a low bleed controller. Repairs must also be evaluated for reconstruction, since it doesn't take much in the way of parts replacement to achieve the 50% threshold. Making this determination for frequently occurring simple repairs that do not require any advanced planning and contracting as is done for large facilities in other source categories cannot be done with any reliability or accuracy. Maintenance personnel are not equipped or trained to make this evaluation, and simple repairs could be delayed if a complete reconstruction analysis was performed for each

occurrence of repair.

When considering the relatively low emissions of a single pneumatic controller combined with the impractical approach of having to determine modification and reconstruction for each instance of controller maintenance, the pneumatic controller affected facility needs to be redefined as a process unit that groups all controllers at a single site.

17.4.4. Proposal for New Definition of Affected Facility

To summarize, from the above discussions, the pneumatic controller affected facility needs to be redefined to limit the category to continuous bleed gas-driven pneumatic controllers, grouped together at each site as a process unit affected facility thereby creating a single source that lowers the exposure to the methodology for determining modifications and reconstruction. API recommends that section §60.5365(d) be changed to read:

§60.5365

* * * * *

- (d) A continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~-affected facility, which is defined as a single continuous bleed gas-driven pneumatically controlled process unit in VOC service. ~~pneumatic controller.~~

The recommended definition of a “continuous bleed gas-driven pneumatically controlled process unit” is then:

§60.5430

Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, continuous bleed gas-driven pneumatic controllers, valve actuators, and valves.

Precedent for this approach is found in the preamble discussion of the NSPS Subpart YYY proposal [59 FR 46780, 09/15/94], in which EPA states:

Defining the affected facility on a process unit basis avoids the problems associated with having multiple individual collection and treatment system equipment components classified as affected facilities, and it also provides a definition sufficiently narrow in scope so as not to preclude the possibility that existing sources will become subject to the NSPS through the modification and reconstruction provisions. Most importantly, defining an affected facility as a process unit reflects industry construction practices. Almost all new construction, reconstruction, and modification in the SOGMI is carried out by process unit.

After carefully considering each of the above alternatives, the EPA selected process

units as the basis for defining affected facilities for the proposed NSPS. This definition allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards.

The last sentence of the first paragraph quoted from 59 FR 46780 above is certainly applicable to pneumatic controllers. A new controller is not constructed by itself, as it would have no function. It is constructed as part of a whole unit construction where each component in our recommended unit definition is a necessary part for a pneumatically controlled valve to operate.

Accepting the arguments above, the pneumatic control process unit affected facility should then be defined as a single continuous bleed gas-driven pneumatically controlled process unit in VOC service.

Accepting the process unit approach, specifying an emissions rate for low bleed controllers, §60.5390(c) is recommended to read:

§60.5390

* * * * *

- (c) Each [weak stream vent from a continuous bleed gas-driven pneumatically controlled process unit](#) ~~pneumatic controller~~ affected facility [in VOC service](#) not located at a natural gas processing plant (as defined in §60.5430) must have natural gas emissions no greater than 6 standard cubic feet per hour. [Compliance with this emissions standard must occur according to the schedule in paragraph \(c\)\(1\) or \(c\)\(2\).](#)

17.4.5. Alternative Proposal for a Process Unit Affected Facility

If EPA refuses to aggregate all pneumatic controllers and associated equipment at a site into a single process unit affected facility, as discussed above in Section 17.4.4, then API alternatively suggests that a pneumatic controller process unit be defined in terms of all of the equipment utilized in a single control loop. This alternative can be implemented by simply amending the definitions of a “pneumatically controlled process unit” and “continuous bleed gas-driven pneumatically controlled process unit” recommended in Section 17.2.2 to:

[Pneumatically controlled process unit means the group of equipment required to operate a single pneumatically controlled valve that regulates a process variable \(such as flow, fluid level, pressure, or temperature of gas and liquids\). This group of equipment includes instrument gas supply lines, filters, pressure regulator, float and switch, pneumatic controller, valve actuator, and valve.](#)

[Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate a single pneumatically controlled valve that regulates a process variable \(such as flow, fluid level, pressure, or temperature of gas and liquids\).](#)

[This group of equipment includes instrument gas supply lines, filters, pressure regulator, float and switch, continuous bleed gas-driven pneumatic controller, valve actuator, and valve.](#)

17.4.6. Benefits of Using a Pneumatically Controlled Process Unit as the Affected Facility

The above recommended change to the pneumatic controller affected facility would mitigate four issues. First, it would alleviate the inherent problem of a single pneumatic controller potentially triggering modification or reconstruction, but would preserve this trigger if major changes were made to the unit as a whole requiring a higher bleed rate. RMRR of a component of an affected facility is not likely to trigger reconstruction since the cost of the entire affected facility is the denominator in the cost analysis.

Second, there would be a significant reduction in the burdensome recordkeeping and reporting requirements which as currently proposed provides a disincentive to voluntarily replacing existing high bleed controllers with new low bleed controllers.

Third, and important to ozone nonattainment areas, using a process unit affected facility would preserve the ability for operators to capture offsets if they voluntarily change existing pneumatic controllers from high bleed to low bleed or intermittent vent. Changing out the controller would be changing a component part of the process unit affected facility but would not be the replacement of an affected facility that would otherwise trigger a new affected facility subject to this rule.

Fourth, defining pneumatic controllers as individual facilities could result in some states requiring that each continuous bleed pneumatic controller to be permitted prior to new construction, modification, or reconstruction for minor or major sources. By changing the affected facility definition to a pneumatically controlled process unit, permitting of individual controllers is not required if installation or replacement of an affected facility component occurs that might otherwise trigger modification or reconstruction. If API's recommendation to define pneumatics as a process unit is rejected, we request a note in the preamble to the effect that EPA does not intend that the installation of a single pneumatic controller would trigger permitting requirements. While this is ultimately a State issue, it would be helpful to have such a statement from EPA.

17.4.7. Continuous Bleed Gas-Driven Pneumatically Controlled Process Unit

Finally, assuming EPA agrees with API's recommendations, for consistency and clarity, every reference to "pneumatic controllers" used in the proposed rule for the affected facility should be changed to "continuous bleed gas-driven pneumatically controlled process unit".

17.5. Sitewide Applicability by Driver Medium

To complement affected facility applicability by the driver medium, which API recommends to be gas-driven only, determination of an affected facility for pneumatic controllers or pneumatic process units can be made on a sitewide basis, rather than by each individual controller. This will be much

less burdensome to an operator, as individual records of each controller are unnecessary. When compressed air is available to drive pneumatic controllers at any oil and gas site, it will be available to drive all controllers.

17.5.1. Natural Gas Processing Plants Have No Affected Facilities

In the proposal, EPA regulates pneumatic controllers with no emissions at natural gas processing plants due to the requirement for plants to use compressed air as the pneumatic driver to achieve zero emissions of natural gas. Recordkeeping and reporting is required for individual controllers which will be extremely burdensome. API knows of no precedent where a facility with no emissions of a regulated pollutant is regulated by an NSPS or other rule under the CAA. It would be much simpler if EPA prohibited the use of gas-driven controllers in VOC service. A plant using instrument air could then easily prove inapplicability to the rule by a single demonstration of the driver gas used to operate pneumatic controllers.

One exception is needed, however. Some operators may choose to use natural gas as the pneumatics driver for emergency and isolation valves, or switch instrument air to natural gas in the event of an emergency. If an emergency exists during a power outage, electric drive air compressors may not be functional to dependably supply needed compressed air to close emergency isolation valves. Operators need the flexibility to use natural gas as the driver, since it will be a dependable supply of gas available for emergency use.

17.5.2. Remote, small facilities

There are several categories of facilities such as Dew Point Suppression Facilities that are remote, unmanned, and have no available power, but meet the §60.5430 definition of a "Natural gas processing plant". Consequently, they do not have a method for meeting the §60.5410(d)(2) requirement of emitting zero natural gas. There is not always a cost-effective way of providing a reliable source of compressed air to be used as the driver for the pneumatic controller, so natural gas must be used. API's recommendation is either to accept API's proposed definitions for natural gas processing plant (gas plant) and forced extraction of natural gas liquids (see Section 6.3), or to exempt these remote facilities from the requirements of §60.5410(d)(2).

17.5.3. Use of Instrument Air at Other Oil and Gas Sites

While it is true that oil and gas sites are frequently remote and do not have access to reliable power supplies, it is not universally true. If a site does have access to reliable power, and if an operator decides that his process requires a high-bleed controller, he should have the option of installing instrument air if he decides that the combination of high-bleed controller and an air compressor provides a better process result. EPA's proposed rule language does not anticipate or allow this zero-emissions option. API provides rule text language in Attachment C that addresses this issue as paragraph §60.5390(c)(2). Switching to instrument air should be encouraged since it will reduce emissions from all controllers at a site. However, API recommends allowing 180 days for this to occur due to the extra time it takes to order and construct an air compressor.

17.6. Natural Gas is Not a Valid Surrogate for VOC

As discussed in General Issue section 5.1.1, there is no basis for the statement in §60.5390 to use natural gas as a surrogate for VOC. EPA assumed that natural gas contains 18% VOC, but the content varies widely. In fact, most unconventionally produced coal bed methane and shale gas has little if any measureable VOC. Additionally, natural gas downstream of an NGL fractionation or extraction gas plant has little or no VOC as VOCs are removed by processing. Further, gas analysis of process streams used for instrument gas are readily available and it is not difficult to use a VOC threshold directly. As stated in Section 5.1, pneumatics not in VOC service should be exempt from the rule.

17.7. Administrator's Approval for Use of High Bleed Pneumatic Controllers

Both §60.5390(a) and §60.5410(d)(1) state: "You have demonstrated, to the Administrator's satisfaction, the use of a high bleed gas-driven pneumatic controller device is predicated..." This suggests that prior approval from the EPA is required before high bleed pneumatic controllers are installed. If this is the intent, then it is a completely unworkable requirement. Construction and maintenance of pneumatic controllers cannot wait weeks or months for agency review and approval, as this would be very costly in terms of lost production while waiting to commence construction or maintenance. As well, EPA would be inundated with requests for approval if this is the expectation, and could not possibly process them in a timely manner.

Our suggested rule text changes in Attachment C delete use of the term "Administrator's satisfaction." If EPA deems use of the term necessary, then API requests clarification that prior approval is not the intent for its use and recommends that rule text in both section be changed to:

"You have maintained adequate records to support your decision that the use of high bleed gas-driven..."

17.8. Annual Reporting Requirements for Pneumatic Controllers

With an estimated 20,000 new gas and oil wells per year and an average of 3 controllers per well, there will be approximately 60,000 new pneumatic controllers installed each year. Additionally, according to EPA's own estimate pneumatic controllers have a 7-year service life^{LL}. This means approximately 1/7th of existing controllers will need replacement annually. There are approximately 3 controllers per well and 1 million existing wells so 1/7th of the controllers is 429,000 controllers. There are approximately 3 controllers per well and 1 million existing wells so 1/7th of the controllers is 429,000 controllers. If even 1/3 of that number is "continuous bleed, gas-driven pneumatic controllers" then 20,000 new controllers and 143,000 replacement controllers will create 163,000 new potentially affected facilities and reports each year. The administrative burden to industry will be overwhelming, just as it will be to state agencies and the EPA. It does not seem possible to demonstrate the benefit of these reports for such small sources, especially when agencies will be unable to review them. API is not supportive of a third party verification system, an idea raised in the preamble. see Section 8.8

^{LL} Page 2-16 of EPA 430-R-93-012, October, 1993 "Opportunities to Reduce Anthropogenic Methane Emissions in the United States"

If EPA refuses to exempt pneumatic controllers from the reporting requirements, then adopting API's recommendation for redefining the affected facility as a continuous bleed gas-driven pneumatically controlled process unit, will provide significant relief to the reporting burden. An initial annual report for each site that constructs a new, modified, or reconstructed process unit using one or more high bleed gas-driven controllers would be all that is necessary. Such a report would only need to include an explanation of why high bleed controllers are being used. Replacement and repair of controllers for existing facilities would normally not require additional reporting since modification or reconstruction would be seldom triggered.

17.9. Recordkeeping

API recommends that only records sufficient to demonstrate compliance with the rule be required. These records would include a sitewide applicability determination by documenting the medium for the pneumatic driver (e.g., air or gas). If the pneumatic driver is air or other gas not in VOC service, then that is the only record needed.

For sites with gas-driven pneumatics, records of controller make and model should then be sufficient but only for process unit affected facilities newly constructed, modified, or reconstructed after the proposal date. Knowing the make and model of controllers is sufficient to validate design specification to demonstrate compliance with the rule.

Records of installation dates are not possible for existing controllers as these are small components for which operators have not had any historical reason to track installation date. Furthermore, controllers are not date stamped with any manufacturing information. Only new controllers installed after Aug. 23, 2011 can be determined, since this proposal is the first time operators have had a demonstrated need to track this kind of information. These records can be made available by agency request or during a site inspection.

17.10. Time Extension for Manufacturer's Guarantee

The requirement in §60.5410(d)(3) specifies that "manufacturer's design specifications guarantee..." establishes a design standard. Currently, there is not a consistent manufacturing-industry practice to label pneumatic controllers or provide documentation with a bleed rate for the weak stream or to correctly specify if a controller is "high bleed" or "low bleed" based on the weak stream constant bleed rate. Since there is no industry standard, this leads to inconsistency amongst manufacturers in how they represent the performance of their products. If it is EPA's intention to establish regulations that require equipment manufactures to standardize the performance representation of their products so that performance is guaranteed, and to have them produce specific labeling, specific documentation, and/or specific performance parameters, then that intention needs to be a requirement directed to the equipment manufacturers. Other NSPS regulations have been accompanied with a grace period to allow manufacturers to conduct meaningful testing, develop necessary documentation, and alter required equipment name plates. API recommends that this grace period be 2 years. If it was not EPA's intent to require a manufacturer guarantee or certification, then API recommends that the term "guarantee" in §60.5410(d)(3) be replaced with "verify" (and the rule text be changed as recommended in Attachment C for §60.5420(b)(5)(iii) and §60.5420(c)(4)(iii)) to avoid confusion and misinterpretation.

17.11. Extend Compliance Date for Pneumatic Controllers by One Year

Unlike the large emission sources regulated in other NSPS Subparts, operators, manufacturers, and suppliers keep inventories of extra pneumatic controllers in stock as they are relatively inexpensive, and malfunctions require quick repair or replacement to maintain production. A compliance date of only 60 days after promulgation will make large inventories of high bleed controllers potentially unusable. Time is needed for manufacturers, suppliers, and operators to make inventory adjustments to adapt to the new requirements. Consequently, API requests the effective date of this rule for pneumatic controllers be delayed for one year past the promulgation date to allow companies to make inventory adjustments. Additionally, a one year extension will also give operators time to switch to instrument air, if feasible as an alternative control strategy. Switching to instrument air, where practicable, should be a desired outcome of this rule proposal since it will eliminate emissions of natural gas.

18. COMPRESSORS

GENERAL COMPRESSORS

18.1. Does Moving Compressors from One Location to Another Trigger Construction (i.e., Installation)?

In §60.5365, EPA states clearly that affected facilities listed in paragraphs (a) through (g) that commenced construction, modification, or reconstruction after August 23, 2011 are subject to the applicable provisions. However, in paragraphs §§60.5365(b) and (c), EPA includes confusing and unnecessary language for determining when a compressor is considered an affected facility. The specific sentences are bolded below:

§60.5365(b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor located between the wellhead and the city gate (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. **For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.**

§60.5365(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor located between the wellhead and the city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. **For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.**

If you breakdown the sentence for when a facility becomes an affected facility, then four clarifying words are important and discussed in detail in the General Provisions under the Definition section (§60.2), the Modification section (§60.14), and the Reconstruction section (§60.15). In §60.2, commenced construction is sufficiently defined as:

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

As you can see from the definitions above, commenced construction includes installation and is based on when the operator enters a contractual obligation to construct or modify an affected facility. Therefore, the last sentences in §60.5365(b) and (c) are unnecessary and could be incorrectly interpreted to apply to existing compressors that are relocated from one location and installed at another without being modified or reconstructed according to the criteria of §60.14 or §60.15.

In addition to removing the confusing reference to "installed" as it relates to commenced construction, EPA should include in the response to comment that the historical position of relocation has not changed for facilities under NSPS OOOO. Some of the rationale and historical decisions are:

- Air pollution controls are generally more effective and less costly when designed as part of the original production facility, rather than retrofitted to an existing facility. Thus, the Clean Air Act amendments established the New Source Performance Standards (NSPS), which requires technology-based emission limitations on "new" sources of air pollution in certain designated industrial categories. It makes little sense in the context of section 111 of the Clean Air Act, to treat as new sources, equipment that was designed and built before the proposal date of an NSPS rule, because it is much less cost effective to retrofit these existing sources. For this reason, EPA appears to have adopted the rule that relocation of an existing source does not trigger NSPS. For this same reason, the installation date should not be used as a trigger for NSPS application to existing equipment. This is consistent with other actions taken by EPA, such as in the RICE and CI NSPS rules:

§60.4208 (h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

The engine and compressor are typically a package unit. When an engine is relocated, the associated compressor is relocated at the same time. If a relocated engine is not considered a modification or reconstruction under NSPS JJJJ or IIII, then EPA should also not consider a compressor relocated with the engine as a modification or reconstruction. Maintaining consistency between the NSPS's will avoid the confusion of having differing NSPS applicability for portions of a packaged unit being relocated to another location.

- Several EPA ADI's have clearly determined that relocation without a modification or reconstruction does not trigger NSPS. Refer to the following ADI's for more details on EPA's historical policy:
 - K003 (1978) – "EPA policy is that relocation of existing facilities does not constitute a modification under 40 CFR 60.14."

- 0900067 (2008) – "Relocation in and of itself does not trigger applicability."

To avoid the confusion and maintain consistency with the NSPS general provisions and historical position, API recommends EPA remove the last sentence from each section. The recommended change is reflected below:

Suggested Rule Text:

§60.5365

* * * * *

- (b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor in VOC service located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) and prior to the natural gas processing plant is not an affected facility under this subpart. ~~For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~
- (c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor in VOC service located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. ~~For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.2. Applicable Provisions for Compressor Located at an Onshore Natural Gas Process Plant

Clarify the applicable provisions for compressors located at an onshore natural gas processing plant. In §60.5365(b) & (c), compressors between the wellsite and the city gate are affected facilities, which are subject to the standards in §60.5380 and §60.5385. In §60.5365(f), compressors and equipment at onshore natural gas processing plants are an affected facility. Affected facilities under §60.5365(f) are subject to the VOC control requirements found in §60.5400, §60.5401, and §60.5402, which reference the LDAR requirements in NSPS VVa. Although NSPS VVa contains requirements for compressors, EPA did not reference the compressor standards found in VVa. The inclusion of compressors in both affected facility descriptions causes confusion as to the applicable requirements under NSPS OOOO. In Chapter 6 of the technical support document (TSD), EPA includes compressors located in the processing category (natural gas processing plants) in the regulatory options evaluation under §60.5380 and §60.5385. In Chapter 8 of the TSD (Equipment Leaks), page 8-21, EPA states "Compressors are not included in this LDAR option and are regulated separately." Therefore, it appears EPA intends to regulate affected compressors under §60.5380 and §60.5385 and not under the LDAR requirements for natural gas processing plants. To avoid confusion as to the appropriate requirements for the compressor affected facility, API recommends the following changes to the applicability section in §60.5365:

Suggested Rule Text:**§60.5365**

* * * * *

(f) ~~Compressors and~~ Equipment (as defined in §60.5430) located at onshore natural gas processing plants.

~~(1) Each compressor in VOC service or in wet gas service is an affected facility.~~

~~(2)~~(1) The group of all equipment, ~~except compressors~~, within a process unit is an affected facility.

RECIPROCATING COMPRESSORS**18.3. Rod Packing Change Out****18.3.1. Extend the Time Period to 43,800 Hours or the Option for Every 5 Years**

EPA's cost-benefit analysis does not account for the cost of downtime. EPA assumes the rod packing replacement is completed during a normally scheduled maintenance shutdown. Major maintenance and overhauls are typically completed on a 5 year cycle. In addition, packing sets are either "continuous" or "split ring". Split ring packing allows for replacement without removing the pistons from the cylinders, but is more prone to leak and some companies do not allow the use of a split ring packing for that reason. Continuous packing is less prone to leakage, but replacement requires pulling the piston and rod out of the cylinder which is a major effort that is only done on major compressor overhaul cycles generally every 5 years. Therefore, the rod packing replacement schedule should be changed to allow the option for every five years or 43,800 hrs in order to meet EPA's intent of not including downtime in the cost-benefit analysis and to coincide with a common frequency for major maintenance. Allowing the option for a set 5 year frequency will simplify the recordkeeping and eliminate the need to track operating hours. For owner/operators having a method to track operating hours, the option to replace the packing every 43,800 hours may be a preferable option.

18.3.2. Tracking Hours of Operation

The requirements of §60.5385(a) imply that the hours of operation of reciprocating compressors must be continuously monitored beginning upon the initial start-up, the date of publication of the final rule, or the date of the previous rod packing replacement. Although not specifically stated as a requirement, it could be interpreted that a "hour meter" be installed on all "engine-compressor" sets to continuously monitor runtime hours. There are other methods of monitoring runtime, such as "telemetry and periodic downloads associated databases", that do a reliable job of tracking hours of operation. EPA should clarify that hours of operation can be monitored using a runtime meter, telemetry and associated database, or other system (maintenance logs, PM databases, or work order tracking system) used to track preventative maintenance schedules.

18.3.3. Option for Preventative Maintenance and Inspection Programs

EPA should include an option for Owner or Operator to rely on preventative maintenance programs for determining a leak from the rod packing, subsequently requiring replacement. The maintenance plan typically contains normally scheduled rod packing frequencies changes to coincide with major preventive maintenance performed during a shutdown. Many owner or operators have a preventative maintenance programs that include periodic inspections and maintenance to ensure the compressor and engine driver are operating properly for maximum reliability. An example of an inspection that is sometimes performed to verify the condition of the rod packing seal, is to conduct a quarterly ultrasound measurements for indications of leak. If a leak is detected, the compressor is scheduled for shutdown and repair. The expert opinion of several reciprocating compressor engineers is that the replacement should be based on inspection/measurements to determine the compressor condition (including rod packing seals) and should not be based on time alone. New packing has a break-in period where the leakage can be higher than it would be for older packing. In addition, the failure of new seals due to installation problems or manufacturing defects is not uncommon. If you also account for the additional emissions that are likely to be released when preparing the compressor for maintenance, a time-based replacement program would probably result in higher emissions than a condition based program. For an engine subject NSPS JJJJ, the owner or operator is required to have a maintenance plan to ensure the engine is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions. Since many of the affected compressors under NSPS OOOO will be associated with an engine subject NSPS JJJJ, EPA should be consistent between the standards and allow for the option to use a preventive maintenance plan under NSPS OOOO.

18.3.4. Suggested Rule Text

§60.5385

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

- (a) You must replace the reciprocating compressor rod packing before the compressor has operated for [a period longer than one of the limits listed in paragraphs \(a\)\(1\) through \(a\)\(3\) of this section](#) ~~26,000 hours~~. The number of hours [or years](#) of operation must be ~~continuously~~ monitored beginning upon initial startup of your reciprocating compressor affected facility, or [60 days from](#) the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. [If monitoring the number of hours of operation, the hours can be monitored using an associated engine runtime meter, telemetry and associated database, or other system \(maintenance logs, PM databases, or work order tracking system\) used to track preventative maintenance and schedules.](#)

[\(1\) 43,800 hours; or](#)

(2) five years; or

(3) a frequency specified by the owner or operator in a preventative maintenance plan designed to maximize the reliability of the reciprocating compressor and minimize VOC emissions.

§60.5415

(c)(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches the limit selected by the owner or operator from §60.5385(a)(1) through (a)(3) ~~26,000 hours.~~

§60.5420

(b)(4) For each reciprocating compressor affected facility, ~~the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.~~

~~(i) The cumulative number of hours of operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.~~

~~(ii) Documentation that if the reciprocating compressor rod packing was due for replacement according to one of the frequencies described in §60.5385(a), but was not replaced as specified before the cumulative number of hours of operation reached 24,000 hours.~~

18.3.5. Ownership

The compressor owners (i.e. rental companies) should be responsible for rod packing change outs and recordkeeping.

18.4. Exclude Reciprocating Compressors in the Transmission and Storage Segment

EPA should exclude reciprocating compressors in the transmission and storage sector, located after the point of custody transfer, due to the low VOC content of natural gas in that sector. A more detailed discussion can be found in Sections 3 and 5.1.

Suggested Rule Text:

§60.5365

* * * * *

(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor in VOC service, located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. ~~For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.5. Reciprocating Compressor Definition

The definition should be changed to a more accurate description. API recommends the following definition:

Suggested Rule Text:

§60.5430

Reciprocating compressor means a [positive-displacement machine in which the compressing and displacing element is a piston having a reciprocating motion within a cylinder. The pressure increase is achieved by reducing the volume of a fixed amount of natural gas or field gas](#) ~~piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.~~

18.6. Typographical Error

It appears there is a typographical error in §60.5420(b)(4)(ii). This paragraph references documentation for the reciprocating rod packing being replaced before reaching 24,000 hours. However, the proposed standard in §60.5385 requires replacement of the rod packing every 26,000 hours.

CENTRIFUGAL COMPRESSORS

18.7. Exclude Centrifugal Compressors in Gathering and Boosting and Transmission Segments

In Chapter 6 of the Technical Support Document (TSD), the evaluation for centrifugal compressors is limited to only centrifugal compressors in processing, transmission, and storage. The cost-benefit analysis does not include centrifugal compressors located in production or gathering and boosting. EPA accurately exempted centrifugal compressors located at a wellsite as an affected facility. However, a centrifugal compressor located in the gathering and boosting segment was considered an affected facility without the necessary cost-benefit analysis to support this decision. EPA should revise the affected facility description to accurately reflect the TSD and basis for determining an affected facility for centrifugal compressors.

Because of the low VOC content, EPA should also exclude centrifugal compressors in the transmission and storage segment, located after the point of custody transfer. A more detailed discussion can be found in Sections 3 and 5.1.

Suggested Rule Text:

§60.5365

- (b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor [in VOC service](#) located between the wellhead and the [point of custody transfer](#) ~~city gate~~ (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) [and prior to the natural gas processing plant](#) is not an affected

facility under this subpart. ~~For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.8. Allow for a Wet Seal Option for Centrifugal Compressors

Although EPA indicates controls for wet seals are not cost-effective, recent information indicates this is not correct and EPA should not preclude the use of a wet seal equipped centrifugal compressor with controls capable of meeting a 95% VOC control efficiency or routing captured seal-oil gas to a fuel gas system, recycle, or another processing system.^{MM} Centrifugal compressors located at natural gas processing plants may have wet seal compressors with a seal-oil degassing recovery system that separates gas from the seal-oil and routes the separated gas back to compression suction, fuel system, or flare system. For example, many Solar® compressors packages will have a seal oil system. But, the system does not vent the seal gas to atmosphere. The oil and gas mixture that drains from the seals is routed through a seal oil trap that separates the oil and gas. The oil is returned to the package oil tank. The gas is returned to the compressor suction. In the case of existing wet seal centrifugal compressors which may become subject to NSPS OOOO due to modification or reconstruction utilizing an existing gas capture system or retrofitting the centrifugal compressor with a seal oil vapor separation and control system is far more cost-effective than installing a dry gas seal compressor. Conversion of a wet seal centrifugal compressor to dry seals costs from \$250,000 to \$1,000,000 per machine while retrofit with a seal oil gas separator is estimated to cost in the range of \$22,000¹. This option would also provide flexibility for cases where the owner/operator believes a dry gas seal system is not technically feasible (e.g., “dirty” gas) or believe the wet seal system is more economic for the specific location and service. This will also allow compressors with wet seals installed between the date for an affected facility and the final rule to be able to install necessary controls or process modifications rather than retrofit a dry gas seal system.

The preliminary results from a joint EPA (Natural Gas STAR) and BP study of these types of seal-oil gas recovery systems in place on wet seal centrifugal compressors at BP's Alaska North Slope operations were co-presented by BP and ICF (as EPA's contractor) at the Global Methane Initiative (GMI) meeting in Krakow, Poland on October 14, 2011. As the preliminary results illustrate, seal-oil gas separation systems have atmospheric vent volumetric rates broadly similar to dry seal leak rates and may perform incrementally better in some instances. Although EPA and BP have additional work prior to publishing detailed results of the study the preliminary results are quite compelling and should be adequate basis for allowance of this option. A full copy of the presentation in Krakow can be downloaded at the GMI website.^{NN}

^{MM} Routing Centrifugal Compressor Seal Oil De-gassing Emissions to Fuel Gas as an Alternative to Installing Dry Seals”; Global Methane Initiative All-Partnership Meeting; Oil and Gas Subcommittee – Technical and Policy Sessions; October 14, 2011 Krakow, Poland; Reid Smith-BP & Don Robinson-ICF

^{NN} http://www.globalmethane.org/documents/events_oilgas_101411_tech_smith2.pdf

Suggested rule text to accommodate the option of using a wet seal gas system:

§60.5380

You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility.

- (a) You must control VOC emissions from centrifugal compressors using one the methods described in paragraph (a)(1),(a)(2), or (a)(3). ~~equip each rotating compressor shaft with a dry seal system upon initial startup.~~

(1) Equip the rotating compressor shaft with a dry seal system upon initial startup.

(2) Equip the rotating compressor shaft with a wet seal-oil degassing system and route the separated gas to one of the following:

(i) a flare designed and operated in accordance with the requirements of §60.18(b), or

(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.

(iii) a combustion device designed to reduce VOC emissions by 95%, or

(iv) a fuel system, or

(v) recycle (compression suction), or

(vi) a combination of (2)(i) through (2)(v)

(3) Equip the rotating compressor shaft with a wet seal. You must route the seal oil degassing tank vapors through a closed vent system to one of the following:

(i) a flare designed and operated in accordance with the requirements of §60.18(b), or

(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.

(iii) a combustion device designed to reduce VOC emissions by 95%, or

(iv) a vapor recovery device routed to a combustion device designed to reduce VOC emissions by 95%; a fuel system, or recycle (compression suction/process), or

(v) a combination of (3)(i) through (3)(iv).

§60.5410

* * * * *

- (b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted ~~with a dry seal system~~ upon initial startup as required by §60.5380.

§60.5415

* * * * *

- (b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped ~~with a dry seal~~ as specified in §60.5380(a).

§60.5420

* * * * *

- (b)(3) For each centrifugal compressor affected facility installed during the reporting period, documentation ~~that if~~ the centrifugal compressor ~~is was not~~ equipped ~~with dry seals~~ as specified in §60.5380(a).

18.9. Centrifugal Compressor Definition

Centrifugal compressors associated with vapor recovery should be excluded from the definition because shutdowns to replace seals would increase emissions as compared to waiting for the next scheduled process unit shutdown. Certain centrifugal compressors are designed to capture and route vapors back into the process to prevent or reduce emissions. The design necessary to efficiently capture and control emissions should be left to the manufacture and not EPA. EPA should make it clear that the definition of centrifugal compressor does not include compressors associated with vapor recovery.

The definition should be changed to more accurately describe affected facility. API recommends the following definition:

Suggested Rule Text:

§60.5430

Centrifugal compressor means a dynamic machine in which one or more rotating impellers, usually shrouded on the sides, accelerate the flow of natural gas or field gas. The main gas flow is radial. The pressure increase is achieved by converting kinetic energy to static energy. Centrifugal compressor does not include compressors associated with vapor recovery or any other pollution control device ~~piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.~~

19. EQUIPMENT LEAKS

API fully supports EPA's determination not to propose NSPS for addressing VOC emissions from equipment leaks at exploration and production field facilities. However, API has a number of concerns and issues with

regard to EPA's proposed revisions to NSPS and NESHAP addressing VOC/HAP emissions from equipment leaks at natural gas processing plants.

19.1. Subpart OOOO – Stringency of Subpart VVa Requirements

EPA states that their technology review has led them to propose that the requirements at 40 CFR Part 60, Subpart KKK for controlling VOC emissions from equipment leaks at natural gas processing plants be updated to reflect the requirements in 40 CFR Part 60, Subpart VVa. EPA indicates that it has evaluated four options for updated control requirements and is proposing a program that is largely based on the equipment leaks standards promulgated under 40 CFR 60 Subpart VVa. The leak detection and repair (LDAR) program prescribed in Subpart VVa requires the monitoring of pumps, pressure relief devices, valves, and connectors. These components are monitored with an Organic Vapor Analyzer (OVA) or Toxic Vapor Analyzer (TVA) to determine if a component is leaking by measuring the concentration of the mixture of organic compounds at the potential leaking interface. Connectors, valves, and pressure relief devices are defined as leaking if the concentration is equal to or greater than a threshold of 500 parts per million by volume (ppmv); pumps are defined as leaking if the concentration around the seals equals or exceeds 2,000 parts per million. Valves and pumps are monitored monthly, connectors are monitored annually, and atmospheric pressure relief valves are monitored after a pressure release event. Open-ended lines must be capped or plugged when not in use or must be equipped with a second valve.

19.1.1. Proposed LDAR Program for Valves

EPA overestimated valve control-effectiveness for its model plant.

The natural gas processing plant model used by the agency in its technical support document (TSD) to analyze the impact of these new leak definitions for the LDAR program is flawed. EPA correctly states that New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, Subpart KKK), and were assumed to be the baseline emissions for this analysis. However, the calculations of baseline emissions for the model plant - as presented in the TSD - significantly overestimate these emissions since the method used relies on component counts and average emission factors by component type, which are, *at best, representative of uncontrolled facilities*. Since Subpart KKK was promulgated in 1985, a significant proportion of the existing natural gas plants that would become subject to Subpart OOOO through modification will already be complying with Subpart KKK, and all new natural gas plants would have to comply with Subpart KKK if Subpart OOOO was not in place. Thus, the basis for evaluating Subpart OOOO impacts must be compliance with Subpart KKK, not an uncontrolled emissions scenario as was used in EPA's TSD analysis that supports the proposed rule.

Table 8-12 of the TSD provides a listing of estimated control effectiveness (CE) for select LDAR programs at a Chemical Process Unit and a Petroleum Refinery. The CE for a quarterly LDAR program with a 10,000 ppm leak definition is assumed to be in the range of 60% to 70%, which is assumed to be applicable also for natural gas processing plants that are subject to 40 CFR 60 Subpart KKK. In the TSD, EPA used baseline VOC emissions of 14.3 tons /yr for its model natural gas processing plant facility. This baseline is in error

because it represents emissions from an uncontrolled facility. A more realistic value, based on applying the CE stated above to EPA’s uncontrolled emissions estimate, would be in the range of 4.3 to 5.7 tons/yr, per facility. This range of values accounts for the CE of Subpart KKK controls, and should be used as the baseline from which it is appropriate to calculate the incremental impact of the proposed regulations.

The TSD model calculates uncontrolled emissions using average emission factors that typically overestimate emissions when compared to calculation methods that are based on Leak/No-Leak factors, or the correlation equation approach when the screening value details are available. This overestimate occurs, among other reasons, because the average emission factors assume a much higher percentage of leaking components than those that are typically found at facilities where monitoring programs, such as the ones imposed by Subpart KKK, are in place. The table below provides a comparison of VOC emissions calculations for valves from several natural gas processing plants. The results in the table are based on using the Average Emission Factor vs. the Leak/No Leak methods for the same facilities. The data are based on examples provided by API members for process units that are currently subject to Subpart KKK. The computed percent difference is an indication of the overestimate of valves emissions due to using an average emission factor.

Table 19-1 Comparison of VOC Emissions Calculations For Valves From Natural Gas Processing Plants

| Facility | VOC Emissions from Valves (tons/year) | | % Difference |
|----------|---------------------------------------|----------------------------|--------------|
| | Average Emission Factor | Subpart KKK (Leak/No Leak) | |
| A | 5.7 | 1.36 | 76% |
| B | 8.2 | 1.54 | 81% |
| C | 0.98 | 0.0055 | 99% |
| D | 6.73 | 0.20 | 97% |
| E | 4.0 | 0.19 | 95% |
| F | 19.4 | 17.00 | 12.4% |

By overestimating the baseline emissions for the model plants, as well as the emission reduction associated with applying the VVa program to facilities that are otherwise subject to a Subpart KKK program, the TSD derives an estimated VOC emission control effectiveness for this proposal of 94%; which is not realistic nor is it representative of the incremental control that might be attained from a Subpart KKK baseline.

API’s data demonstrated EPA’s overestimation.

Based on data provided by API member companies for several natural gas processing plants that are currently subject to 40CFR60 Subpart KKK, the percent of valves that leak above 10,000 ppm ranges between 0.1 - 4.0%; however, these leaking valves contribute 82 - 99% of the total mass emissions from facility valves when using the Leak/No-Leak method from EPA’s 1995 protocol for estimating emissions. This is consistent with an earlier API study (API # 310, November 1997) of petroleum refineries equipment leaks that showed that 92% of reducible emissions are due to only ~ 0.13% of components.

API obtained more detailed data for three different natural gas processing units where the actual parts per million concentration values monitored are recorded. This enables the use of the correlation equation method to calculate total emissions from valves and to estimate the contribution of valves that are leaking in various screening value ranges. The table below summarizes the available data. The data indicate that the existing Subpart KKK is contributing to controlling valve leakage above 10,000 ppm. About 80% or more of the valves monitored screen below 500 ppm, and the fraction that screens between 500 and 10,000 ppm ranges between 2-15%. The fraction of the valves that screens between 500 – 10,000 ppm is shown to contribute less than 30% to overall emissions from facility valves.

Table 19-2. Detailed Data for Valves from Three Natural Gas Processing Units

| Process Unit | Screening Value Range | VOC Emissions (tons/yr) | % of Emission | Valve Count | % of Components |
|--------------|--------------------------------------|-------------------------|---------------|-------------|-----------------|
| A | Less than 500 ppm | 0.030 | 68.7% | 677 | 97.8% |
| | Between 500 and 10,000 ppm | 0.014 | 31.3% | 15 | 2.2% |
| | TOTAL | 0.044 | 100.0% | 692 | 100.0% |
| B | Less than 500 ppm | 0.301 | 15.9% | 3759 | 87.0% |
| | Between 500 and 10,000 ppm | 0.543 | 28.7% | 527 | 12.2% |
| | over 10,000 ppm | 1.049 | 55.4% | 36 | 0.8% |
| | TOTAL | 1.893 | 100.0% | 4322 | 100.0% |
| C | Less than 500 ppm | 0.182 | 1.6% | 2058 | 80.9% |
| | Between 500 and 10,000 ppm | 0.417 | 3.7% | 385 | 15.1% |
| | Between 10,000 and pegged at 100,000 | 2.575 | 23.1% | 73 | 2.9% |
| | Pegged 100,000 | 7.98 | 71.5% | 29 | 1.1% |
| | TOTAL | 11.154 | 100.0% | 2545 | 100.0% |

Hence, the proposed changes to the LDAR program for natural gas processing plants that will redefine leaking valves as those leaking above 500 ppm will not lead to any substantial VOC emissions reductions. Per the examples shown in the table above, for a facility that is either currently subject to Subpart KKK or, if new, would become subject to Subpart KKK, the overall VOC emissions from its valves are about 2 tons/year. Lowering the leak definition to 500 ppm might reduce VOC emissions by less than 0.6 tons/year. This is much lower than the 10.9 tons/yr postulated by EPA for the TSD model plant. Therefore, the proposed revised LDAR program for valves will be burdensome without achieving the VOC control claimed and, considering its poor cost effectiveness, does not represent the Best System of Emission Reduction (BSER) for natural gas plant equipment leaks, as required by the Clean Air Act (CAA) for New Source Performance Standards (NSPS).

19.1.2. Proposed LDAR Program for Connectors

EPA overestimated emission reductions.

The changes to the proposed LDAR program for natural gas processing plants includes introduction of a connector program with a leak definition of 500 ppm, which is based on similar programs for chemical and refinery units. Current Subpart KKK LDAR programs impose only auditory, visual and olfactory (AVO) inspection requirements for connectors. Based on the TSD model plant, EPA expects a VOC reduction of 1.57 tons/year for the model facility with the assumption of a CE of 95.9%. This amounts to about a 20% overestimate of the emission reduction potential when compared to the TSD citations of a 93% CE for a chemical plant, and an 81% CE for a refinery, both with a 500 ppm connector program (TSD Table 8-12).

Moreover, API has collected limited data from three natural gas processing facilities that voluntarily monitor and record screening values for connectors. The table below summarizes the data and it demonstrates - as expected - that connectors do not exhibit significant VOC emissions, and do not typically register concentrations over 10,000 ppm when monitored with VOC sniffers. For the process units analyzed, the number of connectors range from 1,463 to 11,272, and the corresponding emissions range from 0.076 to 1.77 tons per year of VOCs. For those process units 27 - 57% of the connectors are found to be in the screening value range of 500 and 10,000 ppm. When these data are normalized for a facility with an equivalent number of connectors as in the model plant, potentially reducible emissions from connectors are 0.87 tons VOC/year.

Table 19-3. Detailed Data for Connectors from Three Natural Gas Process Facilities

| Process Unit | Screening Value Range | VOC tons/year | % Emissions | Connectors Count | % connectors |
|--------------|----------------------------|---------------|-------------|------------------|--------------|
| A | Less than 500 ppm | 0.0087 | 11.4% | 1069 | 73.1% |
| | Between 500 and 10,000 ppm | 0.0672 | 88.6% | 394 | 26.9% |
| | TOTAL | 0.0759 | | 1463 | |
| B | Less than 500 ppm | 1.5980 | 100.0% | 11272 | 100.0% |
| | TOTAL | 1.5980 | | 11272 | |
| C | Less than 500 ppm | 0.4192 | 23.7% | 2922 | 42.8% |
| | Between 500 and 10,000 ppm | 1.3508 | 76.3% | 3899 | 57.2% |
| | TOTAL | 1.7700 | | 6821 | |

Therefore, a value of 0.87 tons/yr of VOC emission reduction is a more realistic value than EPA's 1.57 ton/yr estimate to judge the effectiveness of the proposed connector program. This value and a more realistic CE than the 95.9% EPA assumed should be used to calculate the cost effectiveness of the proposed connectors program.

EPA underestimated the cost and overestimated cost-effectiveness.

EPA is proposing a connectors control program that is not cost-effective and thus not BSER. In fact, it is evident from the data presented and from a previous study of American Chemistry Council (ACC) member facilities⁰⁰ that there is no statistically significant difference in average connector emissions between the initial Method 21 inspections for connectors and the subsequent inspections. Thus, an LDAR program for connectors is ineffective in leading to significant emission reductions.

EPA is oversimplifying the cost assumptions by basing its entire cost effectiveness analysis on data it has previously developed for promulgating Subpart VVa in 2006. The TSD is based on the assumption that the same cost spreadsheets model used for chemical plants and refineries is also applicable for estimating the costs associated with monitoring at natural gas processing plants. This assumption is erroneous and does not take into account many additional factors that should be considered when assessing the cost impacts of a connectors monitoring program at gas plants. Factors that should be considered include:

- (a) Due to the high turnover associated with LDAR personnel and the annual monitoring interval for connectors, it is likely that each time connectors are monitored training will be required to acquaint the monitoring personnel with the process detail, adding to program costs.
- (b) Many natural gas plants are located in remote locations and monitoring personnel, maintenance personnel and even operators will have to travel significant distances to reach the site, incurring significant additional costs to those typical of chemical and refining operations.
- (c) From a recordkeeping perspective, connectors result in a much greater administrative burden than is incurred for other component types. Unlike pumps and valves, connectors are not typically shown on Process & Instrumentation diagrams. Valve end connectors may be identified in an LDAR database via the valve LDAR identification number, such that the connectors are not individually tagged. Both of these conditions make it much more difficult and costly to track additions or deletions of connectors and to maintain accurate component records.

If we review EPA's cost estimates of \$17.70 for the **initial monitoring and setup costs** for valves, and a mere incremental cost of \$1.13 per connector, it is immediately evident that these figures are grossly underestimated. Adding connectors to an existing monitoring system is costly. It will require expanding data collection and tagging systems to identify the connectors being added, and additional time for the associated logistical and planning aspects of an expanded program. Based on data provided by an API member, the costs for setting up a monitoring system for valves is over \$26 per valve (for a model plant consisting of 1500 valves). For the same such plant, the incremental cost for adding a connectors program would be in the range of \$3 - \$9.50 or more per connector (for a model consisting of 4400 connectors) depending on the exact nature of the existing LDAR program, the

⁰⁰ Exhibit 1 – CMA (ACC) Analysis of Connector Monitoring Data from Hazardous Organic NESHAP (HON) and Miscellaneous Organic NESHAP (MON) Units. Pages 15 through 37 of ACC's comments on proposed NSPS Subpart VV, Docket Number EPA-HQ-OAR-2006-0699, February 8, 2006.

adequacy of the existing data collection and archiving system and the amount of time that needs to be spent on site at remote locations.

Similarly, the assumed equivalency of cost (\$1.50 per monitoring event) for both valves and connectors does not reflect the true cost of monitoring connectors. For the reasons stated above connectors would cost more to monitor per component than valves. None of these costs are reflected in EPA's \$1.50 per component cost estimate. Based on data available from API members a more realistic estimate would be a cost of \$ 2.70 - \$ 3.00, or more, per connector monitoring event, depending on individual facility circumstances and location.

The calculation presented in the TSD lists the cost effectiveness for connectors in the range of \$4,800/ton-VOC. However, for the reasons discussed above, the proposed connector LDAR program is not expected to lead to the emission control estimated by EPA and thus, even if we accept the assumed costs used by EPA to add an incremental connectors program, the cost effectiveness figure would be much higher, something in the range of over \$7800/ton-VOC when the initial capital costs are amortized over 10 years. If more realistic setup and monitoring costs are considered as discussed above, the cost effectiveness for connectors would be on the order of \$14,100/ton-VOC based on average costs reported by a few API members. Moreover, under special circumstances such as very remote locations, and connectors that are hard to access (though would not be considered 'difficult to monitor') the costs might double or triple.

Cost effectiveness is even further diminished if a lower amortization period is used. The capital equipment investment needed for implementing an Equipment Leaks program consists primarily of monitoring equipment and data systems for data collection and analysis in addition to physical tags for the components. The required field equipment would probably have only a 5-year lifetime, due to on-going improvements in both monitoring instrumentation and hand-held devices. Using the 5-year lifetime for capital equipment amortization would lead to a revised cost effectiveness estimate that is over \$8,400/ton-VOC. If we are to apply the API data discussed above assuming a 5-year lifetime for the capital equipment purchased, the cost effectiveness increases to over \$17,000/ton-VOC.

API contends that the low emission reductions that could be attained by a connectors program would entail high incremental costs, rendering a connectors program not cost-effective.

19.1.3. Additional Cost to Repair Valves and Connectors

EPA did not account for the additional cost to repair valves and connectors at natural gas processing plant if a leak is defined as 500 ppm. In contrast with chemical plants and refineries, natural gas processing plants do not have all required maintenance personnel onsite. In order to perform the initial attempt at repair, they have to rely on contractor personnel and in many cases it would be a different 'trades' crew that is dispatched to perform the repairs as compared to the ones that conducted the monitoring and initial data collection. The additional annual costs for repairing valves and connectors to a more stringent leak definition of less than 500 ppm are significant. For a natural gas processing plant, similar to the model plant in the TSD, API estimates the incremental repair costs to

range from \$60,500 to \$121,000 with an average of \$90,750. These costs must also be accounted for in the Agency's BSER analysis prior to promulgating the new LDAR requirements.

API further affirms that the incremental cost of repair of valves and connectors, if the leak definition were to be reduced to less than 500 ppm, is an additional burden which is not justified in terms of its potential for VOC emission reductions.

19.1.4. Proposed LDAR Program for Pumps – BSER Not Demonstrated

EPA is proposing to lower the leak definition for all pumps from 10,000 ppm to 2,000 ppm. Such a requirement could be very costly, but EPA does not address these potential costs nor does it outline the potential for emission reductions due to such an amended program. As a matter of fact, EPA did not include pumps in its model plants for natural gas processing facilities and thus it is not justifying the extra burden and not demonstrating any environmental benefit.

The proposed leak definition for pumps would likely require different seal material. EPA must demonstrate the need for such a LDAR program for pumps and that these requirements are BSER. That demonstration has not been made and thus these requirements cannot be finalized. If the Agency intends to proceed with lower leak thresholds for pumps, the required BSER and other analyses must be published for notice and comment.

19.1.5. Reciprocating Pumps

Reciprocating pumps are much more common in oil and gas operations than in refining and chemical operations. A 2000 ppm or even a 5000 ppm leak definition will be difficult to meet for reciprocating pumps in general and will be impossible to meet for some reciprocating pumps, without recasting the distance piece or pump replacement. Replacement of such pumps or the pump distance piece was not considered in proposal development and does not reflect BSER.

§60.482-3a(j) of Subpart VVa deals with this issue for reciprocating compressors. That paragraph exempts existing reciprocating compressors from VVa requirements if the owner or operator can demonstrate that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance. The term "distance piece" is defined in Subpart VVa for compressors.

Similar provision and definition can be added to Subpart OOOO for reciprocating pumps.

Thus, API requests the final Subpart OOOO includes a provision similar to §60.482-3a(j) of Subpart VVa and a definition of "distance piece" relative to reciprocating pumps.

Suggested Rule Text**§60.5401**

* * * * *

(i) Any existing reciprocating pump in a process unit which becomes an affected facility under the provisions of §60.14 or §60.15 is exempt from §60.482-2a of this part, provided the owner or operator demonstrates that recasting the distance piece or replacing the pump are the only options available to bring the pump into compliance with the provisions of §60.482-2a of this part.

§60.5430

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor or pump cylinder from the crankcase.

19.1.6. API Request: Stringency of Leak Definition in Subpart OOOO

Due to all the issues raised above, API is requesting that EPA reconsider its proposed alteration of the equipment leaks program for natural gas processing plants. If EPA demonstrates that tighter VOC emission control is justified, we offer the below elements as an alternative program. We believe that the alternate program provides for real emissions reductions in a cost-effective manner.

- a) Set up an LDAR program that requires on-going quarterly monitoring for valves (no skip periods allowed), in lieu of going down to a 500 ppm leak definition for valves. This approach retains the current Subpart KKK leak definition of 10,000 ppm, with its associated repair intervals.
- b) For initial compliance purposes, valve monitoring would be undertaken monthly during the first quarter of becoming subject to this program. Following that, monitoring would continue on a quarterly basis. New and repaired components would be monitored on the quarterly basis rather than having to be monitored monthly.
- c) Facilities would be required to establish internal programs to identify valves that are 'chronic leakers' (valves that leak above 10,000 ppm during three of the four quarters in a year). These valves would be placed on a 'chronic leakers' list and would be designated for refurbishment and/or replacement during the next process unit shutdown.
- d) No new LDAR program for connectors would be imposed, as such a program is not cost effective. API recommends that connectors in gas/vapor service and in light liquid service be subject to the monitoring and leak definition provisions in §60.482-8a.
- e) Retain the 10,000 ppm leak definition for pumps because EPA has not demonstrated the proposed 2000 ppm leak definition as BSER. API recommends that if EPA wishes to evaluate lowering the pump leak definition it might consider the possibility of establishing a 5000 ppm leak definition, after notice and comment rulemaking, if the proposed leak definition is justified as BSER.

- f) Incorporate into the final Subpart OOOO a provision similar to §60.482-3a(j) of Subpart VVa relative to reciprocating pumps. A definition of “distance piece” that is similar to the one in Subpart VVa needs to be added in the final Subpart OOOO, §60.5430. The proposed regulatory language is shown in Section 19.1.5 above.

19.2. Subpart OOOO – Alternative Work Practice

EPA has evaluated several options for an LDAR program for gas processing plants using optical gas imaging (OGI). The options evaluated included: (a) OGI monitoring with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at §60.18(g)); (b) monthly OGI without an annual Method 21 check; and (c) Similar to (b) only annual rather than monthly OGI.

19.2.1. Response to EPA's Request for Comments

On page 52755 of the preamble EPA states, “We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies.” EPA recognizes that analysis they have conducted previously have determined that the VOC reduction achieved by bi-monthly OGI monitoring provides an equivalent, or better, VOC emissions reduction when compared to a quarterly M21 based program with a leak definition of 500 ppm. The key to the OGI based monitoring is the ability to conduct more frequent monitoring, with identification and repair of leaking components that contribute a high percentage of the total mass emissions.

The AWP at §60.18(g) specifies the required monitoring frequency and sensitivity threshold for OGI instruments that would ensure the equivalency of emissions control. The analysis that supported the promulgation of §60.18(g) confirmed the specified OGI program would provide equivalent emissions control to a VVa type program without any associated M21 screening. None-the-less the promulgated AWP includes a requirement for annual M21 monitoring.

Requiring an annual leak survey using M21 makes this AWP impractical, burdensome, and ineffective. It actually negates the flexibility that would otherwise be afforded by allowing an OGI only AWP for Subpart OOOO compliance.

Implementing an OGI only AWP is consistent with the monitoring requirements for the mandatory GHG reporting under 40 CFR Part 98 Subpart W. Hence using such an approach to satisfy both LDAR and GHG monitoring would improve its effectiveness and reduce duplicative and redundant requirements for facilities.

19.2.2. API's Previous Recommendations on AWP

API staff and member companies met with Office of Air Quality, Planning and Standards (OAQPS) staff on August 18, 2011 to address the issues and barriers to the implementation of the AWP as noted in Section 19.2.1 above. In response to EPA's request for comment on the potential applicability of an LDAR program that is based solely on OGI monitoring, we

would like to recap here API's major recommendations from the August 2011 meeting with OAQPS:

- a) API urged OAQPS to return to an OGI AWP without requiring an annual M21 survey, as analytical and field studies have been completed and all of them demonstrate AWP equivalency. Additional data will become available as to the effectiveness of the OGI AWP if the M21 requirement is removed and facilities then will start using it.
- b) API urged EPA to restore the 10% AWP Sensitivity Test Option. This option demonstrates high instrument sensitivity and eliminates the need for the burdensome "least-detectable-fraction" stream analyses.
- c) API requested that EPA clarify and modify the video recording requirements by amending rule language to clarify that video records will identify regulated equipment via a defined area grouping, not by a recording of each equipment component. EPA should also evaluate how the video data will be used and whether a complete video recording is really needed.
- d) API believes that OGI has the potential to be useful for difficult or unsafe to monitor components. However in order to make it work in the field, an extended or conditional repair schedule (first attempt at repair) is needed for difficult to access and unsafe to access components, with the final repair falling under the delay-of-repair provisions.
- e) API also urged EPA to work with stakeholders to develop an OGI Application Protocol for the AWP that is based on OGI techniques for LDAR programs. Guidance could include information on instrument sensitivity checks, techniques for process area monitoring, and emissions estimating from the optical imaging monitoring data.

19.2.3. API Requests

API requests that EPA make it possible to use an OGI only approach for LDAR by taking the following steps:

- a) Explicitly allow the use of OGI techniques without requiring an annual M21 survey.
- b) Implement the recommendations provided during the August 18, 2011 meeting with OAQPS, which are summarized in Section 19.2.2 above, to amend §60.18 and make it a real alternative work practice that could be widely implemented.
- c) As a fall back option, evaluate the use of a one-time, side-by-side survey using OGI and M21 as part of initial compliance for Subpart OOOO, with no further requirements for M21 annual surveys.

19.3. Subpart OOOO – Compressors at Natural Gas Processing Plants

As currently proposed, at natural gas processing plants, compressors are affected facilities under §60.5365(b) [centrifugal compressor affected facility] and §60.5365(c) [reciprocating affected facility], as well as §60.5365(f)(1) [compressor in VOC or wet gas service at onshore natural gas

processing plant]. Sections §60.5380 and §60.5385 outline the proposed dry seal and rod packing change-out requirements for centrifugal and reciprocating compressors, respectively. Even though the introductory language for VOC standards at natural gas processing plants in §60.5400 refers to compressors by stating, “(t)his section applies to each compressor in VOC service or in wet gas service...,” compressor control standards in Subpart VVa (§60.482-3a) was not referenced in §60.5400. Additionally, §60.5422, which addresses additional reporting requirements for gas processing plants, contains no VVa references for compressors. Thus, while compressors at natural gas processing plants are affected facilities under §60.5365(f)(1), there are no substantive control or reporting requirements that address VOC equipment leaks from such compressors.

To avoid compliance confusion, EPA should remove the reference to compressors at onshore natural gas processing plants from the VOC equipment leak provisions in the proposed rule, specifically, §§60.5365(f)(1) and 60.5400, and the definition of equipment in §60.5430.

Suggested Rule Text

§60.5365

(f) ~~Compressors and e~~Equipment (as defined in §60.5430) located at onshore natural gas processing plants.

~~(1) Each compressor in VOC service or in wet gas service is an affected facility.~~

~~(1)(2)~~ The group of all equipment, ~~except compressors~~, within a process unit is an affected facility.

~~(2)(3)~~ Addition or replacement of equipment, as defined in §60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

~~(3)(4)~~ Equipment (as defined in §60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in §60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart.

~~(4)(5)~~ Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) ~~and (f)(2)~~ of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

§60.5400

This section applies to ~~each compressor in VOC service or in wet gas service and~~ the group of all equipment (as defined in §60.5430), ~~except compressors~~, within a process unit.

19.4. Subpart OOOO – Applicability

API has concerns with several issues in the proposed rule that will determine whether and/or how the LDAR provisions would apply to certain natural gas processing plants, process units, equipment, or process streams. These issues are described below along with API's recommendations.

19.4.1. Definition of Natural Gas Processing Plant

Under the current definition in the proposed §60.5430, many very small remote sites without stable power supply would be defined as a natural gas processing plant, and thus subject to the LDAR requirements of the proposed rule. One example is the small sites in the production field that operate a single small JT unit. It is both technically and economically infeasible for such sites to comply with any LDAR requirements, especially the very stringent Subpart VVa requirements.

API requests that EPA address this issue by the following:

- (a) Modify the definition of natural gas processing plant by inserting the word "forced" before "extraction of natural gas liquids..."; and
- (b) Add a new definition of "forced extraction of natural gas liquids" that is essentially adopted from the Greenhouse Gas Mandatory Reporting Rule, 40CFR98, Subpart W (see 76 FR 56050).

Suggested Rule Text – one revised definition, one new definition:

§60.5430

Natural gas processing plant (gas plant) means any processing site engaged in the [forced](#) extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

[Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption \(lean oil\), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids or fuel treatment skids.](#)

19.4.2. Definition of in Wet Gas Service

Proposed §60.5430 defines "in wet gas service" based on whether a component is handling material that has not been through the extraction step in a gas plant. As a result, the proposed *equipment leak provisions would apply to all such components regardless of the quantity of VOC present*. In VOC service, on the other hand, while not defined in the proposal is indicated in §60.5400(f) to be based on the VOC content of the material handled

(i.e., ≥ 10 wt% VOC). Under the proposed language, then, the equipment leak requirements would apply to components in wet gas service regardless of the VOC content of that material. This follows the example set in Part 60 Subpart KKK. In the BID for Subpart KKK^{PP}, EPA explained the reason for applying the equipment leak requirements to all components in wet gas service is that it is cost effective since, unlike in refineries and chemical plants, there are a relatively large number of wet gas components **containing between 1 and 10% VOC**.

On pages 5-5 and 5-6 of the NSPS KKK BID EPA states:

Response: In setting the VOC concentration limit, EPA took into consideration the VOC content below which equipment leak controls may not be cost effective. In the case of synthetic organic chemical plants and petroleum refineries, the costs of controlling the small number of streams containing less than 10 weight percent VOC appeared to be unreasonable in light of the emission reduction potential. Therefore [*sic*], EPA considered 10 weight percent VOC appeared to be an appropriate VOC concentration limit for those standards. In contrast, gas processing plants can have a large number of components in streams containing between 1 weight percent and 10 weight percent VOC, and the cost effectiveness of controlling emissions from these components is reasonable. Thus, the lower VOC concentration limit appeared to be warranted as a way to cover these streams.

However, this argument is invalid since cost effectiveness is not a function of the number of components in the 1-10% VOC range. The same overall emission factor and cost is used (and incurred) for every component subject to monitoring. It is the potential VOC emission reduction that changes with the VOC concentration. Thus, the potential VOC emission reduction per dollar of cost from monitoring a component containing 10 percent VOC is one tenth the potential VOC reduction per dollar of cost from monitoring components containing 100% VOC.

EPA has concluded in establishing the criteria for a component in VOC service that it is not cost effective to monitor components containing <10% VOC. That conclusion is consistent with the conclusions reached in NSPS VV, VVa and other VOC regulations. Exactly the same logic applies to components handling wet gas that contains <10% VOC. In the Technical Support Document for this proposal EPA assumed 20% of the TOC found to be leaking is VOC and based its cost effectiveness analyses on this assumption. For wet gas components in the 1-10% VOC concentration range, the cost effectiveness is therefore between 20 and 2 times EPA's estimates, depending on the VOC concentration of each particular stream. Thus, as for components in VOC service, it is not cost effective (and not BSER) to apply the proposed equipment leak requirements to such components and the definition of "in wet gas service" should be deleted and the "in VOC service" criterion should be applied to all components in the source category.

However, if EPA intends to continue regulation of lower VOC content streams at natural gas processing plants, API recommends that the definition of "in wet gas service" be revised as

^{PP} EPA-450/3-82-024b, section 5.1.7

discussed in Sections 5.1.2 and 6.1.2 of the General Comments. As outlined in Section 5.1.2, "in wet gas service" would be defined to include field gas before extraction step that contain more than X% VOC by weight (API recommends X be equal to or greater than 5). While a revised definition of "in wet gas service" will still result in mandate of controls that are not cost-effective, the impact would be lessened because inert gas streams from enhanced recovery systems, coal-bed methane, and dry shale gas streams that contain little to no VOC would no longer require monitoring.

19.4.3. Definition of Equipment

As currently defined in §60.5430, "*Equipment* means each pump, pressure relief device, open-ended valve or line, valve, *compressor*, and flange or other connector that is in VOC *or wet gas service, and any device or system required by this subpart.*"

EPA should modify the definition as follows:

- (a) Remove the reference to compressor as compressors are affected facilities but have no associated requirements under the equipment leak provisions of Subpart OOOO. See the discussion in Section 19.3 above.
- (b) Delete applicability to components in wet gas service. If EPA insists on regulating low VOC content streams at gas processing plants, define "wet gas" such that the equipment leak provisions of this rule apply to only those field gas streams that contain 5% or more by weight of VOC. See the discussion in Section 19.4.2 above, as well as Sections 5.1.2 and 6.1.2 in the General Comments.
- (c) Clarify that the regulated components include *any device or system* required by *the equipment leak provisions* of this subpart. The proposed definition is taken from Part 60 Subpart KKK, because it only addresses VOC equipment leaks. Thus, "Any device or system required by [Subpart KKK]" is associated with controlling equipment leaks. Contrary to Subpart KKK, Subpart OOOO includes requirements for many types of affected facilities in addition to VOC equipment leaks. EPA should modify the definition of "equipment" to clarify that "any device or system required" is limited to "any device or system required by *the equipment leak provisions* of this subpart."

Suggested Rule Text:

§60.5430

Preferred Option:

Equipment means each pump, pressure relief device, open-ended valve or line, valve, ~~compressor~~, and flange or other connector that is in VOC service ~~or in wet gas service~~, and any device or system required by [the equipment leak provisions of](#) this subpart.

Alternative Option:

Equipment means each pump, pressure relief device, open-ended valve or line, valve, ~~compressor~~, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by [the equipment leak provisions of](#) this subpart.

19.4.4. Definition of Modification and Capital Expenditure

EPA should clarify the definition of *modification* as it pertains to applicable *equipment* in order to prevent minor additions/repairs from triggering Subpart OOOO requirements for existing KKK facilities, for consistency with Subpart KKK, and for clear expression of the indicated intent of this proposal.

Under the provisions of §60.14(e)(2), a change made to increase production is not a modification if the change does not require a capital expenditure. Capital expenditure is defined in §60.2 as “an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable ‘annual asset guideline repair allowance percentage’ specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.” The Part 60 equipment leak rules, including Part 60 Subpart KKK and this proposal (at §60.5365(f)(3)), further exclude process improvements made without a capital expenditure.

Part 60 Subpart VVa, whose requirements are applied under this proposal, extends the definition of capital expenditure as follows:

Capital expenditure means, in addition to the definition in §60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:

$$P = R \times A, \text{ where:}$$

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation:

$$Y = 1.0 - 0.575 \log X, \text{ where } X \text{ is } 2006 \text{ minus the year of construction; and}$$

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

| Subpart applicable to facility | Value of B to be used in equation |
|--------------------------------|-----------------------------------|
| VVa | 12.5 |
| GGGa | 7.0 |

Because capital expenditure is not defined in the proposal, the applicability provisions of Part 60 Subpart VVa are not referenced, and the applicable basic annual asset guideline repair allowance is not clearly indicated in the proposal or any of the referenced material, it is unclear how to determine if a modification associated with a production rate increase or process improvement has occurred.

API recommends that EPA add a definition of capital expenditure to Subpart OOOO §60.5430 that copies the definition from Subpart VVa, with modifications that are appropriate for natural gas processing plants and this rulemaking. Specifically, the modifications include: a) the year used in paragraph (2) above is, consistent with the Section 111 of the CAA, the year of the proposed Subpart OOOO, namely, 2011; and b) the value of B, as documented in §60.481 of Subpart VV for these facilities (identified as Subpart KKK facilities), is 4.5, if EPA incorporates in the final rule API's recommendations listed in Section 19.1.6 with regard to leak definition and the connector program. If EPA does not adopt those recommendations, then the value of B should be 12.5, the same as that for Subpart VVa.

Suggested Rule Text – new definition:

§60.5430

Preferred Option (if the leak definition remains at 10,000 ppm, and only AVO is required for connectors):

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:

$P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation:

$Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Alternative Option (if the leak definition is 500 ppm, or there is a connector monitoring program required) The definition would be the same as above, except:

(3) The applicable basic annual asset guideline repair allowance, B, is 12.5.

19.5. Subpart OOOO – New Delay of Repair Option for On-line Equipment Repair Using Specialized Methods

There are multiple technical and logistical issues that impact the feasibility of online repair using specialized methods, such as repair of a valve by injecting packing via drill and tap.

According to §60.482–9(a) of subpart VV, delay of repair is allowed if repair is technically infeasible without a process unit shutdown, and §60.482–9(c) of subpart VV allows delay of repair of valves if emissions associated with immediate repair would exceed continued emissions from the leak.

EPA has not demonstrated that use of specialized on-line repair methods is cost effective, particularly at the proposed leak definitions of 500 ppm for valves and connectors, and that the emissions associated with such repair attempts would be lower than if repair was delayed. Unlike refineries and chemical plants that have ready access to specialized maintenance contractors, many natural gas processing plants have to mobilize specialized contractors from long distances in order to attempt on-line repairs. This results both in increased costs and additional emissions from transportation and other logistical activities. The additional emissions may be more than would result from continued leaking at a low concentration range between 500 – 10,000 ppm.

API recommends that EPA add an additional delay of repair provision for on-line repairs utilizing specialized methods. Such repairs may be technically feasible, but are not logistically or economically feasible to be performed repeatedly to below 500 ppm within very narrow time windows. Facilities should be allowed a maximum of 90 days to complete these specialized repair attempts. Allowing more time reduces the cost burden and minimizes travel-associated emissions by enabling the repair of multiple components during fewer contractor site visits.

Suggested Rule Text:

§60.5401

* * * * *

(h) In addition to the provisions of §60.482-9a, delay of repair for valves and connectors will be allowed if:

(1) Initial (within 5 days of the leak being detected) and follow-up (within 15 days of the leak being detected) repair attempts using routine methods have been completed and were unsuccessful and

(2) Further on-line repair attempts require the use of a specialized repair contractor, and

(3) Further specialized repair attempts are completed as soon as practicable, but not later than 90 days after the leak was detected. If a repair attempt using a specialized

[technique is unsuccessful, repair shall occur before the end of the next process unit shutdown or as otherwise allowed by §60.482-9a\(e\).](#)

[A specialized repair contractor provides repair services not available from the facility or contractor maintenance personnel who perform routine repairs of most facility equipment leaks. An example of a specialized repair contractor is a contractor who provides valve gland drill and tap services.](#)

19.6. Subpart OOOO – Work Practice Implementation

The date by which LDAR work practices must begin is unclear in NSPS rules. At least a one year compliance period is needed for modified facilities to allow time to identify all covered components, tag them, gather and input all required information about each component into an LDAR database, develop testing routes, contract for the service, develop and arrange for required, timely leak repair and institute all of the procedures and recordkeeping associated with these programs. At new or reconstructed facilities, some of this work can be done prior to start-up, but not all of it. Furthermore, the compliance date for new and reconstructed facilities is unclear. For such facilities, we request the Agency clearly provide up to 180 days for sources to complete the initial round of monitoring.

In sum, **API requests** EPA allow at least a year for modified facilities, and 180 days for new or reconstructed facilities to implement work practice requirements.

19.7. Subpart OOOO – Equipment Upgrade Implementation

In some cases, facility upgrades will be needed at sources that become subject through modification. In particular, pump seals may require replacement or PSVs may need to be upgraded. Design, procurement and installation of such equipment takes considerable time and sources that come under these requirements through modification should be allowed up to three years to install such equipment upgrades.

API requests EPA allow three years for modified facilities to implement equipment upgrades as required.

19.8. Subpart OOOO – Exceptions in §60.5401 (d) and (e).

These two paragraphs exempt small gas processing plants and plants located in the Alaskan North Slope from routine monitoring requirements. However, there are several issues in these paragraphs that need to be addressed.

19.8.1. Typo in §60.5401(d)

There is an apparent typographical error in §60.5401(d), which reverses the small non-fractionating plant exemption in Subpart KKK. Subpart KKKK exempts any non-fractionating plant that does not have the design capacity to process 10 million scf/day or more of field gas.

19.8.2. Exemption from Reporting

Paragraph §60.5401(d) exempts certain components at small non-fractionating gas plants from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), and 60.5401(b)(1). Paragraph §60.5401(e) exempts the same group of components located in the Alaskan North Slope from the same monitoring requirements. API recommends that these components also be exempt from the reporting requirements by adding the following words at the end of these paragraphs: “*and the reporting requirements found in §§60.5420 and 60.5422.*”

19.8.3. Exemption for Connectors

As stated above, paragraphs (d) and (e) exempt the small non-fractionating plants and Alaskan North Slope plants from routine monitoring of pumps, valves and pressure relief devices (PRDs). Since Subpart KKK does not require routine monitoring of connectors, an exception for connector routine monitoring is not necessary in Subpart KKK. As discussed in Sections 19.1.2 and 19.1.6, API recommends that EPA only require auditory, visual and olfactory (AVO) inspections on connectors in the final rule. If EPA adopts API's recommendation, then no additional revision of §60.5401(d) and (e) is necessary. However, if EPA decides to adopt the Subpart VVa connector program requirements in the final rule, then API recommends that these two paragraphs be revised such that connectors at small non-fractionating plants and Alaskan North Slope plants are also exempt from routine monitoring, as pumps, valves and PRDs are.

19.9. Subpart OOOO – Clarifications Sought.

A couple of parts of the proposed rule language seem to either have typographical errors or statements that require clarification by EPA:

19.9.1. Pressure Relief Devices

It is unclear whether the stated alternate leak definition for PRDs in §60.5401(b)(2) is a typographical error. It states, “If an instrument reading of 5000 ppm or greater is measured, a leak is detected.” This seems to be in contrast with §60.5421(b)(2)(iv), where the language suggests a leak definition of 500 ppm.

19.9.2. Sampling Connection Systems

§60.5400(a) lists all the provisions in Subpart VVa with which an affected facility must comply, including the sampling connection systems requirements in §60.482-5a. However, §60.5401(c) exempts the affected sampling connection systems from the requirements in §60.482-5a. API requests that §60.482-5a be deleted from the list in §60.5400(a).

19.10. Subpart HH – Alternative Work Practice.

Concerns and recommendations described in Section 19.2 also apply to Subpart HH.

19.11. Subpart HH – Applicability.

19.11.1. Definition of Natural Gas Processing Plant

Concerns and recommendations described in Section 19.4.1 also apply to Subpart HH.

19.11.2. Definition of In Wet Gas Service

Concerns and recommendations described in Section 19.4.2 also apply to Subpart HH.

19.12. Subpart HH – Lower Leak Definition for Valves

§63.769 (c) states that,

“For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR Part 61, Subpart V, §§61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except for valves subject to §61.247–2(b) a leak is detected if an instrument reading of 500 ppm or greater is measured.”

This section of the rule may apply not only to large natural gas processing plants that are subject to Subpart KKK but also to smaller natural gas processing plant units where certain streams might be in VHAP service, which are currently not subject to Subpart KKK per the intent expressed in §63.769(b). Therefore, as documented in the discussion above (see Section 19.1), EPA's analysis overestimates the potential for emission reductions by lowering the leak definition for valves to 500 ppm. Therefore, the imposition of such a lower leak definition for valves at both new and existing natural gas processing plants is not warranted in terms of exposure reduction from plant operations. The risk benefit from the lower leak definition has not been demonstrated by EPA especially for smaller natural gas processing units.

API recommends that EPA retain the leak definitions for equipment leaks as currently promulgated in Subpart HH. This will prevent added compliance confusion and high costs to industry without demonstrated significant risk reductions.

19.13. Subpart HH – Extending Compliance Time

40 CFR 63 Subpart HH applies to both new and existing facilities. It is not feasible to expect existing facilities to be able to be in compliance instantaneously upon promulgation. For example, the leak definition for valves would be lowered from 10,000 ppm to 500 ppm. Upon promulgation of the final rule, it is expected that at an existing facility, a great number of valves which were previously not a leaker would suddenly become a leaker. Adequate supply of maintenance personnel and valve parts necessary to repair that many leakers within the time frame allowed in the rule is very questionable. In certain cases, the needed personnel and/or parts would simply not be available. If the rule provides a reasonable compliance time, the owner/operator of the facility would be able to plan and execute the leaker repair maintenance activities in a much more orderly fashion, and more importantly, in compliance with the rule. Our preference is to keep the 10,000 ppm leak definition. However, if the leak definition is to drop down to 500 ppm, then additional time to comply should be allowed as we recommended above for Subpart OOOO, namely, at least a year for existing facilities, and 180 days for new facilities to implement work practice requirements.

19.14. Subpart HH – Overlap with Subpart OOOO

Proposed §63.769(b) exempts ancillary equipment and compressors subject to Part 63 Subpart H and Part 60 Subpart KKK from the proposed §63.769(c) equipment leak requirements. This exemption should also apply to equipment and compressors that are subject to the new Part 60 Subpart OOOO, since otherwise duplicative and sometimes conflicting requirements would apply.

Suggested Rule Text

§63.769

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or the requirements specified in 40 CFR part 60, subparts KKK or OOOO.

20. GLYCOL DEHYDRATORS [NESHAP HH & HHH]

In both the Oil and Gas Production MACT (subpart HH) and the Natural Gas Production and Storage MACT (subpart HHH), EPA separated glycol dehydrators into two groups, or “subcategories.” While the “small dehydrator” and “large dehydrator” terminology is new in the proposed regulations, the concept and criteria defining these groups is present in the existing subparts HH and HHH. Table 20-1 shows the characteristics of each of these groups, as well as the current and proposed standards for each.

Table 20-1. Summary of Glycol Dehydrator Group Criteria and Emission Limitations

| Subpart | Dehydrator Group | Characteristics of Group | Requirements | |
|---------|------------------|--|---|--|
| | | | Current | Proposed |
| HH | Large | Flow rate ≥ 85,000 m ³ /day (3 million ft ³ /day) AND benzene emissions ≥ 0.9 Mg/yr (1 ton/yr) | Reduce HAP by 95% or reduce benzene emissions < 0.9 Mg/yr (1 tpy) | Reduce HAP by 95% |
| | Small | Flow rate < 85,000 m ³ /day (3 million ft ³ /day) OR benzene emissions < 0.9 Mg/yr (1 ton/yr) | NONE | Reduce BTEX emissions to a unit-specific emission limit calculated based on the dehydrator throughput and BTEX concentration at the inlet to the glycol dehydration unit |
| HHH | Large | Flow rate ≥ 283,000 m ³ /day (10 million ft ³ /day) AND benzene emissions ≥ 0.9 Mg/yr (1 ton/yr) | Reduce HAP by 95% or reduce benzene emissions < 0.9 Mg/yr (1 tpy) | Reduce HAP by 95% |
| | Small | Flow rate < 283,000 m ³ /day (10 million ft ³ /day) OR benzene emissions < 0.9 Mg/yr (1 ton/yr) | NONE | Reduce BTEX emissions to a unit-specific emission limit calculated based on the dehydrator throughput and BTEX concentration at the inlet to the glycol dehydration unit |

As can be seen in Table 20-1, EPA proposed two significant changes to the glycol dehydrator provisions:

- (1) eliminate the alternative 0.9 Mg/yr benzene emission limitation for large dehydrators, and
- (2) propose standards for small dehydrators.

API disagrees with both these decisions and does not believe that EPA has adequately justified them.

20.1. Large Dehydrators – The 0.9 Mg/yr Benzene Alternative Emission Limitation Must Be Retained in both Subpart HH and Subpart HHH

As discussed above, the Oil and Gas Production MACT (Subpart HH) currently includes two compliance options for glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr (i.e., “large” dehydrators). These options are to reduce organic HAP emissions by 95% or to reduce benzene emissions to less than 0.9 Mg/yr. Similarly, the Natural Gas Transmission and Storage MACT (subpart HHH) requires glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr to reduce HAP emissions by 95% or benzene emissions to less than 0.9 Mg/yr. EPA is proposing to eliminate the 0.9 Mg/yr benzene emissions compliance alternative for large dehydrators for both source categories.

Note that EPA decisions related to the 0.9 Mg/yr benzene alternative for large dehydrators in both MACT standards are unrelated to the 0.9 Mg/yr benzene emission threshold used to differentiate between small and large dehydrators. API has comments on the emission limits proposed for small dehydrators, which are provided in Section 20.3. However, as will be evident in API's comments below, EPA must restore the 0.9 Mg/yr benzene emissions for large dehydrators independent of any decisions related to small dehydrators.

For both MACT standards, these decisions were proposed under the authority of CAA section 112(f)(2). Thus, these are “risk-based” decisions. As discussed in Section 12, we have numerous basic concerns with EPA's decision to make significant and substantive changes unilaterally to the residual risk procedure that has been established in accordance with CAA mandates, vetted with Congress, and ratified by precedent. Some of the primary areas of concern include consideration of risk from the total facility, consideration of risk across selected social, demographic, and economic groups within the population living near the facility, and consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard. In addition, API believes that several factors, including the following, result in overestimates of risk that are between 100 and 1000-fold higher than estimates using more central factors:

- Assuming that all members of the population are continuously exposed for their lifetimes,
- Failing to consider time-activity patterns,
- Using only high end URE for decision-making, and
- Using only ultra conservative URE from CalEPA in the absence of IRIS values.

More detail on API's concerns with these aspects is provided in Attachment N, which is incorporated in these comments by reference.

While API has the overarching concerns with EPA's risk assessment and methodologies mentioned above, the risk-related decisions for large glycol dehydrators are based on flawed analysis. The evidence provided by EPA to support these conclusions is incorrect, and the outcome is that EPA has no basis for removing the 0.9 Mg/yr benzene alternative for either subpart HH or subpart HHH. Further details are provided in Attachment O, which is incorporated in these comments by reference.

20.1.1. Oil and Gas Production MACT – Subpart HH

In EPA's analysis for subpart HH,^{QQ} there are two facilities with a cancer MIR greater than 100-in-1 million based on MACT allowable emissions. These facilities are the Hawkins Gas Plant in Hawkins, Texas and the Kathleen Tharp 2 facility in Huffman, Texas. Since EPA determined that these facilities had a cancer maximum individual risk (MIR) greater than 100-in-1 million based on MACT allowable emissions, EPA determined that the risks are unacceptable for the oil and gas production MACT category and additional regulation is needed. However, as will be shown below, the results are entirely incorrect due to fundamental errors in EPA's calculations of MACT allowable risk for these two facilities. In addition, even if the analysis had been correct, there are significant issues associated with the data for both of these facilities that are sufficient to invalidate the results and EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable.

Fundamental Errors in EPA's Analysis. As noted above, EPA identified two facilities with cancer MIRs greater than 100-in-1 million based on MACT allowable emission levels. However, examination of EPA's analysis shows that the results are entirely incorrect due to fundamental errors in EPA's calculations of MACT allowable risk. This caused the calculation of MACT allowable risk estimates that are orders of magnitude too high. Following are details of this error.

In the analysis of risk based on the MACT allowable emissions level, EPA assumes that glycol dehydrators which control benzene emissions to levels less than 0.9 Mg/yr could increase benzene emissions to 0.9 Mg/yr. The analysis assumes a linear relationship between benzene emissions and risk, so the risk due to the actual benzene emissions level was multiplied by the ratio of 0.9 Mg/yr divided by the actual emission level. For example, if the cancer MIR based on 0.45 Mg/yr of actual benzene emissions was 40-in-1 million, the cancer MIR based on the 0.9 Mg/yr benzene MACT allowable emissions level would be 80-in-1 million.

In their MACT allowable analysis, EPA used the incorrect actual emissions level to adjust the risk to a 0.9 Mg/yr basis. Specifically, for dehydrator DN0005 at the Hawkins Gas Plant, EPA used a benzene emission rate of 0.00004 tons/yr instead of the correct value of 0.01290

^{QQ} Memorandum. From Heather Brown, P.E., EC/R Incorporated and Lesley Stobert, EC/R Incorporated, to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT – MACT Allowable Emissions and Risks." July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0055)

tons/yr. This resulted in a multiplier of over 23,000 ($1 / 0.00004$) and a MIR of 400-in-1 million. The benzene emission rate for this point, as shown in the Appendix to EPA's Risk Assessment Document,^{RR} is 0.01290 tons/yr. This emission rate results in a MACT allowable multiplier over 300 times lower than the value used by EPA. Inserting the correct actual emissions number in EPA's analysis results in a MACT Allowable MIR of 3-in-1 million for the Hawkins Gas Plant.

A similar error occurs for the Kathleen Tharp2 facility. For dehydrator DN0001, the correct actual benzene emissions rate is 0.1140 tons/yr. However, EPA used an incorrect emission rate of 0.0001 tons/yr. Inserting the correct benzene rate in the analysis results in a MACT allowable MIR of 0.2-in-1 million for this facility. Details of the errors and API's corrections are provided in Attachment O, which is incorporated in these comments by reference.

After the MACT allowable MIRs are corrected for these two facilities, the highest MACT allowable MIR is 50-in-1 million for the Seneca Resources Corporation facility in Ojai, CA. This is clearly at a level that EPA has never considered as unacceptable.

Major Issues in EPA's Data Set for Facilities Driving the Risk. The issues associated with the data for the two facilities with cancer MIRs greater than 100-in-1 million based on MACT allowable emissions are sufficient to invalidate the results and EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable. The highest risk facility, with a cancer MIR of 400-in-1 million based on MACT allowable emissions, is the Hawkins Gas Plant in Hawkins, Texas. A review of the background data in EPA's dataset for this facility has found significant errors. For example, the EPA data set includes data for eight dehydrators when in fact there are only three dehydrators at the plant. The Hawkins Gas Plant operates three glycol dehydrators, with a fourth dehydrator on site but has been shut down for more than 10 years. In addition, one of these dehydrators (DehyRod) falls into EPA's definition of "small dehydrator" and should not have been considered in the large dehydrator analysis, as its throughput is less than 60,000 m³/day. For the past 10 or more years, only emissions data for the three operating glycol dehydrators has been submitted to the TCEQ for the annual emissions inventory.

There are no emissions during normal operation of these three dehydrators as the still vent vapors are routed through a vapor recovery compressor (VRC) and back into the process. There is no emissions point. However, as a backup for times when the vapor recovery compressor is down, dehydrator still vent emissions are routed first through a BTEX condenser, then to the low pressure flare. Emissions only occur during VRC downtime which is reported to the TCEQ each year in the emissions inventory. The table below lists the annual emissions reported to the TCEQ for the emissions inventory for 2005-2009.

^{RR} "Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories." EPA, Office of Air Quality Planning and Standards, Office of Air and Radiation. July 2011. (Docket Item EPA-HQ-OAR-2010-0505-0032)

Table 20-2. Hawkins Plant Dehydrator Emissions

| Hawkins Plant Dehy | Annual Emissions (tons/yr) | | | | | | | | | |
|--------------------------|----------------------------|-------|-------|------|-------|------|-------|------|-------|------|
| | 2005 | | 2006 | | 2007 | | 2008 | | 2009 | |
| | VOC | BTEX | VOC | BTEX | VOC | BTEX | VOC | BTEX | VOC | BTEX |
| DehyHP | 0.05 | 0.009 | 0.15 | NA | 0.024 | NA | 0.01 | NA | 0.004 | NA |
| Dehy80 | 0.86 | 0.03 | 0.027 | NA | 0.21 | NA | 0.045 | NA | 0.023 | NA |
| DehyRod | 0.005 | 0.005 | 0.33 | NA | 0.057 | NA | 0.003 | NA | 0.004 | NA |

The facility with the second highest MACT Allowable risk (200-in-1 million) is the Kathleen Tharp 2 facility in Huffman, Texas. API has confirmed with the Texas Commission on Environmental Quality (TCEQ) that this facility does not have a Title V permit and is not a major source of HAP.^{SS} API has also obtained documentation that a Form PI-8 has been filed for this facility. A Form PI-8 certifies emissions below the minor source limit of 25 tons/yr VOC, and makes the certified emissions enforceable. Therefore, it should not be considered in this analysis.

Conclusion for Oil and Gas Production MACT. EPA must reverse its proposed decision to eliminate the 0.9 Mg/yr benzene compliance alternative in subpart HH for glycol dehydrators with actual annual average natural gas flow rates greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr. The analysis that resulted in risks determined by EPA to be unacceptable, and the data used in the analysis, both have significant errors. Correction of these errors leads to risk estimates well within the ranges that EPA determines to be acceptable.

In the absence of an unacceptability risk determination, EPA cannot legitimately argue that removal of the 0.9 Mg/yr is a cost effective measure under the ample margin of safety decision. In the technical documentation estimating the impacts of RTR control options,^{TT} EPA estimated the cost effectiveness of removing the 0.9 Mg/yr benzene alternative was \$14,000/Mg HAP. This cost effectiveness, which is EPA's estimate, is at the high range of most past EPA MACT decisions. However, this EPA estimate is lacking and actually significantly underestimates the cost effectiveness. EPA's estimate takes full credit for a 95% reduction in HAP emissions. However, any large dehydrator that is currently complying with the 0.9 Mg/yr benzene limit utilizes some type of control device designed to reduce benzene emissions 0.9 Mg/yr. The benzene emission reduction needed to achieve 0.9 Mg/yr could be less than 95%. In such cases, it would only be appropriate to consider the incremental emission reduction obtained when additional control is installed.

^{SS} Personal Communication. Norwood, P., ERM, and Moore, S., TCEQ Houston Regional Office. October 13, 2011.

^{TT} Memorandum. From Heather Brown, P.E., and Lesley Stobert, EC/R Inc. to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Impacts for Control Options for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage Categories as a Result of the Residual Risk and Technology Review." August 19, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0077)

For example, consider a large dehydrator with uncontrolled benzene emissions of 3 Mg/yr. In order to comply with the 0.9 Mg/yr benzene limitation, a condenser or other control device could be installed that achieves approximately 70% reduction. If the 0.9 Mg/yr benzene emission limitation is removed, the facility would need to install an additional control device to meet the 95% requirement (which would require that emissions be reduced to 0.15 Mg/yr). However, EPA must claim only the incremental reduction (0.75 Mg/yr) and not the total 95% reduction (2.85 Mg/yr). This would increase the calculated cost per ton 4 fold.

In fact, EPA has already estimated the cost effectiveness for this incremental control. The cost effectiveness that is more appropriate for this option is \$167,200/Mg HAP, which is the cost effectiveness estimated by EPA for the addition of a second control device (76 FR 52768). Without a doubt, this cost effectiveness is not reasonable.

In view of these clear facts, EPA must repeal its proposed conclusion under section 112(f)(2) of the CAA to remove the 0.9 Mg/yr benzene compliance alternative for subpart HH. The corrected analysis does not result in an unacceptable risk and the available information cannot support a conclusion that this action is necessary to achieve an ample margin of safety.

Further, EPA has no basis under any other CAA authority to remove the 0.9 Mg/yr benzene alternative for large dehydrators at oil and gas production facilities. Under 112(d)(6), EPA did not identify any developments in practices, processes, or control technologies to further reduce emissions from large dehydrators. EPA already established MACT floors for glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time. Further, since large dehydrators are subject to standards under the existing subpart HH, they do not represent an "unregulated" emission sources that EPA can address under section 112(d)(2) and (3). Finally, as noted above, EPA estimated that the cost effectiveness of additional controls to be \$167,200/Mg HAP, which cannot be justified as reasonable under any circumstance.

20.1.2. Natural Gas Transmission and Storage MACT – Subpart HHH

For the Natural Gas Transmission and Storage source category, EPA found that risks from sources subpart to subpart HHH were acceptable (even when considering MACT allowable emissions). In the second step of the risk decision, EPA then proposed to eliminate the 0.9 Mg/yr benzene compliance alternative as part of their ample margin of safety determination.

While an ample margin of safety decision can consider numerous factors, EPA bases the decision to eliminate the 0.9 Mg/yr benzene emission limitation for subpart HHH on two basic factors: (1) it would reduce the cancer MIR from 90-in-1 million to 20-in-1 million, and (2) the cost effectiveness to comply with this option is reasonable. As will be demonstrated below, both of these conclusions are erroneous.

Removal of 0.9 Mg/yr Benzene Alternative Does Not Reduce Risk. EPA indicates that removal of the 0.9 Mg/yr benzene compliance alternative for glycol dehydrators with actual

annual average natural gas flow rates greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr would reduce the cancer MIR for the source category from 90-in-1 million to 20-in-1 million. However, this assertion is entirely incorrect as EPA's own technical analysis indicates that removal of the 0.9 Mg/yr benzene alternative would have NO effect on the MIR.

To summarize, EPA separates dehydrators into two groups, or subcategories for the natural gas transmission and storage source category:

- 1) Dehydrators with an actual annual average natural gas flow rate greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr (i.e., "large" dehydrators), and
- 2) Dehydrators with an actual annual average natural gas flow rate greater less than 283,000 m³/day or actual average benzene emissions less than 0.9 Mg/yr (i.e., "small" dehydrators).

Large dehydrators in the first group are subject to the current standards, which require that organic reduce HAP emissions be reduced by 95% or benzene emissions reduced to less than 0.9 Mg/yr. Small dehydrators in the second group are not subject to standards in the current rule.

EPA's analysis shows that the dehydrators causing the 90-in-1 million MIR are in the second small dehydrator category, which means they are not even subject to the 0.9 Mg/yr benzene alternative. Therefore, removing it will have **NO** impact on these highest MIRs. This is clearly stated in a technical memorandum prepared by EPA's contractor which shows the MIR for the source category unchanged (90-in-1 million) without the 0.9 Mg/yr benzene alternative.^{UU}

EPA's Cost Analysis is Severely Flawed. Second, EPA concludes that the cost effectiveness of the proposed removal of the 0.9 Mg/yr benzene compliance alternative for natural gas transmission and storage facilities is reasonable. However, the costs estimates used by EPA in the ample margin of safety determination are inadequate. EPA did conduct any analysis using actual data. Rather, EPA used costs estimated for small dehydrators and rashly made general assumptions to estimate an upper-end cost effectiveness for removing the 0.9 Mg/yr benzene alternative limit for large dehydrators at natural gas transmission and storage facilities.

Specifically, EPA based their cost "analysis" on the following points.

"Although control methodologies are similar for large and small dehydrators, we expect that the costs for controls on large units could be as much as twice as high as for small units because of the large gas flow being processed." (76 FR 52783).

^{UU} Memorandum. From Heather Brown, P.E., and Lesley Stobert, EC/R Inc. to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Impacts for Control Options for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage Categories as a Result of the Residual Risk and Technology Review." August 19, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0077)

API agrees that flow rates for the large dehydrators would, in general, be higher than those for small dehydrators. API also agrees that the costs for these controllers would be higher, although EPA has provided no support for the argument that the upper range of this cost would be twice that of controls for small dehydrators.

“However, we also expect that the amount of HAP emission reduction for the large dehydrators, in general, to be as much as, or more than, the amount achieved by small dehydrators.” (76 FR 52783).

EPA provides no data to support this claim. API disagrees with this statement, and believes that in general, the emission reductions for dehydrators forced to switch from the 0.9 Mg/yr benzene alternative to 95% control would be considerably less than those achieved by small dehydrators. The cost effectiveness calculated for small dehydrators is based on a 95% reduction from an uncontrolled baseline level. If a large dehydrator has installed controls to meet the 0.9 Mg/yr alternative benzene limitation, the cost effectiveness must be based on the incremental reduction between the existing controls and 95%. EPA has provided no evidence that these incremental reductions would be greater than or equal to the 95% reductions that would be achieved for smaller dehydrators.

This does not even approach a credible analysis that should be considered for any EPA decision, much less a major decision to eliminate the 0.9 Mg/yr benzene alternative emission limitation.

Conclusion for Natural Gas Transmission and Storage MACT. The rationale used by EPA in the preamble to support the removal of the 0.9 Mg/yr compliance alternative for dehydrators at natural gas transmission and storage facilities under 112(f)(2) of the CAA is not supported by any of the background technical documentation and analyses. The high risks that EPA claims will be reduced by removal of the 0.9 Mg/yr benzene alternative are, by EPA's own estimation, dehydrators that are not even subject to the current 0.9 Mg/yr benzene alternative in the regulation. Further, the cost analysis relied upon by EPA to conclude that controls for this option are cost effective does not even pass a “straight-face” test. Therefore, EPA has demonstrated no valid rationale for removing this 0.9 Mg/yr benzene alternative at natural gas transmission and storage facilities. Since there is no justification for removing the 0.9 Mg/yr benzene alternative, EPA must maintain it in subpart HHH.

Further, EPA has no basis under any other CAA authority to remove the 0.9 Mg/yr benzene alternative for large dehydrators at natural gas transmission and storage facilities. Under 112(d)(6), EPA did not identify any developments in practices, processes, or control technologies to further reduce emissions from large dehydrators. EPA already established MACT floors for glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time. Further, since large dehydrators are subject to standards under the existing subpart HHH, they do not represent an “unregulated” emission sources that EPA can address under section 112(d)(2) and (3).

20.2. 90 Day Compliance Time For Large Dehydrators Is Insufficient If The 0.9 Mg/Yr Benzene Compliance Option Is Removed

The proposed regulation only allows a 90 day compliance period for large dehydrators that are currently complying with the 0.9 Mg/yr benzene alternative emission limitation. As discussed above in Section 20.1, EPA's rationale for eliminating the 0.9 Mg/yr benzene limitation is severely flawed. We expect that EPA will restore the 0.9 Mg/yr benzene limitation after consideration of these comments. However, in the unlikely case that EPA does not restore this alternative limitations, EPA must extend the compliance date to the same three year period proposed for newly regulated small dehydrators and storage vessels without the potential for flash emissions.

In the preamble, EPA states the following:

“Without the compliance alternative, affected glycol dehydrators (i.e., those units with annual average benzene emissions of 0.9 Mg/yr or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary.” (76 FR 52783)

EPA's assertion that existing controls used to comply with the 0.9 Mg/yr benzene alternative emission limitation could achieve compliance with the 95% requirement “in most cases” does not appear to be supported by information or analysis. This clearly was a factor in EPA's decision to only allow 90 days for compliance. However, basic logic would not lead to a conclusion that existing control devices installed to meet the 0.9 Mg/yr benzene limit could also achieve 95% BTEX control. It is logical to assume that owners and operators complying with the 0.9 Mg/yr benzene limitation selected this alternative because it was less costly and less burdensome than complying with the 95% HAP reduction standard. As EPA is aware, the composition of natural gas processed in dehydrators across the county varies considerably. For situations with lower benzene content, the 0.9 Mg/yr emission limitation could be met using controls that achieve less than 95% reduction. While these units are in full compliance with the 0.9 Mg/yr limit, additional controls would need to be added to comply with the 95% standard. The process for evaluating, identifying, selecting, and installing these controls would be the same for these situations as for a small dehydrator previously not subject to any standards. Therefore, the time frame for compliance should also be the same – 3 years.

20.3. Small Dehydrators – The BTEX Emission Limit Is Not Necessary And Should Be Removed

In the preamble for the proposed rule (76 FR 52746), EPA identifies small dehydrators as an unregulated emission source. Therefore, under the authority of section 112(d)(2) and (3), EPA proposed to establish emission standards for small dehydrators in both subpart HH and subpart HHH.

EPA already established MACT floors for glycol dehydrators and promulgated regulatory decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time and should not promulgate any standards for small dehydrators.

Further, as will be demonstrated below, small dehydrators are already subject to emission standards under the current regulations and therefore, cannot be classified as unregulated emission sources. Given the fact that the 0.9 Mg/yr benzene level serves as both an emission limitation and a threshold separating the two groups of dehydrators, the reality that small dehydrators are subject to standards is not readily apparent. API will demonstrate that this is, in fact, consistent with the original regulatory determinations in 1998/1999.

It is very clear from the language of subparts HH and HHH that dehydrators of any size are subject to the rules:

Subpart HH: §63.760

* * * * *

(b)(1) For major sources, the affected source shall comprise each emission point located at a facility that meets the criteria specified in paragraph (a) of this section and listed in paragraphs (b)(1)(i) through (b)(1)(iv) of this section.

- (i) Each glycol dehydration unit;

Subpart HHH: §63.1270

* * * * *

(b) The affected source is each glycol dehydration unit.

Small dehydrators are clearly subject to rules of general applicability, such as reporting and recordkeeping. They are subject to the general duty in §63.6(e) (as it was in effect at the time the rule was published) relating to good operation and maintenance requirements, effectively imposing a work practice standard on these units, even if no emissions standard actually applies. Section 63.762 also imposes similar work practice requirements on all affected facilities. But, in effect, subparts HH and HHH do impose emissions limitations on all dehydrators.

As shown in Table 20-1, the 0.9 Mg/yr benzene level appears both as a criterion distinguishing small and large dehydrators and as an emission limit for large dehydrators. The effect is that the current regulation actually imposes emission limitations on all dehydrators. This is particularly clear from the fact that small dehydrators must document that the control requirements do not apply to a dehydrator by, in effect, performing an emissions analysis.

This fact was extremely obvious in the original proposal, where EPA stated the following:

“An owner or operator must be able to demonstrate that exemption from control criteria are met when controls are not applied. For example, owners or operators of glycol dehydration units that do not install air emission controls because the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy) must be able to demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy).” (63 FR 6295, February 6, 1998)

In response to both subparts HH and HHH, many owners and operators installed controls or made process improvements to reduce benzene emissions to less than 0.9 Mg/yr benzene. In some of these situations, the dehydrators are subject to the control device, testing, and monitoring provisions in

subpart HH or HHH, while in other situations owners and operators obtained permit conditions to limit their benzene emissions below 0.9 Mg/yr. In all these cases, the benzene emissions were reduced to achieve a level below 0.9 Mg/yr. For example, an API member company operates a glycol dehydrator at a major source production facility in Texas with an actual average annual natural gas flow rate of 570,000 SCMD (20 MMSCFD). Emissions are reduced by a condenser, followed by a flare. The facility complies with the provisions in §63.765(b)(1)(ii) to reduce benzene emissions to less than 0.9 Mg/yr. The facility has a state federally enforceable permit condition limiting the benzene emissions less than 0.9 Mg/yr. The facility also complies with the associated testing, monitoring, recordkeeping, and reporting requirements under subpart HH. Another example is an API member company glycol dehydrator at a production facility in Colorado. Emissions are reduced by a condenser, followed by a flare. The facility complies with the provisions in §63.765(b)(1)(ii) to reduce benzene emissions to less than 0.9 Mg/yr. The facility has a state federally enforceable permit condition limiting the benzene emissions less than 0.9 Mg/yr. The facility also complies with the associated testing, monitoring, recordkeeping, and reporting requirements under subpart HH.

In many situations, the benzene emissions without any controls may be less than 0.9 Mg/yr. For example, an API member facility in the Barnett Shale contains several dehydrators that treat a very dry east Barnett Shale gas with a VOC content of around 0.25 mole% (0.63 weight %) and a benzene content of around 10 ppm. The uncontrolled emissions from each of these units, which process over 500,000 SCMD (18 MMSCF), are only around 0.13 tpy benzene and 0.36 tpy total BTEX. As described above in the excerpt from the 1998 preamble, in such situations owners and operators would be required to “*demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy).*”

Therefore, in reality, the 0.9 Mg/yr represents an emission limit to which every facility is subject, thus meaning there are no “unregulated” dehydrators.

In the original proposal and promulgation of subparts HH and HHH (February 5, 1998 and June 17, 1999, respectively), EPA was not consistent in the discussion of subcategorization and MACT floors for glycol dehydrator vents. In the preamble for the promulgated rule (June 17, 1999), EPA states the following:

To determine the MACT floor, the EPA divided glycol dehydration units into two sizes: (1) small glycol dehydration units with actual annual average natural gas throughputs less than 85 thousand m³/day or with actual average benzene emissions less than 0.90 Mg/yr, and (2) large glycol dehydration units with actual annual average natural gas throughputs equal to or greater than 85 thousand m³/day or with actual average benzene emissions equal to or greater than 0.90 Mg/yr. For small glycol dehydration units, the EPA determined that the MACT floor was no control and that it was not cost effective to select a regulatory alternative beyond the floor. For large glycol dehydration units, the EPA reviewed the information that was available to develop a MACT floor (a detailed discussion of the development of the MACT floor can be found in the docket, Air Docket A-94-04). (64 FR 32613)

However, examination of the MACT floor technical memorandum^{vv} does not indicate that there was any consideration given to different sizes of dehydration units. In fact, the memorandum states the following:

Therefore, the determination of the MACT floor level of control for glycol dehydration units in this analysis is based on the data reported for all glycol dehydration units from the company responses to the four Air Emission Survey Questionnaires.” (p. 6).

Similarly, the proposed preamble made it clear that the MACT floor determination was not limited to large dehydrators –

The MACT floor for all process vents at glycol dehydration units . . . (63 FR 6304, underline added).

Further, while EPA's terminology was inconsistent, EPA recognized that the proposed and promulgated standards did subject all glycol dehydrators to standards. The 0.9 Mg/yr threshold/emission limit recognized and rewarded compliance via more environmentally friendly and cost effective process modifications and pollution prevention measures. However, it was clear that EPA was not totally exempting dehydrators below 0.9 Mg/yr benzene from the responsibility to maintain emissions below this level and demonstrate compliance with this alternative.

“For example, owners or operators of glycol dehydration units that do not install air emission controls because the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy) must be able to demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy). In general, the selected exemption criteria minimize the demonstration burden on owners and operators.” (63 FR 6295)

Therefore, EPA must consider the proposed limit for small glycol dehydrators as an adjustment to the existing limit under the authority of § 112(d)(6). As such, if EPA intends to promulgate these provisions, the Agency must first re-propose these provisions and justify the proposal as “necessary (taking into account developments in practices, processes, and control technologies).” This must include consideration of the naturally occurring variability in gas compositions, the variable throughput of dehydrators in this sector, and the resulting variation in dehydrator emissions and cost effectiveness of control.

EPA estimated the cost effectiveness of the proposed small dehydrator standards to be \$8,360/Mg HAP (76 FR 52768). While this EPA cost effectiveness is high, API maintains that this cost effectiveness analysis significantly underestimates the cost effectiveness of many dehydrators. This is primarily due to the fact that EPA did not account for the naturally occurring variability in HAP content in natural gas streams that would be covered by the proposed small dehydrator standards. Table 20-3 was generated from GRI-GLYCalc runs using a range of dehydrator operating throughputs and actual gas compositions (furnished by API member companies); and EPA's

^{vv} Memorandum. From Graham Fitzsimons and George Viconovic, EC/R Inc. to Martha Smith, EPA/WCPG. “Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category.” September 23, 1997. (Docket A-94-04, Item Number II-A-7)

annualized cost of control for dehydrators from Table 3-7 of the proposal RIA.^{ww} Unless noted, these examples reflect actual dehydrators in operation with their actual throughputs and gas compositions. More detail on these calculations is provided in Attachment P, which is incorporated in these comments by reference.

Table 20-3. Cost Effectiveness for Compliance with Proposed Small Dehydrator Emission Limitation at Oil and Gas Production Facilities

| Facility Name | Inlet BTEX Content ppmv (Ci, BTEX) | Throughput SCMD | Uncontrolled BTEX Emissions (tons/yr) | Annualized Control Cost ¹ | Control % to meet proposed equation (BTEX) | HAPS \$/Ton ² | BTEX \$/Ton ² |
|---|------------------------------------|-----------------|---------------------------------------|--------------------------------------|--|--------------------------|--------------------------|
| N. San Juan Basin Gas Treating and Compression Facility Dehy #1 | 0.9 | 2,406,935 | 0.93 | \$30,409 | 94.0% | \$34,322 | \$34,605 |
| N. San Juan Basin Comp. Station M Dehy #1 | 1 | 849,506 | 0.77 | \$30,409 | 97.1% | \$40,449 | \$40,749 |
| N. San Juan Basin Comp. Station WP Dehy | 0 | 56,634 | 0 | \$30,409 | Undefined | \$152,045,000 | Undefined |
| N. San Juan Basin Comp. Station WP Dehy - 2 Test | 1 | 56,634 | 0.014 | \$30,409 | 89.8% | \$2,318,324 | \$2,350,522 |
| N. San Juan Basin Comp. Station Q Dehy | 16 | 424,753 | 1.6 | \$30,409 | 89.2% | \$20,363 | \$20,907 |
| Barnett Shale Comp. Station Dehy - uncontrolled | 12 | 580,213 | 1.2 | \$30,409 | 85.2% | \$29,333 | \$29,435 |
| Barnett Shale Comp. Station Dehy - flash tank & condenser | 12 | 580,213 | 1.0 | \$30,409 | 82.3% | \$36,323 | \$36,470 |
| Arkoma Basin Gas Treating and Compression Facility SB Dehy | 0 | 849,506 | 0 | \$30,409 | Undefined | Undefined | Undefined |
| Haynesville Shale Generic Dehydrator | 77 | 212,377 | 1.8 | \$30,409 | 76.5% | \$21,225 | \$22,079 |
| GGRB Basin Generic Well Site Dehy | 404 | 42,475 | 4.9 | \$30,409 | 91.0% | \$6,638 | \$6,779 |
| GGRB Basin Generic Well Site Dehy | 404 | 28,316 | 3.286 | \$30,409 | 91.0% | \$9,956 | \$10,169 |
| GGRB Basin Generic Well Site Dehy | 404 | 14,158 | 1.643 | \$30,409 | 91.0% | \$19,913 | \$20,337 |
| GGRB Basin Generic Well Site Dehy | 404 | 5,663 | 0.6572 | \$30,409 | 91.0% | \$49,782 | \$50,843 |

¹Annualized Cost from page 3-26; Table 3-7 of RIA; with control % above ~20% the only viable option is to use a combustion device which is the basis for the Table 3-7 cost. Hence, the control cost does not go down with incrementally lower control %.

²For sites with no BTEX and undefined BTEX control % the control cost uses total emissions for species present.

As can be seen in Table 20-3, the cost effectiveness at the small dehydrator threshold ranges from \$152,000,000/ton-HAP to \$6,638/ton-HAP with most of the costs evaluated being substantially

^{ww} Regulatory Impact Analysis. Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry – U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711. July 2011. (Docket Item EPA-HQ-OAR-2010-0505-0075)

greater than EPA's estimate. These unreasonable costs occur for low BTEX content (San Juan Basin Coal Bed Methane) gasses regardless of throughput; moderate BTEX content (Haynesville shale) gasses with relatively high throughputs; and high BTEX content (Green River Basin Tight Sand) gasses with low throughputs (which are common in the Green River Basin). Obviously most of the illustrated control costs far exceed any reasonableness test and EPA cannot possibly justify the proposed requirements as a beyond the floor option with knowledge of these values. The situation for dehydrators in service for gas streams without any BTEX content (at a detection limit of 1 ppmv) becomes even more untenable and unreasonable. As defined in the proposed rule, these dehydrators would be classified as "small" and subject to application of "Equation 1" to determine allowable emissions. Application of "Equation 1" results in zero allowable emissions of BTEX. With the likely prospect of BTEX at some concentration lower than normal gas analysis detection limits this outcome essentially imposes 100% control requirements on dehydrators with almost zero potential for HAP emissions and almost infinite control costs. Obviously this is an unreasonable and likely technically unachievable requirement and must be corrected.

In conclusion, both subpart HH and subpart HHH, as currently promulgated, impose emission limitations on all glycol dehydrators. Therefore, these small dehydrators cannot be considered unregulated sources and EPA does not need to develop emission standards for the small dehydrators under CAA section 112(d)(2) and (3). In fact, since EPA already established MACT floors for all glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days), EPA does not have authority to revisit the floor determinations at this time. EPA's proposed scheme for regulation of "small" dehydrators requires control on all dehydrators regardless of emissions or potential for emissions and results in completely unreasonable control costs for a wide range of gas compositions and throughputs. Further, as shown above, if EPA elects to move forward to propose separate standards for small dehydrators, such standards must be shown to be "necessary" in light of the factors specified in § 112(d)(6).

20.4. If EPA Moves Forward With Standards for Small Dehydrators, They Must Account for Fundamental Differences in Naturally Occurring Inlet Gas Concentrations and Dehydrator Design

As noted above, API does not believe that a separate standard is justified for small dehydrators. However, if EPA decides to move forward with standards for small dehydrators, they must not promulgate the proposed standards, as they are not technically and legally sound.

Subpart HH Proposed Equation 1 Would Require Over 90% Of The "Best Performing" Dehydrators To Install Additional Control. The severe flaws in EPA's small dehydrator floor analysis, derived equation 1, and control approach to calculate dehydrator-specific BTEX emission limitations are clearly illustrated by the application of Equation 1 to the 11 dehydrator units used by EPA for the MACT floor analysis for subpart HH. Table 20-4 illustrates the flawed construct by applying the proposed equation for subpart HH to the specific dehydrators making up the "top 12%" in EPA's MACT floor dataset.

Table 20-4. Application of Subpart HH Proposed Equation 1 for Small Dehydrators to MACT Floor Oil and Natural Gas Production Small Dehydrators

| Unit ID No. | Legacy Docket A-94-04, Docket ID No. | No of Units | Control at Baseline? | BTEX Inlet Conc (ppmv) | Throughput (SCMD) Per Dehy Unit | BTEX Emissions at Baseline (Mg/yr) | Equation 1 Allowable BTEX Emission (Mg/yr) | Control % to meet proposed equation |
|-------------|--------------------------------------|-------------|----------------------|------------------------|---------------------------------|------------------------------------|--|-------------------------------------|
| A | II-D-10, pg 55 | 1 | Y | 116 | 17,556 | 0.0036 | 0.0477 | n/a |
| B | II-D-09, pg 182 | 1 | N | 69 | 566,338 | 0.9979 | 0.9157 | 8.2% |
| C | II-D-19, pg 73 | 5 | Y | 60 | 45,307 | 0.0762 | 0.0637 | 16.4% |
| D | II-D-19, pg 21 | 1 | N | 140 | 99,109 | 0.5443 | 0.3251 | 40.3% |
| E | II-D-10, pg 115 | 1 | N | 39 | 42,475 | 0.0907 | 0.0388 | 57.2% |
| F | II-D-19, pg 41 | 1 | N | 308 | 29,450 | 0.8165 | 0.2125 | 74.0% |
| G | II-D-19, pg 39 | 1 | N | 5 | 45,307 | 0.0181 | 0.0053 | 70.7% |

As can be seen in Table 20-4, only one of the 11 dehydrators that were used to calculate the MACT floor for small dehydrators in the oil and natural gas production source category can meet the proposed standard without the installation of additional controls. This would mean that the equation represents the average emission limitation achieved by best performing 1% of the dehydrators, not the best performing 12%. This obviously does not represent a legitimate MACT floor. Rather, the equations represent a beyond-the-floor level of control that EPA has not contemplated nor justified.

Proposed Small Dehydrator Equations Are Only Sensitive to BTEX Inlet Concentration. API believes the absurd results from application of the proposed Equation 1 to small dehydrators are an outcome of the floor analysis EPA conducted and erroneous conclusions reached that led to the Equation 1 construct. This construct is inherently flawed. Despite EPA’s inclusion of a throughput variable in the equations, the net effect is that the equations are only sensitive to the BTEX concentration (ppmv) in the inlet gas stream. Therefore, throughput or potential emissions have no effect on the control efficiencies required to meet the calculation emission limitation. This artifact is illustrated by the analysis summarized in Table 20-5, which clearly shows the Equation 1 outcome to be sensitive only to BTEX inlet concentration from the perspective of required control percentage. More details on this analysis are provided in Attachment Q.

Table 20-5. Illustration of Sensitivity of the Proposed Subpart HH Proposed Equation 1 for Small Dehydrators to Throughput Rates

| Facility Name/Throughput (in MMSCFD) | Inlet BTEX Content ppmv (Ci, BTEX) | Throughput SCMD | Uncontrolled BTEX (tpy) | BTEX Emissions Allowed by Equation (tpy) | Control % to meet proposed equation (BTEX) | HAPS \$ ¹ /Ton | BTEX \$ ¹ /Ton |
|--|------------------------------------|-----------------|-------------------------|--|--|---------------------------|---------------------------|
| Coal Bed Methane - North San Juan Basin - SW Colorado | | | | | | | |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 1 MMSCFD | 0.9 | 28,317 | 0.011 | 0.0007 | 94.0% | \$2,913,934 | \$2,940,424 |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 10 MMSCFD | 0.9 | 283,169 | 0.11 | 0.0066 | 94.0% | \$291,656 | \$294,042 |

| | | | | | | | |
|--|-----|-----------|------|-------|--------------|-----------|-----------|
| N. San Juan Basin Gas Treating and Compression Facility Dehy 50 MMSCFD | 0.9 | 1,415,844 | 0.55 | 0.033 | 94.0% | \$58,354 | \$58,831 |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 100 MMSCFD ² | 0.9 | 2,831,688 | 1.1 | 0.066 | 94.0% | \$29,174 | \$29,416 |
| Haynesville Shale - East Texas Basin - East Texas | | | | | | | |
| Haynesville Shale 1 MMSCFD | 77 | 28,317 | 0.24 | 0.056 | 76.5% | \$159,187 | \$165,555 |
| Haynesville Shale 2 MMSCFD | 77 | 56,634 | 0.48 | 0.11 | 76.5% | \$79,599 | \$82,800 |
| Haynesville Shale 4 MMSCFD | 77 | 113,268 | 0.96 | 0.22 | 76.5% | \$39,799 | \$41,400 |
| Haynesville Shale 7.5 MMSCFD | 77 | 212,377 | 1.8 | 0.42 | 76.5% | \$21,225 | \$22,079 |
| Haynesville Shale 8 MMSCFD (Large Dehy) | 77 | 226,535 | 1.9 | 0.45 | 95.0% | \$16,030 | \$16,675 |
| Tight Sand Gas - Greater Green River Basin - SW Wyoming | | | | | | | |
| GGRB Basin Generic Well Site Dehy 0.2 MMSCFD | 404 | 5,663 | 0.66 | 0.059 | 91.0% | \$49,782 | \$50,843 |
| GGRB Basin Generic Well Site Dehy 0.5 MMSCFD | 404 | 14,158 | 1.6 | 0.15 | 91.0% | \$19,913 | \$20,337 |
| GGRB Basin Generic Well Site Dehy 1.0 MMSCFD | 404 | 28,316 | 3.3 | 0.30 | 91.0% | \$9,956 | \$10,169 |
| GGRB Basin Generic Well Site Dehy 1.5 MMSCFD | 404 | 42,475 | 4.9 | 0.44 | 91.0% | \$6,638 | \$6,779 |
| GGRB Basin Generic Well Site Dehy 2 MMSCFD | 404 | 56,634 | 6.6 | 0.59 | 91.0% | \$4,978 | \$5,084 |

¹Annualized Cost of \$30,409 from page 3-26; Table 3-7 of RIA.

²100 MMSCFD is about the maximum throughput limit for a dehydration system.

The Proposed Requirements Do Not Account For The Naturally Occurring Differences In HAP/BTEX In The Gas Being Treated In The Dehydrators. As shown above, the proposed small dehydrator equations are only sensitive to BTEX concentration. In addition, another fundamental problem with the proposed equations is the failure to account for situations where the very gas being treated contains very low levels of BTEX. Unlike processes where owners and operators have some ability to adjust raw materials to impact emissions, operators of dehydrators at oil and gas production and natural gas transmission and storage sites must deal with the naturally occurring composition of the natural gas. The proposed requirements would cover ALL dehydrators without regard to the inlet gas composition, throughput, or potential emissions. In other words, the propose approach for small dehydrators require controls in situations where the emissions rate is not a result of some kind of controllable circumstance, like emissions controls or affirmative choices as to raw materials.

Table 20-3 illustrated how this coverage of all dehydrators at oil and gas production sites results in unreasonable control scenarios. Further, Table 20-5 shows that the proposed subpart HH equation results in higher required control efficiencies for lower BTEX concentration streams. For example, the proposed rule would require a 94% reduction in BTEX emissions for a 10 MMSCFD dehydrator in the North San Juan Basin with inlet BTEX concentration of 0.9 ppmv and uncontrolled BTEX

emissions of 0.011 tpy. A similarly sized dehydrator in the Haynesville Shale with an inlet BTEX concentration over 85 times higher, and uncontrolled BTEX emissions over 4 times higher, would only be required to reduce BTEX emissions by 76.5%.

If EPA elects to pursue the development of standards for small dehydrators, API offers the following two suggestions for moving forward with standards that are both technically sound and legally defensible: (1) subcategorize small dehydrators appropriately and develop MACT floors for each subcategory and (2) identify de minimis emission levels for dehydrators with insignificant emission levels.

20.4.1. EPA Must Properly Subcategorize Small Dehydrators and Establish Legal and Technically Feasible Standards

The analyses discussed above demonstrate that EPA has not properly subcategorized or otherwise appropriately accounted for fundamental differences among small dehydrators in determining the “classes, types, and sizes” of sources to be regulated. The record clearly shows that the cost of controlling HAP emissions from small dehydrators varies considerably, depending on such factors as concentration of HAP/BTEX in the inlet gas, throughput, and the type and efficiency of control measures. While EPA has attempted to account for some of these factors in the form of the equation-based standard, the cost data described above in Tables 20-3 and 20-5 (which show that the cost of compliance for certain classes of small dehydrators will be inordinate) prove that the form of the standard fails to properly accommodate certain classes of small dehydrators. EPA has ample authority to further subdivide the population of small dehydrators to make sure the standard reasonably fits each affected dehydrator. *See Sierra Club v. EPA*, 479 F.3d 875, 885 (D.C. Cir. 2007) (Williams concurring) (“[O]ne legitimate basis for creating additional subcategories must be the interest in keeping the relation between “achieved” and “achievable” in accord with common sense and the reasonable meaning of the statute.”). In the face of the cost data showing inordinate impacts on certain small dehydrators, the Agency’s failure to consider alternative groupings of small dehydrators is arbitrary and capricious.

EPA recognized differences in emission potential based on factors such as inlet BTEX concentration and throughput, as evidenced by the attempt to develop an equation to adjust the emission limitation based on these factors. However, as proven above, this approach was entirely insufficient. The proposed subcategorization scheme and resulting equations would require controls on every dehydrator, no matter how low the natural BTEX level or the potential dehydrator emissions. That is not the CAA’s intent of an emission “floor.”

API examined EPA’s small dehydrator dataset^{xx} to evaluate potential subcategorization and MACT floor options. Table 20-6 illustrates EPA’s small dehydrator dataset sorted by uncontrolled BTEX emissions.

^{xx} Memorandum. From Heather Brown, P.E, EC/R Incorporated, to Bruce Moore and Greg Nizich., EPA/OAQPS/SPPD/FIG. “Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options”. July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0047)

Table 20-6. Summary of EPA's Small Dehydrator Dataset

| EPA Unit ID No. | BTEX Emissions (tpy) | | Benzene Emissions (tpy) | | BTEX Inlet Concentration (ppmv) | Throughput (MMSCFD) |
|-----------------|----------------------|--------------------|-------------------------|-------------------|---------------------------------|---------------------|
| | Actual | Uncontrolled | Actual | Uncontrolled | | |
| G | 0.02 | 0.02 | 0.02 | 0.02 | 5 | 1.6 |
| E | 0.1 | 0.1 | 0 | 0 | 39 | 1.5 |
| A | 0.004 | 0.2 ¹ | 0.001 | 0.05 ¹ | 116 | 0.62 |
| R | 0.2 | 0.2 | 0.1 | 0.1 | 150 | 0.1 |
| D | 0.6 | 0.6 | 0.6 | 0.6 | 140 | 3.5 |
| F | 0.9 | 0.9 | 0.4 | 0.4 | 308 | 1.04 |
| B | 1.1 | 1.1 | 0.1 | 0.1 | 69 | 20 |
| W | 1.2 | 1.2 | 0.3 | 0.3 | 102 | 0.65 |
| HH | 1.5 | 1.5 | 0.7 | 0.7 | 410 | 0.09 |
| GG | 1.9 | 1.9 | 0.2 | 0.2 | 39 | 1.34 |
| Y | 2.4 | 2.4 | 0.2 | 0.2 | 157 | 0.75 |
| DD | 3 | 3 | 0.2 | 0.2 | 19 | 6.34 |
| Q | 3.5 | 3.5 | 0 | 0 | 50 | 5.8 |
| M | 3.8 | 3.8 | 1.2 | 1.2 | 400 | 1.2 |
| T | 3.9 | 3.9 | 0.4 | 0.4 | 216 | 1.2 |
| C | 0.084 | 4.2 ¹ | 0.007 | 0.35 ¹ | 60 | 1.6 |
| J | 4.4 | 4.4 | 3 | 3 | 823 | 0.7 |
| S | 4.5 | 4.5 | 1.5 | 1.5 | 400 | 0.8 |
| EE | 4.6 | 4.6 | 1.2 | 1.2 | 500 | 0.32 |
| O | 4.71 | 4.71 | 0.99 | 0.99 | 348 | 1.3 |
| U | 4.8 | 4.8 | 0.5 | 0.5 | 316 | 1 |
| I | 5.02 | 5.02 | 0.64 | 0.64 | 40 | 17.5 |
| BB | 5.3 | 5.3 | 0.7 | 0.7 | 198 | 1.21 |
| Z | 5.4 | 5.4 | 0.7 | 0.7 | 2,560 | 0.1 |
| K | 6.5 | 6.5 | 4.6 | 4.6 | 1,499 | 0.55 |
| AA | 6.9 | 6.9 | 1.3 | 1.3 | 320 | 1 |
| H | 7.9 | 7.9 | 4.9 | 4.9 | 1,560 | 1 |
| P | 10.4 | 10.4 | 0.8 | 0.8 | 174 | 5.11 |
| V | 11.7 | 11.7 | 1.3 | 1.3 | 329 | 2 |
| X | 13.8 | 13.8 | 0.6 | 0.6 | 668 | 1.1 |
| L | 17.7 | 17.7 | 1.7 | 1.7 | 1,400 | 1.6 |
| FF | 2.5 | 125 ¹ | 0.2 | 10 ¹ | 32 | 2.3 |
| N | 7.5 | 375 ¹ | 5.1 | 255 ¹ | 340 | 2.2 |
| CC | 59.3 | 2,965 ¹ | 10.5 | 525 ¹ | 920 | 2.7 |

¹ Emissions from these dehydrators were identified as controlled. A control efficiency of 98% was assumed to calculate the uncontrolled emissions.

If the outliers created by applying an assumed 98% control efficiency to the controlled streams are not considered (this assumption resulted in uncontrolled BTEX emissions of 125 tpy, 375 tpy, and 2,965 tpy), the data do show some expected outcomes. For example:

- The average emissions for the 25% lowest inlet BTEX concentrations are 2.5 tpy BTEX and 0.2 tpy benzene, while the remaining 75% have average emissions of just over 5 tpy BTEX and 1.2 tpy benzene.
- The BTEX emissions for the lowest 25% of the throughputs average 3 tpy, while the BTEX emissions for the remaining 75% of the data set with higher throughputs average over 5 tpy.

However, the average benzene emissions from the lowest 25% throughput dehydrators (1.3 tpy) are actually higher than the average benzene emissions for the higher throughput dehydrators (0.8 tpy).

Evaluation of all the data show a slight correlation between BTEX emissions and inlet BTEX concentration ($R^2 = 0.2$), but the data show a decrease in BTEX emissions with increasing throughput.

In conclusion, this cursory analysis of EPA's dataset (see Attachment R) indicates that neither inlet BTEX concentration or dehydrator throughput have a sufficient correlation with emissions to further break small dehydrators into technically and legally sound subcategories based only on these characteristics.

Therefore, API recommends that an uncontrolled emissions threshold be established to subcategorize small dehydrators. Given the large number of variables that impact emissions from dehydrators, emissions are the most relevant and comprehensive indicator of differences in dehydrator class, type, and size.

Further, EPA has already established the appropriate threshold for this subcategorization – 0.9 Mg/yr (1 tpy) benzene. During the original development of subparts HH and HHH, EPA established this 0.9 Mg/yr level “for owners or operators of facilities with low BTEX concentrations in the natural gas”^{YY}. Therefore, API recommends that the small dehydrator subcategory for oil and natural gas production (subpart HH) be separated into (1) those dehydrators with uncontrolled average benzene emissions less than 0.9 Mg/yr and (2) those dehydrators with uncontrolled average benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates less than 85,000 SCMD. For natural gas transmission and storage, these subcategories are (1) those dehydrators with uncontrolled average benzene emissions less than 0.9 Mg/yr and (2) those dehydrators with uncontrolled average benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates less than 283,000 SCMD.

Once the subcategories are established, EPA must then determine MACT floors for each subcategory. EPA's dataset available in the docket does not include sufficient levels of detail to fully evaluate process variations or other factors that influence emissions. More importantly, there is no way that EPA can determine whether any simple “floor” level calculated from these data can be achievable by all dehydrators in the subcategory. This is especially germane in this situation where many aspects that impact emissions are not under

^{YY} National Emission Standards For Hazardous Air Pollutants For Source Categories : Oil And Natural Gas Production And Natural Gas Transmission And Storage - Background Information For Final Standards: Summary Of Public Comments And Responses. EPA-453/R-99-004b. May 1999.

the control of the owner or operator. However, the owner or operator can ensure that the dehydrator is operated in a manner to reduce emissions to the maximum extent possible without add-on controls by optimizing the glycol circulate rate. This practice is already recognized as an effective method by EPA and is required by §63,764(d)(2) for area source dehydrators not located within an urbanized area (UA) plus offset and urban cluster (UC) boundary, as defined in §63.761 of subpart HH.

This is a clear example of the type of “design, equipment, work practice, or operational standard, or combination thereof,” standard allowed under section 112(h) of the CAA. To establish standards under the authority of 112(h), the CAA requires EPA to establish that:

- (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law, or
- (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

In many situations, the emissions from these low-emitting dehydrators are below the detection limit of prescribed test methods. This clearly meets the criteria in paragraph (B) above, justifying the establishment of standards that require the optimization of glycol circulation rate to reduce emissions.

As dehydrator emissions increase (i.e., are above 0.9 Mg/yr), the ability to effectively control increases and differences in inlet BTEX concentration, throughput, and other variables are less critical. Therefore, API believes it is technically valid and legally defensible to determine the MACT floor for those small dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater.

For oil and natural gas production, the average of the lowest 5 emitting dehydrators (since there are less than 30 dehydrators in the data set for the subcategory) is 4 tpy BTEX. For natural gas transmission and storage, there is only one dehydrator in the dataset with benzene emissions of 1 tpy or greater, and the BTEX emissions for this dehydrator are 5.5 tpy.

In summary, API offers the recommendations shown in Table 20-7.

Table 20-7. Recommended Subcategories and Standards for Small Dehydrators

| Recommended Dehydrator Subcategory | Recommended MACT Floor/Standard |
|---|---|
| Oil and Natural Gas Production | |
| Dehydrators with uncontrolled benzene emissions less than 0.9 Mg/yr | Optimize glycol circulation rate in accordance with §63,764(d)(2) |
| Dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates of less than 85,000 SCMD | BTEX Emissions < 3.6 Mg/yr or 95% reduction ¹ |
| Natural Gas Transmission and Storage | |
| Dehydrators with uncontrolled benzene emissions | Optimize glycol circulation rate in accordance |

| | |
|--|--|
| less than 0.9 Mg/yr | with §63.764(d)(2) |
| Dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates of less than 283,000 SCMD | BTEX Emissions < 5.0 Mg/yr or 95% reduction ¹ |

¹ A mass emissions limit imposes complicated and costly compliance and recordkeeping obligations when contrasted with a control efficiency standard. Therefore, API recommends that small dehydrators have the option to comply with 95% control requirements for large dehydrations in §63.765(b) as an alternative to complying the mass emission limitations determined by the equation. API believes that EPA should welcome this option, which would result in greater emission reduction for a lower burden.

If EPA does not decide to adopt API’s recommendations noted above, they must, at a minimum, revisit the proposed subcategorization and MACT floor decisions, which as was clearly shown above, do not meet their statutory-mandated requirements. EPA must then re-propose their updated evaluations and standards.

20.4.2. Dehydrators With No/Low Emission Potential Should Be Considered De Minimis

In MACT standards, EPA has routinely identified equipment with such low HAP emission potential that they should not be regulated.

As was shown in the real-world examples provided in Tables 20-3, 20-4, and 20-5, there are situations across the country where the natural gas being treated in dehydrators has such low benzene, BTEX, and HAP that the emissions will be trivial. API recommends that EPA establish de-minimis levels of HAP emissions that would exempt small dehydrators from all requirements under subparts HH and HHH.

In Alabama Power, the District of Columbia Circuit held that EPA could exempt de minimis sources of air pollution from the requirements of the Clean Air Act (See Alabama Power Co. v. Costle, 636 F.2d 323, 360 (D.C.Cir.1979)).

Glycol dehydrators are a clear example of where the establishment of a de minimis threshold is warranted. API insists there is a strong justification for such a threshold in the oil and natural gas production and natural gas transmission and storage source categories due to the naturally occurring differences in gas composition across the United States and thus, varying differences in dehydrator input stream HAP concentrations, throughputs, and in emissions.

API is recommending that EPA adopt a lower bound threshold below which dehydrators would not be subject to standards. As discussed above, the inlet composition of gas entering the dehydrator is not a stand-alone determiner of HAP emissions. However, situations where the inlet stream contains no BTEX should be exempt from regulation. In addition, API recommends that EPA establish a de minimis emission level. Owners and operators can document their emission level by using GRI-GLYCalc™ or another acceptable emission estimation method. Further, API recommends that this de minimis level be 0.5 Mg/yr total uncontrolled BTEX emissions.

20.5. EPA’s Proposed Equation Does Not Reflect the MACT Floor Determined

As discussed above, API does not believe that any new standards are required for small dehydrators. Further, as also discussed above, if EPA does elect to pursue standards for small dehydrators they must (1) establish reasonable and legal subcategories and promulgate standards reflecting the MACT floor for each subcategory and (2) establish de minimis thresholds to exempt dehydrators with insignificant emissions.

In the event that EPA chooses to continue with the proposed subcategorization approach (which, as clearly demonstrated above, is unlawful and technically unjustified), EPA must make changes to the proposed equations. In short, the BTEX emission limit equation for small dehydrators should not go to zero. For small dehydrators in the oil and natural gas production source category (subpart HH), EPA determined a MACT Floor of 0.286 tpy BTEX. For small dehydrators in the natural gas and production source category (subpart HHH), EPA determined a MACT floor of 1.45 tpy BTEX. However, the equations proposed in the rules approach a mass limit of zero.

This was undoubtedly an inadvertent error by EPA in the proposed equation, as it does not represent the MACT floor calculated. The equation would give the intended result if the product of Throughput and Concentration ($C_{i,BTEX}$) were assigned a lower bound, as shown below. This correction to the equation would result in a minimum emission limit of 0.286 tpy BTEX for oil and natural gas production and 1.45 tpy BTEX for natural gas transmission and storage (i.e., the MACT floors), rather than 0.

For Equation 1 in subpart HH:

$$EL_{BTEX} = (1.10 \times 10^{-4})(\text{Throughput})(C_{i,BTEX})(365 \text{ day/yr})(1 \text{ Mg}/10^6 \text{ g})$$

where:

$$EL_{BTEX} = \text{Unit-specific BTEX emission limit (Mg/yr)}$$

$$1.10 \times 10^{-4} = \text{BTEX emission limit (g BTEX}/(\text{standard m}^3 - \text{ppmv}))$$

$$\text{Throughput} = \text{annual average daily natural gas throughput (standard m}^3/\text{day)}$$

$$C_{i,BTEX} = \text{BTEX concentration of the natural gas at the inlet to the glycol dehydrator unit (ppmv)}$$

If:

$$\underline{(\text{Throughput})(C_{i,BTEX}) < 6.46 \times 10^6 (\text{standard m}^3 - \text{ppmv})/\text{day},}$$

then set:

$$\underline{(\text{Throughput})(C_{i,BTEX}) = 6.46 \times 10^6 (\text{standard m}^3 - \text{ppmv})/\text{day}.}$$

For Equation 1 in subpart HHH:

$$EL_{BTEX} = (6.42 \times 10^{-5})(\text{Throughput})(C_{i,BTEX})(365 \text{ day/yr})(1 \text{ Mg}/10^6 \text{ g})$$

where:

EL_{BTEX} = Unit-specific BTEX emission limit (Mg/yr)

6.42×10^{-5} = BTEX emission limit (g BTEX/(standard m^3 – ppmv))

Throughput = annual average daily natural gas throughput (standard m^3 /day)

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydrator unit (ppmv)

If:

$$(\text{Throughput})(C_{i,BTEX}) < 5.61 \times 10^7 \text{ (standard } \text{m}^3 \text{ – ppmv)/day,}$$

then set:

$$(\text{Throughput})(C_{i,BTEX}) = 5.61 \times 10^7 \text{ (standard } \text{m}^3 \text{ – ppmv)/day.}$$

A mass emissions limit imposes complicated and costly compliance and recordkeeping obligations when contrasted with a control efficiency standard. Therefore, API recommends that small dehydrators have the option to comply with 95% control requirements for large dehydrations in §63.765(b) as an alternative to complying the mass emission limitations determined by the equation. API believes that EPA should welcome this option, which would result in greater emission reduction for a lower burden.

If EPA's proposed equation were to be promulgated, it represents a level of control beyond the MACT floor. This is clearly demonstrated above in Table 20-4, as the proposed equation for subpart HH would result in every dehydrator in the top 12% of the dataset, save one, to install controls. EPA estimates that the incremental cost effectiveness of beyond the floor controls to be \$167,200/Mg for oil and gas production small dehydrators (40 FR 52768) and \$33,000/Mg for natural gas transmission and storage small dehydrators (40 CFR 52769). In both cases, EPA clearly stated that they did not believe these cost effectiveness values were reasonable. If EPA does not adjust the equations in accordance with the above suggestions, then they are in effect accepting these unreasonable cost effectiveness values. API does not believe this is justified and maintains that EPA must not promulgate the equations as proposed.

20.6. Clarification of Terminology

API maintains that the following changes are needed to clarify terminology related to glycol dehydrators.

20.6.1. Boiler Definition

In the NESHAP boiler definition, the rule must clarify that glycol reboilers are not boilers.

§63.761

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10. [This definition excludes line heaters and glycol reboilers.](#)

20.6.2. Glycol System Condensers are not Control Devices

EPA uses the term “condenser” multiple times in the rule when describing control devices and requirements. It is not uncommon for a condenser on a dehydrator vent stream to precede a flare or other combustion device. A key purpose of this condenser is to remove water vapor. Since the 95% HAP emission reduction is met by the flare or combustion device, it is not reasonable to consider the condenser as a control device in this situation and require all the associated monitoring, recordkeeping, and reporting requirements. We therefore, request that only condensers that are the final control device, or condensers used to help achieve the 95% control efficiency, be classified as control devices. We ask that EPA clarify that condensers which are part of a glycol system prior to a control device should not be considered control devices.

21. PRODUCED WATER EVAPORATION PONDS

EPA solicited comments on several questions regarding produced water evaporation ponds in the Preamble. EPA stated, “*We believe that produced water ponds are also a potentially significant source of emissions, but we have only limited information. We, therefore, solicit comments on produced water ponds...*”

It is wrong for EPA to conclude that produced water ponds are “a potentially significant source of emissions,” especially based on their statement that “limited information” is available. In fact, there is no information to date indicating that produced water ponds are significant emission sources. The appropriate method for determining potential impacts is to rely on a valid scientific approach to addressing the concern. Preferably that would include determining what information is available, evaluating available data to determine data gaps, developing a plan to fill data gaps, and evaluating the updated data set. With that in mind, industry is open to cooperating with EPA in an appropriate manner to address their concerns.

Here are the questions that EPA included and our responses.

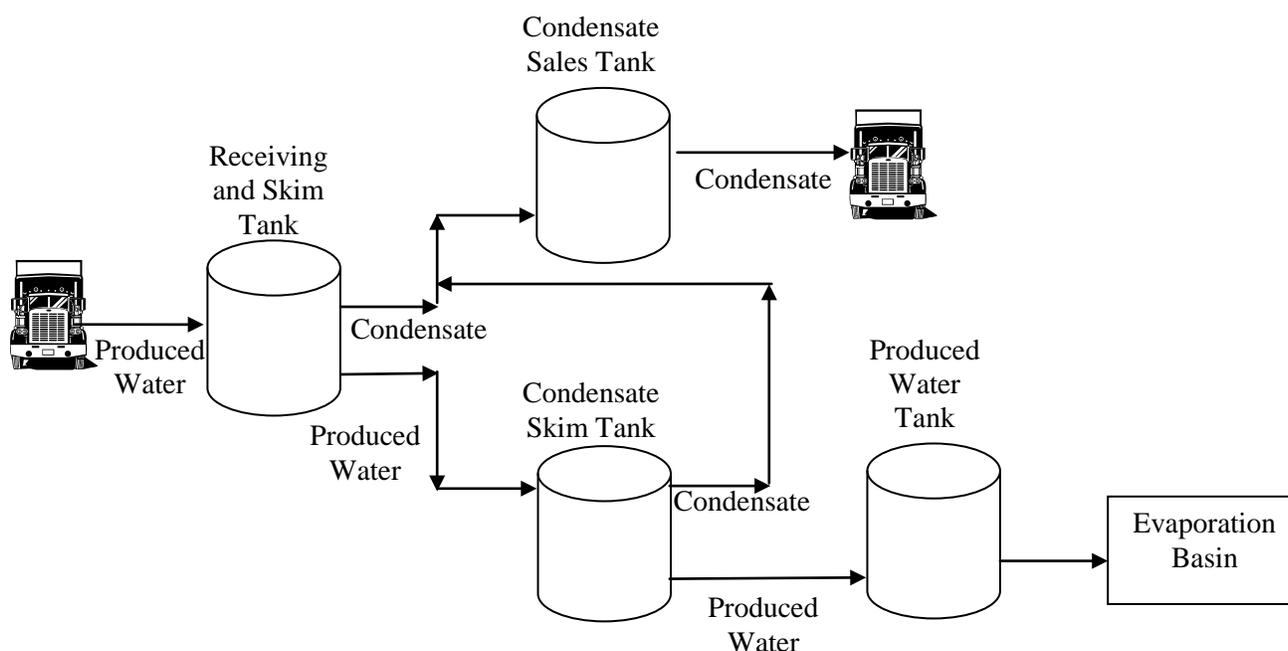
(a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation.

Any model used for calculating emissions will depend upon valid input data. All inputs must be confirmed, subjected to quality analysis, sensitivity tested, and validated. Initial input VOC concentrations to ponds, local climatic conditions, biodegradation potential, sorption to solids and other parameters must be properly determined through process examination or measurement.

The Endangered Species Act strictly limits the amount of hydrocarbons that can be on an unnetted pond. Consequently, evaporation pond operators are very sensitive to the existence of hydrocarbons on/in a pond

and they take extensive steps to prevent them. Typically, oil /condensate and water are separated initially at the wellhead with a three phase separator. Then the produced water enters a tank. Any oil or condensate entrained in the produced water then separates out in the produced water tank. Trucks are used to vacuum the oil or condensate from the top of the tank. The produced water is then trucked to the evaporation pond facility. There additional separation is done using a series of skim oil tanks as shown below. The produced water then enters the evaporation pond. Hydrocarbon emissions from the evaporation ponds are minimized since almost no separate phase hydrocarbon remains in the produced water placed into the evaporation ponds.

Figure 20-1. Process Flow for Produced Water To Evaporation Basins



As far as estimating emissions, WATER9 is the only EPA approved method for calculating emissions from evaporation basins. The assumptions in this model are quite conservative and tend to overestimate emissions, not underestimate emissions. Assuming 100% of VOCs in the water enter the atmosphere is a completely false assumption that ignores the fate and transport of various chemicals. Many chemicals, like methanol, have a very high affinity for water and do not evaporate. Also, many chemicals, like methanol, can only be removed from water using biodegradation. EPA's "Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1"^{ZZ} found minimal emissions from the evaporation ponds.

The Office of Pollution Prevention and Toxics of the U.S. Environmental Protection Agency (EPA) acknowledges that "most methanol is removed from water by biodegradation"^{AAA}. The Hazardous Substances Data Bank of the National Library of Medicine says that aquatic hydrolysis, oxidation, and

^{ZZ} <http://www.epa.gov/nrmrl/pubs/600r09132/600r09132.pdf>

^{AAA} United States Environmental Protection Agency, Office of Pollution and Toxics. *Chemical Summary for Methanol, Report No. EPA749-F-94-013a*. United States Environmental Protection Agency, August 1994.

photolysis are not significant fate processes for methanol^{BBB}. Additionally, in 1999, Malcolm Pirnie conducted a study for the American Methanol Institute called "Evaluation of the Fate and Transport of Methanol in the Environment"; part of this study included reviewing the losses of methanol in water. Malcolm Pirnie found that the dominant loss mechanism was biodegradation^{CCC}. According to a 1991 study "The reported half-life of methanol in surface waters under aerobic conditions is short and has been reported to be as low as 24 hours^{DDD}". In fact, the half-life of methanol even in anaerobic conditions is from 1 to 5 days^{EEE}.

Since methanol is very polar and stable in water, hydrolysis does not contribute significantly to methanol removal from bodies of water. Photolysis is not a significant contributor to methanol degradation either since methanol does not absorb light in the visible spectrum and long wavelength UV. Methanol does, however, absorb very short wavelength ultra violet (UV), which is present in negligible amounts in solar radiation. "In addition, methanol can be naturally oxidized by hydroxyl radicals formed in the water by the photolysis of nitrate, nitrite, and hydrogen peroxide resulting from reactions with excited humic material or from the reaction with H₂O₂ with Fe(II)"^{FFF}.

Bioaccumulation in aquatic organisms is expressed in bioconcentration factors (BCF). The bioaccumulation in solids and organic materials is expressed as the octanol-water coefficient. The BCF and octanol-water partition coefficient for methanol, as represented in the Malcolm Pirnie study, was less than ethanol and significantly less than for benzene. Thus the bioaccumulation of methanol is fairly low. Further, since methanol has a low partition air/water coefficient and a rate of biodegradation that exceeds the rate of volatilization, volatilization is not a primary source of methanol losses either. The half-life of methanol from volatilization is 60 days in comparison to 24 hours for biodegradation^{GGG}. This comparison leads to the conclusion that the most of the methanol losses in water are from biodegradation.

The EPA WATER9 model considers biodegradation, bioaccumulation of solids and organic materials, and volatilization of chemicals in water. Since photolysis is not a significant contributor to methanol losses, WATER9 is an acceptable tool to use to estimate methanol emissions to air from wastewater. WATER9 predicts that the emissions of methanol decrease as temperatures increase. The phenomenon occurs because biodegradation increases with temperature, leaving less material to volatilize. Additionally, volatilization is much slower than biodegradation for methanol. Enviromega determined that WATER8 (the predecessor to WATER9) predicted methanol emissions at a relatively high rate because the biorate coefficient was

^{BBB} Hazardous Substances Data Bank (HSDB), MEDLARS Online Information Retrieval System, National Library of Medicine, 1994.

^{CCC} Malcolm Pirnie, Inc. *Evaluation of the Fate and Transport of Methanol in the Environment*. Oakland, California: Malcolm Pirnie, January 1999.

^{DDD} Howard, C. E., Baker, J. F., O'Hannesin, S. F., Vandergriendt, M. and Gillham, R. W. *Transport and Fate of Dissolved Methanol, Methyl-Tertiary-Butyl-Ether, and Monoaromatic Hydrocarbons in a Shallow Aquifer*, American Petroleum Institute Publication No. 4601. American Petroleum Institute, 1991.

^{EEE} Howard, C. E., Baker, J. F., O'Hannesin, S. F., Vandergriendt, M. and Gillham, R. W. *Transport and Fate of Dissolved Methanol, Methyl-Tertiary-Butyl-Ether, and Monoaromatic Hydrocarbons in a Shallow Aquifer*, American Petroleum Institute Publication No. 4601. American Petroleum Institute, 1991.

^{FFF} Schwarzenbach, R. P., Gschwend, P. M and Imboden, D. M. *Environmental Organic Chemistry*. New York: John Wiley & Sons, Inc., 1993.

^{GGG} Malcolm Pirnie, Inc. *Evaluation of the Fate and Transport of Methanol in the Environment*. Oakland, California: Malcolm Pirnie, January 1999.

erroneously assumed low relative to the stripping coefficient^{HHH}. Later, Enviromega was retained by a large manufacturing association to estimate the biodegradation rate coefficient for methanol using a version of 40 CFR 63, Appendix C, Method 304. First order biodegradation rate coefficients were estimated by Enviromega. The biorate coefficients for methanol determined by this study were two orders of magnitude higher than in the WATER8 model. The Monod first order biodegradation rate from their study was -32.6 L/g-h at 22°C and in WATER8 it is only -0.2 L/g-h^{III}. The table below summarizes the findings from Enviromega's study.

Comparison of Methanol First Order Biodegradation Rate Coefficients

| Compound | Initial MeOH Con. (mg/L) | No. of Data Points | K ₀ (mg/L-min.) | r ² | Monod Parameters | | | |
|----------|--------------------------|--------------------|----------------------------|----------------|-------------------------------|-----------------------|-------------------------------|-----------------------|
| | | | | | Montheith Study | | WATER8 | |
| | | | | | K _{max} (mg/g VSS-h) | K _s (mg/L) | K _{max} (mg/g VSS-h) | K _s (mg/L) |
| Methanol | 20 | 6 | -0.185 | 0.988 | -11.08 | 0.34 | -18 | 90 |
| | 15 | 5 | -0.365 | 0.909 | | | | |
| | 10 | 5 | -0.246 | 0.870 | | | | |
| | 5 | 4 | -0.236 | 0.694 | | | | |
| Ethanol | 20 | 5 | -0.117 | 0.974 | -6.14 | 0.36 | -8.8 | 9.8 |
| | 15 | 5 | -0.168 | 0.944 | | | | |
| | 10 | 4 | -0.137 | 0.940 | | | | |
| | 5 | 4 | -0.121 | 0.762 | | | | |

Enviromega found that the emissions from various units using the biorate coefficient from their study were lower than the emissions using the biorate coefficient from WATER8. The largest difference was in the activated sludge unit, which had 0.03 g/d of methanol emissions using biorate coefficient from their study compared to 0.8 g/d of methanol using the biorate coefficient from WATER8. Based on this information, the methanol emissions estimated by the EPA models WATER8 and WATER9 are significantly conservatively high.

(b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content.

Evaporation pond operators use pre-treatment facilities to ensure that free hydrocarbons do not enter the ponds as discussed above. The limited comment period has not allowed for time to gather comprehensive data on the concentrations of VOCs in produced water evaporation ponds but they are believed to be very insignificant. While the water cut of some wells may increase with age, there is an insufficient database of information on the VOC content of such waters over time to come to any reasonable conclusion as to increases or decreases in VOC content that may occur over the life of a well. In the case of wells completed

^{HHH} Enviromega. *Estimation of Methanol Biodegradation Rate Coefficient Using EPA's Method 304*. Wastewater Toxics, <http://www.enviromega.com/methbio.htm>.

^{III} Montheith, H. D. and Tischler, L. F. *Testing EPA's Method 304: Biodegradation Rates for Methanol and Other Oxygenated Solvents in a Pharmaceutical Wastewater*. Flamborough, ON, Canada: Enviromega Ltd., 1996.

in shale formations, the water flow from such diminishes rapidly following completion and usually has a minimal flow rate over time.

(c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those warrant control and, if so, how controls should be developed.

There is no such thing as a "typical" evaporation facility. The limited comment period has not allowed for time to gather comprehensive data for determining a statistically valid set of data for pond size and throughput. Throughput may range from a few barrels a day to several thousand. There are facilities with a simple gun barrel separator and a small pond to facilities with multiple stages of inlet separation and multiple ponds. Evaporation ponds are the least likely facilities in upstream oil and gas to provide cost effective reductions in VOC or HAP.

(d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well.

Salable hydrocarbons are captured prior to entering the pond as described above, using existing recovery technologies. As EPA's intent of this question is likely to determine just that, API suggests that EPA conduct a valid study. The complexity of the study might range from well planned mass balance calculations to more detailed data collection and analysis. Industry welcomes the opportunity to cooperate with EPA on any necessary study performed with sufficient time allotted.

(e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints.

Typically, evaporation ponds are placed in locations with access to 3-phase power to operate pumps, aerators, and lighting. The main limitation is that the VOC concentrations in the produced water are already extremely low. Further treatment to remove VOCs would be quite difficult and expensive and would bear little environmental benefit.

(f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency.

Traditional gravity separation as described above is very effective. More sophisticated technology has been much less effective. Industry may be able to respond further if provided the information that led EPA to conclude that existing separation technologies are not effective, and with sufficient time to respond.

Attachment A
Pre-Proposed Rule Presentations and White
Papers by API

Materials Supplied To EPA By API
on the O&G NSPS/NESHAP Rulemaking
Before Proposed Rule

| | Page # |
|--|--------|
| Presentation on O&G Basics, March 4, 2010 | 2 |
| Presentation on O&G Emission Inventories, March 23, 2010 | 13 |
| Email Submittal of Document for July 21, 2010 Meeting | 24 |
| O&G VOC Control Option Table | 25 |
| Email Submittal of Green Completions Issue Paper, August 5, 2011 | 30 |
| Green Completions Issue Paper | 31 |
| Email Submittal of Thief Hatch and Flare Issue Papers, November 18, 2011 | 34 |
| Thief Hatch Issue Paper | 35 |
| Flare Issue Paper | 40 |
| Appendix – Table 1 | 45 |
| Pressure-Assisted Flare Emission Testing | 46 |
| API O&G NSPS/NESHAP Rule Comments, February 23, 2011 | 58 |

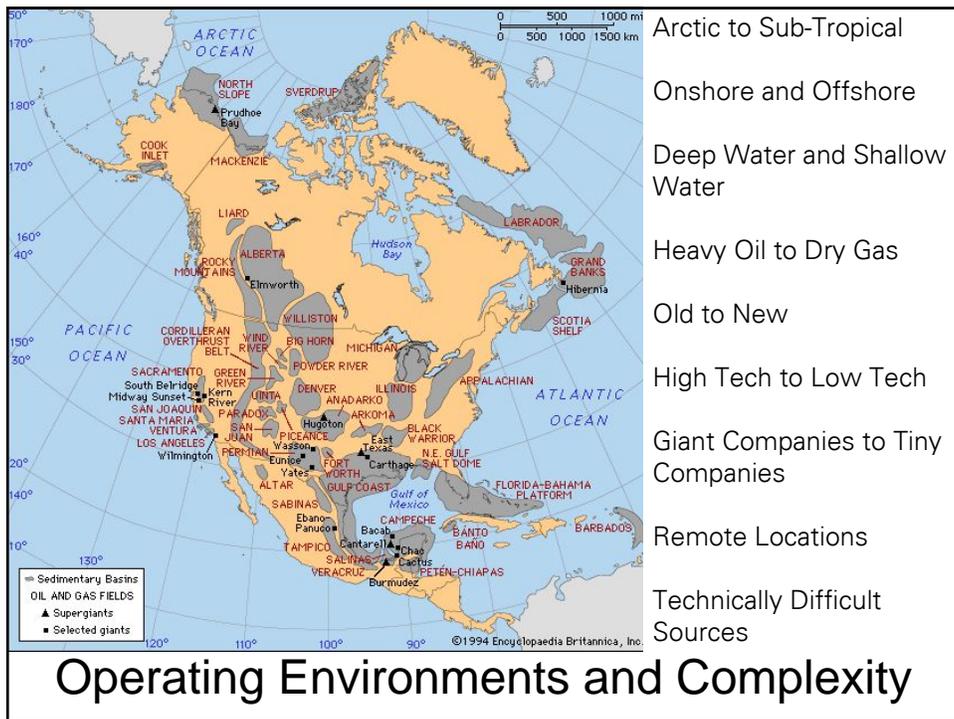
Oil & Gas Exploration & Production Basics

EPA Meeting On O&G
NSPS/NESHAP Review
March 4, 2010



Oil & Gas Overview

- Size of Industry – **Its Big**
- Complexity – Highly Variable
 - Operating Environments
 - Number and Size of Sites
 - Types of Operations
 - Ages of Operations
 - Business Arrangements
 - Variability Operators – Size and Capabilities
- Remote, Dispersed Nature



United States & Canada
Distribution of Wells by Production Rate Bracket

| Prod. Rate Bracket (BOE/Day) | United States | | | | | | Canada | | | | | | Combined | |
|------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|------------|------------|
| | # of Oil Wells | % of Oil Wells | % of Oil Prod. | # of Gas Wells | % of Gas Wells | % of Gas Prod. | # of Oil Wells | % of Oil Wells | % of Oil Prod. | # of Gas Wells | % of Gas Wells | % of Gas Prod. | # of Wells | % of Wells |
| 0 - 1 | 125,933 | 35.4 | 1 | 83,132 | 19.9 | 0.3 | 4,382 | 7.0 | 0.1 | 4,500 | 6.2 | 0.1 | 217,947 | 24% |
| Subtotal <=10 | 275,362 | 77.4 | 13.3 | 271,109 | 64.7 | 7.9 | 26,935 | 43.1 | 7.3 | 39,453 | 53.9 | 5.5 | 612,859 | 67% |
| Subtotal <=15 | 302,220 | 85 | 19.9 | 309,340 | 73.9 | 12.3 | 34,632 | 55.5 | 13.2 | 46,087 | 63.0 | 8.1 | 692,279 | 76% |
| 15 - 20 | 13,589 | 3.8 | 4.8 | 22,948 | 5.5 | 3.7 | 5,362 | 8.6 | 5.8 | 3,619 | 4.9 | 2.0 | 45,518 | 5% |
| 20 - 25 | 8,670 | 2.4 | 3.9 | 14,741 | 3.5 | 3 | 3,781 | 6.1 | 5.3 | 2,500 | 3.4 | 1.8 | 29,692 | 3% |
| 25 - 30 | 5,710 | 1.6 | 3.1 | 10,403 | 2.5 | 2.6 | 2,899 | 4.6 | 4.8 | 2,053 | 2.8 | 1.8 | 21,065 | 2% |
| 30 - 40 | 7,352 | 2.1 | 5 | 13,526 | 3.2 | 4.3 | 4,099 | 6.6 | 8.7 | 3,095 | 4.2 | 3.4 | 28,072 | 3% |
| 40 - 50 | 4,799 | 1.3 | 4.1 | 8,660 | 2.1 | 3.5 | 2,772 | 4.4 | 7.6 | 2,352 | 3.2 | 3.3 | 18,583 | 2% |
| 50 - 100 | 7,703 | 2.2 | 9.9 | 19,038 | 4.5 | 11.6 | 5,806 | 9.3 | 24.4 | 6,600 | 9.0 | 14.1 | 39,147 | 4% |
| 100 - 200 | 3,009 | 0.8 | 7.4 | 11,517 | 2.8 | 12.9 | 2,193 | 3.5 | 16.8 | 4,097 | 5.6 | 17.8 | 20,816 | 2% |
| 200 - 400 | 1,311 | 0.4 | 6.4 | 5,173 | 1.2 | 10.8 | 619 | 1.0 | 7.8 | 1,810 | 2.5 | 15.8 | 8,913 | 1% |
| 400 - 800 | 606 | 0.2 | 5.8 | 1,852 | 0.4 | 7.3 | 222 | 0.4 | 3.9 | 590 | 0.8 | 10.3 | 3,270 | 0% |
| 800 - 1600 | 253 | 0.1 | 4.8 | 814 | 0.2 | 6.7 | 52 | 0.1 | 1.1 | 228 | 0.3 | 8.2 | 1,347 | 0% |
| 1600 - 3200 | 160 | 0 | 6.3 | 450 | 0.1 | 8.1 | 4 | 0.0 | 0.4 | 77 | 0.1 | 5.4 | 691 | 0% |
| 3200 - 6400 | 95 | 0 | 7.3 | 233 | 0.1 | 8.5 | 1 | 0.0 | 0.2 | 40 | 0.1 | 5.7 | 369 | 0% |
| 6400 - 12800 | 47 | 0 | 7.1 | 57 | 0 | 3.9 | 0 | 0.0 | 0.0 | 8 | 0.0 | 2.3 | 112 | 0% |
| > 12800 | 13 | 0 | 4.3 | 6 | 0 | 0.8 | 0 | 0.0 | 0.0 | 0 | 0.0 | 0.0 | 19 | 0% |
| Remainder | 53,317 | 15 | 80 | 109,418 | 26 | 88 | 27,810 | 45 | 87 | 27,069 | 37 | 92 | 217,614 | 24% |
| Total | 355,537 | 100 | 100 | 418,758 | 100 | 100 | 62,442 | 100.0 | 100.0 | 73,156 | 100.0 | 100.0 | 909,893 | 100% |

Then there is the collection, compression, treating, and processing

- **Conventional O&G Reservoirs**
 - High Permeability
- **Unconventional Gas**
 - Deep Reservoirs – Typically Dry/High Pressure Gas
 - Low Permeability
 - Coal Bed Methane – No Petrol. Liq.; Often Lower Pressure; Shallower Depth; Higher Water Production
 - Tight Sands Gas
 - Shale
- **Field Pressure Decreases as Field is Produced.**

Wild Cat Wells

- Prospect Identification
 - Basin Evaluation, Seismic and Other Geotechnical Evaluation, Offset Area Evaluation, Land Evaluation
- Obtain a Land/Lease (mineral and surface) Position
- Drill, Complete and Test Exploratory Well(s)

Initial Field Development

- Evaluate Reserves, Costs, and Initial Full Cycle Economics
- Drill, Complete and Test Initial Development Wells;
- Install Infrastructure
- Begin Production Operations
- Competing Operators Start Developing the Field.

Life Cycle of a Field

Mature Field Development

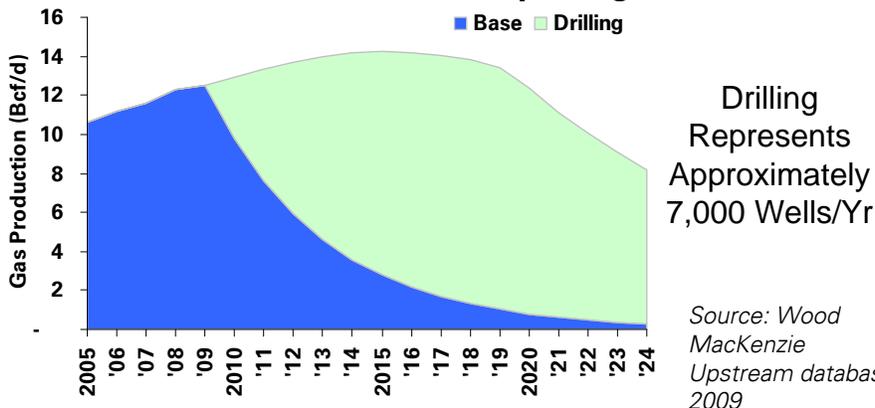
- On-going Economic Evaluations/Optimization on a Well-by-Well Basis
- Buy/Sell/Trade Assets
- Reservoir Drainage Evaluation
- Step-Out Delineation (i.e. reservoir boundaries)
- Explore Alternate Reservoir Potential (i.e. deeper prod. zones)

Infield Development

- Optimize Production Systems as Decline Progresses
- Reduced Well Spacing to Increase Recovery of Reserves
- Abandon Field at End of Economic Life

Drill to Maintain Production

Projected gas production from Colorado, New Mexico and Wyoming

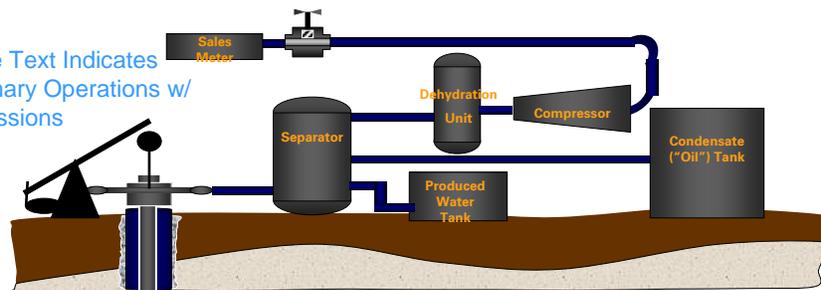


Ongoing drilling, well work, and infrastructure investment are required to maintain a steady state of U.S. natural gas production.

- **One Operator Fields**
 - Typically Only Young Fields
 - Even These Have Partners
 - Other Operators Drill Wells
- **More Operators as Field Mature**
 - Increasingly Complex as Multiple Companies Install Infrastructure
 - Services (i.e. comp., dehyd., gas proc., etc.) are contracted within negotiated limits.
 - Assets Bought/Sold/Traded/Change Operators Often
- **Contracts and Ownership Issues Get Very Complex with Infinite Variations**

- Gas/Oil/Water Separation
- Oil/Water Storage
- Gas Measurement
- Dehydration
- Gas Gathering
- Compression
- Gas Sweetening
- Gas Processing Plant

Blue Text Indicates Primary Operations w/ Emissions





Typical Traits of O&G Well and Most Compressor Station Sites

- Disperse – often miles apart
- Remote – closest receptor often mile +
- Unmanned – checked only periodically
- No Utilities – generator, water and air compressor must be brought with operator if it is needed.



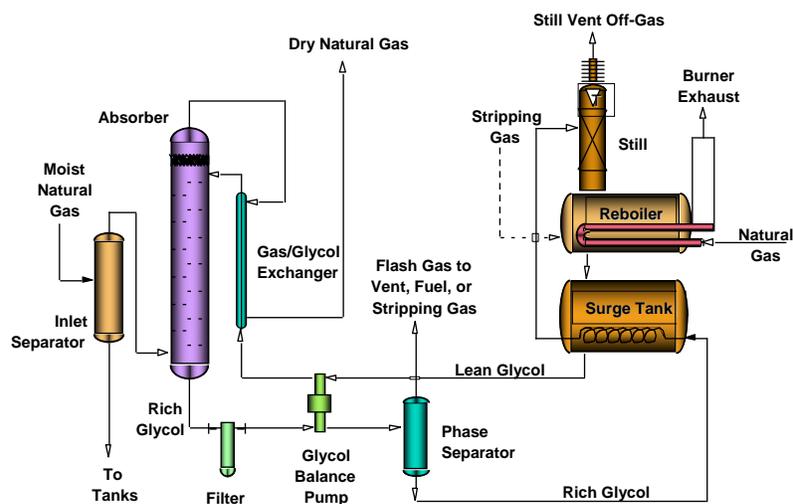
Liquid Storage Location

- Most often at well head
- During in-field development – central tank batteries may be considered.
 - Requires same well operator and
 - Wells close together.

Dehydrator Location

- Wet/high pressure gas causes hydrate formation (hydrocarbon/ice mixture) at warm temperatures.
- Water limitations in gathering/transmission lines for corrosion protection.
- High pressure fields may require dehydration at well head.
- Med. pressure fields may be dehydrated at compressor station.
- Low pressure fields may be dehydrated at gas processing plant.
- Dry gas (low NGL content) has lower hydrate formation concerns

Process Flow Diagram for Glycol Dehydration Field Unit





Glycol Dehydrator



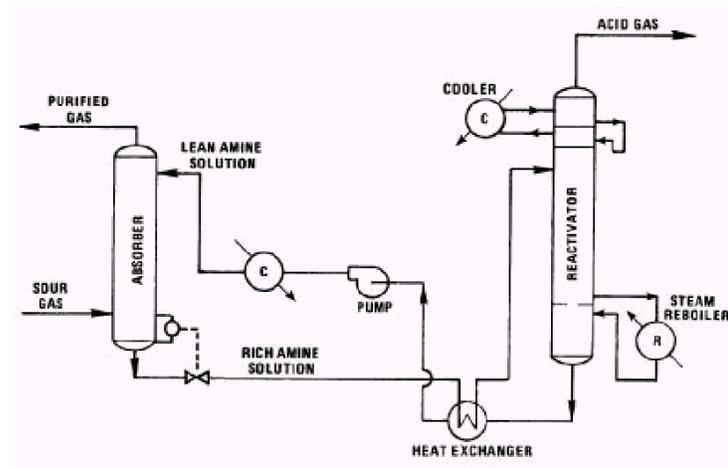
- Absorber (Contactor)
 - Countercurrent contacting of incoming wet gas and lean TEG to reduce water content
 - Avoid corrosion & hydrate formation
 - In EG system, glycol is injected directly into natural gas stream, thus absorber is not used
 - Glycol also absorbs some organics (including HAPs) from gas stream
- Key design parameters:
 - Gas flow rate & specific gravity
 - Gas temperature & Pressure
 - Outlet dewpoint required



- Still/Stripper Column
 - Used with reboiler to regenerate glycol
 - Often placed vertically on top of reboiler
 - Reboiler supplies heat to regenerate glycol via simple distillation

- Well head compression most often used in older, low pressure fields with multiple production operators in gathering system.
- Compressor stations used for better utilization of existing pipe.
- Most gas processing plants have pre- and or post compression.
- Reciprocating natural gas fired engines typically the only choice.

- Typically at gas processing plant.
- Removes H₂S (safety) & CO₂ (heat content and dry ice formation in cryogenic gas plants)
- Gas must be dehydrated after amine treater.
- Acid gas may be:
 - Processed in Sulfur Recovery Unit (SRU)
 - Flared, etc.
 - Vented (CO₂, methane, typically few hydrocarbons).



- Removes NGL (natural gas liquids) and lowers hydrocarbon dew point.
 - Liquids in gathering/transmission lines causes operational problems.
 - Heavy hydrocarbons cause consumer problems
 - NGLs used as feed stock and gasoline blending stocks.
- Gas processing also includes fractionation of NGLs into individual components (ethane, propane, iso-butane, n-butane, natural gasoline).

- Oil & Gas Operations Vary Widely Between
 - Reservoir Type/Basin
 - Maturity of Field
 - Type, Size, Age and Location of Equipment
 - Business Arrangements
 - Geography (Arctic, Mountainous, Offshore, etc.)
- One Control Scheme Doesn't Fit All

Oil & Gas Emission Inventories

EPA Meeting On O&G
NSPS/NESHAP Review
March 23, 2010



Sources of Oil & Gas Emissions Data

- State Inventories
 - Triennial reports to EPA
- Regional Partnership Inventories
 - Western Regional Air Partnership (WRAP)
 - <http://www.wrapair.org>
 - Central Regional Air Planning Association (CENRAP)
 - <http://www.cenrap.org>



State Agency Prepared Inventories

- Often have little or no Operator input
- Are frequently based upon Permitted rather than Actual Emissions
 - Tends to overestimate emissions for permitted source categories
- May use broad assumptions not applicable to all basins or types of operations within a State or jurisdiction
 - For example, emission factors applicable to oil operations may be applied to gas wells, or vice versa



State Agency Prepared Inventories

- May omit equipment or activities with permit exempt emissions that are prevalent and due to the large number of sources emit significant emissions.
 - Pneumatic controllers
 - Pneumatic pumps
 - Natural gas fueled burners less than 5 MMBTU/hr used in separators, heater treaters, dehydrators, storage tanks, etc.



Western Regional Air Partnership Oil & Gas Emission Inventories

- Phase I and Phase II Inventories are available at:
 - http://www.wrapair.org/forums/ogwg/Phases_I_and_II_Inventories.html
- Developed initially as a tool for regional haze evaluations
 - Phase I report completed in late 2005 developed baseline emissions for year 2002
 - Phase II report completed in Fall of 2007 improved upon the 2002 inventory methods and developed emissions for year 2005
- Provided a foundation for regional Oil & Gas Industry Emissions
- Phase II did not meet all the needs of the regulated community
 - Need for regional inventories suitable for use in photochemical models for ozone analyses



Western Regional Air Partnership Oil & Gas Emission Inventories

- Recognized limitations of the WRAP Phase II Inventory
 - As a result of the initial focus on Regional Haze planning, many sources of VOC emissions were omitted
 - Limited Operator participation
 - Broad assumptions concerning emission factors were applied across vastly different basins and types of operations
- To address these limitations, member companies of the Independent Petroleum Association of Mountain States (IPAMS) volunteered to fund a WRAP Phase III Oil and Gas inventory initiative.

energy API WRAP Phase III Oil & Gas Inventory



Phase III inventories are completed for the following basins:

- Denver-Julesburg (D-J)
- Piceance
- Uinta
- North and South San Juan

• *Wind River inventory to be available shortly*

The inventories are publically available:
http://www.wrapair.org/forums/ogwg/Phase III_Inventory.html

energy API WRAP Phase III Oil & Gas Inventory

- Evaluated a comprehensive spectrum of emission sources, many of which were not previously considered
- Included all phases of the well life-cycle (Drilling, Completion, Production, Decline).
- Types of production operations (oil, gas, coal-bed methane (CBM)) were differentiated within each source category
 - Lateral/wellhead compressor engines
 - Drilling rigs
 - Workover rigs/frac rigs
 - CBM well pump engines
 - Salt-water disposal pump engines
 - Artificial lift engines (pumpjacks)
 - Vapor recovery unit (VRU) compressor engines
 - Miscellaneous gas-fired engines
 - Wellsite heaters
 - Miscellaneous gas-fired heaters or boilers
 - Flaring
 - Pneumatic devices
 - Stock tanks- working, breathing, storage, losses, flashing emissions
 - Fugitive emissions
 - Completions (well flowback)
 - Venting events
 - Periodic well blowdowns
 - Glycol Dehydrators
 - Amine units
 - Truck loading operations
 - Pipeline/compressor station emissions
 - Water treatment/water injection facilities



WRAP Inventory Comparison

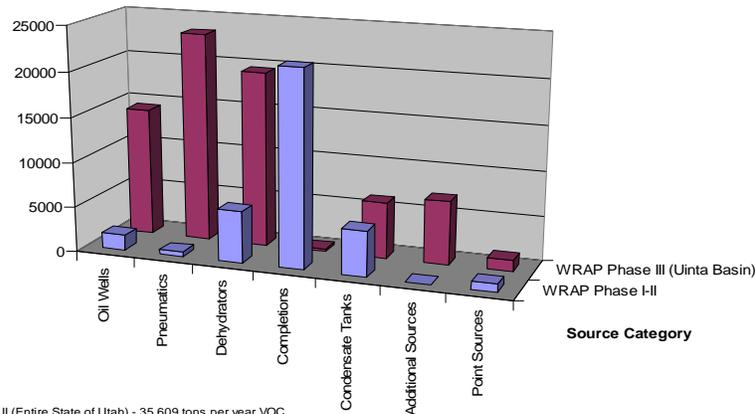
| WRAP Phases I and II | Issue Identified | Example | WRAP Phase III |
|--|---|--|---|
| Very limited industry participation | Inventory didn't reflect the dynamic regulatory changes since 2002 and the emission reduction strategies industry has implemented on non-regulated source groups. | Green completions, low-bleed pneumatics, EPA tiered diesel emission standards | Better than 70% operator participation in most basins |
| Did not reflect basin specific emissions | Due to limited information, final inventory reflected the most conservative emission rate from collected data. | Completion emissions for conventional wells in Southwest Wyoming were incorrectly applied to other basins. | All emission factors were basin specific |
| Inventoried NOx emission from 4 source groups | Many smaller sources not adequately addressed | Unpermitted pump engines excluded from the inventory | Inventory considered 23 separate source categories |
| Inventoried VOC emissions from 5 source groups | Many significant sources of VOC not addressed | Truck loading, pneumatic pumps, fugitive emissions were never considered. Standard WY estimates used for pneumatic controllers, dehydrators, and condensate tanks. | |



WRAP Inventory Comparison

| WRAP Phases I and II | Issue identified | Example | Uinta WRAP Phase III |
|---|---|---|--|
| Projections - basin wide emissions were divided by the number of operating wells to determine a well based emission factor. | Did not allow projections to incorporate production decline or new emission control technology. | Emission projections for NEPA projects were based on a single dimensional growth and significantly over estimated potential emissions for individual sources. | Multi dimensional growth projection methodology based on number of spuds, total well count, annual gas production, and annual liquid hydrocarbon production. Inventory reflects dynamic changes in product composition, production rates (production decline and new production) and operating conditions between the basins. This multi dimensional approach allows potential emissions to be more accurately characterized as the basin matures and the number of spuds continues to grow but regional gas production stabilizes or declines. |
| Focused as a NO _x and SO ₂ inventory | VOC inventories used for photo-chemical modeling showed poor alignment with monitored data. | Photo-chemical modeling assigns source specific chemistry to each source category. | Significant changes to the VOC emission profile in each basin. This update allows better source specific chemistry to be implemented for each source category. |
| Snap-shot in time | Was not possible to efficiently update the baseline year/2018 projections. | | Provides for a planned methodology to periodically update information to reflect actual growth rates in spuds, well counts, gas and hydrocarbon production. |

VOC Emissions (TPY)



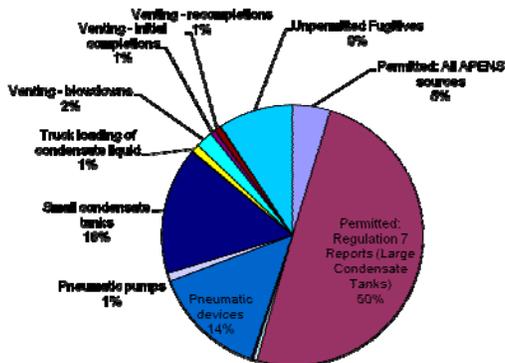
Phase II (Entire State of Utah) - 35,609 tons per year VOC
 Phase III (Uinta Basin) - 70,663 tons per year VOC

1. IPAMS conducted outreach meetings with State permitting authorities
 - a. Provided and overview of the Phase III initiative
 - b. Gathered State input on source categories of concern
 - c. Obtained State inventories for permitted sources
2. Operators were selected for participation within each basin
 - a. State Oil and Gas Commission records used to identify top producing companies
 - b. Selection reviewed to ensure adequate representation for oil, gas and CBM operations
3. A detailed emission source survey was prepared and provided to participating Operators
 - a. An example survey form is available on the WRAP website
4. Survey responses were reviewed for technical accuracy
 - a. Outlier data were verified with the Operator and corrected when necessary

5. Survey responses were processed to develop representative emission factors for each source category
 - a. Weighted averages were applied to develop the emission factors
 - b. Individual operator survey responses are held confidential
6. Emissions were extrapolated to include 100% of Oil and Gas Industry Operations
 - a. Extrapolations were based upon 4 factors
 - i. Number of Spuds (newly drilled wells)
 - ii. Total number of wells within the basin
 - iii. Total natural gas production (conventional and CBM)
 - iv. Total oil and condensate production
 - b. Extrapolation factors were obtained from public Oil and Gas Commission record
7. Inventories were reviewed by basin Operators prior to posting on the WRAP website.

In the D-J Basin (Eastern Colorado) VOC emissions are predominately generated from Condensate Storage Tanks (large and small throughputs)

D-J Basin VOC Emissions by Source Category

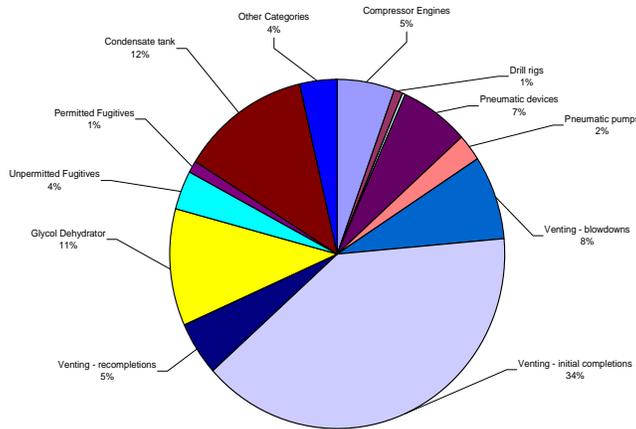




WRAP Phase III Inventory Results

In the Piceance Basin (Western Colorado), well completion flowback and periodic blowdowns are the predominate VOC emission sources

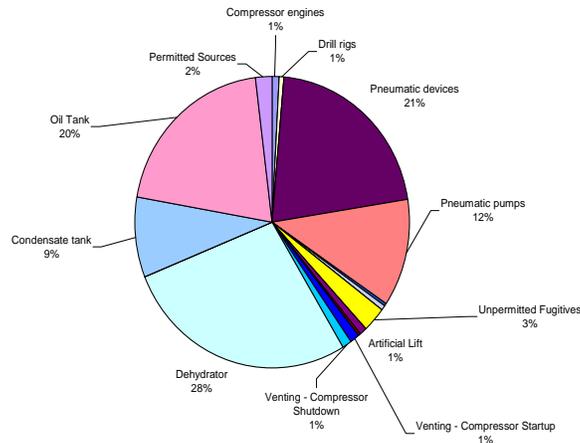
Piceance Basin VOC Emissions by Source Category



WRAP Phase III Inventory Results

In the Uinta Basin (Eastern Utah) glycol dehydrator still vents and pneumatic controls predominate VOC emission sources.

Uinta Basin VOC Emissions by Source Category





WRAP Inventory Conclusions

- Represents a significant improvement over previous Oil & Gas emission inventories
- Includes unpermitted sources and activities which may be significant in some basins
- Documents the diversity of the industry between basins and types of operations (oil, gas, CBM) within basins



Other Sources of Oil & Gas Emission Inventory Data

- Central Regional Air Planning Association (CENRAP)
<http://www.cenrap.org>
 - Includes Texas, Oklahoma, Louisiana, Kansas
 - Emissions are not available from CENRAP
 - State have developed independent inventories
 - There has been limited Operator involvement
 - Roughly similar to the WRAP Phase II effort, likely with similar limitations
- Wyoming 2008 Statewide Emission Inventory
 - Extensive surveys completed by Operators across the state
 - Data currently undergoing QA
 - Contact Brian Bohlmann at WDEQ for more information
 - BBohlm@wyo.gov, (307) 777-6993



Stock Tank Flashing Emissions

- Industry standard practice is to estimate emissions utilizing E&P Tank simulation software
 - Program inputs include a pressurized oil sample fractional analysis
- A 2009 study* completed for the Texas Commission on Environmental Quality (TCEQ) found that the E&P Tank methodology overestimates emissions by a factor of 2.8 when compared to actual emission measurements.
- WRAP III and other inventories probably over estimate tank flashing emissions.

• Upstream Oil and Gas Storage Tank Project Flash Emission Models Evaluation – Final Report.
July 16, 2009



Conclusions

- Oil and Gas is a diverse industry with emissions that vary greatly between basins and types of operations – One size does not fit all
- The WRAP III Oil and Gas emission inventory provides a comprehensive study of emissions across multiple basins within the Rocky Mountain West.
- Stock tank flashing emissions are most probably over estimated in the WRAP III and other inventories



Questions or Comments

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Oil & Gas¹ VOC Emission Control Options

| Emission Control Technology | Applicable Emission Sources | Description of Control | Limitations of Control Technology ³ | Implementation Concerns and Limitations | Variables Impacting Control Cost | Current Use | Cost Effectiveness Factors |
|--|---|---|--|--|--|---|--|
| Flare | VOC emissions from emergency operations, equipment blow downs, tank vapors, dehydration units, etc. | Naturally aspirated pipe flare with auto ignition (spark ignited) pilot | Low flow can lead to inefficient combustion for flare designed for high flows. Low BTU gases (i.e. amine overhead) may have low combustion efficiencies and require use of “assist gas” (also referred to as make-up or power gas) to boost BTU. | Remote, unmanned operations may lead to safety and pilot monitoring concerns for continuous operation. When tying in tanks or other sources that may contain air, proper flame arrestor design must be included to mitigate explosion potential. | Maximum expected flow for flare size, minimum BTU content for operational cost of enrichment gas. | Mainly at gas plants and larger compressor stations and sour gas treating facilities. May also be used at tank batteries. Portable flares may be used for temporary maintenance and gathering system blow down. Spark ignition system often used in lieu of continuous flame pilots to overcome safety concerns of remote operations. | Cost effective for routine operations blow downs or upset/emergency use. |
| Smokeless Combustion Chambers (vapor flares) | VOC emissions from tank flash, dehydration units, pneumatic pumps, etc. | An enclosed combustor with air intake flame arrestor | Heat input capacity per stack height and diameter per manufacturer's information. | Remote, unmanned operations lead to safety and pilot monitoring concerns for continuous operation | Maximum hourly heat input | Controlling tank flash, dehydration units, and pneumatic pumps in Wyoming. | |
| Vapor Recovery Unit | VOC emissions from tank flash and vapors, dehydration still vents, treater vents, etc. | Compressor or venturi used to pressurize gas vapor and inject into the process stream. VRU is considered a part of the process and not an emission control. | Need relatively constant flow to prevent frequent cycling of compressor, | Availability and stability of electricity or gas supply to drive VRU. Frequently cycling of VRU may cause increased downtime of gas fired engines particularly at unmanned operations. Venturi type VRUs require high pressure motive gas. Low pressure gas system needed for discharge. | Wide variation in gas flow, suction pressure and discharge pressure can make designing a properly sized VRU difficult. | Mainly at gas plants and compressor stations, and some tank batteries | Availability of electricity at site as well as sufficient vapors to meet minimum design volume requirements. |

¹ Characterized by dispersed²/remote operations.

² Dispersed – typically small facilities spread out over large areas.

³ Space and weight limitations limit the retrofitting of existing offshore platforms

Oil & Gas¹ VOC Emission Control Options

| Emission Control Technology | Applicable Emission Sources | Description of Control | Limitations of Control Technology ³ | Implementation Concerns and Limitations | Variables Impacting Control Cost | Current Use | Cost Effectiveness Factors |
|---|---------------------------------|---|--|--|--|--|--|
| LDAR - AVO (Auditory, Visual, Olfactory) Inspection | Fugitive components | Audio/Visual/Olfactory inspection of fugitive components for leaks | Small leaks can be missed. | | Low to no cost, depending on recordkeeping requirements. | Common operator inspection at dispersed and remote oil and gas production facilities. Typically documented by exception only (i.e. work order completed when maintenance is required). Required for NSPS, Subpart KKK regulated gas plants for heavy liquid streams. | |
| LDAR - Method 21 | Fugitive components | Inspection of fugitive components for leaks utilizing an organic vapor analyzer under Method 21 | May be difficult at times to determine the exact source of the leak. | Difficult and costly for dispersed oil and gas facilities. Cost and availability of third party contractors (monitoring and valve repair) are an issue in some remote areas (i.e. Alaska and Wyoming). | Number of components, number of facilities, dispersed location travel, hot work permits, etc. | Gas plants subject to NSPS KKK or HAP Major subject to NESHAP, Subpart HH | Increased operating expense for all upstream facilities. potential for little emission reduction |
| LDAR - Infrared Camera | Fugitive components | Inspection of fugitive components for leaks utilizing an infrared camera. | Requires viewing the component from different angles and good weather conditions. No quantification of flow. | Must be trained in proper use of the camera and able to distinguish between water vapor and emissions. | Number of cameras and operators needed to scan dispersed oil and gas facilities. May be reasonable alternative to Method 21 if recordkeeping burden is manageable. | Mainly for equipment integrity purposes. | Costly equipment and operator training required |
| Collection of low pressure gases into fuel supply. | Pneumatic pumps and controllers | Routing of emissions from pneumatic pumps and controllers that use natural gas to a collection line for fuel supply. Process, not emission control. | | Sufficient pressure must be available to enter the closed loop system. If routing to a fuel system, may have more emissions than needed for fuel. | | Dispersed oil and gas production facilities with pneumatic pumps and controllers | |

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Oil & Gas¹ VOC Emission Control Options

| Emission Control Technology | Applicable Emission Sources | Description of Control | Limitations of Control Technology ³ | Implementation Concerns and Limitations | Variables Impacting Control Cost | Current Use | Cost Effectiveness Factors |
|--|---|--|--|--|---|---|----------------------------|
| Solar Pumps | Replace small pneumatic pumps (<100 gallons/day) | Using solar pumps in place of pneumatic pumps that use natural gas | Only available for pumps that circulate <100 gallons/day. Sold as a package. | Solar panels are often stolen. | | Chemical and methanol pumps at dispersed oil and gas production facilities. | |
| Installation of air compression to replace natural gas driven (i.e. pressure drop) equipment | Instruments, controls, starting air and pneumatic pump services | Provide compressed air to drive pressure drop driven equipment to replace natural gas that is vented to atmosphere | Requires availability of electricity to be reliable and affordable. | | Certain weather conditions may require air dehydrators for instrument systems to prevent condensate blocking the signal. High cost of manpower for frequent inspection. | Gas plants and some central tank batteries and compressor stations. | |
| Low Bleed/No Bleed Controllers | controllers | Install, replace, or retrofit low bleed/no bleed controllers in place of high bleed controllers | | Some old high bleed controllers can not be retrofitted and would have to be replaced | | Controllers at dispersed oil and gas production facilities and gas plants | |
| Minimize manual blow down/venting to atmosphere during maintenance/operational events. | Depressurizing equipment for maintenance. Response to vapor locked equipment (i.e. pumps or de-liquefying well bore), | Have personnel on site during the blow down/venting, operator training, etc. to ensure that minimal gas venting occurs | | Over restrictive procedures may cause reoccurrence (vapor locked equipment) or safety concerns (depressurizing equipment). | Distance between facilities. | | |

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Oil & Gas¹ VOC Emission Control Options

| Emission Control Technology | Applicable Emission Sources | Description of Control | Limitations of Control Technology ³ | Implementation Concerns and Limitations | Variables Impacting Control Cost | Current Use | Cost Effectiveness Factors |
|---|---|---|---|--|--|--|----------------------------|
| Minimize upset or emergency blow down/venting to atmosphere. Upsets include loss of electricity, loss of distribution point without ability to shut off source, or process event. | Natural gas released to atmosphere due to emergency event or upset (typically a third party event out of the operators control). | Prior contingency planning for predictable events. Communication with third parties to determine duration, thus select option to minimize emissions. | Operator does not have control of the event causing the blow down/venting. Cooperation of third parties required. May have contractual limitations. | Source of natural gas is typically a gathering system with dispersed well locations. Significant time is required to shut each well in. Stopping the flow in many wells may require atmospheric venting to de-liquefy the well to start flow (resolve vapor lock). | | Venting or blow downs during an emergency or upset situation is a common occurrence in upstream oil and gas operations, venting is usually through a vent stack or relief valve system | |
| Glycol Dehydrator Rich Glycol Flash Separator | Water saturated glycol in dehy. must drop the pressure from contactor pres. to near atmospheric pressure before the water can be cooked off in the still. | A flash tank can separate the gas from the glycol for use as fuel or to be returned to the process. | Requires a low pressure gas collection system or use, such as fuel system, low pressure gathering system, vapor recovery compressor, flare, etc. | If use or system is insufficient for gas volume generated, then gas must be vented | | | |
| Secondary Separator for liquid stream | High pressure production separators where a low pressure gas handling system is available. | Condensate/crude oil from a high pressure prod. separator is flashed at a lower pressure, so flash gas can be collected for use or return to the process. | Requires a low pressure gas collection system or use, such as fuel system, low pressure gathering system, vapor recovery compressor, flare, etc. | If use or system is insufficient for gas volume generated, then gas must be vented | Process system and stability of gas volume | Primarily fuel systems and vapor recovery compressors. | |

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Oil & Gas¹ VOC Emission Control Options

| Emission Control Technology | Applicable Emission Sources | Description of Control | Limitations of Control Technology ³ | Implementation Concerns and Limitations | Variables Impacting Control Cost | Current Use | Cost Effectiveness Factors |
|--|---|---|--|---|--|---------------------------|----------------------------|
| Green Completions (i.e. reduction of natural gas vented to the atmosphere during well completion operations) | Venting and flaring during completions (flow back of hydraulic fracturing fluids) | After hydraulic fracturing the much of the injected fluids must “flow back” out of the well. Historic operations produce flow back fluids into an open pit until the gas/oil is sellable. Green completions use specially designed sand traps and 3-phase separators to capture the natural gas for sale quicker than normal production equipment allows. | Sand traps and separators must be designed to handle the highly erosive conditions associated with producing high volume, high pressure completion fluids. Produced gas must meet the gathering system specifications before natural gas can be delivered into the pipeline. Certain well completion activities (i.e. drilling out frac. plugs and running production tubing) must be completed before space is available for the equipment required for “green completions”, requiring well fluids to be routed to the pit during these operations. | Gathering system piping must be run to the well before the well test is complete and production volumes are known. Gas pressure is typically below pipeline pressure during initial flow back operations. Pipeline pressure may limit how soon natural gas can be delivered to the pipeline. Hydrate formation – Hydrates are a solid ice/hydrocarbon mixture that forms because of high pressure and/or low temperature. Hydrates can form for many reasons including cold weather, pressure reduction from high pressure reservoirs, and excessive moisture due to dehydration equipment not being available. | Location of well – Green completions are most economical during infield drilling projects (drilling wells to reduce “well spacing” to allow remaining reserves to be produced in an older reservoir), due to gather system availability. Gathering system will not be available before well testing on wild cat wells or reservoir boundary exploration wells. | See attached issue paper. | See attached issue paper. |

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“Green Completions” for Natural Gas Issue Paper

Use of Green Completion techniques can recover and preserve valuable energy resources while protecting the environment. Depending on the field/well characteristics, it may also be economically positive for the operator to use these techniques. However, application of Green Completion techniques are limited due to technical barriers in many instances and must be well planned and designed where used.

Process Description:

Flaring or venting wells, against atmospheric pressure, for clean-up following completion and fracture stimulation is the traditional practice/methodology. This approach results in the least back-pressure on the well, the highest flow rates and velocity up the well-bore, and promotes better flow back of the fracture fluids and clean-up of the formation near the well-bore. Adequate clean-up of the near well formation is critical to prevent formation damage and allow optimum long-term production from the well.

Green Completions is a departure from this traditional practice where the well clean-up is done through specialty surface separation equipment and part of the gas and condensate, which would have been flared (or gas vented), is recovered for sales. Gas recovered during Green Completions operations is routed to a sales gas or gathering line which increases the back pressure on the well by whatever pressure the line is operating at along with the additional pressure drop caused by the surface equipment. This results in more back-pressure on the well, lowers the flow rates and velocity up the well-bore, and may not allow adequate clean-up of the formation near the well-bore. Due to this affect, the applicability of Green Completions techniques to a particular area/field needs to be carefully considered and adequate clean-up with no damage to the formation or long term well productivity demonstrated.

Technical and Operational Limitations – There are many situations that limit the ability to utilize green completions for reducing emissions in natural gas production. Some of them include:

- Sand traps and three phase separators must be designed and manufactured to endure the highly erosive conditions associated with producing high volume, high pressure fluids containing sand. A one-size-fits all or off-the-shelf design philosophy can lead to operational problems/delays, short equipment life, and/or safety concerns like the erosion created washout pictured below.

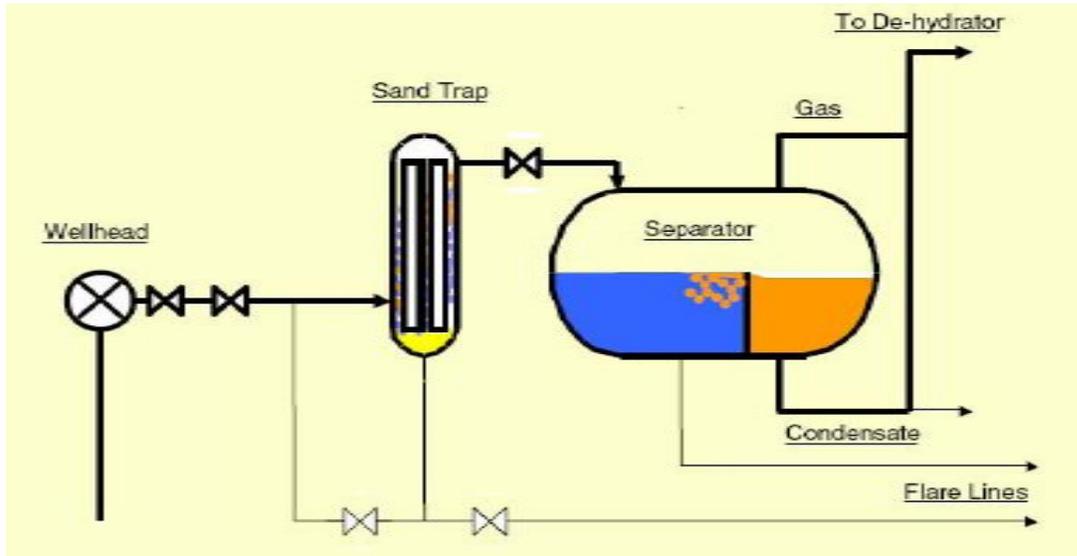


EPA Natural Gas Star Website

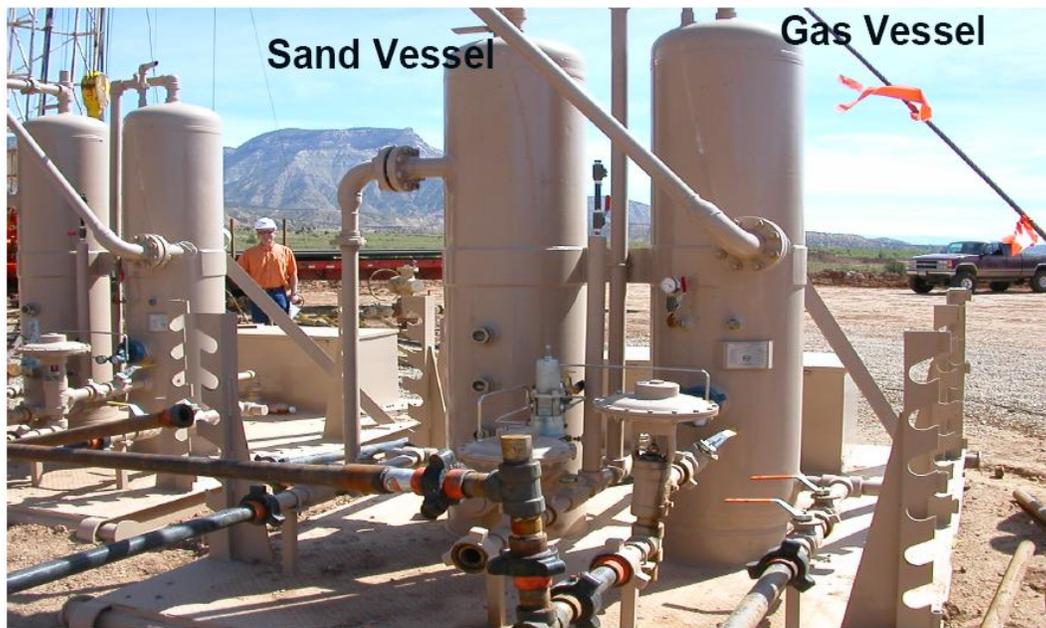
- In order to deliver gas to the sales pipeline or gathering system, gas must meet quality specifications. Many well stimulations are energized with nitrogen or carbon dioxide to assist the flow back and cleanup. Since these gases come back with the well production, gas cannot be routed to the pipeline.
- A pipeline must be laid to the well in advance of the completion, which results in a capital outlay risk for the pipeline company since the results of the well are not fully understood until the completion is performed. It is difficult for a pipeline company to size the pipeline and spend capital in advance without fully understanding the production potential of the well.
- Gas gathering pipelines are not in close proximity to all drilling locations. Wild cat wells are drilled in areas where O&G reserves have not been proven or developed. Gas gathering lines must be run many miles to the nearest gas transmission line or consumer, which will not be done until sufficient gas reserves are proven to make the pipeline economical. Reservoir boundary exploration wells seek to extend the production area outside the area of existing gathering system infrastructure. Again, the well must be completed and tested to have reasonable confidence that running a pipeline to the well will be economical. Typically, only infield drilling projects (inside known production areas, often to reduce well spacing to completely produce remaining reserves) have sufficient certainty of production volumes and close availability of gathering system to make green completions viable.
- When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure. Any time this occurs, the well will be flared or vented until enough pressure is available to send gas to the pipeline. This allows clean up of the wellbore and is critical to minimize the potential for formation damage. Once a fracture stimulation is pumped, flowback and clean-up must proceed regardless of sufficient pressure to enter pipeline system.

Therefore, green completions should be encouraged where possible, but understood that they are only feasible in certain situations.

Attachment A



Green Completion Process Schematic



Typical Green Completion Surface Equipment

Thief Hatch Work Practices

Research indicates there are no API or ASTM standards that address specific inspection and maintenance practices for thief hatches. However, API RP 12R may come the closest to being a technical reference for thief hatch work and maintenance practices.

From what has been found in engineering and vendor literature, four general work practices for thief hatches on tanks controlled for emissions can be listed as the following:

- Operator needs to select the appropriate gasket material based on fluid composition of the storage tank and weather conditions.
- Inspect in a regularly scheduled preventive maintenance (PM) program. Annual inspection of thief hatch seal is the most common suggestion although some sites inspect on a more or less frequent basis. When applicable, inspection should occur in conjunction with thieving or gauging tank to minimize additional periods of an open hatch.
- Replace gasket within 30 days if inspection shows evidence of deterioration or cracking. In the interim, grease the gasket if deterioration or leakage is found to improve seal while waiting on replacement gasket.
- Keep thief hatch in good working order. Verify thief hatch seal is capable of holding pressure in excess of the pressure/vacuum relief device (PRD). The thief hatch spring or weight relief set point should be greater than the set point on the PRD, and both the thief hatch and PRD set points need to be greater than the back pressure set point of the control system.

Standard practice is to implement preventative maintenance during routine inspections including cleaning surfaces and seals, greasing the gasket to improve the seal, and repairing or replacing springs. If a leaking gasket is discovered during inspection, the temporary initial fix is to grease the gasket to improve the seal. If unable to verify a good seal, then replace the gasket within 30 days unless a custom gasket must be fabricated for replacement (e.g. older storage tanks).

Gasket selection

Elastomers nitrile and neoprene appear to be the “standard” gasket materials for oil storage, with Fluoroelastomers for H₂S service. Thermoplastic seals are not commonly used, but can be. There are various grades of seals within each material category for selection in the proper fluid composition and temperature environment the gasket will be used.

Any rulemaking should not mandate specific gasket materials but rather specify gasket material appropriate for type of chemical service and operating conditions including weather.

References

www.jayco.org

www.enardo.com

API RP 12R

Oil and Gas Flaring and Issues with 40 CFR §60.18

Introduction

For emissions control in oil and gas production operations, flare design and purpose is varied. Oil and gas flares generally serve one or a combination of several different purposes. Uses include continuous control for process operations, standby for backup to primary control systems, and blowdowns for maintenance startup shutdown (MSS) events or emergency upset events. Each use requires a flare design that is fit for purpose for optimum operational efficiency.

In many cases, especially at newer, larger natural gas compressor stations and gas processing plants, flares are designed to meet 40 CFR §60.18 requirements. Even if there is no applicable NSPS Subpart, permits often refer to §60.18 for flare design. However, depending on operating conditions, additional operating efficiencies would be possible if these sites were not restricted to the continuous pilot and Vmax provisions of §60.18.

For situations or sites that don't presently require a §60.18 compliant flare, flares may not operate with a continuous 24/7 pilot or they may have "sonic" high velocity flare tips that exceed the Vmax of 400 ft/sec in §60.18. In either case, if properly designed, these flares can meet or exceed the control efficiencies of a §60.18 compliant flare. With new NSPS rules that increase the scope of regulated facilities, the default reference to §60.18 for flare design will be impractical and detrimental to many oil and gas sites. Allowances need to be made for alternative flare designs.

Attached to this document is a short white paper from John Zink, a large, well known vendor for flare systems as well as the test study referenced in the Zink paper. The paper argues the value of allowing sonic flare designs for oil and gas applications where high BTU gas will be flared. Sonic flares have destruction efficiencies that exceed conventional flares and are used worldwide in the oil and gas industry. However, due to NSPS limitations from §60.18, efficient sonic flare designs are in limited use in the U. S. You will note that at the end of the Zink paper is a table of recent test results witnessed by the TCEQ in October, 2010 in which all but one of 8 tests achieved 100% destruction efficiency. The one lone test achieved a destruction efficiency of > 99%.

Below is a discussion for making allowances for flares that do not have continuous pilots (24 hours a day/7 days a week).

Flare Pilots

There are a number of operating scenarios where use of a continuous 24/7 pilot is not desirable, and is inefficient. In these cases, pilot fuel gas may be in limited supply or not available, or flaring events are so infrequent, that use of continuous pilot gas is wasteful and creates unnecessary emissions. Unnecessary wear also occurs to the flare tip when a pilot is needlessly lit continuously. Listed below are a few examples of flare uses where these conditions would apply:

Emergency Only/Planned MSS Flare: Flare is designed for control of emergency upsets only, planned MSS events only or both. No continuous process streams are routed to the flare. Use of flare is intermittent with long periods between flaring events that could be less than once per year. A separate conventional flare system may exist to handle process streams.

Low Pressure Backup Flare: Flare is designed for low pressure, low volume burning and may serve as a backup to a primary emissions control or recycling device such as a vapor recovery unit (VRU). Use is intermittent with potentially long periods of time in between uses (e.g., during periods of maintenance or downtime to the primary control or recycling system).

Intermittent Low Pressure Process Control Flare: Flare is designed for controlling intermittent emission periods such as during truck loading when operating conditions warrant emissions control of vapors. Truck loading is a manual operation, so emissions are generated manually, and flare is used only as needed when a truck pulls up to be loaded. This type of flare may have a dual use as a Low Pressure Backup Flare.

Storage Tank Vapor Flare¹: Another low pressure flare that burns storage tank vapors. Pilot gas may not be available due to insufficient produced gas volume associated with oil production and a gas delivery system is unavailable. Purchased gas may have to be used for ignition gas as a substitute for produced gas.

In cases where a 24/7 pilot is not used, it is recognized that a good pilot flame is necessary to ensure combustion efficiency during flaring events. Consequently, a good flare design will have a stream detection system tied to an auto ignition system so that the pilot lights as needed to combust the waste stream going to flare. When the waste stream stops, the pilot shuts off. In effect, the pilot is continuously lit, but only during the flare event itself.

In cases where pilot gas is not available, or use of a separate pilot gas stream is undesirable due to intermittent flaring events, low pressure flare designs exist where the flare stream itself operates as its own pilot so that a separate pilot fuel stream is unnecessary. As an example, below is a technical description from John Zink of how this type of flare might work. Other vendors should have equivalent designs.

- **Model EFF-ZFF Flaring System:** The ZFF is a gas-assisted, pre-mix flare for smokeless burning of waste gas. The flare is highly efficient for the combustion of small waste gas flows; the ZFF is capable of combusting hydrocarbons, low BTU, and toxic gases. An additional feature of the ZFF is that the flare acts as its own pilot. The pre-mix feature allows the ZFF to be utilized in applications with very low available pressure.
- **Purge Gas Reduction:** The ZFF induces a vacuum in the knockout drum when initially being ignited. This reduces the need for venting purge gas continuously through the system, which makes the ZFF more economic during normal operations because gas will not be continuously vented to the atmosphere.
- **Purge Gas:** During operations the ZFF will utilize 1000 scfh of pilot gas.
- **Ignition Gas:** During ignition the ZFF will utilize 250 scfh of ignition gas.
- **Purge Gas Seal:** Due to the aspirating mixer drawing a vacuum on the waste line it is not necessary to have a seal on the flaring system. This is ideal for installing a flare system on a VRU system; The VRU system generally operates at 3-6 ounces.
- **Non-continuous Ignition/ Purge Gas Flare:** The ZFF is not a conventional flare. The flare neither requires continuous purge gas or a seal mechanism to ensure that air does not become entrained in the system. The lack of continuous purge gas or a seal mechanism is possible because of the pre-mix feature. Also, the ZFF does not have continuous ignition, this is possible because the flare acts as its own pilot.
- **ZFF Control Panel Logic:** Once the vapor pressure reaches 5 ounces, and the control valve will send a signal to the control panel to ignite the ZFF. Then the panel will send a signal to the fuel gas control valves to allow pilot gas and ignition gas to the flare. The igniter will continue sparking approximately every ten seconds until the thermocouple

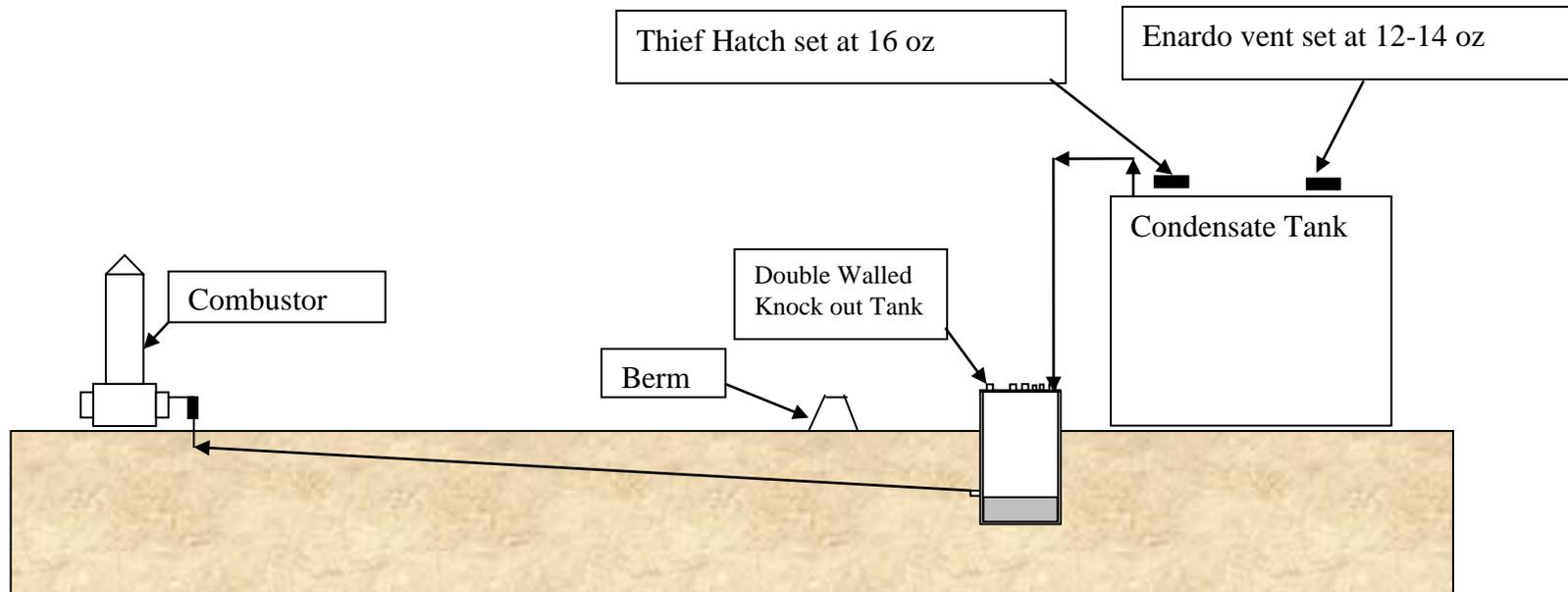
senses it is lit. Once the pilot is lit, the control panel will send a signal to close the ignition gas control valve. The flare will operate until the control valve senses that the system pressure is below 5 ounces.

While the above describes the operation for a low pressure vapor flare application, the control panel logic described in the last paragraph can be applied to more conventional flare designs as well. Intermittent flare streams can be detected by sensors that trigger lighting of the pilot.

¹ To avoid confusion, the flare described here refers to a conventional flare with a flare tip at the end of a vertical stack designed to promote efficient burning. **Another type of combustion unit known within industry as a vapor combustor to control tank emissions is sometimes misnamed as an enclosed flare.** This is not really a flare in the conventional sense. Vapor combustors generally consist of an enclosure/stack, a burner array (typically a ring burner), a pilot (some have dual pilots), a backflash preventer, and a thermal well for temperature monitoring that is mostly tied into the automation system for data archiving and alarms when the combustor fails for any number of reasons. A fair number of these units have a "hot point" element (a metal probe with a high heat holding capacity) which provides "re-light" for momentary flame outages. A much smaller number have UV fire detection and electronic re-light capabilities. These units are generally naturally aspirated with no air or gas assist. Many of these units have been "stack tested" in the Jonah/Pinedale area of Wyoming and have DRE's north of 98-99%. Attachment 1 provides a diagram showing how combustor systems are typically designed.

This rulemaking needs to allow for the use of combustors without reference §60.18.

Pressure Drop Profile for Combustor System Example Design



System Description:

1. *Maximum* flow conditions are detailed in adjacent text box. 400 BBL is sometimes seen on new 5 pad wells, but normal production is less than 100 BBL/day.
2. All lines from the condensate tank to the combustor are 4" pipe.
3. The tank Enardo is set at 12-14 oz. The tank Thief Hatch is set at 16 oz.
4. The knock out tank prevents any liquid head in the underground line
5. The combustor is generally set with 300 feet of the tank.
6. Additional pressure drop – other than piping associated with the combustor system, there is an additional pressure drop at the combustor consisting of an orifice, burner and flash back arrestor, with the majority of the drop across the orifice. If excessive pressure is encountered on the orifice, the orifice size is increased to eliminate any venting of the Enadros.

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February 23, 2011

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via e-mail

**Ref.: Review of Federal Air Regulations for the Oil and Natural Gas Sector
40 CFR Part 60, Subparts KKK and LLL
40 CFR Part 63, Subparts HH and HHH**

The American Petroleum Institute (API) is a national trade association with over 400 member companies that are involved with all aspects of the oil and natural gas industry. We are writing to provide commentary on issues pertaining to the pending review by the U.S. Environmental Protection Agency (EPA) of federal air regulations for the Oil and Natural Gas Sector, specifically:

- 40 CFR Part 60 Subpart KKK, Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants,
- 40 CFR Part 60 Subpart LLL, Standards of Performance for Onshore Natural Gas Processing: SO₂ Emissions,
- 40 CFR Part 63 Subpart HH, National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities, and
- 40 CFR Part 63 Subpart HHH, National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities.

The attached comments are provided to assist EPA in understanding issues that are critical to the operations of oil and natural gas facilities that would be potentially affected by the pending rulemaking.

We appreciate your consideration of our comments. If you have any questions, please contact me at 202-682-8319 or toddm@api.org.

Sincerely,

/s/ Matthew Todd

Matthew Todd



Contents

| | |
|---|----|
| 1. WORKER SAFETY MUST BE CONSIDERED | 2 |
| 2. THE FLOORS DO NOT NEED TO BE FIXED | 2 |
| 2.1. Adjustments to Floors are Limited by Statute..... | 2 |
| 2.2. One ton/year Threshold for Benzene is an Effective Standard | 3 |
| 3. GREEN COMPLETIONS HAVE LIMITED FEASIBILITY | 3 |
| 3.1. Background on Well Completion, Flow-Back, and Clean-up | 3 |
| 3.2. Conditions Necessary for Green Completions | 4 |
| 4. THE EFFECTIVE DATE MUST BE REASONABLE | 6 |
| 4.1. Allow One Year for Equipment Supplies to Meet Demand..... | 6 |
| 4.2. NSPS Compliance Should be Triggered by the Final Rule, Not the Proposed Rule | 7 |
| 5. A WELL WORKOVER DOES NOT CONSTITUTE A NSPS MODIFICATION | 7 |
| 6. THIEF HATCH REQUIREMENTS APPLY ONLY TO CONTROLLED TANKS | 8 |
| 7. FLARE REQUIREMENTS NEED TO BE CLARIFIED..... | 8 |
| 7.1. Flare Continuous Pilots and Vmax Limits | 8 |
| 7.2. Enclosed Combustors Need To Be Distinguished From Flares | 9 |
| 7.3. Provisions are Needed for Approval of New Control Technologies | 9 |
| 8. NSPS RULES SHOULD RETAIN THE VOC 10% EXEMPTION | 10 |
| 9. INCREASED REGULATION WILL DECREASE OIL AND GAS PRODUCTION | 10 |
| 10. ALLOW FLEXIBILITY FOR WELL-BORE DELIQUIFICATION CONTROLS..... | 11 |
| 10.1. Background on Well-bore Deliquification (liquids unloading)..... | 12 |
| 10.2. Background on Plunger Lift | 15 |
| 10.3. Industry Research on Well-Bore Deliquification | 16 |



1. WORKER SAFETY MUST BE CONSIDERED

EPA needs to consider worker safety in this rulemaking. These requirements will mandate control technologies and practices be applied to equipment and/or activities that have never before been regulated and therefore the risk of performing this work has not been fully evaluated. EPA needs to avoid instances where the requirements contained in this rule expose workers unnecessarily to dangers including but not limited to fire and explosion, toxic atmospheres, falling, equipment rupture, and rotating equipment injury.

2. THE FLOORS DO NOT NEED TO BE FIXED

EPA has indicated that it intends to “fix the floors” for some units in the Subpart HH standards and, in particular, the 1 ton/year (or 0.9 megagram per year) of benzene exemption threshold. When EPA says “floor” we assume that means the Clean Air Act requirement where the MACT control level must set at least at the average of the best 12% performing sources in that source category. However, these standards have been in effect for some years and never challenged. The values do not need to be “fixed”. Indeed, as explained below, EPA’s authority under the current review is prescribed by the terms of § 112(d)(6).

2.1. Adjustments to Floors are Limited by Statute

Once EPA establishes a MACT standard for a particular source category, the Agency has the authority (and the obligation) under § 112(d)(6) to “review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years.” In other words, EPA does not have unfettered discretion to revisit a prior MACT determination once that determination has been issued. Rather, EPA may revise a prior determination only “as necessary” according to explicit statutory criteria.

In 2006, NRDC filed a multi-faceted challenge to EPA’s final residual risk and § 112(d)(6) determinations for the Hazardous Organic NESHAP (“HON”) in the D.C. Circuit. Among numerous other claims, NRDC argued that EPA is required to make a new MACT determination each time an existing standard is reviewed pursuant to § 112(d)(6). The court quickly dispensed with this argument, concluding that “the words “review and revise as necessary” [cannot] be construed reasonably as imposing any such obligation.” *NRDC v. EPA*, 529 F.3d 1077, 1083 (D.C. Cir. 2008).

More specifically, NRDC also asserted that EPA was obligated under § 112(d)(6) to re-determine MACT for certain source types because cost had been considered in



determining the MACT “floor” in the original HON rule. The D.C. Circuit disagreed, reasoning that “EPA squarely found that there were no “significant developments in practices, processes and control technologies” and “[s]ince that is the core requirement of subsection 112(d)(6) and EPA’s finding satisfies that requirement, it is irrelevant whether EPA considered costs in arriving at the initial MACT floor and reaffirming that standard in the residual risk rulemaking.” *Id.* at 1084.

In short, this holding clearly establishes EPA is not required to redetermine MACT under § 112(d)(6) and that EPA cannot be forced pursuant to § 112(d)(6) to revise an existing MACT determination in order to “correct” an alleged deficiency in that determination based on subsequent judicial decisions.

2.2. One ton/year Threshold for Benzene is an Effective Standard

Lastly, the 1 ton/year (or 0.9 megagram per year) of benzene exemption threshold should be considered an “emission standard.” An exemption tied to an emission has the advantage of encouraging the over-control of affected sources (validated by State NSR permits so that the PTE limitation is federally enforceable) to avoid the complexities and continuous monitoring burden of NESHAP regulations. This practice was recognized in the January 3, 2007 proposed revision of the Once-In-Always-In policy. Thus, even at major sources, the use of emission limits to exempt affected sources from regulation under NESHAP is beneficial to the environment.

3. GREEN COMPLETIONS HAVE LIMITED FEASIBILITY

API wishes to reiterate the conditions and criteria that enable “green completions” to be used when completing or re-completing an oil and/or gas well. As context, we are including a short description of well flow-back and clean-up.

3.1. Background on Well Completion, Flow-Back, and Clean-up

As EPA is aware, most oil and gas development in the onshore US is in non-traditional reservoirs, such as shales, coal-beds, and tight sands, and the majority of wells require fracture stimulation to enable production. Hydraulic fracturing is the most common stimulation technique and requires pumping a fluid (such as gelled water or inert gas) carrying a proppent (such as sand) into the well-bore at a high flow rate and pressure to enhance fractures in the reservoir rock which are then propped open by the proppent material and provide a flow path for oil and gas to flow to the low pressure zone created by a well-bore.

After stimulation, a well must be “flowed back” at a rate sufficient to lift fluids and solids in the well-bore to the surface. Wells must be adequately cleaned-up to enable

production and avoid long term reservoir damage caused by foreign fluids and accumulated solids which stay in the formation. The ability of a well to flow back at a pressure and rate sufficient to lift the fluids and adequately clean-up the formation is dictated by the reservoir pressure/energy, the reservoir flow potential, the depth of the well, and the physical characteristics of the fracture fluids.

A common well clean-up technique is a clean-out where a high pressure gas is injected into the wellbore to jet debris from the wellbore and transport the solids to surface along with the gas. This technique is very common and works best with homogenous gases like air, CO₂, nitrogen, or methane. Gases with a wide range of components (like many natural gases) are less effective than homogenous gases due to condensation effects.

The flow rate up a well bore is dependent on the reservoir pressure being higher than the sum of flowing friction losses up the well-bore, the weight of any vertical column of fluid in the well bore, surface equipment and piping pressure losses, and any collection system/flow-line back-pressure. When green completions are used, this resistance to flow is much higher than the resistance observed in traditional completions (that flow against atmospheric pressure rather than collection system/flow-line pressure), which can reduce the flow rate to values inadequate to properly lift liquids and solids from the wellbore.

In the initial stages of a completion flow-back most of the flow is comprised of introduced fluids and proppent with little formation fluids or gas. As a well cleans-up, more formation fluid and gas enters the well-bore and the fluid column in the well-bore becomes “lighter” with less back-pressure on the formation.

3.2. Conditions Necessary for Green Completions

Green completions are the use of surface equipment, often purpose-designed and operated, to separate the introduced fluids, proppent, hydrocarbon liquids, and gas – with the gas routed to a collection line for sales and the hydrocarbon liquids routed to on-site storage for sales. To enable the use of green completion techniques a number of conditions/criteria must be met:

- 3.2.1. Availability of specialized equipment and personnel. Adequate equipment and qualified personnel must be in-place or available to allow the safe implementation of green completion techniques. Often, this will require that sufficient “purpose designed and constructed” surface equipment be available. Equipment and procedures for green completions must be able to safely handle the erosive forces of high rate flow with abrasive proppent without cutting through the surface piping and/or equipment.
- 3.2.2. Not feasible with air, CO₂, or nitrogen. The mixture of gases produced from the wellbore must be such that they can meet gathering-system quality requirements with simple mechanical separation equipment. When air, CO₂, or nitrogen is used in well operations, these gases would require extensive chemical and/or thermodynamic

processes to extract natural gas from the gas stream. This equipment is inappropriate and unsafe for wellsite use, and any of the processes that cannot be done without using these gases must be excluded from any green-completion requirement.

Meeting the gas composition specifications to enable sales is problematic where an inert gas or air is used to “jet” a well for clean-up, where an inert gas, such as CO₂ or N₂ is used to “energize” a hydraulic fracture, and where an inert gas, such as CO₂, is used as the stimulation fluid. In all of these cases, flow-back gas cannot be routed to a collection system for sales until it meets the system operator’s composition specifications and green completions is not an option.

- 3.2.3. Not viable for low pressure reservoirs. The reservoir must have sufficient flow potential and energy to lift fluids and adequately clean-up against the back pressure imposed by flowing to a gas collection line for sales. If the reservoir pressure/energy is too low to lift fluids and overcome the collection line back-pressure the well will not flow to a pipeline. Often in the early stages of a well clean-up, the flow-back is predominantly fracture fluid and the well will not be able to flow to a pipeline until it has partially cleaned-up. For some low pressure and depleted reservoirs green completions is not an available option.
- 3.2.4. Not viable unless collection infrastructure is in place. There must be a collection line in place to receive the flow-back gas. This is only common in in-fill situations where the risk of a dry hole is low and gas collection infrastructure is close. Exploration wells, flank extension wells, and wells having a high risk of being dry typically will not have a flow line in place to receive the gas.

If all of these conditions are met, then green completions may be a valid practice for a particular well. If any of these conditions cannot be overcome, then green completions cannot be used on a particular well.

API is aware that the addition of compression between the outlet of the surface green completion separation equipment and the gas pipeline has been tried in the past to lower back pressure on a well and broaden the pressure range where green completions can be accomplished. In fact, several of our member companies were the operators that piloted these trials – some for multiple years. Due to the unstable flow-back rates and pressures during a well clean-up coupled with compressor’s sensitivity to suction pressure and rate changes these pilots have not been successful yet. API does not consider the addition of compression to a green completion operation to be proven technology and EPA should not consider it as proven or available technology.

In crafting a regulatory program addressing well completions and flow-back, EPA must consider these physical and operational facts and provide the necessary regulatory clarity/ certainty and flexibility to enable companies to continue developing US oil and gas resources while complying with any regulation promulgated.



4. THE EFFECTIVE DATE MUST BE REASONABLE

4.1. Allow One Year for Equipment Supplies to Meet Demand

An appropriate effective date will lessen the production and cost impacts caused by competition for limited supplies of control equipment. API anticipates that compliance with this proposal will place heavy demands on limited supplies of control equipment and this will have significant negative consequences on production and drive up the cost of compliance. The EPA must avoid mandating control requirements before equipment supplies can meet demand.

Emission control equipment is in limited supply because many of the proposal's performance requirements will impact source types that have never before been regulated. It will take time for the supply of this equipment to match demand since the equipment is specialized and only available from a limited number of suppliers. If the EPA does not establish an appropriate effective date for controls, competition for limited supplies of control equipment will drive up cost and will negatively impact production.

As an example, if the proposal contained a requirement for all of industry to begin "green completing" their wells where practical (see "Green Completions" Section) at a time when specialized flowback equipment is in short supply, the result would be a bottleneck, affecting the industry's ability to bring on new production. The economic consequences of this will be significant. Further, in some cases, fluid-caused damage to the reservoir will occur if a company was delayed in flowing back wells because equipment wasn't available. This would result in permanent impacts to production and reserves.

Similarly, when demand for vent and fugitive emission control equipment outpaces supply, a producer's ability to begin operation of new production facilities will be impacted.

To avoid the negative consequences stemming from competition for control equipment, EPA should consider making control requirements effective at least one year after rule promulgation for equipment installed after the proposal date. Relocated equipment should not be considered a new source subject to the rule.

Emission control requirements should also become effective at least one year after rule promulgation for activities such as well flowback or well venting that aren't directly related to the installation of production equipment.

It is anticipated that equipment suppliers will need at least one year to ramp up production to meet demand.



4.2. NSPS Compliance Should be Triggered by the Final Rule, Not the Proposed Rule

Under the NSPS program, typically, any affected unit constructed, modified or reconstructed after the rule proposal date must comply with the NSPS rule. This approach will not work for many oil and gas operations because of the short-term or temporary nature of the operation. For example, if the upcoming O&G NSPS rule includes requirements to control well completion operations, it is unreasonable to require all well-completion jobs carried out between rule proposal date and the final rule date to adopt the control measures in the proposed rule. For the completion jobs performed shortly after the rule is proposed, it is most likely they will be completed or terminated before the final rule takes effect. In addition, the final rule may contain a vastly different requirement than the proposal. To expect and require such well completion projects to comply with the rule while the rule takes effect after the project is concluded is extremely unreasonable. Therefore, EPA should use the final rule effective date as the rule applicability threshold date.

5. A WELL WORKOVER DOES NOT CONSTITUTE A NSPS MODIFICATION

Because the O&G industry's operations are driven by the geology of the reservoirs that they are harvesting, impacts of NSPS and NESHAP General Provisions and definitions can have unintended consequences. The common interpretation of "modification" may be an example of this. EPA has already recognized at least part of this issue by stating that a well workover does not constitute a modification of a facility, even though it will increase the production (O&G flow) of the well. API sees this as a valid approach, since the purpose of a workover is to regain at least some of the original production flow of the well that has been lost to reservoir depletion.

API would like to assure that this approach is extended to other equipment both at the facility and downstream in the gathering system. The actual emissions of equipment (tank, dehydrator, compressor, etc.) decreases as the production flow depletes and correspondingly increases when the production rises due to a workover. API believes that a modification as defined in the NSPS is not triggered when the flow from the well and in the equipment downstream of the well increases as the result of well workover. API also believes that a modification as defined in NSPS is not triggered for equipment in a gathering system when there is an increase of flow from the workover of a well, or even the addition of new wells. Gathering system equipment should be subject to the rule based on the date of construction or the definition of reconstruction.



6. THIEF HATCH REQUIREMENTS APPLY ONLY TO CONTROLLED TANKS

In a short one page brief submitted to EPA in early December, a strawman was provided for developing work practice requirements to maintain thief hatches on storage tanks being controlled for emissions. Four key items were presented for consideration. These were: gasket selection, inspection schedule, replacement/repair of gasket material, and the proper pressure seal of the hatch in relation to the tank PRD or Enardo valve. The key limitation in recommending these practices was to apply them at tanks being controlled for emissions only. Maintaining a good seal at the thief hatch improves efficiency of the control device connected to the tank vent

Applying these practices to uncontrolled tanks will have no impact on reducing emissions and will only increase maintenance costs. If a tank's vent is uncontrolled, no control efficiency is gained by mandating work practices for the thief hatch. Depending on the condition of the hatch, the full stream of uncontrolled emissions will either exit through the tank vent or partial emissions may exit through the thief hatch instead of the vent. In either case, all tank emissions will be vented to atmosphere. No vapors are being captured, condensed, or burned to limit emissions.

7. FLARE REQUIREMENTS NEED TO BE CLARIFIED

7.1. Flare Continuous Pilots and Vmax Limits

Among the several papers provided to EPA in December was a short white paper discussing the various types of flares and their use in the oil and gas industry. Included as an attachment, was a study by John Zink for the TCEQ that demonstrates the efficiency of high velocity sonic flares. The key issues pointed out in the paper were the flare design limitations of 40 CFR §60.18. In particular the requirements of most concern are continuous pilots and Maximum velocity (Vmax). Our request is that continuous pilot requirements be clarified to mean "continuously lit pilot only during flaring events". Additionally, we ask that upper Vmax limits be removed so that more efficient sonic flares can be used for high BTU waste streams.

Changes to NSPS rules that widen the scope of applicability to oil and gas emission sources may also increase the applicability of §60.18 to flares used in the industry. While there is a rulemaking team established to modify flare requirements as a part of the uniform standard effort, the schedule for the oil and gas NSPS rules precedes any new flare standards. Consequently, it's our understanding that any changes to flaring requirements will need to be included in the oil and gas rulemaking directly.

7.2. Enclosed Combustors Need To Be Distinguished From Flares

API would also like to emphasize again that the “enclosed combustor” type of thermal device should be classified as a “burner”, not a “flare” and should not be subject to the requirements of §60.18. These devices are completely different from flares in their design and operation which renders the requirements of §60.18 inappropriate. EPA has recognized this in several past determinations where they have determined that enclosed flame combustors are not flares even if they are termed (enclosed) flares by the manufacturer.

These enclosed combustor types of devices are increasingly being deployed for emission control of streams that would historically have been burned in flares or not controlled. We would also like to emphasize that the type of units typically deployed in the E&P industry are quite different than those which might be deployed at industrial facilities. Specifically, the combustors typically deployed in the E&P segment do not have electricity available and hence depend on natural draft rather than forced air (blower) for combustion, tend to be less complex, and tend to have limited instrumentation. Although simpler in design and dependent on natural draft these units have been shown able to consistently deliver destruction efficiencies in the 98 – 99%+ range in Wyoming areas.

Given the design of these enclosed combustors and the typical materials (fuels) that are burned, API also believes they should be considered as burners rather than thermal oxidation devices.

EPA should not create disincentives to use a broader deployment of these types of devices by requiring unnecessary or infeasible testing and/or monitoring.

7.3. Provisions are Needed for Approval of New Control Technologies

During the last teleconference with the Agency several weeks ago, there was a favorable discussion about inserting provisions in the rulemaking that (with appropriate approvals) would allow for the experimental use and implementation of new control technologies. This would be a welcome provision in the rules. However, the ability to implement new technologies can sometimes be hampered by the approval process and the time it may take to get necessary approvals. Though extensively used worldwide in industry, as flaring rules stand right now, use of a sonic flare would have to get special approval as a new technology (if indeed a new technology provision is put into the new NSPS rule) before implementation. With backing from the Zink paper, it would seem more efficient to include use of sonic flares directly into the rule. This would eliminate the burden of getting special approvals for its use.



8. NSPS RULES SHOULD RETAIN THE VOC 10% EXEMPTION

API believes that the applicability criteria for the entire proposed *Oil & Gas New Source Performance Standards (NSPS)* should be the same cutoff (10 wt% VOC) used in the current NSPS Subpart KKK (which references Subpart VV, 40 CFR 60.481). That subpart (§60.632) states that “For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight”. In its analysis EPA determined that it is not cost effective to include equipment that handles liquid or gas with less than 10 wt% VOC.

Since the primary objective of the proposed O&G NSPS regulation is to reduce VOC emissions, the sources to be regulated must be capable of emitting VOC. Therefore, API requests that the 10 wt% VOC criteria apply to all of the O&G source types that are to be regulated by this proposed rule, not just the fugitive sources (i.e., those suitable for a Leak Detection and Repair program).

9. INCREASED REGULATION MAY DECREASE OIL AND GAS PRODUCTION

In prior discussions and presentations EPA has voiced the opinion that NSPS regulation of the E&P industry will not result in less production or reserves (natural gas supply). API believes this position is erroneous and offers the following discussion to underpin our belief.

US onshore oil and gas production is a mature industry with a very large proportion of low rate “marginal” producing wells and an increasing focus hydrocarbon deposits that are more difficult to find and extract in developing resource plays. As an indicator, the average production per new well has been declining for several years.

The US Energy Information Administration’s (EIA) listing of oil and gas wells by production rate bracket illustrates the preponderance of low rate wells in the US E&P industry. Of 363,459 producing US oil wells EIA data shows some 286,109 (78.7%) produce at a rate of 10 barrel-of-oil-equivalent (BOE) or less per day. For gas wells, EIA’s data shows that of 461,388 producing gas wells some 297,371 (64.5%) produce at a rate of 10 barrel-of-oil-equivalent (BOE) or less per day. With these low production rates, these wells are economically marginal and very sensitive to additional costs. Costs imposed by regulation may make the “tail” end of these wells non-economic and result in their shut-in and abandonment. Some proportion of this segment of the well portfolio may be abandoned which will reduce oil and natural gas production, royalty and tax income to mineral owners and government entities, and overall reserves. The extent of this reduction will be dependent on the scale of costs imposed by regulation.



The shift towards non-traditional resource plays for domestic production is illustrated by the focus on and increasing importance of natural gas from shale, coal beds, and tight sands. Not many years ago, these reservoir types were regarded as uneconomic because the technology to produce them didn't exist. At the gas prices of 2006-2007, the Shale Gas plays became economic and the industry began actively acquiring leasehold acreage and began drilling. With the price collapse in 2008, activity in the shale was significantly curtailed back to only those projects that were contractually mandatory. With the cost of drilling and completion under today's regulations, the threshold price is a sustained market price well above today's prices (the exact price level required to sustain production is a matter of much conjecture). Adding significant costs to reach new environmental goals will further delay the development of this resource, and may increase imports of natural gas. The extent of reduction in oil and gas production, reserves, royalties, and tax payments will depend on the scale of the costs imposed by regulation.

These impacts can disproportionately impact small oil and gas companies/operators who tend to have a portfolio of low rate marginal wells that are not economic for larger companies. There are 10,439 operators in the Oil & Gas industry that produced a combined 22 MMCF/d from 233,607 wells in 2008. This average of 0.1 MCF/day/well is very sensitive to costs and many of these operators cannot tolerate any additional costs and remain solvent. With an average of 22 wells (233,607 wells/10,439 operators) per operator it is obvious that most of these low rate wells are operated by small operators and regulatory imposed costs would disproportionately impact these small businesses.

10. ALLOW FLEXIBILITY FOR WELL-BORE DELIQUIFICATION CONTROLS

API has significant concerns with EPA's apparent focus in the December, 2009, CAAAC Multi-pollutant Sector Approach presentation on plunger-lift as a single technology-choice for addressing the challenge of reduced well venting. Deliquification of gas wells is a highly complex and technical subject with many approaches and technologies in use and venting of wells is one technique used. A very large amount of industry focus and attention is applied to gas-well deliquification with innovation and research continually underway. It is not appropriate for EPA to specify a particular technology or approach to the highly complex problem of well-bore deliquification through regulation. API does recognize that well-venting can be a significant source of hydrocarbon pollutant emissions and that there are technologies and techniques in use and available to sharply reduce, but not eliminate, venting of wells to assist in deliquification. In fact, many of API's member companies have been on the forefront of developing and applying innovative solutions for well-bore liquids unloading with no venting or reduced venting.



Specifying a single technology or approach could negatively impact the continued ability to produce low rate gas wells, stifle innovation, shorten the economic life of the majority of US gas wells, and disproportionately impact many small operators who tend to have portfolios of low rate “marginal” wells. Specifying one approach to deliquification will limit the economic life of gas wells and could cause companies to rethink their investment in US gas development. This may negatively impact the clean-fuel natural gas supply and the country’s energy security. Operators must have the flexibility to choose the most appropriate and cost effective approach for each individual well/reservoir/age/production combination and the regulatory certainty to underpin continued investment.

API suggests that EPA take a different approach to reducing venting by providing regulatory dis-incentives for continued venting rather than trying to enter the discipline of production engineering and well deliquification. Additionally, API suggests that EPA fully understand the issue of well liquid-loading and venting control prior to crafting regulations addressing it. API would like to offer assistance, through organizing meetings, workshops, and/or training sessions with well deliquification experts to help EPA gain the necessary understanding to craft a workable and effective regulation.

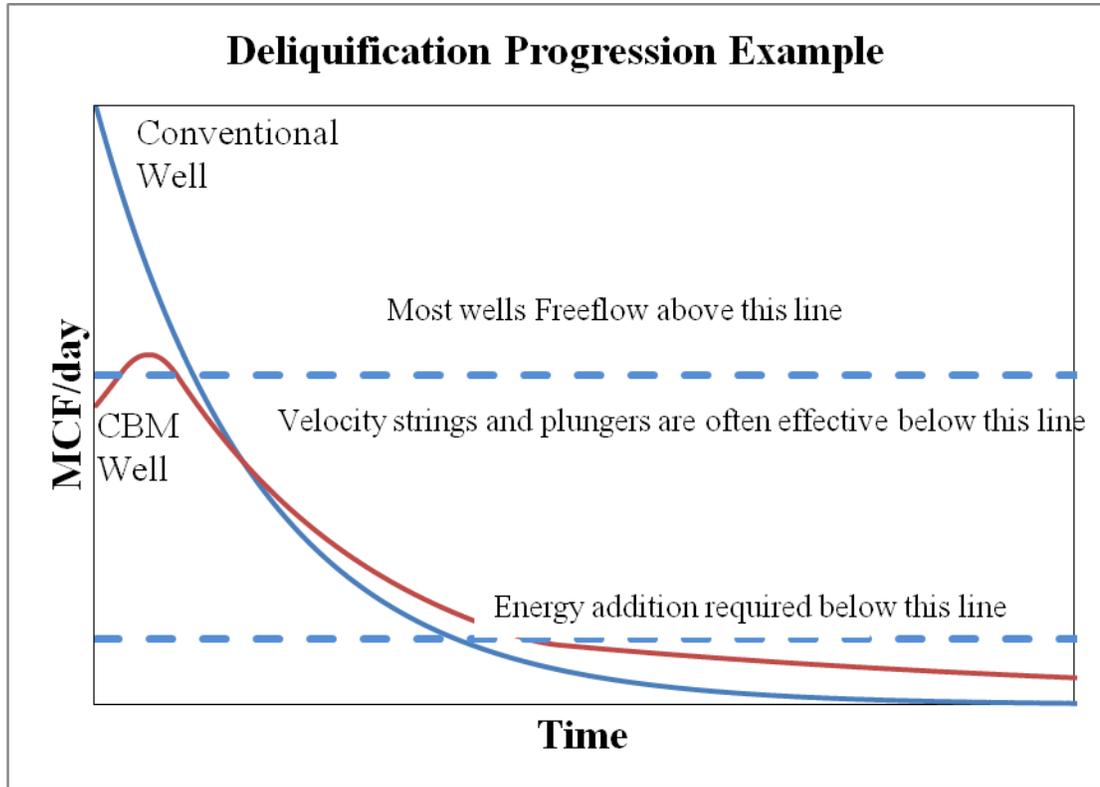
10.1. Background on Well-bore Deliquification (liquids unloading)

It is important to fully understand the fundamental nature of well bore liquid loading or the range of technologies in use to address it – in particular plunger lift and its appropriate use, limitations, and efficacy. API offers the following discussion of well venting and well-bore deliquification to assist EPA in crafting workable, appropriate, and effective requirements for reducing well venting for well-bore deliquification. Additionally, we highly recommend the June, 2009 American Oil and Gas Report article *Artificial Lift Advances Address Challenges, Trends in Gas Well Deliquification* and the February 27, 2006 Oil & Gas Journal article *Low-Pressure Gas Well Deliquification Requires Different Approaches*. Both articles provide a robust discussion of this topic.

Well deliquification is a fundamental challenge for continued production from the majority of US gas wells and the proportion is expected to grow with new growth concentrated in non-traditional gas reservoirs such as shales, coal-beds, and tight-gas sands which are all very susceptible to liquid loading. Liquid loading of well-bores occurs when the gas production-rate up the well-bore is not sufficient to carry liquids out of the well-bore. When a liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and the production rate declines to the point where the well can quit flowing. According to the Energy Information Administration’s 2009 “Distribution of Wells by Production Rate Bracket” some 338,056 (73%) wells out of a total gas well inventory of 461,388 gas

wells produce 90 mcf of gas (15 BOE or less) or less per day (http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html) . These low rate wells are either impaired by liquids accumulation or are using a deliquification method to produce.

Wells and reservoirs follow a continuum of flow regimes, in their economic life, as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore. In the early stage of a well’s life many (but by no means all) wells can flow freely and with sufficient velocity to avoid liquid loading problems. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquid-loading begins to be a problem and one of a portfolio of technologies or techniques will be used to help lift liquids using the reservoirs energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoirs energy is not sufficient to lift liquids and energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned. The following figure shows a generalized well life-cycle curve with these different stages of a wells life illustrated.



The production rate of a well, consequent velocity up the well-bore, and hence ability to lift liquids is mostly a function of the differential pressure between the reservoir and the flow-line/collection system and the reservoir's sensitivity to backpressure. In order to flow, the total reservoir pressure must be greater than the total resistance to flow. This resistance is comprised of fluid friction and fluid interference across the reservoir; the flowing friction up the well-bore; the weight of the vertical fluid column in the well-bore; surface equipment and piping pressure losses; and the collection system/flow-line back-pressure. Opening a well-bore to atmospheric pressure (venting a well) removes the surface equipment/piping pressure-loss and the back pressure from the collection line and increases differential pressure to increase flow rates and velocities, which may enable the well to lift the liquid from the well-bore (unload the well). Venting of wells has been a common practice in low rate gas well deliquification for decades and is not restricted to wells without deliquification assist technologies, such as plunger lifts, in place.

To combat this normal well/reservoir depletion and assist liquid lift a number of techniques are used – dependent on the well configuration, reservoir properties, well depth, and surface equipment and collection system. Some of these techniques are:

- The tubing in a well may be changed to smaller diameter “velocity strings” which provide for higher velocity at any given flow rate and provide higher liquid lift capabilities.
- Soap injection may be used to “foam” the liquids to reduce the unit density and enable liquids lifting.
- Wells may be put on a shut-in cycle to allow pressure/energy build-up of the reservoir near the well bore which equals higher production rates/velocity (temporary) and better liquids lifting.
- Plunger lift may be installed in a well. This is generally coupled with a shut-in cycle to build enough pressure under the plunger to lift it and the liquid column.
- Mechanical pumps are selected when liquid rate is too high for plungers to operate or reservoir pressure is too low for plungers to operate without excessive shut-ins for build up.
- Gas lift which raises tubing velocity to lift liquids by injecting gas down the tubing-casing annulus.
- Compression which lowers the surface pressure creating more differential for flow and increasing velocity by lowering pressure.
- Combinations of above approaches such as foaming, gas lift, and compression

The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of the production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology-selection requires a thorough understanding of the conditions that a reservoir is flowing into, the reservoir's sensitivity to backpressure and the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology. This is a matter for engineering analysis and should not be a matter for regulation. For the EPA to mandate or even provide incentives to use a specific technology such as plungers will have the effect of stifling innovation and often deploying inappropriate technology. Saying that venting should be curtailed is a long way from the EPA requiring a broad implementation of a niche technology like plungers. In crafting regulations addressing well venting, EPA must encourage the flexibility to apply engineering analysis while introducing minimum venting as a criterion.

Once wells reach the point where energy must be added, there are many options such as pumps, gas lift, and compressors available to work in gas wells both before and after the brief time that plungers might be applied.

An excellent overview of this subject is Gas Well Deliquification, Second Edition, by Dr. James F. Lea, Dr. Henry V. Nickens, and Mr. Mike R. Wells (Gulf Publishing, 2008, ISBN 978-0-7506.8280-0). This 588 page book does a good job of explaining the basis for choosing among the various technologies, but it does not presume to force a one-size-fits-all solution on the industry.

10.2. Background on Plunger Lift

Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful. Plunger capacity is limited by well depth, differential between reservoir pressure/surface pressure, and the gas/liquid ratio that the well produces. Even plunger lifted wells reach a point where they lack the reservoir pressure to run a plunger against backpressure often enough to lift the liquid that must be lifted. At that point the operator has the choice of replacing the plunger with a lift method that adds energy to the system or plugging the well. In the case of CBM wells for example, this point is generally reached around 50% of original gas in place (OGIP). Operators look at these wells and have to make the decision to spend capital on a pump or spend capital on drilling a new well—the economics of that decision generally favor installing a pump.

Although plungers are among the most common tools used in middle stage deliquification, plungers do not eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. This can be controlled and minimized but not eliminated.

- One of the primary studies/projects EPA likes to highlight from its Natural Gas Star program is the BP “smart automation” well bore venting control system in the San Juan basin. What is generally misunderstood or not acknowledged is that the majority of the wells which were venting (around 4.2 BCF of gas per year) were plunger equipped and were vented in order to generate the energy necessary to lift the plunger and liquid column.
- The fact that it took nearly 6 years to fully develop the system and achieve 90% + venting reduction is also often ignored. It is technically and operationally very difficult.
- Plungers are not universally applicable to well-bores. For example, a plunger cannot be run in a well-bore with changing tubing sizes, defects or buildups of scale or in coil tubing which has an “internal upset” weld seam. Plungers can only be run where the inside of the well-bore is smooth and in reasonably good condition. They also do not work well in highly deviated directional or horizontal well-bores.
- Although casing plungers are available for wells without tubing, they have had significant reliability problems and it is also difficult to control the velocity up the well-bore to avoid high velocities which have blown the top off of well-heads resulting in uncontrolled release of significant quantities of gas.
- Once a well/reservoir declines sufficiently, plungers will no longer work and energy must be added to the well-bore or the well abandoned. This is an economics decision.

10.3. Industry Research on Well-Bore Deliquification

There is a tremendous amount of research and work focused on well-bore deliquification, from a production and economics perspective alongside emissions reduction, and EPA needs to not discourage this or insert road-blocks. This work is both optimizing and improving existing techniques along with developing entirely new types of systems. Industry needs the flexibility to pilot some of these ideas/developments without regulatory impediments – even if they ultimately do not succeed.



For example, the 9th Annual Gas Well Deliquification Workshop is scheduled for February 28 – March 2, 2011 in Denver, Colorado. This workshop series, along with a portfolio of other venues dedicated to well deliquification and artificial lift, is organized by the Artificial Lift Research and Development Council (ALRDC), and the Southwestern Petroleum Short Course (SWPSC). The 34th Annual ASME/ALRDC International Gas-Lift Workshop was held in Singapore on February 7 - 11, 2011 with past annual workshops at various venues around the world. The ALRDC / SWPSC 2011 Appalachian Basin Gas Well Deliquification Seminar and workshop is scheduled for June 2011. For more information, please visit <http://www.alrdc.com>.

Attachment B
EPA Data Requested Table

Attachment B: EPA Requested Comment – Cross Reference Table

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---|-------------------------|--|---|
| 18.8 | 48 | 1. On the suitability of a compliance option allowing the use of wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device as an acceptable alternative to installing dry seals | 1.) EPA is aware that some owners and operators may need to use centrifugal compressors with wet seals, and is soliciting comment on the suitability of a compliance option allowing the use of wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device as an acceptable alternative to installing dry seals. (pg 48 of pre-publication) |
| 18.3 | 49 | 2. We solicit comment on the appropriateness of a fixed replacement frequency and other considerations that would be associated with regular replacement. | 2.) When the hours of operation reaches 26,000 hours, the owner or operator would be required to change the rod packing immediately. However, to avoid unscheduled shutdowns when 26,000 hours is reached, owners and operators could track hours of operation such that packing replacement could be coordinated with planned maintenance shutdowns before hours of operation reached 26,000. Some operators may prefer to replace the rod packing on a fixed schedule to ensure that the hours of operation would not reach 26,000 hours. EPA solicits comment on the appropriateness of a fixed replacement frequency and other considerations that would be associated with regular replacement. (pg 49 of pre-publication) |
| API had insufficient time to provide detail information | 56 | 3. The EPA has attempted to ensure that we have neither overlooked nor failed to propose to remove from the existing text any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption, nor included any such provisions in the proposed new regulatory language. We are specifically seeking comment on whether there are any such provisions that we have inadvertently overlooked or incorporated. | |
| 15.7 8 – 8.4 | 57 | 4. We discuss some innovative implementation approaches being considered and seek comment on these and other potential methods of streamlining notification and reporting for well completions covered by the proposed rule. p. 58 | |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---------------------|-------------------------|--|--|
| 8 – 8.4 8.7 | 67 | | 3.) Under a traditional approach, owners or operators would provide notifications and keep records of information required by the NSPS. In addition, they would certify compliance with the NSPS as part of a required annual report that would include compliance-related information, such as details of each well completion event and information documenting compliance with other requirements of the NSPS. The EPA, state or local agency would then physically inspect the affected facilities and/or audit the records retained by the owner or operator. As an alternative to the traditional approach, EPA is seeking an innovative way to provide for more transparency to the public and less burden on the regulatory agencies and owners and operators, especially as it relates to modification of existing sources through recompletions of hydraulically fractured gas wells. These innovative approaches would provide compliance assurance in light of the absence of requirements for CAA title V permitting of non-major sources. (pg 67 of the pre-publication) |
| 8 – 8.1 | 68 | 5. We are seeking comment regarding the scope of application of one or more of these approaches, i.e., which provisions of the standards being proposed here would be suitable for specific compliance approaches, and whether the approaches should be alternatives to the requirements in the regulations. P.68 | 4.) EPA requests comments and suggestions on all aspects of the innovative compliance approaches discussed below and how they may be implemented appropriately. EPA is seeking comment regarding the scope of application of one or more of these approaches, i.e., which provisions of the standards being proposed here would be suitable for specific compliance approaches, and whether the approaches should be alternatives to the requirements in the regulations. (pgs 68 – 76 of the pre-publication) |
| 8.2-8.2.1, 15.7 | 70 | 6. We seek comment on potential methodologies that would minimize burden on operators, while providing timely and useful information for regulators and the public. P.70 | <u>Registration of Wells and Advance Notification of Planned Completions (pg 69-70)</u> Notification and registration could be streamlined through optional electronic reporting with web-based public access or other methods. 4a.) EPA seeks comment on potential methodologies that would minimize burden on operators, while providing timely and useful information for regulators and the public. |
| 15.7 | 70 | 7. We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance. However, we would expect an owner or operator to provide the follow-up notification only in cases where the completion date was expected to deviate from the original date provided. P.70 | 4b.) EPA also solicits comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance. |
| 15.7 | 70 | 8. We ask for suggestions regarding how much advance notification is needed and the most effective method of providing sufficient and accurate advance notification of well completions. P.70 | |
| 8.7 | 71 | 9. we are considering and seeking comment on the potential use of third party verification to assure compliance. P. 71 | |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---|-------------------------|--|--|
| 8.7 | 72 | 10. We seek comment on whether annual reports for well completions would be needed if a suitable third party verification program was in place and already housed that same information. P. 72 | |
| 8.7 | 72 | 11. We also solicit comment on the range of potential activities the third party verification program could handle with regard to well completions. P. 72 | |
| 8.7 | 73 | 12. We are seeking comment on appropriate third party reviewers and qualifications and registration requirements under such a program. P. 73 | <p><u>Third Party Verification (pg 70-73)</u> EPA is considering and seeking comment on the potential use of third party verification to assure compliance.</p> <p>4c.) EPA is seeking comment on appropriate third party reviewers and qualifications and registration requirements under such a program.</p> |
| 8.7 | 73 | 13. We are seeking comment on whether third party verification paid for by industry would result in impartial, accurate and complete data information. P. 73 | 4d.) The cost of third party verification would be borne by the affected industries. EPA is seeking comment on whether third party verification paid for by industry would result in impartial, accurate and complete data information. |
| 8.7 | 73 | 14. We are seeking comment on whether or not the EPA should approve third party verifiers p.73 | 4e.) EPA is seeking comment on whether or not the EPA should approve third party verifiers. |
| 8.4.3 | 74 | 15. We solicit comment on requiring sources to electronically submit their emissions data for the oil and gas rules proposed here. P.74 | <p><u>Electronic Reporting Using Existing Mechanisms (pg 74 -75)</u></p> <p>4f.) EPA solicits comment on requiring sources to electronically submit their emissions data for the oil and gas rules to the EPA's <u>Electronic Greenhouse Gas Reporting Tool (e-GGRT) used to report under Subpart W.</u></p> |
| API had insufficient time to provide detail information | 76 | 16. We seek comment on approaches that may be suitable for allowing temporary field testing of technology in development. These approaches could include not only established procedures under the CAA and its implementing regulations, but new ways to apply or interpret these provisions to avoid impeding innovation while remaining environmentally responsible and legal. P. 76 | <p><u>Provisions for Encouraging Innovative Technology (pg 75 -76)</u> The oil and natural gas industry has a long history of innovation in developing new exploration and production methods, along with techniques to minimize product losses and reduce adverse environmental impacts. As more emission sources in this source category are covered by regulation, as in the case of the action being proposed here, there likely will be situations where innovation and development of new control techniques potentially could be stifled by risk of violation.</p> <p>4g.) EPA seeks comment on approaches that may be suitable for allowing temporary field testing of technology in development. These approaches could include not only established procedures under the CAA and its implementing regulations, but new ways to apply or interpret these provisions to avoid impeding innovation while remaining environmentally responsible and legal.</p> |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---------------------|-------------------------|--|--|
| 19.2.1 – 19.2.2 | 102 | 17. We request comment on the applicability of a LDAR program based solely on the use of optical gas imaging. Of most use to us would be information on the effectiveness of this and, potentially, other advanced measurement technologies, to detect and repair small leaks on the same order or smaller than specified in the 40 CFR part 60, subpart VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording and repair practices. P. 102 | 5.) EPA requests comment on the applicability of a LDAR program based solely on the use of optical gas imaging. Of most use would be information on the effectiveness of this and, potentially, other advanced measurement technologies, to detect and repair small leaks on the same order or smaller than specified in the 40 CFR part 60, subpart VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording and repair practices. (pg 102) |
| 21 | 111 | 18. We, therefore, solicit comments on produced water ponds, particularly in the following subject areas: (a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation. | 6.) EPA solicits comments on produced water ponds, particularly in the following subject areas: 6a) EPA is requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation. |
| 21 | 111 | (b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content. | 6b) EPA is requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content. |
| 21 | 111 | (c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those warrant control and, if so, how controls should be developed. | 6c) EPA solicits information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those warrant control and, if so, how controls should be developed. |
| 21 | 112 | (d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well. | 6d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. EPA is seeking information on these considerations as well. |
| 21 | 112 | (e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints. | 6e) EPA is also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints. |
| 21 | 112 | (f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency. P. 112 | 6f) EPA solicits information on separator technologies that are able to improve the oil-water separation efficiency. |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|--------------------------------------|-------------------------|--|--|
| 15.2, 15.3, 15.3.2 | 122 | 19. The EPA requests comment on this and seeks input on whether alternative approaches to requiring REC for all operators with access to pipelines may exist that would allow operators to meet a performance-based standard if they can demonstrate that an REC is not cost effective. P.122 | 7.) EPA recognizes that there is heterogeneity in well operations and costs, and that while RECs may be cost effective on average, they may not be for all operators. Nonetheless, EPA is proposing to require an operational standard rather than a performance-based standard (e.g., requiring that some percentage of emissions be flared or captured), because EPA believes there are no feasible ways to demonstrate compliance with a performance-based standard for REC in combination with pit flaring. The EPA requests comment on this and seeks input on whether alternative approaches to requiring REC for all operators with access to pipelines may exist that would allow operators to meet a performance-based standard if they can demonstrate that an REC is not cost effective. (pg 122) |
| 15.3.1, 15.3.3, 15.3.7, | 122 | 20. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible, and potential criteria that would support venting in lieu of pit flaring. P122 | |
| 5.1.2., 15.3.2, 15.6.3, Attachment B | 122 | 21. We solicit comment on criteria and thresholds that could be used to exempt some well completion operations occurring in coalbed methane reservoirs from the requirements for subcategory 1 wells. | |
| 15.4 | 123 | 22. We request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS | 8.) EPA believes that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, energy availability could be affected if a shortage of REC equipment was allowed to cause delays in well completions. EPA requests comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS. |
| 15.4 | 123 | 23. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually | EPA also requests specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually. (pg 123) |
| 15.4 | 124 | 24. We solicit comment on the phasing of requirements for REC along with suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS, while also achieving a comparable level of reduced emissions to the air. P. 124 | 9.) EPA solicits comment on the phasing of requirements for REC along with suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS, while also achieving a comparable level of reduced emissions to the air. (pg 124) |
| 15.10, Attachment B | 125 | 25. We request comment and any available technical information to judge whether our assumption of \$33,237 per well completion for this service given the projected number of wells in 2015 subject to this requirement is accurate. P. 125 | 10.) EPA requests comment and any available technical information to judge whether our assumption of \$33,237 per well completion for this service given the projected number of wells in 2015 subject to this requirement is accurate. (pg. 125) |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
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| 5.1.2, 15.3.2, 15.6, 15.10 | 125 | 26. We solicit comment and supporting data on appropriate thresholds (e.g., pressure, flowrate) that we should consider in specifying which well completions are subject to the REC requirements for subcategory 1 wells. Comments specifying thresholds should include an analysis of why sources below these thresholds are not cost effective to control. P. 125 | 11.) EPA believes that the proposed rule regulates only significant emission sources for which controls are cost-effective. Nevertheless, EPA solicits comment and supporting data on appropriate thresholds (e.g., pressure, flowrate) that should be considered in specifying which well completions are subject to the REC requirements for subcategory 1 wells. Comments specifying thresholds should include an analysis of why sources below these thresholds are not cost effective to control. (pg. 125) |
| 15.2, 15.3, 15.4 | 126 | 27. We request information on such opportunities and barriers that we should consider and suggestions for how we may take them into account in structuring the NSPS. P.126 | 12.) There may be economic, technical or other opportunities or barriers associated with performing cost-effective REC that EPA did not identified in their review. For example, some small regulated entities may have an increased source of revenue due to the captured product. On the other hand, some small regulated entities may have less access to REC than larger regulated entities might have. EPA requests information on such opportunities and barriers that should be considered and suggestions for how they may take them into account in structuring the NSPS. (pg. 125) |
| 15.3.1, 15.3.3, 15.3.7, | 128 | 28. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible and potential criteria that would support venting in lieu of pit flaring. P. 128 | 13.) Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion. EPA solicits comment on whether there are other such situations where flaring would be unsafe or infeasible and potential criteria that would support venting in lieu of pit flaring. (pg 128) |
| 15.11 | 130 | 29. EPA seeks comment on the 10 percent per year rate of refracturing for natural gas wells assumed in the impacts analysis found in the TSD. EPA has received anecdotal information suggesting that refracturing could be occurring much less frequently, while others suggest that the percent of wells refractured in a given year could be greater. P, 130 | 14.) EPA seeks comment on the 10 percent per year rate of refracturing for natural gas wells assumed in the impacts analysis found in the TSD. EPA has received anecdotal information suggesting that refracturing could be occurring much less frequently, while others suggest that the percent of wells refractured in a given year could be greater. |
| 15.11 | 130 | 30. We seek comment and comprehensive data and information on the rate of refracturing and key factors that influence or determine refracturing frequency. P.130 | EPA seeks comment and comprehensive data and information on the rate of refracturing and key factors that influence or determine refracturing frequency. (pg 129-130) |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
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| 17, 17.1, 17.6 | 137 | | 15.) There may be situations where high-bleed controllers and the attendant gas bleed rate greater than 6 cubic feet per hour, are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. For such situations, EPA provided in the proposed rule an exemption where pneumatic controllers meeting the emission standards discussed above would pose a functional limitation due to their actuation response time or other operating characteristics. EPA is requesting comments on whether there are other situations that should be considered for this exemption. If you provide such comment, please specify the criteria for such situations that would help assure that only appropriate exemptions are claimed. (pg 137) |
| 18.8.1 | 143 | | 16.) EPA seeks comment on available cost data of a dry seal versus wet seal compressor, including all ancillary equipment costs. (pg 143) |
| 18.8.1 | 144 | 31. We are soliciting comments on the emission reduction potential, cost and any limitations for the option of routing the gas back to a low pressure fuel stream to be combusted as fuel gas. | 17.) Although EPA is proposing to determine dry seal systems to be BSER for centrifugal compressors, EPA is soliciting comments on the emission reduction potential, cost and any limitations for the option of routing the gas back to a low pressure fuel stream to be combusted as fuel gas. |
| 18.8.1 | 144 | In addition, we solicit comments on whether there are situations or applications where wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate. P.144 | In addition, EPA solicits comments on whether there are situations or applications where wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate. (pg 144) |
| 18.3.3 | 149 | 32. We are soliciting comments on incorporating a method similar to that in the Natural Gas STAR's Lessons Learned document entitled, Reducing Methane Emissions from Compressor Rod Packing Systems p.149 | 18.) Some industry partners of the Natural Gas STAR program currently conduct periodic testing to determine the leakage rates that would identify economically beneficial replacement of rod packing based on natural gas savings. Therefore, EPA is soliciting comments on incorporating a method similar to that in the Natural Gas STAR's Lessons Learned document entitled, Reducing Methane Emissions from Compressor Rod Packing Systems (http://www.epa.gov/gasstar/documents/ll_rodpack.pdf), to be incorporated in the NSPS. |
| API had insufficient time to provide detail information | 149 | 33. We are soliciting comments on how to determine a suitable leak threshold above which rod packing replacement would be cost effective for VOC emission reduction. | EPA is soliciting comments on how to determine a suitable leak threshold above which rod packing replacement would be cost effective for VOC emission reduction. |
| 18.3 | 149 | 34. We are also soliciting comment on the appropriate replacement frequency and other considerations that would be associated with regular replacement periods. P.149 | EPA is also soliciting comment on the appropriate replacement frequency and other considerations that would be associated with regular replacement periods. (pg 149) |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---|-------------------------|---|--|
| API had insufficient time to provide detail information | 166 | 35. We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies. Of most use to us would be information on the effectiveness of advanced measurement technologies to detect and repair small leaks on the same order or smaller as specified in the VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording, and repair practices. P.166 | 19.) EPA requests comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies. Of most use to EPA would be information on the effectiveness of advanced measurement technologies to detect and repair small leaks on the same order or smaller as specified in the VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording, and repair practices. (pg 166) |
| 10, 10.12, 10.3, 10.4, 10.6 | 167 | 36. Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim. P.167 | |
| API had insufficient time to provide detail information | 176 | 37. We are requesting that the public provide a detailed review of the information in this dataset and provide comments and updated information where appropriate. Section X of this preamble provides an explanation of how to provide updated information for these datasets. | 20.) The NEI database was used to evaluate the number of major sources, EPA is requesting that the public provide a detailed review of the information in this dataset and provide comments and updated information where appropriate. Section X of this preamble provides an explanation of how to provide updated information for these datasets. (pg 176) |
| API had insufficient time to provide detail information | 212 | 38. We solicit comment on the use of the occupational values described above in the interpretation of these worst-case acute screening exposure estimates. P.212 | |
| 20.2 | 245 | 39. Pursuant to CAA section 112(f)(4), we are proposing that this change (i.e., removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not this is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A). p. 245 | |
| 20.1, 20.2, 20.3, 20.4 | 246 | 40. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work and how it would reduce risk. P.246 | |
| 20.1, 20.2, 20.3, 20.4 | 262 | 41. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work, and how it would reduce risk. P262 | |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
|---|-------------------------|--|--|
| API had insufficient time to provide detail information | 283 | 42. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked. 0,282 | |
| API had insufficient time to provide detail information | 290 | 43. We are asking for comment regarding the likelihood of this occurrence and data demonstrating the circumstances where it occurs. In light of the potential issue, we are asking for comment regarding the addition of provisions in the NESHAP to require area sources to recalculate their PTE to confirm that they are indeed area sources and whether that calculation should be performed on an annual or biannual basis to verify that changes in gas composition have not increased their emissions. P.290 | 21.) EPA is seeking comment on several PTE related issues. According to the data available to the Administrator, when 40 CFR part 63, subpart HH was promulgated, the level of HAP emissions was predominantly driven by natural gas throughput (i.e., HAP emissions went up or down in concert with natural gas throughput). Since promulgation, EPA has learned that there is not always a direct correlation between HAP emissions and natural gas throughput. EPA has received information suggesting that, in some cases, HAP emissions can increase despite decreasing natural gas throughput due to changes in gas composition. EPA is asking for comment regarding the likelihood of this occurrence and data demonstrating the circumstances where it occurs. In light of the potential issue, EPA is asking for comment regarding the addition of provisions in the NESHAP to require area sources to recalculate their PTE to confirm that they are indeed area sources and whether that calculation should be performed on an annual or biannual basis to verify that changes in gas composition have not increased their emissions. (pg. 290) |
| API had insufficient time to provide detail information | 317 | 44. In particular, the EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency-modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined earlier in this notice. These comments will be considered in developing the final rule for this rulemaking. P.317 | |
| API had insufficient time to provide detail information | 319 | 45. We are soliciting comments on all aspects of this proposed action. All comments received during the comment period will be considered. | |

| API Comment Section | EPA Ref. Pre-Pub Page # | Oil & Gas Comment Solicitation List | Specific Data/Comments EPA requests in the preamble |
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| API had insufficient time to provide detail information | 319 | In addition to general comments on the proposed actions, we are also interested in any additional data that may help to reduce the uncertainties inherent in the risk assessments. We are specifically interested in receiving corrections to the datasets used for MACT analyses and risk modeling. Such data should include supporting documentation in sufficient detail to allow characterization of the quality and representativeness of the data or information. Please see the following section for more information on submitting data. P. 319 | |

Attachment C
Suggested Rule Text Table

Attachment C

| Ref # | Comment | Regulatory Text |
|---|---|--|
| Subpart 0000-Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution | | |
| § 60.5360 What is the purpose of this subpart? | | |
| 1 | See Section 3. for Title deletion. | § 60.5360 This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO ₂) emissions from affected facilities that commenced construction, modification or reconstruction after August 23, 2011. |
| § 60.5365 Am I subject to this subpart? | | |
| 2 | See Section 3.1, 3.2, and 5.1.2. | § 60.5365 If you are the owner or operator of <u>a site prior to the point of custody transfer at which is located</u> one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. <u>Paragraphs §60.5365(a)-(e) apply only to affected facilities in VOC service. For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.</u> |
| 2A | Primary Recommendation: see Section 2. Alternative Recommendation : see Section 4. and regulatory text for 60.5365(a)-(e) below. | Remove 60.5365(a)-(e) and associated sections/paragraphs of Subpart OOOO from this proposal and place in a separate supplemental proposal to be finalized at a later date. |
| 2B | See Section 5.4.3 and 15.6. | § 60.5365 (a) <u>An onshore natural gas wellhead affected facility, is a single natural gas well-, except for one that does not have flowback immediately following hydraulic fracturing stimulation. VOC emissions from flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore is the only activity regulated at this affected facility. For the purposes of this subpart, an existing onshore natural gas wellhead facility is considered modified if it meets the criteria of modification in §60.14. The modification of an existing natural gas wellhead affected facility does not affect the status of other equipment, process units, storage vessels, or pneumatic devices located at the well site.</u> |

| Ref # | Comment | Regulatory Text |
|-------|--|--|
| 3 | See Section 18.1. | § 60.5365 (b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor <u>in VOC service</u> located between the wellhead and the <u>point of custody transfer eity gate</u> (as defined in § 60.5430), except that a centrifugal compressor located at a well site (as defined in § 60.5430) <u>and prior to the natural gas processing</u> plant is not an affected facility under this subpart. For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility. |
| 4 | See Section 18.1 and 18.4. | § 60.5365 (c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor <u>in VOC service</u> located between the wellhead and the <u>point of custody transfer eity gate</u> (as defined in § 60.5430), except that a reciprocating compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility. |
| 5 | See Section 17.4 Process unit affected facility concept from SOCOMI NSPS in 59 FR 46780 <ul style="list-style-type: none"> • Avoids RMRR triggering modification, reconstruction • Significant relief in recordkeeping and reporting • Controllers are a component piece of a process unit, not a standalone emissions source. | § 60.5365 (d) A pneumatic controller affected facility, which is defined as a single pneumatic controller. A continuous bleed gas-driven pneumatically controlled process unit affected facility which is defined as a single continuous bleed gas-driven pneumatically controlled process unit, if it is located before the point of custody transfer. |
| 5A | Alternative Recommendation – See Section 17.4.3 | § 60.5365 (d) A <u>continuous bleed gas-driven</u> pneumatically controller affected facility, which is defined as a single pneumatic <u>controller, if it is located before the point of custody transfer.</u> |
| 5B | See Section 17.1 New sub-paragraphs inserted <ul style="list-style-type: none"> • Intermittent vent pneumatic controllers are not continuous bleed controllers Non-gas driven pneumatic controllers have no regulated emissions | <u>§ 60.5365 (d)(1) Intermittent vent pneumatic controllers are not considered part of an affected facility.</u> |
| 5C | See Section 17.4.2 | <u>§ 60.5365 (d)(2) Non gas-driven pneumatic controllers are not considered part of an affected facility.</u> |
| 6 | See Section 5.2, 5.3, and 16.4 | § 60.5365 (e) A storage vessel affected facility, which is defined as a single storage vessel <u>storing condensate or crude oil</u> and <u>located prior to the point of custody transfer.</u> |
| 7 | See Section 18.2 and 19.3 | § 60.5365 (f) Compressors and e Equipment (as defined in § 60.5430) located at onshore natural gas processing plants. |
| 8 | See Section 18.2 and 19.3 | § 60.5365 (f)(1) Each compressor in VOC service or in wet gas service is an affected facility. |

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| 9 | See Section 18.2 and 19.3 | § 60.5365 (f) (2) <u>(1)</u> The group of all equipment, except compressors , within a process unit is an affected facility. |
| 10 | See Section 19.3 | § 60.5365 (f) (3) <u>(2)</u> Addition or replacement of equipment, as defined in § 60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart. |
| 11 | See Section 19.3 | § 60.5365 (f) (4) <u>(3)</u> Equipment (as defined in § 60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in § 60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart. |
| 12 | See Section 19.3 | § 60.5365 (f) (5) <u>(4)</u> Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) and (f)(2) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part. |
| 13 | See Section 5.5 | § 60.5365 (g) Sweetening units located <u>at onshore natural gas processing plant</u> that process natural gas produced from either onshore or offshore wells. |
| 14 | | § 60.5365 (g)(1) Each sweetening unit that processes natural gas is an affected facility; and |
| 15 | | § 60.5365 (g)(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility. |
| 16 | | § 60.5365 (g)(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H ₂ S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and paragraphs 60.5410(g) and 60.5415(g) of this subpart. |
| 17 | | § 60.5365 (g)(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, and §§ 60.5410(g), 60.5415(g), and § 60.5423 of this subpart. |
| 18 | § 60.5370 When must I comply with this subpart? | |
| 19 | See Section 7.1 and 15.4 | § 60.5370 (a) You must be in compliance with the standards of this subpart no later than <u>60 days after</u> the date of publication of the final rule in the Federal Register or upon startup, whichever is later <u>except for the provisions provided in (d) and (e) of this section.</u> |
| 19A | See Section 7.2 and 15.4 | <u>§ 60.5370 (a)(1) Compliance with 60.5375 (natural gas wellhead facility) will begin [two years after the effective date]. From the [effective date] until [two years after the effective date] comply only with § 60.5375 (a)(1)(ii).</u> |

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| 19B | See Section 7.3, 17.10 and 17.11 | <u>§ 60.5370 (a)(2) Compliance with §60.5390 is required beginning [one year after the effective date], except for the following</u> |
| 19C | See Section 17.10 API prefers to remove manufacturer guarantee, but this text is offered as an alternative | <u>§ 60.5370 (a)(2)(i) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date</u> |
| 19D | See Section 17.10 API prefers to remove manufacturer guarantee, but this text is offered as an alternative | <u>§ 60.5370 (a)(2)(ii) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date</u> |
| 19E | See Section 17.10 API prefers to remove manufacturer guarantee, but this text is offered as an alternative | <u>§ 60.5370 (a)(2)(iii) Compliance with §60.5420(c)(4)(iii) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date</u> |
| 19F | See Section 7.3 | <u>§ 60.5370 (a)(3) Compliance with §60.5395 is required beginning [three years after the effective date].</u> |
| 19G | See Section 19.6 | <u>§ 60.5370 (a)(4) If your new or reconstructed process unit equipment is subject to §§60.5400, 60.5401, and 60.5402, you must be in compliance no later than 180 days after startup.</u> |
| 19H | See Section 19.6 & 19.7 | <u>§ 60.5370 (a)(5) If you become subject to §§60.5400, 60.5401 and 60.5402 due to modification under provisions of §60.14, the group of all equipment within that process unit must be in compliance with the work practice provisions of §§60.5400, 60.5401, and 60.5402 of this subpart no later than a year after the modification. If any equipment upgrade is required in order to achieve initial compliance (e.g., pump seal and pressure relief device upgrades), you must complete all equipment upgrades and comply with §§60.5400, 60.5401 and 60.5402 for that equipment no later than three years after the modification.</u> |
| 20 | | § 60.5370 (b) The provisions for exemption from compliance during periods of startup, shutdown, and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart. |
| 21 | | § 60.5370 (c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart. |
| 21A | See Section 19.6 | <u>§ 60.5370(d) If your new or reconstructed process unit equipment is subject to §§60.5400, 60.5401, and 60.5402, you must be in compliance no later than 180 days after startup.</u> |
| 21B | See Section 19.6 and 19.7 | <u>§ 60.5370(e) If you become subject to §§60.5400, 60.5401 and 60.5402 due to modification under provisions of §60.14, the group of all equipment within that process unit must be in compliance with the work practice provisions of §§60.5400, 60.5401, and 60.5402 of this subpart no later than a year after the modification. If any equipment upgrade is required in order to achieve initial compliance (e.g., pump seal and pressure relief device upgrades), you must complete all equipment upgrades and comply with §§60.5400, 60.5401 and 60.5402 for that equipment no later than three years after the modification.</u> |

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| 22 | | § 60.5375 What standards apply to gas wellhead affected facilities? |
| 23 | | § 60.5375 If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section. |
| 24 | Preferred Option See Section 15.2 | § 60.5375 (a) Except as provided in paragraph (f) of this section, for flowback immediately following of each well completion operation with hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore , as defined in § 60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through and (a)(32) of this section. |
| 24A | Alternative Option See Section 15.2 | § 60.5375 (a) Except as provided in paragraph (f) of this section, for flowback of each well completion operation with immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore , as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section. |
| 25 | Preferred Option See Section 15.2 | § 60.5375 (a)(1) You must minimize the <u>VOC</u> emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore , as defined in § 60.5430, utilizing one or more of the following options by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system. |
| 25A | Alternative Option See Section 15.2 | § 60.5375 (a)(1) You must minimize the <u>VOC</u> emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback duration of immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore , as defined in §60.5430, utilizing one or more of the following options: by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system. |
| 25B | Preferred Option See Section 15.2 | § 60.5375 (a)(1)(i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. |
| 25C | Alternative Option See Section 15.2 | § 60.5375 (a)(1)(i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. When the well head pressure (in absolute units) immediately following perforation is four times the static sales meter pressure then the operator is obligated to flow the well to an available sales line or document the reasons for failing to flow to sales. |

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| 25D | Preferred Option See Section 15.2 | <u>§ 60.5375 (a)(1)(ii) Capture and route VOC emissions associated with flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore that cannot be directed to the gathering line to a completion combustion device except when conditions may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to 60.18.</u> |
| 25E | Alternative Option See Section 15.2 | <u>§ 60.5375 (a)(1)(ii) Capture and route flowback emissions that cannot be directed to the gathering line to a completion combustion device except when conditions may result in a fire hazard, or explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to 60.18. For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, reduce emissions by using a completion combustion device when not precluded by one of the conditions described above.</u> |
| 25F | Preferred Option See Section 15.2 | <u>§ 60.5375 (a)(1)(iii) Other method that minimizes VOC emissions associated with flowback immediately following hydraulic fracture stimulation.</u> |
| 26 | Preferred Option See Section 15.2 | <u>§ 60.5375 (a)(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable-quality gas must be routed to the gas gathering line as soon as practicable. Develop and implement a management plan for each basin for how you will minimize VOC emissions associated with flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facilities onshore utilizing the options in 60.5375(a)(1). The plan must include:</u> |
| 26A | Alternative Option See Section 15.2 | <u>§ 60.5375 (a)(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable-quality gas must be routed to the gas gathering line as soon as practicable.</u> |
| 26B | See Section 15.2 | <u>§ 60.5375 (a)(2)(i) Methods and techniques to enhance direction of gas during the flowback immediately following hydraulic fracturing to the natural gas gathering system.</u> |
| 26C | See Section 15.2 | <u>§ 60.5375 (a)(2)(ii) Equipment to be used.</u> |
| 26D | See Section 15.2 | <u>§ 60.5375 (a)(2)(iii) Operating procedures.</u> |
| 26E | See Section 15.2 | <u>§ 60.5375 (a)(2)(iv) Definition of roles and responsibilities for implementation of the plan.</u> |

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| 26F | See Section 15.2 | <u>§ 60.5375 (a)(2)(v) Review of the effectiveness of the plan in minimizing VOC emissions every 2 years.</u> |
| 27 | See Section 15.2 | § 60.5375 (a)(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback. |
| 28 | See Section 15.2 | § 60.5375 (b) You must maintain <u>a log records</u> for each well completion operation at each gas wellhead affected facility. The log must be completed on a daily basis and must contain the <u>information records</u> specified in § 60.5420(c)(1)(iii). |
| 29 | | § 60.5375 (c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5410. |
| 30 | | § 60.5375 (d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5415. |
| 31 | | § 60.5375 (e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420. |
| 32 | See Section 15.2 | § 60.5375 (f) For wells meeting the criteria for wildcat, <u>appraisal, or delineation wells, or where production equipment or a natural gas gathering line is not reasonably available</u> , each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(3)(1)(ii) of this section. You must also maintain records specified in § 60.5420(e)(1)(iii) for wildcat or delineation wells. |
| 32A | Preferred Option See Section 15.2 | <u>§ 60.5375 (g) The provisions of this Section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing at a natural gas wellhead facility onshore that ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f)</u> |
| 32B | Alternative Option See Section 15.2 | <u>§ 60.5375 (g) The provisions of this Section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f).</u> |
| 33 | | § 60.5380 What standards apply to centrifugal compressor affected facilities? |
| 34 | | § 60.5380 You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility. |

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| 35 | See Section 18.7 and 18.8 | <u>§ 60.5380 (a) You must control VOC emissions from centrifugal compressors using one of the methods described in paragraph (a)(1), (a)(2), or (a)(3). equip each rotating compressor shaft with a dry seal system upon initial startup</u> |
| 35A | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(1) Equip the rotating compressor shaft with a dry seal system upon initial startup.</u> |
| 35B | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2) Equip the rotating compressor shaft with a wet seal-oil degassing system and route the separated gas to one of the following:</u> |
| 35C | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(i) a flare designed and operated in accordance with the requirements of §60.18(b), or</u> |
| 35D | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.</u> |
| 35E | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(iii) a combustion device designed to reduce VOC emissions by 95%, or</u> |
| 35F | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(iv) a fuel system, or</u> |
| 35G | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(v) recycle (compression suction), or</u> |
| 35H | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(2)(vi) a combination of (2)(i) through (2)(v)</u> |
| 35I | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3) Equip the rotating compressor shaft with a wet seal. You must route the seal oil degassing tank vapors through a closed vent system to one of the following:</u> |
| 35J | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3)(i) a flare designed and operated in accordance with the requirements of §60.18(b), or</u> |
| 35K | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3)(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.</u> |
| 35L | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3)(iii) a combustion device designed to reduce VOC emissions by 95%, or</u> |
| 35M | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3)(iv) a vapor recovery device routed to a combustion device designed to reduce VOC emissions by 95%; a fuel system, or recycle (compression suction/process), or</u> |
| 35N | See Section 18.7 and 18.8 | <u>§ 60.5380 (a)(3)(v) a combination of (3)(i) through (3)(iv).</u> |
| 36 | | § 60.5380 (b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410. |
| 37 | | § 60.5380 (c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415. |
| 38 | | § 60.5380 (d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420. |
| 39 | | § 60.5385 What standards apply to reciprocating compressor affected facilities? |

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| 40 | | § 60.5385 You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility. |
| 41 | See Section 18.3 | § 60.5385 (a) You must replace the reciprocating compressor rod packing before the compressor has operated for <u>a longer period than one of the limits listed in paragraphs (a)(1) through (a)(3) of this section 26,000 hours</u> . The number of hours <u>or years</u> of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or <u>60 days from</u> the date of publication of the final rule in the Federal Register, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. <u>If monitoring the number of hours of operation, the hours can be monitored using an associated engine runtime meter, telemetry and associated database, or other system (maintenance logs, PM databases, or work order tracking system) used to track preventative maintenance and schedules.</u> |
| 41A | See Section 18.3 | <u>§ 60.5385 (a)(1) 43,800 hours; or</u> |
| 41B | See Section 18.3 | <u>§ 60.5385 (a)(2) five years; or</u> |
| 41C | See Section 18.3 | <u>§ 60.5385 (a)(3) a frequency specified by the owner or operator in a preventative maintenance plan designed to maximize the reliability of the reciprocating compressor and minimize VOC emissions.</u> |
| 42 | | § 60.5385 (b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410. |
| 43 | | § 60.5385 (c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415. |
| 44 | | § 60.5385 (d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420. |
| 45 | | § 60.5390 What standards apply to <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facilities? |
| 46 | See Sections 5.1 and 17.1 <ul style="list-style-type: none"> Emissions must be expressed in terms of VOC Natural gas not an acceptable surrogate | § 60.5390 For each <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. <u>Continuous bleed gas-driven pneumatically controlled process units Pneumatic controllers</u> meeting the conditions in paragraph (a) are exempt from this requirement. |

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| 47 | <p>See Section 17.9</p> <ul style="list-style-type: none"> • If demonstration and approval is required prior to construction to get Administrator approval, this is not workable due to the extended time required and resultant construction delays. • Removed Administrator’s satisfaction” to avoid misinterpretation or an unworkable requirement | <p>§ 60.5390 (a) The requirements of paragraph (b) or (c) of this section are not required if you <u>have maintained adequate records to support your decision demonstrate, to the Administrator’s satisfaction,</u> that <u>demonstrates</u> the use of a <u>continuous bleed gas-driven pneumatically controlled process unit with one or more high bleed gas-driven pneumatic controllers is required high bleed device is predicated.</u> The demonstration may include, but is not limited to, response time, safety and actuation. <u>Records of demonstration for the high bleed gas-driven pneumatic controller exclusion must be available for inspection.</u></p> |
| 47A | <p>See Section 17.9 If EPA refuses to delete “To the Administrators satisfaction” in the above row, alternative language API proposes.</p> | <p>§ 60.5390 (a) The requirements of paragraph (b) and (c) of this section are not required if your <u>recordkeeping can verify to the Administrator’s satisfaction, the use of a continuous bleed gas-driven pneumatically controlled process unit with one or more high bleed pneumatic controllers is required.</u> The demonstration may include, but is not limited to, response time, safety, and actuation.</p> |
| 48 | <p>See Section 17.5.2 Small Gas Processing Facilities may not have dependable power avail. Removing zero emissions of natural gas inherently requires use of non-VOC containing gas. If not using a continuous bleed gas-driven controller, it is not an affected facility</p> | <p>§ 60.5390 (b) <u>Except for dewpoint depression facilities or other remote natural gas processing plant without reliable electrical power, use of continuous bleed gas-driven pneumatic controllers</u> Each pneumatic controller affected facility located at a natural gas processing plant (as defined in § 60.5430) <u>is prohibited must have zero emissions of natural gas.</u></p> |
| 49 | <p>See Section 17.1 Need clarity that continuous bleed rate applies only to the weak stream, not any intermittent vent and should only apply to controller vents in VOC service.</p> | <p>§ 60.5390 (c) Each <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility not located at a natural gas processing plant (as defined in § 60.5430) must have natural gas emissions <u>from the weak stream vent of each low bleed gas-driven pneumatic controller</u> no greater than 6 standard cubic feet per hour. <u>Compliance with this emissions standard must occur according to the schedule in paragraph (c)(1) or (c)(2)</u></p> |
| 49A | <p>New subparagraph (1) and (2) to set compliance schedule that includes use of instrument air</p> | <p><u>§ 60.5390 (c)(1) Immediately upon installation, for each new, modified, or reconstructed continuous bleed gas-driven pneumatically controlled process unit</u></p> |

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| 49B | See Section 15.5.3 Proposal doesn't include control strategy to switch to instrument air. Allowing 180 days gives time to order and construct air compressor, Result will be greater reduction in VOC emissions than that achieved by using low bleed controllers. | <u>§ 60.5390 (c)(2) At existing sites only, within 180 days of installing a new, modified, or reconstructed continuous bleed gas-driven pneumatically controlled process unit, if control strategy is to replace gas-driven pneumatic controllers with non-gas driven pneumatic controllers by constructing an air compressor to supply compressed air as the gas driver.</u> |
| 50 | See Section 17.4 | § 60.5390 (d) You must demonstrate initial compliance with standards that apply to <u>continuous bleed gas-driven pneumatically controlled process unit</u> pneumatic controller affected facilities as required by § 60.5410. |
| 51 | See Section 17.4 | § 60.5390 (e) You must demonstrate continuous compliance with standards that apply to <u>continuous bleed gas-driven pneumatically controlled process unit</u> pneumatic controller affected facilities as required by § 60.5415. |
| 52 | | § 60.5390 (f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a). |
| 53 | § 60.5395 What standards apply to storage vessel affected facilities? | |
| 54 | | § 60.5395 You must comply with the standards in paragraphs (a) through (e) of this section for each storage vessel affected facility. |
| 55 | See Section 16.4 | § 60.5395 (a) You must comply with the standards for storage vessels <u>storing condensate or crude oil</u> specified in 40 CFR part 63, subpart HH, §63.766(b) and (c) (b) , except as specified in paragraph (b) of this section. Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section. Storage vessels with annual average VOC emissions less than 12 TPY estimated according to (c)(3) are exempt. |
| 56 | See Section 16.4 | § 60.5395 (a)(1) The annual average condensate throughput is less than 1 barrel per day per storage vessel. |
| 57 | See Section 16.4 | § 60.5395 (a)(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel. |
| 57A | See Section 16.7 | <u>§ 60.5395 (b) Within 90 days of the first date of production the owner or operator shall equip the affected storage vessel closed vent system and control device meeting the following specifications:</u> |
| 57B | See Section 16.7 | <u>§ 60.5395 (b)(1) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions.</u> |
| 57C | See Section 16.7 | <u>§ 60.5395 (b)(2) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.</u> |
| 57D | See Section 16.7 | <u>§ 60.5395 (c) The annual average throughput, pressure, and emissions for a new well should be determined as follows:</u> |

| Ref # | Comment | Regulatory Text | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---------------------------|--|--|---------------------------|--|---|----|-----|-----|----|-----|-----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|-----|----|------|-----|----|-----|-----|----|-----|-----|----|-----|-----|----|-----|-----|----|-----|-----|----|-----|-----|----|-----|-----|----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| 57E | See Section 16.7 | <u>§ 60.5395 (c)(1) First 30 days of throughput after the first date of production divided by 30 times the average decline factor for the reservoir based on Lease Automatic Custody Transfer (LACT) meter, haul records (run tickets), sales tickets, or other sales documentation to show the amount transferred to a truck or liquids pipeline.</u> | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 57F | See Section 16.6 and 16.7 | <u>§ 60.5395 (c)(2) Pressure of separator prior to the tank averaged over the first 30 days after the first date of production.</u> | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 57G | See Section 16.7 | <u>§ 60.5395 (c)(3) Calculated using either methods (i) or (ii) using the average annual throughput calculated under (c)(1) and with the average pressure calculated under (c)(2) for demonstrating compliance with (a)(1):</u> | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 57H | See Section 16.7 | <u>§ 60.5395 (c)(3)(i) E&P TANK or an appropriate flashing model</u> | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 57I | See Section 16.7 | <u>§ 60.5395 (c)(3)(ii) Interpolating the table below:</u> <p>Table 6 Throughput Exemption Thresholds vs. Separator Pressure. (corresponding to 12 tpy VOC emissions per tank)</p> <table border="1"> <thead> <tr> <th>Separator Pressure (psig)</th> <th>Crude Oil Throughput Threshold (bbl/day)</th> <th>Condensate Throughput Threshold (bbl/day)</th> </tr> </thead> <tbody> <tr><td>10</td><td>330</td><td>330</td></tr> <tr><td>20</td><td>130</td><td>130</td></tr> <tr><td>30</td><td>73</td><td>66</td></tr> <tr><td>40</td><td>50</td><td>41</td></tr> <tr><td>50</td><td>39</td><td>30</td></tr> <tr><td>60</td><td>31</td><td>22</td></tr> <tr><td>80</td><td>23</td><td>14</td></tr> <tr><td>100</td><td>19</td><td>10.0</td></tr> <tr><td>120</td><td>16</td><td>8.0</td></tr> <tr><td>140</td><td>15</td><td>6.6</td></tr> <tr><td>160</td><td>14</td><td>5.7</td></tr> <tr><td>180</td><td>13</td><td>5.0</td></tr> <tr><td>200</td><td>12</td><td>4.5</td></tr> <tr><td>240</td><td>11</td><td>3.8</td></tr> <tr><td>260</td><td>10</td><td>3.6</td></tr> <tr><td>300</td><td>10</td><td>3.2</td></tr> <tr><td>350</td><td>9.0</td><td>2.8</td></tr> <tr><td>400</td><td>8.7</td><td>2.5</td></tr> <tr><td>450</td><td>8.3</td><td>2.3</td></tr> <tr><td>500</td><td>8.0</td><td>2.1</td></tr> </tbody> </table> | Separator Pressure (psig) | Crude Oil Throughput Threshold (bbl/day) | Condensate Throughput Threshold (bbl/day) | 10 | 330 | 330 | 20 | 130 | 130 | 30 | 73 | 66 | 40 | 50 | 41 | 50 | 39 | 30 | 60 | 31 | 22 | 80 | 23 | 14 | 100 | 19 | 10.0 | 120 | 16 | 8.0 | 140 | 15 | 6.6 | 160 | 14 | 5.7 | 180 | 13 | 5.0 | 200 | 12 | 4.5 | 240 | 11 | 3.8 | 260 | 10 | 3.6 | 300 | 10 | 3.2 | 350 | 9.0 | 2.8 | 400 | 8.7 | 2.5 | 450 | 8.3 | 2.3 | 500 | 8.0 | 2.1 |
| Separator Pressure (psig) | Crude Oil Throughput Threshold (bbl/day) | Condensate Throughput Threshold (bbl/day) | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | 330 | 330 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | 130 | 130 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | 73 | 66 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | 50 | 41 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | 39 | 30 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 60 | 31 | 22 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 80 | 23 | 14 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 100 | 19 | 10.0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 120 | 16 | 8.0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 140 | 15 | 6.6 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 160 | 14 | 5.7 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 180 | 13 | 5.0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 200 | 12 | 4.5 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 240 | 11 | 3.8 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 260 | 10 | 3.6 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 300 | 10 | 3.2 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 350 | 9.0 | 2.8 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 400 | 8.7 | 2.5 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 450 | 8.3 | 2.3 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 500 | 8.0 | 2.1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 58 | See Section 16.7 | <u>§ 60.5395 (b) (d)</u> This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in § 63.766(b)(1) or (2) of this chapter. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

| Ref # | Comment | Regulatory Text |
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| 59 | See Section 16.7 | § 60.5395- (e) <u>(e)</u> You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410. |
| 60 | See Section 16.7 | § 60.5395- (d) <u>(f)</u> You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415. |
| 61 | See Section 16.7 | § 60.5395- (e) <u>(g)</u> You must perform the required notification, recordkeeping, and reporting as required by § 60.5420. |
| 62 | § 60.5400 What VOC standards apply to affected facilities at an onshore natural gas processing plant? | |
| 63 | See Section 19.3 | § 60.5400 This section applies to each compressor in VOC service or in wet gas service and the group of all equipment (as defined in § 60.5430), except compressors, within a process unit. |
| 64 | See Section 19.3 & 19.8.3. | § 60.5400 (a) You must comply with the requirements of § 60.482-1a(a), (b), and (d), § 60.482-2a, and § 60.482-4a, and § 60.482-6a through 60.482-104a, except as provided in <u>(a)(1) through (a)(4) below and in § 60.5401.</u> |
| 64A | See Section 19.1. | <u>§ 60.5400 (a)(1) In lieu of §60.482-2a(b)(1), a leak in a pump in light liquid service is detected if an instrument reading of 10,000 ppm or greater is measured.</u> |
| 64B | See Section 19.1. | <u>§ 60.5400 (a)(2) In lieu of §60.482-7a(b), a leak in a valve is detected if an instrument reading of 10,000 ppm is measured.</u> |
| 64C | See Section 19.1. | <u>§ 60.5400 (a)(3) In lieu of §60.482-7a(c)(2), if a leak is detected, the valve shall be monitored after it is repaired, and then, quarterly thereafter.</u> |
| 64D | See Section 19.1. | <u>§ 60.5400 (a)(4) If a leak is detected in three of any four consecutive quarters, the valve shall be designated as a chronic leaker. All valves designated as chronic leaker shall be refurbished or replaced during the next process unit shut-down.</u> |
| 65 | See Section 19.1. API is offering to give up alternative standards (skip period and allowable percentage) in lieu of the leak definition of 500 ppm. LDAR 1.1 | § 60.5400 (b) You may elect to comply with the requirements of §§ 60.483-1a and 60.483-2a, as an alternative. |
| 65A | See Section 19.1. API commits to VAO monitoring in lieu of M21 monitoring with a 500 ppm leak definition. LDAR 1.1 | <u>§ 60.5400 (b) Connectors in gas/vapor service or light liquid service shall comply with the monitoring and leak definition provisions of §60.482-8a.</u> |
| 66 | | § 60.5400 (c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of§ 60.5402 of this subpart. |
| 67 | | § 60.5400 (d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section. |
| 68 | | § 60.5400 (e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part. |

| Ref # | Comment | Regulatory Text |
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| 69 | | § 60.5400 (f) You must use the following provision instead of § 60.485a(d)(1): |
| 70 | Preferred 19.4.2 | § 60.5400 Each piece of equipment is presumed to be in VOC service or in wet gas unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in § 60.17) must be used. |
| 70A | Alternative 19.4.2 | Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. <u>For a piece of equipment to be considered not in wet gas service, it must be determined that the VOC content can be reasonably expected never to exceed X percent by weight [Note: API recommends X be 5.0 or greater].</u> For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in § 60.17) must be used. |
| 71 | § 60.5401 What are the exceptions to the VOC standards for affected facilities at onshore natural gas processing plants? | |
| 72 | | § 60.5401 (a) You may comply with the following exceptions to the provisions of subpart VVa of this part. |
| 73 | | § 60.5401 (b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa. |
| 74 | Section 19.8.2 EPA should clarify whether it is 5000 or 500 ppm [see 60.5421(b)(2)(iv)] LDAR 1.9.1 | § 60.5401 (b)(2) If an instrument reading of 5000 ppm or greater is measured, a leak is detected. |
| 75 | | § 60.5401 (b)(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a. |

| Ref # | Comment | Regulatory Text |
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| 76 | | § 60.5401 (b)(3)(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected. |
| 77 | | § 60.5401 (b)(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa. |
| 78 | | § 60.5401 (b)(4)(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring. |
| 79 | | § 60.5401 (c) Sampling connection systems are exempt from the requirements of § 60.482–5a. |
| 80 | See Section 19.8.1. and 19.8.3. Preferred- no VVa connector program | § 60.5401 (d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant with a design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or less more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section, <u>and the reporting requirements found in §60.5420 and 60.5422.</u> |
| 80A | Alternative- with VVa connector program See Section 19.8.1. and 19.8.3. | § 60.5401 (d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant with a design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or less more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), <u>60.482-11a</u> , and paragraph (b)(1) of this section, <u>and the reporting requirements found in §60.5420 and 60.5422.</u> |
| 81 | See Section 19.8.3. | § 60.5401 (e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section, <u>and the reporting requirements found in §60.5420 and 60.5422.</u> |
| 81A | | |
| 82 | See Section 9.3. and 60.5414(i) | § 60.5401 (f) Flares used to comply with this subpart must comply with the requirements of § 60.18 (b) , <u>except as provided in § 60.5415 (i)(1) and (2).</u> |
| 83 | | § 60.5401 (g) An owner or operator may use the following provisions instead of § 60.485a(e): |
| 84 | | § 60.5401 (g)(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17). |

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| 85 | | § 60.5401 (g)(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302°F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17). |
| 85A | See Section 19.5 | <u>§ 60.5401 (h) In addition to the provisions of 60.482-9a, delay of repair for valves and connectors will be allowed if:</u> |
| 85B | See Section 19.5 | <u>§ 60.5401 (h)(1) Initial (within 5 days of the leak being detected) and follow-up (within 15 days of the leak being detected) repair attempts using routine methods have been completed and were unsuccessful and</u> |
| 85C | See Section 19.5 | <u>§ 60.5401 (h)(2) Further on-line repair attempts require the use of a specialized repair contractor, and</u> |
| 85D | See Section 19.5 | <p><u>§ 60.5401 (h)(3) Further specialized repair attempts are completed as soon as practicable, but not later than 90 days after the leak was detected. If a repair attempt using a specialized technique is unsuccessful, repair shall occur before the end of the next process unit shutdown or as otherwise allowed by 60.482-9a(e).</u></p> <p><u>A specialized repair contractor provides repair services not available from the facility or contractor maintenance personnel who perform routine repairs of most facility equipment leaks. An example of a specialized repair contractor is a contractor who provides valve gland drill and tap services.</u></p> |
| 85E | See Section 19.1.4 | <u>§ 60.5401 (i) Any existing reciprocating pump in a process unit which becomes an affected facility under the provisions of §60.14 or §60.15 is exempt from§60.482-2a of this part, provided the owner or operator demonstrates that recasting the distance piece or replacing the pump are the only options available to bring the pump into compliance with the provisions of §60.482-2a of this part.</u> |
| 86 | § 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants? | |
| 87 | | § 60.5402 (a) If, in the Administrator’s judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the Federal Register, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means. |
| 88 | | § 60.5402 (b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing. |

| Ref # | Comment | Regulatory Text |
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| 89 | | § 60.5402 (c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment. |
| 90 | | § 60.5402 (d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate: |
| 91 | | § 60.5402 (d)(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section. |
| 92 | | § 60.5402 (d)(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard. |
| 93 | § 60.5405 What standards apply to sweetening units at onshore natural gas processing plants? | |
| 94 | | § 60.5405 (a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO ₂ emission reduction efficiency (Z _i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility. |
| 95 | | § 60.5405 (b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO ₂ emission reduction efficiency (Z _c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility. |
| 96 | 60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants? | |
| 97 | | § 60.5406 (a) In conducting the performance tests required in § 60.8, you must use the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b). |
| 98 | | § 60.5406 (b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO ₂ emissions as required in § 60.5405(a) and (b) as follows: |
| 99 | | § 60.5406 (b)(1) The average sulfur feed rate (X) must be computed as follows:[Equation]Where:X = average sulfur feed rate, Mg/D (LT/D).Q _a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).γ = average H ₂ S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.K = (32 kg S/kg-mole) / ((24.04 dscm/kgmole) (1000 kg S/Mg)) = 1.331 × 10 ⁻³ Mg/dscm, for metric units = (32 lb S/lb-mole) / ((385.36 dscf/lb-mole) (2240 lb S/long ton)) = 3.707 × 10 ⁻⁵ long ton/dscf, for English units. |
| 100 | | § 60.5406 (b)(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q _a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run. |

| Ref # | Comment | Regulatory Text |
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| 101 | | <p>§ 60.5406 (b)(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E-260 (incorporated by reference—see § 60.17) to determine the H₂S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H₂S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.</p> |
| 102 | | <p>§ 60.5406 (b)(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO₂ emissions.</p> |
| 103 | | <p>§ 60.5406 (c) You must determine compliance with the SO₂ standards in § 60.5405(a) or (b) as follows:</p> |
| 104 | | <p>§ 60.5406 (c)(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:[Equation]</p> |
| 105 | | <p>§ 60.5406 (c)(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage tanks. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.</p> |
| 106 | | <p>§ 60.5406 (c)(3) You must compute the emission rate of sulfur for each run as follows:[Equation]Where: E = emission rate of sulfur per run, kg/hr. C_e = concentration of sulfur equivalent (SO₂ + reduced sulfur), g/dscm (lb/dscf). Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr). K₁ = conversion factor, 1000 g/kg (7000 gr/lb).</p> |
| 107 | | <p>§ 60.5406 (c)(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO₂ and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of Appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m² (54 ft²) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m² or more, and the centroid is more than 1 m (39 in.) from the wall.</p> |
| 108 | | <p>§ 60.5406 (c)(4)(i) You must use Method 6 of Appendix A to part 60 of this chapter to determine the SO₂ concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.</p> |

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| 109 | | <p>§ 60.5406 (c)(4)(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft³/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^3 to convert the results to sulfur equivalent.</p> |
| 110 | | <p>§ 60.5406 (c)(4)(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter to determine the reduced sulfur concentration from oxidation type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^3 to convert the results to sulfur equivalent.</p> |
| 111 | | <p>§ 60.5406 (c)(4)(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.</p> |
| 112 | <p>§ 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?</p> | |
| 113 | | <p>§ 60.5407 (a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:</p> |

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| 114 | | § 60.5407 (a)(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage tanks with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation. |
| 115 | | § 60.5407 (a)(2) The H ₂ S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H ₂ S concentration obtained from one or more samples over a 24-hour period is samples collected at equally spaced intervals during the 24-hour period. In instances where the H ₂ S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule. |
| 116 | | § 60.5407 (a)(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings. |
| 117 | | § 60.5407 (a)(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(3). |
| 118 | | § 60.5407 (a)(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H ₂ S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b). |
| 119 | | § 60.5407 (b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows: |
| 120 | | § 60.5407 (b)(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO ₂ in the gases discharged to the atmosphere. The SO ₂ emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system. |

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| 121 | | <p>§ 60.5407 (b)(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.</p> |
| 122 | | <p>§ 60.5407 (b)(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO₂) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.</p> |
| 123 | | <p>§ 60.5407 (b)(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).</p> |
| 124 | | <p>§ 60.5407 (c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO₂ equivalent in the gases discharged to the atmosphere. The SO₂ equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.</p> |

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| 125 | | § 60.5407 (d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1). |
| 126 | | § 60.5407 (d)(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S. |
| 127 | | § 60.5407 (d)(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average. |
| 128 | | § 60.5407 (e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H ₂ S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:[Equation]Where: R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent. K ₂ = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr). S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr). X = The sulfur feed rate in the acid gas, Mg/D (LT/D). |
| 129 | | § 60.5407 (f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b). |
| 130 | | § 60.5407 (g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section. |
| 131 | § 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure? | |
| 132 | | § 60.5408 (a) When an instantaneous sample is desired and H ₂ S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine. |

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| 133 | | § 60.5408 (b) Apparatus. (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle. |
| 134 | | § 60.5408 (c) Reagents. |
| 135 | | § 60.5408 (c)(1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass stoppered brown glass bottle. |
| 136 | | § 60.5408 (c)(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H ₂ S per cubic feet of gas. |
| 137 | | § 60.5408 (c)(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days. |
| 138 | | § 60.5408 (d) Procedure. Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D. |
| 139 | | § 60.5408 (e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H ₂ S per 100 cubic foot of gas = 100 (D-C) |
| 140 | | § 60.5408 (f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H ₂ S-free gas or air, is required. |

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| 141 | | <p>§ 60.5410 How do I demonstrate initial compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?</p> |
| 142 | | <p>§ 60.5410 You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the Federal Register or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in § 60.5420(b).</p> |
| 143 | | <p>§ 60.5410 (a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.</p> |
| 144 | See Section 15.7.2 | <p>§ 60.5410 (a)(1) You have notified the Administrator <u>monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month if you have one or more fracs including within 30 days of the commencement of the well completion operation</u>, the <u>tentative scheduled start date of the well flowback and of the well completion operation</u>, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983</p> |
| 145 | | <p>§ 60.5410 (a)(2) You have maintained a log of records as specified in § 60.5375(b) or (f) for each well completion operation conducted during the initial compliance period.</p> |
| 146 | | <p>§ 60.5410 (a)(3) You have submitted the initial annual report for your wellhead affected facility as required in § 60.5420(b).</p> |
| 147 | See Section 18 | <p>§ 60.5410 (b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted <u>with a dry seal system</u> upon initial startup as required by § 60.5380.</p> |
| 148 | | <p>§ 60.5410 (c) You have achieved initial compliance with standards for each reciprocating compressor affected facility if you have complied with paragraphs (c)(1) and (c)(2) of this section.</p> |
| 149 | | <p>§ 60.5410 (c)(1) During the initial compliance period, you have continuously monitored the number of hours of operation.</p> |
| 150 | | <p>§ 60.5410 (c)(2) You have included the cumulative number of hours of operation for your reciprocating compressor affected facility during the initial compliance period in your initial annual report required in § 60.5420(b).</p> |

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| 151 | See Section 17.4 | § 60.5410 (d) You have achieved initial compliance with emission standards for your <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility if you comply with the requirements specified in paragraphs (d)(1) through (d)(43) of this section. |
| 152 | See Section 17.1 and 17.7 (Note: typo, should be 60.5390(a), there is no 5490 section.) As in 60.5390(a), “Administrator’s satisfaction” suggests prior approval. Removed for consistency and clarity. | § 60.5410 (d)(1) You have demonstrated to the Administrator’s satisfaction, the use of a high bleed <u>gas-driven pneumatic controller device</u> is predicated as specified in § 60.54390(a). |
| 153 | See Section 17.5.1 Remove for consistency and clarity. If pneumatic controllers are non-gas driven they are not part of an affected facility, therefore this paragraph is unnecessary | § 60.5410 (d)(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas. |
| 154 | See Section 17.10 Uncertain if use “guarantee” is for descriptive purposes or means an actual certified guarantee <ul style="list-style-type: none"> If an actual guarantee required, manufacturers not prepared to provide this on effective date. “Guarantee” should be replaced with “verify” if an actual statement of guarantee not required. | § 60.5410 (d)(3) You own or operate a <u>continuous bleed gas-driven pneumatically controlled process unit affected facility pneumatic controller affected facility</u> not located at a natural gas processing plant and the manufacturer’s design specifications <u>verify guarantee</u> the <u>low bleed gas-driven pneumatic controller weak stream</u> emits less than or equal to 6.0 standard cubic feet of gas per hour. |
| 155 | See Section 17 | § 60.5410 (d)(4) You have included the information in paragraphs (d)(1) through (d)(3) of this section in the initial annual report submitted for your <u>continuous bleed gas-driven pneumatically controlled process unit affected facility pneumatic controller</u> affected facilities according to the requirements of § 60.5420(b). |
| 156 | See Section 16 | § 60.5410 (e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1), (2), or (3) through (e)(7) of this section. |
| 157 | See Section 16 | § 60.5410 (e)(1) You have equipped the storage vessel with a closed vent system that meets the requirements of § 63.771(e) of this chapter connected to and a control device that meets the conditions specified in § 63.771(d) 60.5395(b). |
| 158 | See Section 9.5 | § 60.5410(e)(2) You have <u>a copy of the performance test results for a performance test conducted by the manufacturer as specified in §60.772(h)</u> conducted an initial performance test as required in § 63.772(e) of this chapter within 180 days after initial startup or the date of publication of the final rule in the Federal Register and have conducted the compliance demonstration in § 63.772(f). |

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| 159 | | § 60.5410 (e)(3) You have conducted the initial inspections required in § 63.773(e) of this chapter. |
| 160 | See Section 16.7 | § 60.5410 (e)(4) You have installed and operated continuous parameter monitoring systems in accordance with § 63.773(d) of this chapter. |
| 161 | See Section 16.7 | § 60.5410 (e) (5) <u>(3)</u> If you are exempt from the standards of § 60.5395 according to § 60.5395(a) (1) or (a)(2) , you have determined the condensate or crude oil throughput, <u>pressure, and emissions according to 60.5395(c)</u> , as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank. |
| 162 | See Section 16.7 | § 60.5410 (e)(5)(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications. |
| 163 | See Section 16.7 | § 60.5410 (e)(5)(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput. |
| 164 | See Section 16.7 | § 60.5410 (6) <u>(4)</u> You have submitted the information in paragraphs (e)(1) through (e) (5) <u>(3)</u> of this section in the initial annual report for your storage vessel affected facility as required in § 60.5420(b). |
| 165 | | § 60.5410 (f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400. |
| 166 | | § 60.5410 (g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (g)(3) of this section. |
| 167 | | § 60.5410 (g)(1) To determine compliance with the standards for SO ₂ specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z _i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (g)(1)(ii) of this section. |
| 168 | | § 60.5410 (g)(1)(i) If $R \geq Z_i$, your affected facility is in compliance. |
| 169 | | § 60.5410 (g)(1)(ii) If $R < Z_i$, your affected facility is not in compliance. |
| 170 | | § 60.5410 (g)(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1). (3) You have submitted the results of paragraphs (g)(1) and (g)(2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants. |

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| 171 | | <p>§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my <u>continuous bleed gas-driven pneumatically controlled process unit</u> pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?</p> |
| 172 | | <p>§ 60.5415 (a) For each gas wellhead affected facility, you must demonstrate continuous compliance by maintaining the records for each completion operation (as defined in § 60.5430) specified in § 60.5420.</p> |
| 173 | See Section 18.8 | <p>§ 60.5415 (b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped with a dry seal as specified in § 60.5380(a).</p> |
| 174 | | <p>§ 60.5415 (c) For each reciprocating compressor affected facility, you have demonstrated continuous compliance according to paragraphs (c)(1) and (2) of this section</p> |
| 175 | | <p>§ 60.5415 (c)(1) You have continuously monitored the number of hours of operation for each reciprocating compressor affected facility since initial startup, or the date of publication of the final rule in the Federal Register, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. The cumulative number of hours of operation must be included in the annual report as required in § 60.5420(b)(4).</p> |
| 176 | See Section 18.3.4 | <p>§ 60.5415 (c)(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches the limit selected by the owner or operator from § 60.5385(a)(1) through (a)(3) 26,000 hours.</p> |
| 177 | <p>See Section 17.1</p> <ul style="list-style-type: none"> Pilot valve design in controller will determine max bleed rate, creating records of “operated as required” not possible <p>Records of installation and design specs would seem sufficient demonstration.</p> | <p>§ 60.5415 (d) For each <u>continuous bleed gas-driven pneumatically controlled process unit</u> pneumatic controller affected facility, continuous compliance is demonstrated by maintaining the records demonstrating that you have installed and operated the <u>continuous bleed gas-driven</u> pneumatic controllers as required in § 60.5390(a), (b) or (c).</p> |
| 178 | See Section 16.7 | <p>§ 60.5415 (e) For each storage vessel affected facility, continuous compliance is demonstrated according to § 63.772(f) of this chapter. The owner or operator of each source that is equipped with a closed vent system and control device as required in 60.5395(b) shall meet either the requirements of (1) or (2) below.</p> |
| 178A | See Section 16.7 | <p><u>§ 60.5415 (e)(1) Develop and maintain for review of an operating plan containing the information listed below and operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (2)(i) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.</u></p> |

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| 178B | See Section 16.7 | <p><u>§ 60.5415 (e)(1)(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.</u></p> |
| 178C | See Section 16.7 | <p><u>§ 60.5415 (e)(1)(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).</u></p> |
| 178D | See Section 16.7 | <p><u>§ 60.5415 (e)(2) A control device that has been certified by the manufacture with a performance test to demonstrate the device meets the requirements of 60.5395(b) and parameters limits needed to meet the requirements of 60.5395(b) to measure. Monitor the parameters of the control device to demonstrate the control device is operating within the parameter limits specified by the manufacture.</u></p> |
| 179 | | <p>§ 60.5415 (f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.</p> |
| 180 | | <p>§ 60.5415 (g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO₂ specified in § 60.5405(b) according to paragraphs (g)(1) and (g)(2) of this section.</p> |
| 181 | | <p>§ 60.5415 (g)(1) The minimum required SO₂ emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.</p> |
| 182 | | <p>§ 60.5415 (g)(1)(i) If $R \geq Z_c$, your affected facility is in compliance.</p> |
| 183 | | <p>§ 60.5415 (g)(1)(ii) If $R < Z_c$, your affected facility is not in compliance.</p> |
| 184 | | <p>§ 60.5415 (g)(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).</p> |

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| 185 | | § 60.5415 (h) Excess emissions resulting from SSM activities Affirmative defense for exceedance of emission limit during malfunction. In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief. |
| 186 | | § 60.5415 (h)(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in § 60.5420(a), and must prove by a preponderance of evidence that: |
| 187 | | § 60.5415 (h)(1)(i) The excess emissions: |
| 188 | | § 60.5415 (h)(1)(i)(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and |
| 189 | | § 60.5415 (h)(1)(i)(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and |
| 190 | | § 60.5415 (h)(1)(i)(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and |
| 191 | | § 60.5415 (h)(1)(i)(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and |
| 192 | | § 60.5415 (h)(1)(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and |
| 193 | | § 60.5415 (h)(1)(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and |
| 194 | | § 60.5415 (h)(1)(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and |
| 195 | | § 60.5415 (h)(1)(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and |
| 196 | | § 60.5415 (h)(1)(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and |
| 197 | | § 60.5415 (h)(1)(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and |
| 198 | | § 60.5415 (h)(1)(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and |

| Ref # | Comment | Regulatory Text |
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| 199 | | § 60.5415 (h)(1)(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction. |
| 200 | | § 60.5415 (h)(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, and 60.5400 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance. |
| 200A | See Section 9.3 | <u>§ 60.5415 (i) Flares used for compliance of this section will comply with 60.18(b), except as provided in § 60.5415 (i)(1) and (2).</u> |
| 200B | See Section 9.1.1. | <u>§ 60.5415 (i)(1) “flame present at all times” required in 60.18(c)(2) means that a pilot that must be present at all times while a VOC or waste stream is being sent to the flare for emissions destruction, or</u> |
| 200C | See Section 9.1.2. | <u>§ 60.5415 (i)(2) or thru the use of an electronic ignition device.</u> |
| 200D | See Section 9. | <u>§ 60.5415 (j) For the purposes of this subpart if the vapors from the affected facility are routed back to process and meet the definition provided for routed to process in § 60.5430 then this equipment is not considered a control device or closed vent system.</u> |
| 201 | | § 60.5420 What are my notification, reporting, and recordkeeping requirements? |
| 202 | See Section 15.7.2 | § 60.5420 (a) You must submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4), and according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365. For the purposes of this subpart, a workover that occurs after August 23, 2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under § 60.7(a)(4). |

| Ref # | Comment | Regulatory Text |
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| 203 | See Section 17 | § 60.5420 (a)(1) If you own or operate a <u>continuous bleed gas-driven pneumatically controlled process unit</u> pneumatic controller affected facility you are not required to submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4). |
| 204 | See Section 15.7.2 | § 60.5420 (a)(2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator <u>monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month if you have one or more fracs within 30 days of the commencement of the well completion operation.</u> The notification must include the <u>tentative scheduled start</u> date of <u>the well flowback and commencement of the well completion operation</u> , the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983. |
| 205 | See Section 17.1 and 17.4 Operators install or replace pneumatic controllers continually throughout year. Tens if not hundreds of reports per year would be required per operator just for pneumatics. No obvious benefit to annual reporting. <ul style="list-style-type: none"> • If EPA agrees, accept recommended exception. • If EPA refuses, refer to next row for alternative language recommendation | § 60.5420 (b) Reporting requirements. <u>Except for continuous bleed gas-driven pneumatically controlled process unit affected facilities,</u> you must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year after the date of publication of the final rule in the Federal Register, whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section. |
| 205A | See Section 17.9 Alternative reporting requirement if primary recommendation in above row is refused. <ul style="list-style-type: none"> • Only a single initial report for construction of new, modified, or reconstructed process unit affected facilities should be required. • A set reporting date is needed due to the potentially high number of installations each year that could require one or more reports every day. | <u>(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. Except for continuous bleed gas-driven pneumatically controlled process unit affected facilities, the initial annual report is due 1 year after the initial startup date for your affected facility or 1 year after the date of publication of the final rule in the Federal Register, whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section For continuous bleed gas-driven pneumatically controlled process unit affected facilities, the annual report period ends on April 30, and report must be submitted by July 1, and is only required when a new, modified, or reconstructed affected facility occurs in the current reporting period.</u> |
| 206 | | § 60.5420 (b)(1) The general information specified in paragraphs (b)(1)(i) through (b)(1)(iii) of this section. |

| Ref # | Comment | Regulatory Text |
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| 207 | See Section 17.9 <ul style="list-style-type: none"> • Mailing address from where report is submitted is proper. • Address of affected facility is redundant with (ii), especially if multiple sites being reported. | § 60.5420 (b)(1)(i) The company name and <u>mailing</u> address of the affected facility. |
| 208 | For a pneumatically controlled process unit affected facility this would be the name and location of each site included in the report. | § 60.5420 (b)(1)(ii) An identification of each affected facility being included in the annual report. |
| 209 | | § 60.5420 (b)(1)(iii) Beginning and ending dates of the reporting period. |
| 210 | See Section 8.5 | § 60.5420 (b)(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) through and (b)(2)(iii) of this section. |
| 211 | See Section 8.5 | § 60.5420 (b)(2)(i) An identification <u>by API well number and date flowback ended</u> of each <u>flowback immediately following hydraulic fracturing stimulation at natural gas wellhead facilities onshore well-completion operation, as defined in § 60.5430, for each gas wellhead affected facility</u> conducted during the reporting period; |
| 212 | See Section 8.5 | § 60.5420 (b)(2)(ii) A record of deviations <u>and reasons for the deviations</u> in cases where well-completion operations with flowback immediately following hydraulic fracturing <u>stimulation at natural gas wellhead facilities onshore</u> were not performed in compliance with the requirements specified in § 60.5375 for each gas well affected facility. |
| 213 | See Section 8.5 | § 60.5420 (b)(2)(iii) Records specified in § 60.5375(b) for each well-completion operation that occurred during the reporting period. |
| 214 | See Section 8.5 | § 60.5420 (b)(3) For each centrifugal compressor affected facility installed during the reporting period, documentation that the centrifugal compressor is <u>not</u> equipped with dry-seals <u>as specified in § 60.5380(a).</u> |
| 215 | See Section 8.5 | § 60.5420 (b)(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section. |
| 216 | See Section 8.5 | § 60.5420 (b)(4)(i) The cumulative number of hours or operation since initial startup, the date of publication of the final rule in the Federal Register, or since the previous reciprocating compressor rod packing replacement, whichever is later. |
| 217 | See Section 8.5 | § 60.5420 (b)(4)(ii) D documentation that the reciprocating compressor rod packing was <u>not</u> replaced <u>according to one of the frequencies described in § 60.5385(a) before the cumulative number of hours of operation reached 24,000 hours.</u> |

| Ref # | Comment | Regulatory Text |
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| 218 | Annual reports would be same as initial report, except for updating the date on the cover letter. Eliminate annual reporting, no value as it will not change year to year. Burdensome to industry and agencies, would add wasteful but considerable cost to third party verifier. | § 60.5420 (b)(5) For each <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section. |
| 219 | No need to prove high bleed specifications if operator has to justify its use elsewhere in report. | § 60.5420 (b)(5)(i) The date, <u>site name location</u> and <u>quantity of high bleed gas-driven manufacturer specifications for each pneumatic controllers</u> installed. |
| 220 | For only high bleed controller report, “if applicable” is unnecessary | § 60.5420 (b)(5)(ii) If applicable, d Documentation that the use of high bleed <u>gas-driven pneumatic controllers devices</u> is predicated and the reasons why. |
| 221 | No need to mention gas plant if gas-driven controllers prohibited. A certification statement: <ul style="list-style-type: none"> • Simplifies report preparation • Is the equivalent of a compliance certification Eliminates problem of relying on manufacturer’s guarantee. | § 60.5420 (b)(5)(iii) <u>For all low-bleed gas driven controllers installed, a statement certifying that each controller was designed to meet the emissions threshold of less than 6 standard cubic feet per hour. For pneumatic controllers not installed at a natural gas processing plant, the manufacturer’s guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.</u> |
| 222 | Reporting for non-gas driven individual controllers should not be required since there are no regulated emissions and are consequently not an affected facility. | § 60.5420 (b)(5)(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions. Deleted due to unregulated facility at gas plant. |
| 223 | | § 60.5420 (b)(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section. |
| 224 | See Section 8.4.2 | § 60.5420 (b)(6) (i) If required to reduce emissions by complying with paragraph §60.5395(ab)(1), the records specified in § 63.774(b)(2) through (b)(8) of this chapter. <u>the API number of the location of the tank and date of installation.</u> |
| 224A | | <u>§ 60.5420 (b)(6)(i)(A) A copy of the operating plan if using 60.5415(e)(1).</u> |
| 224B | | <u>§ 60.5420 (b)(6)(i)(B) A copy of manufacturer certification if using 60.5415(e)(2).</u> |
| 224C | | <u>§ 60.5420 (b)(6)(i)(C) A record of the measured values of the parameters monitored.</u> |
| 225 | See Section 8.4.2 | § 60.5420 (b)(6)(ii) <u>If exempt from §60.5395 in accordance with §60.5395(a), the API number of the location of the exempt tank and date of installation.</u> Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in § 60.5395(a)(1) or (a)(2). |

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| 226 | | § 60.5420 (c) Recordkeeping requirements. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (c)(5) of this section |
| 227 | | § 60.5420 (c)(1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii). |
| 228 | See Section 15.5 | § 60.5420 (c)(1)(i) Records identifying <u>by API well number and date flowback ended</u> , each <u>flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facility well completion operation for each gas wellhead affected facility</u> conducted during the reporting period; |
| 229 | See Section 15.5 | § 60.5420 (c)(1)(ii) Record of deviations <u>and reasons for the deviations</u> in cases where <u>well completion operations with flowback immediately following</u> hydraulic fracturing <u>stimulation at natural gas wellhead facilities onshore</u> were not performed in compliance with the requirements specified in § 60.5375. |
| 230 | See Section 15.5 | § 60.5420 (c)(1)(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section. |
| 231 | | (A) For each <u>flowback immediately following hydraulic fracturing stimulation at natural gas wellhead facilities onshore gas wellheads affected facility</u> required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion <u>including but not limited to wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, and where combustion is not allowed due to fire hazard, conditions that may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement.</u> The duration must be specified in hours of time. |
| 232 | See Section 15.9 | § 60.5420 (c)(1)(iii)(B) For each gas wellhead affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line. |
| 233 | | § 60.5420 (c)(2) For each centrifugal compressor affected facility, you must maintain records on the type of seal system installed. |
| 234 | | § 60.5420 (c)(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) and (c)(3)(ii) of this section. |
| 235 | | § 60.5420 (c)(3)(i) Records of the cumulative number of hours of operation since initial startup or the date of publication of the final rule in the Federal Register, or the previous replacement of the reciprocating compressor rod packing, whichever is later. |

| Ref # | Comment | Regulatory Text |
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| 236 | | § 60.5420 (c)(3)(ii) Records of the date and time of each reciprocating compressor rod packing replacement. |
| 237 | See Section 17.8 Detailed records are not needed for air or non gas-driven controllers as they have no regulated emissions and are not affected facilities | § 60.5420 (c)(4) For each <u>continuous bleed gas-driven pneumatically controlled process unit pneumatic controller</u> affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(iv-iii) of this section. |
| 238 | See Section 17.8 | § 60.5420 (c)(4)(i) Records of the date <u>and site name location and manufacturer specifications</u> for each <u>continuous bleed gas-driven pneumatic controller</u> installed. |
| 239 | See Section 17.8 | § 60.5420 (c)(4)(ii) Records of the determination that the use of high bleed <u>gas-driven pneumatic controllers devices</u> is predicated and the reasons why. |
| 240 | See Section 17.8 | § 60.5420 (c)(4)(iii) If the <u>For each continuous bleed gas-driven pneumatic controller affected facility is not located at a natural gas processing plant,</u> records of the manufacturer's <u>specifications for low bleed pneumatic controllers specifications must verify guarantee</u> that the device is designed such that <u>weak stream natural gas</u> emissions are less than 6 standard cubic feet per hour. |
| 241 | <ul style="list-style-type: none"> Air driven controllers have no regulated emissions and are not part of an affected facility Instrument air driven controllers occur at other productions sites not just gas plants. | § 60.5420 (c)(4)(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used. |
| 242 | | § 60.5420 (c)(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section. |
| 243 | See Section 16.7 | § 60.5420 (c)(5)(i) If required to reduce emissions by complying with § 63.766-60.5395(b), maintain the <u>following</u> records <u>specified in § 63.774(b)(2) through (8) of this chapter.</u> |
| 243A | See Section 16.7 | <u>§ 60.5420 (c)(5)(i)(A) A copy of the operating plan if using §60.5415(e)(1).</u> |
| 243B | See Section 16.7 | <u>§ 60.5420 (c)(5)(i)(B) A copy of manufacturer certification if using §60.5415(e)(2)</u> |
| 243C | See Section 16.7 | <u>§ 60.5420 (c)(5)(i)(C) A record of the measured values of the parameters monitored.</u> |
| 244 | See Section 16.7 | § 60.5420 (c)(5)(ii) Records of the determination <u>of the throughput, pressure, and emissions using the methods in 60.5395(c) to demonstrate emissions are below 12 TPY. that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under § 60.5395(a)(1) and (a)(2).</u> |
| 245 | | § 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants? |

| Ref # | Comment | Regulatory Text |
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| 246 | | § 60.5421 (a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a. |
| 247 | | § 60.5421 (b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart. |
| 248 | | § 60.5421 (b)(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired. |
| 249 | | § 60.5421 (b)(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location: |
| 250 | | § 60.5421 (b)(2)(i) The instrument and operator identification numbers and the equipment identification number. |
| 251 | | § 60.5421 (b)(2)(ii) The date the leak was detected and the dates of each attempt to repair the leak. |
| 252 | | § 60.5421 (b)(2)(iii) Repair methods applied in each attempt to repair the leak. |
| 253 | | § 60.5421 (b)(2)(iv) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater. |
| 254 | | § 60.5421 (b)(2)(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak. |
| 255 | | § 60.5421 (b)(2)(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown. |
| 256 | | § 60.5421 (b)(2)(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days. |
| 257 | | § 60.5421 (b)(2)(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired. |
| 258 | | § 60.5421 (b)(2)(ix) The date of successful repair of the leak. |
| 259 | | § 60.5421 (b)(2)(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator. |
| 260 | § 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants? | |
| 261 | | § 60.5422 (a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). |

| Ref # | Comment | Regulatory Text |
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| 262 | | § 60.5422 (b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c). |
| 263 | | § 60.5422 (c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi): |
| 264 | | § 60.5422 (c)(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and (2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3). |
| 265 | § 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants? | |
| 266 | | § 60.5423 (a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions. |
| 267 | | § 60.5423 (b) You must submit a written report of excess emissions to the Administrator semiannually. For the purpose of these reports, excess emissions are defined as: |
| 268 | | § 60.5423 (b)(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z). |
| 269 | | § 60.5423 (b)(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours. |
| 270 | | § 60.5423 (c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H ₂ S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H ₂ S expressed as sulfur. |
| 271 | | § 60.5423 (d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H ₂ S expressed as sulfur. |

| Ref # | Comment | Regulatory Text |
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| 272 | | § 60.5423 (e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. |
| 273 | § 60.5425 What part of the General Provisions apply to me? | |
| 274 | | § 60.5425 Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you. |
| 275 | § 60.5430 What definitions apply to this subpart? | |
| 276 | | As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them. |
| 277 | | <i>Acid gas</i> means a gas stream of hydrogen sulfide (H ₂ S) and carbon dioxide (CO ₂) that has been separated from sour natural gas by a sweetening unit. |
| 278 | | <i>Alaskan North Slope</i> means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean. |
| 279 | | <i>API Gravity</i> means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute 279(API) and is expressed in degrees. |
| 279A | See Section 6.2 | <u><i>Appraisal well</i> means a well drilled in an area where the reservoir has not been classified for that area as containing proved reserves of a natural gas.</u> |
| 279B | See Section 20.6.1 | <u><i>Boiler</i> means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10. This definition excludes line heaters and glycol reboilers.</u> |

| Ref # | Comment | Regulatory Text |
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| 279C | <p>See Section 22.4.4.</p> <p>New Definition</p> <p>LDAR 1.4.4</p> | <p><u>Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:</u></p> <p><u>(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:</u></p> <p><u>(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:</u></p> <p><u>$A = Y \times (B \div 100)$;</u></p> <p><u>(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and</u></p> <p><u>(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.</u></p> |
| 280 | See Section 18.9.2 | <p><u>Centrifugal compressor means a dynamic machines in which one or more rotating impellers, usually shrouded on the sides, accelerate the flow of natural gas or field gas. The main gas flow is radial. The pressure increase is achieved by converting kinetic energy to static energy. Centrifugal compressor does not include compressors associated with a vapor recovery unit or any other pollution control device.</u>means a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.</p> |
| 281 | | <p><i>City gate</i> means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.</p> |
| 281A | See Section 18.1 | <p><u>Commenced means, with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.</u></p> |
| 282 | | <p><i>Completion combustion device</i> means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers.</p> |
| 283 | | <p><i>Compressor</i> means a piece of equipment that compresses process gas and is usually a centrifugal compressor or a reciprocating compressor.</p> |
| 284 | | <p><i>Compressor station</i> means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.</p> |

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| 285 | See Section 5.1.1 and (Storage Vessels). Definition from EIA glossary. | Condensate means a hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in § 60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate natural gas-natural gas liquid recovered from associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 50 degrees Fahrenheit. |
| 285A | See Section 20.6.2 | Condenser means any equipment using an internal temperature change to facilitate condensation. Condensers do not affect non-condensable vapors and cannot be considered a device to control VOC or HAP. |
| 285B | See Section 18.1 | Construction means fabrication, erection, or installation of an affected facility. |
| 285C | Missing Definition | Continuous bleed pneumatic controller means a pneumatic controller that does not have a mechanical barrier between the pressure source and the end device and controls the signal to the end device by adjusting the magnitude of the flow rate of the bleed gas to the atmosphere (weak stream) through an adjustable port. |
| 285D | See Section 17.3.4 Primary Option Missing definition that is needed because of API proposed change to pneumatic controller affected facility | Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, continuous bleed gas-driven pneumatic controllers, valve actuators, and valves. |
| 285E | See Section 17.3.5 Secondary Option Used if site wide process unit is unacceptable to EPA | Pneumatically controlled process unit means the group of equipment required to operate a single pneumatically controlled valve that regulates a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulator, float and switch, continuous bleed gas-driven pneumatic controller, valve actuator, and valve.” |

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| 286 | Definition from Energy Information Administration glossary | <p><i>Crude oil</i> means crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil. <u>a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:</u></p> <ul style="list-style-type: none"> <u>Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are comingled with the crude stream without being separately measured.</u> <u>Small amounts of nonhydrocarbons produced with the oil.</u> |
| 286A | See Section 3.1 | <p><u><i>Custody transfer</i> means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.</u></p> |
| 286B | See Section 3.2 | <p><u><i>Custody Transfer Station</i> means a facility where custody of natural gas is transferred from an interstate transmission pipeline or local producer to a natural gas local distribution utility.</u></p> |
| 287 | | <p><i>Dehydrator</i> means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).</p> |
| 288 | | <p><i>Delineation well</i> means a well drilled in order to determine the boundary of a field or producing reservoir.</p> |
| 288A | See Section 19.1. New Definition | <p><u><i>Distance piece</i> means an open or enclosed casing through which the piston rod travels, separating the compressor or pump cylinder from the crankcase.</u></p> |
| 289 | Preferred Regulatory Text See Section 19.4.3 | <p><i>Equipment</i> means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by <u>the equipment leak provisions of</u> this subpart.</p> |
| 289A | Alternative Regulatory Text See Section 19.4.3 | <p><i>Equipment</i> means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by <u>the equipment leak provisions of</u> this subpart.</p> |
| 290 | | <p><i>Field gas</i> means feedstock gas entering the natural gas processing plant.</p> |
| 291 | | <p><i>Field gas gathering</i> means the system used to transport field gas from a field to the main pipeline in the area.</p> |

| Ref # | Comment | Regulatory Text |
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| 291A | See Section 6.3 | <p><u>First Date of Production</u> means the date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.</p> |
| 292 | See Section 8.1.3 or 15.3.9 | <p><i>Flare</i> means a thermal oxidation system using an open (without enclosure) flame. <u>A completion combustion device is not a flare.</u></p> |
| 293 | | <p><i>Flowback</i> means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. <u>Flowback immediately following hydraulic fracture stimulation may occur in conjunction with a well completion, recompletion, or workover.</u></p> |
| 294 | | <p><i>Flow line</i> means surface pipe through which oil and/or natural gas travels from the well.</p> |
| 294A | See Section 5.1.3 and 19.4.1. | <p><u>Forced extraction of natural gas liquids</u> means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. <u>Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint depression skids or fuel treatment skids.</u></p> |
| 295 | Controllers are not “powered by” the gas stream. | <p><i>Gas-driven pneumatic controller</i> means a pneumatic controller <u>powered by that directs a signal to an end device using</u> pressurized natural gas.</p> |
| 296 | See Section 6.1.3 | <p><i>Gas processing plant</i> process unit means equipment assembled for the forced extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.</p> |
| 297 | Definition from Energy Information Administration glossary | <p><i>Gas well</i> means a well, <u>the principal production of which at the mouth of the well is gas, completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.</u></p> |

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| 298 | The end devices are not the issue. The emission quantity is absolutely controlled by the controller and any end-device can be driven by either a continuous bleed controller or an intermittent vent controller. | <i>High-bleed pneumatic devices controller</i> means <u>a automated, continuous bleed pneumatic controller which controls flow control devices powered by</u> pressurized natural gas <u>that has the ability to vent the weak stream and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate greater than in excess of</u> six standard cubic feet per hour. |
| 299 | See Section 6.2 | <i>Hydraulic fracturing</i> means the process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers. <u>a stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at a high pressure and rate into the reservoir interval to be treated, causing a fracture(s) to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and by passes any damage that may exist in the near-wellbore area.</u> |
| 300 | | <i>In light liquid service</i> means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(h)(2) of this part. |
| 300A | Copied from NSPS Subpart VVa | <i>In VOC service</i> means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. |
| 301 | See Section 4.1 | <i>In wet gas service</i> means that a compressor or piece of equipment contains or contacts wet gas, the field gas before the extraction step at a gas processing plant process unit. |
| 301A | Missing definition that is needed because of reference to API proposed §60.5365(d)(1) | <i>Intermittent vent pneumatic controller</i> means <u>a pneumatic controller that has an internal mechanical barrier between the source of gas pressure and the end device. In response to an input signal, these devices will shut the vent and open the mechanical barrier to send gas pressure to the end device. When the input signal has been satisfied it shuts the mechanical barrier and opens a vent to remove pressure from the end device.</u> |
| 302 | | <i>Liquefied natural gas unit</i> means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, noncorrosive and non-toxic. |

| Ref # | Comment | Regulatory Text |
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| 303 | The end devices are not the issue. The emission quantity is absolutely controlled by the controller and any end-device can be driven by either a continuous bleed controller or an intermittent vent controller. | <i>Low-bleed pneumatic controller</i> means a <u>continuous bleed pneumatic controller which controls automated flow control devices powered by</u> pressurized natural gas <u>that has the ability to vent the weak stream and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds)</u> to the atmosphere at a rate equal to or less than six standard cubic feet per hour. |
| 304 | Preferred Option See Section 15.6.2 | <i>Modification</i> means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification. |
| 304A | Alternative Option See Section 15.6.2 | <i>Modification</i> means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or existing gas well is considered to be a modification. |
| 304B | Basis of this definition is NSPS Subpart Da | <u><i>Natural gas</i> means a naturally occurring mixture of hydrocarbons and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. LNG is not considered natural gas, since impurities such as VOCs and HAPs have been removed.</u> |
| 305 | | <i>Natural gas liquids</i> means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas. |
| 306 | See Sections 5.1.3 and 19.4.1. | <i>Natural gas processing plant (gas plant)</i> means any processing site engaged in the <u>forced</u> extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. |
| 307 | | <i>Nonfractionating plant</i> means any gas plant that does not fractionate mixed natural gas liquids into natural gas products. |
| 308 | See Section 17.2.1 | <i>Non gas-driven pneumatic <u>controller device</u></i> means <u>a pneumatic controller that directs a signal to an end device in a medium other than natural gas. The signal can include compressed air, electric power, or hydraulic power.</u> an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air. |
| 309 | | <i>Onshore</i> means all facilities except those that are located in the territorial seas or on the outer continental shelf. |
| 310 | An orphaned definition that is not used in the subpart and should be removed. See Section 5.6. | <i>Plunger lift system</i> means an intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. |

| Ref # | Comment | Regulatory Text |
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| 311 | Imprecise definition | <i>Pneumatic controller</i> means an automated instrument <u>that is able to sense the state of a process variable and send a pressure signal to an end device to affect a change in that process variable. used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature.</u> |
| 311A | Missing definition needed to complement API proposed change to pneumatic controller affected facility. | <i>Pneumatically controlled process unit</i> means the group of <u>equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, pneumatic controllers, valve actuators, and valves.</u> |
| 312 | An orphaned definition that is not used in the subpart and should be removed. See Section 5.6. | <i>Pneumatic pump</i> means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm. |
| 313 | LDAR 1.4.1 | <i>Process unit</i> means components assembled for the <u>forced</u> extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products. |
| 313A | See Section 6.2 | <u><i>Proven reserves</i> of a natural gas are reserves which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas – oil and/or gas – water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.</u> |
| 314 | See Section 18.5 | <i>Reciprocating compressor</i> means a <u>positive-displacement machines in which the compressing and displacing element is a piston having a reciprocating motion within a cylinder. The pressure increase is achieved by reducing the volume of a fixed amount of natural gas or field gas.</u> means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft. |
| 315 | | <i>Reciprocating compressor rod packing</i> means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere. |

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| 316 | An orphaned definition that is not used in the subpart and should be removed. See Section 5.6. | Reduced emissions completion means a well completion where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line. |
| 317 | An orphaned definition that is not used in the subpart and should be removed. See Section 5.6. | Reduced emissions recompletion means a well completion following refracturing of a gas well where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line. |
| 318 | | Reduced sulfur compounds means H ₂ S, carbonyl sulfide (COS), and carbon disulfide (CS ₂). |
| 319 | See Section 9.4 | Routed to a process or route to a process means the emissions are conveyed to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. |
| 320 | | Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas. |
| 321 | | Sales line means pipeline, generally small in diameter, used to transport oil or gas from the well to a processing facility or a mainline pipeline. |
| 321A | See Section 15.5 | <u>Standard of Performance means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction</u> |
| 322 | See Section 6.3 | Storage vessel or Tank means a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy. unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials. Storage vessel or Tank does not include: <u>(1) Process tanks, including vessels used for a process function such as reactions, blending, or separation, vessels such as sumps used to collect discharged material such that it can be transferred to a process or to storage, vessels used for surge control, and vessels used as knockouts,</u> <u>(2) Vessels with a design capacity less than or equal to 472 barrels with a maximum true vapor pressure less than 11.1 psia.</u> <u>(3) Vessels storing wastewater,</u> <u>(4) Pressure vessels designed to operate without emissions to the atmosphere,</u> <u>(5) Subsurface caverns and porous rock reservoirs, and</u> <u>(6) Vessels that do not remain at a given site for more than 90 consecutive days.</u> |
| 323 | | Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit. |
| 324 | | Sulfur recovery unit means a process device that recovers element sulfur from acid gas. |

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| 325 | | <i>Surface site</i> means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed. |
| 326 | | <i>Sweetening unit</i> means a process device that removes hydrogen sulfide and/or carbon dioxide from the natural gas stream. |
| 327 | | <i>Total Reduced Sulfur (TRS)</i> means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter. |
| 328 | | <i>Total SO2 equivalents</i> means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO2 to the quantity of SO2 that would be obtained if all reduced sulfur compounds were converted to SO2 (ppmv or kg/dscm (lb/dscf)). |
| 329 | | <i>Underground storage tank</i> means a storage tank stored below ground. |
| 329A | Missing definition needed because term is referenced in API §60.5410(d)(3) and §60.5420(c)(4)(iii) | <u><i>Weak stream</i> means the stream of gas that is vented when the end device is “at rest” in its idle position (e.g., when the end device is shut on a pressure-to-open system).</u> |
| 330 | | <i>Well</i> means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected. |
| 331 | See Section 15.8.3 | <i>Well Completions</i> means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment. of making a new oil or natural gas well ready for production. It allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics and also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packers(s), or lifting equipment. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture stimulate and prop open new fractures in lower permeability reservoirs. <i>Well completion operation</i> means any well completion occurring at a gas wellhead affected facility <u>onshore.</u> |
| 331A | See Section 6.2 | <u><i>Well recompletion</i> means completing a well again. See the definition of well completion.</u> |
| 332 | | <i>Well site</i> means the areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad. |

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| 332A | See Section 6.2 | <p><u>Well workover means the work conducted on wells with a rig or coiled tubing unit after the initial completion is over. Such process(es) may include performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production or return the well to its normal production rate. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability reservoirs or re-complete an existing well to a new production zone/horizon. A well workover does not include routine maintenance activities that are performed on the well with the tree installed (See 30 CFR Part 250.601 Definitions for further details). Such routine activities may include maintenance, repair, or replacement of equipment such as rods, pumps, tubing, packers, or other mechanical devices.</u></p> |
| 333 | | <p><i>Wellhead</i> means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.</p> |
| 334 | <p>See Section 4.1 New Definition LDAR 1.4.2 <i>[API recommends X be 5.0 or greater.]</i></p> | <p><u>Wet gas means the field gas before the extraction step at a gas processing plant process unit that is >X% VOC by weight or does not include gas streams that are >50% by weight inert gases (e.g. nitrogen or carbon dioxide).</u></p> |
| 335 | | <p><i>Wildcat well</i> means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.</p> |

Attachment D
SMM Coalition Letter

November 29, 2010

EPA Docket Center (EPA/DC)
Environmental Protection Agency
Mailcode 6102T
1200 Pennsylvania Avenue, NW.
Washington, DC 20460
Attention Docket ID No. EPA-HQ-OAR-2009-0559

Re: Comments on Proposed Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Docket ID No. EPA-HQ-OAR-2009-0559

Dear Sir or Madam:

This letter provides comments of the SSM Coalition on EPA's proposal to promulgate National Standards of Performance for New Stationary Sources under Clean Air Act ("CAA") sections 111(b) and 129(a) and emission guidelines for existing sources under CAA sections 111(d) and 129(b) for sewage sludge incineration units ("SSIs"), as published on October 14, 2010, 75 Fed. Reg. 63260 (the "Proposed Rule" or the "Proposed Standards").

The SSM Coalition is an *ad hoc* coalition of trade associations and business organizations interested in the methodologies EPA uses to develop stationary source emission standards under the CAA and the way those standards are expressed in EPA regulations. SSM Coalition's current members are the American Chemistry Council, American Forest & Paper Association, American Home Furnishings Alliance, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Coalition for Responsible Waste Incineration, Council of Industrial Boiler Owners, Florida Sugar Industry, National Association of Manufacturers, National Petrochemical & Refiners Association, Rubber Manufacturers Association, Treated Wood Council, and the Vegetable Oil SSM Coalition (consisting of the Corn Refiners Association, the National Cotton Council, the National Cottonseed Products Association, the National Oilseed Processors Association, and Sessions Peanut Company).

The members of the SSM Coalition have an interest in, and many of the associations' members are directly affected by, various rules that are in the active rulemaking stage or that are scheduled for review in the near future. The SSM Coalition objects to the new manner in which EPA is proposing to address periods of startup, shutdown, or malfunction ("SSM") in the SSI rulemaking and in several other recently proposed and final rules. SSM Coalition members believe EPA has failed to account adequately for emissions that occur during SSM periods. EPA bases its action on an improperly narrow reading of the D.C. Circuit's *Sierra Club v. EPA*

decision and on unreasonable or insufficiently supported assumptions about SSM events and emissions during SSM periods. EPA should revise the proposed standards to account better for SSM events, rather than rely on an “affirmative defense” to make up for its failure to do so. The affirmative defense EPA describes in the Proposed Rule inappropriately shifts the burden to the source to disprove alleged violations during malfunctions. In addition, the limitations and requirements EPA proposes for the affirmative defense are unreasonable and impracticable. It would require substantial modification and streamlining if EPA persists on relying on it.

1. EPA Misreads *Sierra Club v. EPA*

EPA has recognized for decades that generally it is unreasonable to require sources to meet technology-based emission standards, such as NSPS promulgated under section 111, during SSM periods. See 40 C.F.R. § 60.8(c). Despite that fact, the Proposed Standards, to be issued under sections 111 and 129, state that they are applicable at all times, even during SSM events. Proposed section 60.5180. EPA suggests that its treatment of excess emissions during SSM events in the Proposed Standards is supported, perhaps even compelled, by the D.C. Circuit’s decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), which vacated the exemption¹ for excess emissions during SSM events contained in the 40 C.F.R. part 63, subpart A General Provisions for emission standards for hazardous air pollutants under CAA section 112. Since that decision involved the Court’s interpretation of the definition of “emission standards,” which appears in CAA section 302(k), and which EPA asserts “applies equally” to “emission standards” under CAA section 112 and “performance standards” under section 129, EPA states that “the legality of source category-specific SSM exemptions in rules promulgated pursuant to section 129 is questionable.” See 75 Fed. Reg. at 63,282 col. 3.

The D.C. Circuit’s *Sierra Club* decision manifestly is not binding on EPA’s establishment of performance standards for SSI units under CAA sections 111 and 129. First, the *Sierra Club* decision interpreted section 112, not section 129 (which incorporates by reference section 111). This is not merely a technical distinction. The language that the D.C. Circuit considered dispositive in interpreting EPA’s standards-setting authority under section 112 — the statement in the definition of “emission limitation” and “emission standard” that it “limits the quantity, rate, or

¹ Although the D.C. Circuit (and EPA in the preamble to the Proposed Rule) referred to the provision vacated in the *Sierra Club* decision as an “exemption” from hazardous air pollutant standards during SSM events, in fact other portions of the NESHAP General Provisions impose various requirements that apply to sources during SSM events (including the obligation to minimize excess emissions), and in anticipation of and following SSM events (including requirements to prepare a plan to address SSM events and to report SSM events).

concentration of emissions of air pollutants on a continuous basis” — has been in the statute since 1977. Throughout that time, EPA has exempted emissions during SSM events from compliance with NSPS under CAA section 111. See 40 C.F.R. § 60.8(c). In fact, Congress enacted the “continuous basis” language in section 302(k) knowing that EPA’s emissions standards under section 111 exempted SSM periods. There is nothing in the legislative history of the 1977 amendments to the CAA that suggests Congress intended to overturn that practice.² Moreover, court decisions both before and after the Clean Air Act Amendments of 1977, some of which are cited below, have affirmed the appropriateness of including an SSM exemption in standards issued under section 111.

Secondly, the *Sierra Club* decision did not address whether EPA could use a “design, equipment, work practice or operational standard,” as authorized under CAA section 112(h) [and 111(h)] and included in the definition of “emission limitation” and “emission standard” in CAA section 302(k), in lieu of a numerical emission limitation during SSM events. EPA told the Court that the General Provisions SSM exemption struck down in *Sierra Club* was not an alternative standard based on that work practice, etc. authority. See 551 F.3d at 1028. Indeed, EPA argued in that case that section 112(h) was irrelevant to its authority to exempt excess emissions during SSM events. *Id.* at 1030 (Randolph, J. dissenting).

EPA’s assertion that “the legality of source category-specific SSM exemptions in rules promulgated pursuant to section 129 is questionable” does not acknowledge, much less contradict, these facts. See 75 Fed. Reg. at 63,282 col. 3. Although EPA claims that by requiring that the Proposed Standards be met at all times—and basically ignoring or assuming away SSM events—it is acting “consistent with *Sierra Club*,” this claim does not justify EPA’s actions in the Proposed Rule, since the *Sierra Club* opinion relates to a different type of action (exempting emissions from any standard) under a different statutory provision (section 112). See *id.* Even if *Sierra Club* were relevant to and binding upon EPA’s promulgation of performance standards for SSI units under sections 111 and 129, however, it would not compel EPA to eschew distinct requirements applicable during SSM events.

EPA claims that the D.C. Circuit’s interpretation of the definition of “emission standards” “requires EPA to apply MACT emission standards on a continuous basis, thereby precluding exemptions applied for malfunctions or other singular events.” 75 Fed. Reg. at 63,282 col. 2 (emphasis added). While a blanket exemption from any standard under sections 111 and 129 may be inconsistent with the *Sierra Club* panel

² Rather, the “continuous basis” language related to a debate in Congress about whether sources should be allowed to use temporary or intermittent pollution control technologies, as the *Sierra Club* court recognized. See 551 F.3d at 1027, citing *Kamp v. Hernandez*, 752 F.2d 1444, 1452 (9th Cir.1985). It had nothing to do with limitations applied during SSM nor with EPA’s established practice of exempting excess emissions during SSM events from its performance standards.

holding that, for section 112 maximum achievable control technology (MACT) standards, “there must be continuous section 112-compliant standards” (551 F.3d at 1027), *Sierra Club* does not preclude EPA from applying different standards during SSM events than apply during normal operations. In fact, the opinion acknowledges that section 302(k)’s “inclusion of [the] broad phrase” “any requirement relating to the operation or maintenance of a source to assure continuous emission reduction” in the definition of “emission standard” suggests that EPA need not “necessarily continuously apply [] a single standard.”³

Thus, EPA cannot hide behind the *Sierra Club* decision as a justification for ignoring the inability of even the “best performers” to achieve the proposed emission standards during SSM events. CAA section 129 (a)(2), which incorporates the same MACT requirements for solid waste incinerators as CAA section 112(d) applies to sources of hazardous air pollutants, mandates that the emission standards be “achievable.” Moreover, if EPA sets the emission standards based on the “best performing 12% of units in the category” (the “MACT floor”), those limitations must on average be “achieved” by the best performers.

An emission limitation that applies during SSM events does not meet the requirement of CAA section 129(a)(2) that “emission standards” under that section be “achievable” if in fact EPA has not demonstrated that the limitation is “achievable” with available technology, “taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements.” Similarly, an emission limitation that applies during SSM events has not been demonstrated to be “achieved” by the best-performing 12% of units in the category” unless EPA can show that those best performers actually meet that emission limitation during SSM events.

Similarly, CAA section 111(a)(1), which also applies to emission standards promulgated under section 129, requires that any emission limitation be “achievable through the application of” emission reduction technology that “the Administrator determines has been adequately demonstrated.” EPA therefore must demonstrate that a numerical limitation, if it is to apply even during SSM events, is in fact achievable with available technology during such events.

³ 551 F.3d at 1027. “Indeed, this reading is supported by the legislative history of section 302(k).” *Id.* See also *id.* at 1021 (“accepting that ‘continuous’ for purposes of the definition of ‘emission standards’ under CAA section 302(k) does not mean unchanging”); *id.* (referring to “the CAA’s requirement that some section 112 standard apply continuously”) (emphasis added). Moreover, since it was addressing only a generic SSM exemption, the *Sierra Club* decision did not consider whether EPA, in the context of individual categorical standards, could determine that it is infeasible to apply the same limits, or any limits on the mass or concentration of pollutants emitted at all, during SSM events, or that it would lead to absurd results to do so.

These plain-language readings of the applicable statutory requirements are echoed by extensive case law. The courts have long recognized that a “technology based standard discards its fundamental premise when it ignores the limits inherent in technology.” *NRDC v. EPA*, 859 F.2d 156, 208 (D.C. Cir. 1988). For example, the D.C. Circuit recognized, in *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that “‘start-up’ and ‘upset’ conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated.” *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are “necessary to preserve the reasonableness of the standards as a whole.” *Id.* at 433. In *National Lime Ass’n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held CAA technology-based standards must be capable of being met “under most adverse circumstances which can reasonably be expected to recur,” such as during periods of SSM. 627 F.2d at 431 n.46.

Courts have reached a similar conclusion when considering the analogous Clean Water Act requirements that EPA establish technology-based effluent limitations based on the best available control technology. Knowing that there would be periods where a discharger, even with “exemplary use of” the identified best technology, would exceed the effluent limitations because of conditions “beyond the control of the permit holder,” EPA violated the Clean Water Act by failing to provide an “upset provision” to address those periods. *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-74 (9th Cir. 1977). See also, e.g., *NRDC v. EPA*, 859 F.2d at 207 (distinguishing between technology-based effluent limitations, where some provision for “upsets” is required, and water-quality-based effluent limitations, which are tied to achieving water quality standards rather than based on available technology, and therefore need not include an upset provision).⁴

As noted above, the *Sierra Club* decision does not prevent EPA from adopting emission standards for SSM periods that are different from those required during periods of normal operation. Nor did the *Sierra Club* court conclude that EPA is barred from using a “requirement relating to the operation or maintenance of a source to assure continuous emission reduction” as the emission standard that applies during such events. See 551 F.3d at 1027. The *Sierra Club* decision only

⁴ *Weyerhaeuser Co. v. Costle*, 590 F. 2d 1011 D.C. Cir. 1078), does not support EPA’s position. In that case, the court was discussing a “technology forcing” standard, rather than one, like MACT and NSPS, that is to be based on what is already being “achieved” or has been demonstrated to be achievable. Also, the decision came long before *NRDC v. EPA*, 859 F.2d 156 (D.C. Cir. 1988) which, as noted above, affirmed the need for an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee, and which endorsed *Marathon Oil*.

rejected EPA's assertion that it had discretion to decide not to impose *any* emission standard whatsoever during SSM periods. See *id.* at 1027-28, 1030 (noting that EPA was not claiming that the General Provisions SSM exemption was either an emission standard under CAA section 112(d) or a design, equipment, work practice, or operational standard under section 112(h)).⁵ Thus, despite EPA's suggestions to the contrary, the *Sierra Club* decision expressly recognizes that different standards, including non-numerical standards, may (and in some cases must) apply during non-standard operating conditions, such as SSM.

2. EPA Has Not Justified Applying the Same Emission Limitations During Startup and Shutdown

In the Proposed Rule, EPA does not say that it is precluded from adopting different emission limitations that would apply during startup and shutdown periods. Rather, EPA asserts that it is not necessary to do so in this case, because EPA "believes" that SSI units will be able to comply with the emission limitations proposed for normal operations, even during periods of startup and shutdown. See 75 Fed. Reg. at 63,282 col. 3.

SSM Coalition members do not have sufficient information to comment on whether in fact the emission limitations EPA has proposed for normal operations of SSI units can also be met during startup and shutdown. However, SSM Coalition members do have considerable experience with and emissions data for similar types of combustion units (i.e., boilers), and these data clearly demonstrate that emissions during startup and shutdown are much different than during normal operation. While mass emissions of pollutants can be lower during startup and shutdown events, emissions in terms of concentration (ppmvd, gr/dscf, mg/dscm, etc., which are the units of the proposed standards) can be much higher during these periods, because of lower exhaust gas volumes. It is reasonable to believe that SSI units would experience similar conditions during startup and shutdown, since they are enclosed combustion devices like boilers.

EPA, on the other hand, presents no information in either the preamble or in the docket supporting the contention that the proposed emission limitations for normal operations can also be met by the best performing SSI units during startup and shutdown. In fact, so far as the SSM Coalition can determine, EPA presents no

⁵ The statement in the majority opinion that "Congress gave no indication that it intended the application of MACT standards to vary based on different time periods," 551 F.3d at 1028: (1) is contradicted by other statements in the opinion, referenced above, that a MACT standard need not continuously apply a single emission limitation, (2) is *dicta*, because that was not the situation presented by the challenged regulations and argued by EPA, (3) ignores the extensive case law about technology-based limitations referenced above, and (4) does not in any event say that the CAA precludes EPA from adopting different emission limitations that apply during SSM events.

data at all about emissions from the best performing units during SSM events, or about best practices for minimizing emissions during SSM events. Instead, EPA simply asserts that emissions from burning natural gas, landfill gas, or distillate oil before adding waste to the SSI unit “are expected to generally be lower than from burning solid wastes” and that emissions during shutdowns “are also generally lower than emissions during normal operations because the materials in the incinerator would be almost fully combusted before shutdown occurs.” 75 Fed. Reg. at 63,282 col. 3, 63,283 col. 1.

These bare assumptions that emissions are “expected” to be lower, “generally,” do not constitute a demonstration that applying the proposed emission limitations during startup and shutdown reflects the performance of the best-performing SSI units under CAA section 129(a)(2) or is “adequately demonstrated” to be “achievable through the application of the best system of emission reduction” under CAA section 111(a)(1). EPA cannot conclude that special provisions for emissions during startup and shutdown are not needed based on “mere speculation.” See *NRDC v. EPA*, 859 F.2d 156, 210 (D.C. Cir. 1988).

The CAA does not authorize EPA to set limitations that only “generally” are achieved by the best performers or achievable with demonstrated technology. Moreover, the general assertions EPA has offered as support for insisting that emission limitations developed for normal operations must apply even during startup and shutdown are not even superficially persuasive. For example, EPA’s statement that emissions should be lower during startup before waste is added to an SSI unit fails to consider whether emissions will be higher than during normal, steady-state operations when the incinerator is first charged with sludge and before operations have stabilized. Nor is it obvious that the atypical combustion conditions occurring when the SSI unit is shutting down necessarily will result in lower emissions of all pollutants than during normal operations, especially pollutants that may be degraded at high stack temperatures.⁶ In some pollution control configurations, it is not possible to route exhaust gases to control equipment until the control equipment is fully operational, or until pollutants in the exhaust gases are sufficiently concentrated to be above the upper explosive limit. EPA’s undocumented “expectations” that the amount and/or concentration of all regulated pollutants emitted during startup or shutdown will be less than during normal operations simply ignore these possibilities.

⁶ To the contrary, a document in the docket for this rulemaking indicates that “NO_x and CO emissions are inversely proportional” and “[b]oth THC and CO emissions decrease with temperature, while NO_x emissions increase.” EPA-HQ-OAR-2009-0559-0032.pdf, at p. 2. Also, as noted above, low exhaust gas flows during shutdown may result in higher concentrations of pollutants even if the mass emitted is less. These facts appear directly to contradict EPA’s assumption that emissions of all of the regulated pollutants will be less under startup and shutdown conditions than at normal operating conditions.

EPA also claims that, because it has accounted for emissions variability in setting emissions standards based on actual performance of existing units, those emission standards “have adequately addressed any minor variability that may potentially occur during startup or shutdown.” 75 Fed. Reg. at 63,283 col. 1. There is no apparent basis for EPA’s assertion that there will only be “minor variability” during startup or shutdown. But in any event, EPA has not, in its variability analysis for setting the Proposed Standards, taken into account variability associated with startup or shutdown.

When developing technology-based emission standards, EPA often will not have emissions data that reflect startup and shutdown conditions. To the extent emissions data come from required performance tests, the applicable regulations generally prohibit testing during SSM conditions, and require that data not be used for compliance purposes if obtained during a startup, shutdown, or malfunction event.⁷ To the extent EPA evaluates emissions data collected through continuous monitoring, the applicable regulations generally require or allow the source to exclude from its reporting of continuous monitoring data those data reflecting SSM conditions. So in most cases, when EPA performs its variability analyses on emissions data for existing units, it assesses the variability only of a data set that already excludes SSM events.

In the case of the SSI rulemaking, EPA based the Proposed Standards, and conducted its variability analysis, solely based upon stack test data from nine publicly-owned treatment works that were targeted by EPA’s information collection request. See EPA-HQ-OAR-2009-0559-0006, pp. 5-9, 10-12 and Attachment J. In other words, the variability EPA used in setting the Proposed Standards—because the analysis was performed on emissions data from performance tests, when the source is being operated at normal levels and when efforts are being made to maintain steady-state conditions—reflects at most only the normal variation in emissions experienced during normal operations. Since performance test data are not collected during SSM events, the variability factors EPA derived to establish the Proposed Standards could not possibly incorporate emissions variability experienced during SSM events. Thus, by virtue of the variability analysis itself, the Proposed Standards are representative of emissions achieved during normal (very stable) operations and are not representative of emissions during SSM events (which can be highly variable). (For the same reasons, EPA’s attempt to consider variability in setting emission standards does not eliminate the need for different standards that apply during malfunctions.)

⁷ See, for example, the General Provisions applicable to NSPS, which state that performance tests can only be conducted under representative conditions and which specify that: “Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test....” 40 C.F.R. § 60.8(c).

EPA has a number of options for promulgating performance standards for SSI units under CAA sections 111 and 129. First, EPA could conduct stack testing during startup and shutdown events, just as it required stack testing at existing sludge incinerators for purposes of deriving the Proposed Standards. (Emissions testing during startup and shutdown will not be an option in all cases, because it may not be possible to obtain accurate sampling of exhaust gases during startup or shutdown of certain types of process or pollution control equipment. Stack sampling procedures may not apply or produce accurate results during the abnormal flow and concentration conditions present during startup or shutdown.) If sources are so equipped, EPA also may be able to analyze continuous monitoring data for some parameters that would include monitoring during startup or shutdown periods.⁸ These data could enable EPA to set alternative emission standards that apply during startup and shutdown, or to conclude that sources with the identified control technology will be able to meet emission limitations established for normal operations during startup and shutdown periods, as well. It would be appropriate for EPA to defer promulgating any emission limitations that apply during periods of startup or shutdown until after EPA obtains such data. EPA also could study facilities' operational logs to determine an averaging time for an emission standard sufficiently long that typical startups and shutdowns would not cause an exceedance of the standard. EPA also might determine, based on infeasibility of collecting representative data during startup and shutdown events, that it is necessary and appropriate to promulgate a design, equipment, work practice, or operational standard, pursuant to CAA section 111(h) and/or section 302(k), in lieu of deriving limitations on the mass or concentration of pollutants emitted during startup or shutdown.

Any one of these approaches would be consistent with the CAA. What EPA has done instead—merely assuming the problem away without conducting the necessary analysis of the performance actually achieved—is not. EPA should defer establishing any standards under CAA sections 111 and 129 for startup and shutdown periods until EPA can collect the necessary data and/or determine the appropriate work practice or operational standards to establish “emission limitations or other limitations” for SSI units during startup and shutdown. See CAA section 129(a)(1).

⁸ If the Proposed Regulations are adopted, EPA should be able to use continuous monitoring data reflecting at least some SSM events for the next review of SSI emission standards, from those facilities that opt to use the continuous emission monitor option in the Proposed Rule, since the Proposed Rule would require such facilities to operate and report data from continuous monitors even during SSM events (other than during monitor malfunction or downtime). See 75 Fed. Reg. at 63,281 col. 1.

3. EPA Is Required To Take Malfunctions into Account when Adopting Emission Standards

EPA asserts that it “is reasonable to interpret section 129 as not requiring EPA to account for malfunctions in setting emissions standards.” 75 Fed. Reg. at 63,283 col. 1. EPA offers little support for that assertion, however, other than its *ipse dixit*. For example, EPA says it “has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 129 standards, which, once promulgated, apply at all times.” *Id.* EPA provides no explanation of how it “determined” that malfunctions are not a distinct operating mode. Moreover, EPA offers no explanation of how it “determined” that, even though it believes malfunctions are not a distinct operating mode, emissions during malfunctions should not be used to characterize the source’s operating mode. On its face, asserting that malfunctions are part of normal operations, but then excluding emissions during malfunctions when determining emission limitations for normal operations, makes no sense.

EPA acknowledges that the best performing SSI units (like any technologies), are subject to a wide variety of potential malfunctions (e.g., power failures, equipment breakdowns). The operators of these processes and equipment must treat malfunctions as very distinct events from steady-state operations, depending on the severity of the malfunction, requiring anything from shutdown of the unit to emergency fire response actions. The SSM Coalition agrees with EPA’s conclusion that the factual complexity of differing processes and of the severity, frequency, and duration of malfunctions makes standard-setting difficult. In addition, it is often impossible to gather emission data during malfunctions – either for standard-setting or for compliance demonstration purposes. Malfunctions are by definition unexpected, so it is not possible to plan to have test equipment in place to measure emissions when one occurs. Even if test or monitoring equipment is in place, emissions during malfunctions often are not routed to a stack where they can be measured, and upsets during stack testing invalidate the test results under EPA’s approved test methods.

These findings should lead EPA to the authority under section 111(h) to prescribe alternative design, equipment, work practice or operational standards where it is not feasible to set or enforce a numerical emission limit. EPA cannot rationally defend its articulated view that applying the concept of “best performing” is inconsistent with a source experiencing a malfunction. See 75 Fed. Reg. at 63,283 col. 1. This ignores that there are work practices – such as monitoring combustion parameters to identify a malfunction and stopping the charging of materials to an incinerator – that represent the best practices for minimizing emissions during a malfunction. While the measures that represent these best practices will depend on facility-specific issues, such as incinerator design, pollution control train, and other

factors, they are nonetheless the “best technological system of continuous emission reduction ... adequately demonstrated.”

EPA claims that it somehow “presents significant difficulties” to attribute malfunctions to a “best performing” source. *Id.* But what really presents significant difficulties is EPA ignoring the undisputed existence of malfunctions even at best-performing sources, and claiming that the best-performing sources “achieve” emission levels that they undisputedly do not achieve part of the time. Since EPA describes malfunctions as being sometimes unavoidable or “not reasonably preventable,” despite proper design and maintenance of equipment, there is no basis for EPA’s conclusion that malfunction events are not representative of best-performing sources. See 75 Fed. Reg. 63,283 cols. 1 and 2. True, one goal (although not “the goal”) “of best performing sources is to operate in such a way as to avoid malfunctions of their units.” But that is all the more reason why EPA must acknowledge the fact that those sources nevertheless experience malfunction events, rather than assume those emissions away. *Cf.* 75 Fed. Reg. 63,283 col. 1.

By proposing a standard that EPA recognizes even the best-performing SSI units cannot achieve part of the time, EPA really is going beyond the MACT floor, yet without making the demonstrations that the statute and case law require EPA to make in order to impose beyond-the-floor MACT standards. (This is especially obvious when one considers the multitude of conditions EPA proposes to impose on sources during malfunctions, in order to be excused from civil penalties: EPA makes no attempt to justify those conditions as reasonable “taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements.” See CAA section 129(a)(2).)

Nor does EPA present any substantiation for its “belief” that “it would be impracticable to take malfunctions into account in setting CAA section 129 standards for SSI.” *Id.* EPA cannot defensibly acknowledge that malfunctions are inevitable, even for the best performing sources, yet refuse to include emissions data during malfunctions from its MACT floor calculations. If it is possible to gather sufficient representative data reflecting emissions during malfunctions, then EPA is obligated to consider these data in its MACT floor calculations for steady-state operating conditions. To the extent EPA has access to continuous monitoring data for SSI units, EPA could have conducted analyses of emissions levels during malfunction events.⁹ Also, although the SSM Coalition does not have information about sewage sludge incinerators in particular, many types of sources are required by many state agencies to submit deviation reports or malfunction reports when they experience a malfunction that causes an exceedance of an applicable limitation. EPA does not

⁹ Even if the continuous monitoring data are for parameters not regulated by the Proposed Standards, analysis of monitoring data for those other parameters during malfunction events might form a reasonable basis for EPA’s assessment of what standards are achieved or achievable during malfunctions.

appear to have made any attempt to obtain and analyze such reports, in order to assess what type of requirement might reasonably apply to SSI units during malfunctions.

There are several options EPA could use for setting performance standards under CAA sections 111 and 129 that would apply during malfunction events. For example, EPA could establish an emission limitation that applies at all times, but that has an averaging time of sufficient duration that short, infrequent spikes in emissions due to malfunctions would not cause the source to exceed the emission limitation (while at the same time assuring that the source does not operate in a way that causes frequent, lengthy excursions above the normal information rate). EPA could expand the Operator Training and Certification portion of the rules, issued under authority of CAA section 129(d), to provide greater specificity about the procedures the operator must follow to avoid and minimize excess emissions during malfunctions. Cf. proposed 40 C.F.R. § 60.4814(c)(1). EPA could use the flexibility accorded by CAA section 129(a)(1)(A) (performance standards “shall include emissions limitations and other requirements”) (emphasis added) and section 302(k) (defining “emission limitation” and “emission standard” to include “any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under” the CAA) to address emissions during malfunction events through operational requirements rather than by applying the limits on pollutant concentrations in exhaust gases that apply during normal operations. EPA could have concluded, as explained above, that it has grounds to exercise its authority under CAA section 111(h) to promulgate a design, equipment, work practice, or operational standard, or combination thereof, because it is not feasible to prescribe or enforce a standard of performance. EPA might also use several of these approaches in combination.

There is no indication in the Proposed Rule that EPA gave much if any consideration to these types of options. In short, there are ample reasons to reject EPA’s conclusory assertions that it cannot take malfunctions into account when setting performance standards for SSI units. EPA’s failure to evaluate these options thoroughly renders the Proposed Rule arbitrary and requires EPA to develop a new proposal.

4. The Proposed Affirmative Defense Is Not a Substitute for Setting Emission Standards for SSM Periods

EPA acknowledges that SSI units sometimes will be unable to comply with the Proposed Standards because of malfunctions, even if their equipment is properly designed and maintained, through no fault of the source. See 75 Fed. Reg. at 63,283. Rather than promulgate an emission standard that eliminates that situation, so that SSI units will be subject to differentiated requirements, achievable with the

identified best technology, during SSM events, EPA offers instead an “affirmative defense.” The proposed affirmative defense shifts the burden to the source to prove that a myriad number of criteria are met and actions were taken by the source (which bear no direct relation to the statutory factors for performance standards under CAA sections 111 and 129), in order to avoid “civil penalties.” Inclusion of the affirmative defense does not cure EPA’s failure to set emission standards that are achievable during SSM events. The Proposed Standards, incorporating the affirmative defense, still do not meet the criteria of CAA sections 111 and 129.

It is unclear where EPA finds the legal authority in the CAA to shift the burden to the regulated community of proving (or disproving) essential elements of an alleged violation. The statute is silent as to the issue and “the ordinary default rule [is] that plaintiffs bear the risk of failing to prove their claims.” *Shaeffer v. Weast*, 546 U.S. 49 (2005), quoting McCormick on Evidence §337, at 412 (“The burdens of pleading and proof with regard to most facts have and should be assigned to the plaintiff who generally seeks to change the present state of affairs and who therefore naturally should be expected to bear the risk of failure or proof or persuasion”); C. Mueller & L. Kirkpatrick, Evidence § 3.1, p. 104 (3d ed. 2003) (“Perhaps the broadest and most accepted idea is that the person who seeks court action should justify the request, which means that the plaintiffs bear the burdens on the elements in their claims”). While the Supreme Court has recognized exceptions such as affirmative defenses, courts retain the authority to establish such rules unless Congress acts to delegate that authority. In this instance, EPA has not provided any justification for requiring a source to prove its innocence; in fact, to fully demonstrate its innocence within 30 days of the event, without even being charged. Rather, if EPA adopts an approach along the lines of the proposed affirmative defense, it should be stated instead in terms that, once a source has claimed that its excess emissions were related to a malfunction, it will not be considered to be in violation of the standards unless the enforcement authority demonstrates that the source is not entitled to claim the malfunction.

EPA’s rationale for excluding startup and shutdown events from the proposed affirmative defense is unclear, as well. As noted above, EPA has for decades recognized in NSPS regulations that it may not be possible to meet normally applicable emission limitations, even using the best demonstrated technology, during startup, shutdown, and malfunction events. If EPA persists in its proposal not to provide separate emission limitations for startup and shutdown of the SSI units, and if in fact excess emissions from an SSI unit cannot reasonably be avoided during a startup or shutdown, not because of failure of a process or equipment but because of the nature of conditions while starting up or shutting down the source, there is no apparent reason why EPA would not provide the same kind of affirmative defense that it proposes to provide for malfunctions.

Even if the proposed affirmative defense were not unreasonably restrictive, as discussed in the following portion of these comments, being able to assert a defense obviously is not the same as complying with emission limitations that are properly set in accordance with sections 111 and 129. Although a source believes it qualifies for the affirmative defense, it may be considered to have violated the standards—and may have to report violations, certify noncompliance, etc.—until there has been an enforcement proceeding and the source has successfully asserted the affirmative defense. The affirmative defense places the source in the position of proving its innocence, rather than EPA or another enforcement authority having to prove that the source violated the CAA.

Furthermore, it is not even clear what the affirmative defense covers. In the Proposed Rule, EPA states that the affirmative defense is “to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in section 60.2.”¹⁰ Is the term “civil penalties,” which is not defined in the Proposed Rule, intended to apply as well to a “civil administrative penalty” imposed by EPA under CAA section 113(d)? (The term “civil penalty” in other contexts means only penalties imposed by a court.) Does the affirmative defense apply to “noncompliance penalties” under CAA section 120 (which apply, *inter alia*, to noncompliance with a section 111 NSPS)? To meet the purported purpose of the affirmative defense, which is to provide relief from emission limitations that cannot be met at times even with equipment that is properly designed and maintained (see 75 Fed. Reg. 63,283 col. 2), the affirmative defense would need to apply to civil and administrative penalties, including noncompliance penalties.

It is unclear as well how the affirmative defense would apply to enforcement actions by state and local governments, or to private citizen enforcement actions under CAA section 304. The preamble to the Proposed Rule, for example, speaks only in terms of application of the affirmative defense in an EPA enforcement action.¹¹ An affirmative defense should clearly state that it is applicable to enforcement actions by states or citizen-suit plaintiffs, as well.

¹⁰ Proposed 40 C.F.R. § 60.4861. (These comments refer to sections of proposed Subpart LLLL; nearly identical language is also included in proposed Subpart MMMM.) Note that the reference here to the definition of “malfunction” in section 60.2 is confusing, and its purpose is unclear, given that the proposed SSI standards themselves contain a definition of “malfunction.” See proposed 40 C.F.R. § 60.4930. But that definition in itself is unclear, since it states that: “During periods of malfunction the operator shall operate within established emissions and operating limits and shall continue monitoring of all applicable operating parameters until all waste has been combusted or until the malfunction ceases, whichever comes first.” *Id.* This language—indicating that an event can only be a malfunction if the source operates within its normal emission limitations—is circular and nonsensical and must be removed.

¹¹ See, e.g., 75 Fed. Reg. at 63,283 col. 2 (“In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense....”).

In a November 5, 2010 notice, EPA clarified its intent behind the October 14, 2010 proposal concerning how the affirmative defense would apply to injunctive relief. See 75 Fed. Reg. 68,296. Although that notice says that EPA is merely clarifying its intention in the original proposal that operators not be able to assert the affirmative defense to a claim for injunctive relief (see *id.* at 60,297), in fact the preamble to the Proposed Rule does not give any explanation for why the affirmative defense would not apply to injunctive relief. If in fact the excess emissions associated with the equipment or process failure are not reasonably preventable, then there is no apparent reason why injunctive relief should be available either. In fact, as a matter of law, injunctive relief may not be available in cases where a civil penalty cannot be imposed. See *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008 (8th Cir. 2010) (under concurrent remedy doctrine, injunctive relief for a CAA violation is barred when civil penalty is barred by statute of limitations).

Maintaining liability for injunctive relief renders the affirmative defense particularly ineffective with respect to citizen suits. If the source is even potentially subject to injunctive relief, and therefore could be required to pay the citizen-plaintiff's attorneys fees even if the source successfully demonstrated that it otherwise qualified for the affirmative defense, then the affirmative defense would not accomplish EPA's stated objective of providing relief in situations where the emission limitations cannot be met despite proper design and operation of process and control equipment.

EPA has not addressed these and other apparent limitations and shortcomings of the affirmative defense, which make it an entirely inadequate substitute for setting standards that include provisions for SSM events. Moreover, EPA has provided no analysis that would supersede its previous and long-standing determination that it is not desirable to rely on enforcement, rather than regulatory language, to address the inability to comply with section 111 performance standards during SSM events.¹²

At a minimum, then, EPA should state that the affirmative defense applies to civil penalties, civil administrative penalties, noncompliance penalties, and injunctive relief. EPA also should reword the "affirmative defense," so that it states that a

¹² See 37 Fed. Reg. 17,214, 17,214 (Aug. 25, 1972). See also *Marathon Oil Co. v. EPA*, 564 F.2d at 1273 (explaining why EPA's statement that it would not take enforcement action against sources that exceeded effluent limitations because of upset events was "not an adequate response" to the argument that standards that cannot be met during unavoidable upsets fail to reflect available technology). Also for these reasons, EPA's statements in the Proposed Rule preamble about EPA "determining an appropriate response" to reported exceedances of the Proposed Standards, based on whether the exceedances were avoidable, minimized, etc. (which seems to be in addition to providing the affirmative defense) are not in any way a substitute for EPA setting the standards at an achievable level to begin with. See 75 Fed. Reg. at 63,283 cols. 1-2.

source “will not be deemed in violation of” the Part LLLL or Part MMMM standards for excess emissions unless the event, and the source’s response to the event, do not meet the criteria spelled out in the regulations.¹³ Configured in that way, this provision for malfunction should be called something other than an “affirmative defense,” such as an “alternative standard for SSM events.”

5. The Proposed Affirmative Defense As Written Is Unreasonable and Impracticable

If EPA refuses to set alternative emission standards that apply during SSM periods and continues to rely instead on the proposed affirmative defense, the affirmative defense must be substantially modified for it to provide any significant relief. First, as noted above, the affirmative defense needs to state clearly that a source that qualifies for the affirmative defense shall not be deemed to have violated the applicable standards during that time. If EPA does that, it may be unnecessary to state also that the affirmative defense relieves the source from liability for all types of penalties and injunctive relief (save criminal penalties), but that should be the clear effect of qualifying for the affirmative defense.

The affirmative defense should be available not only for malfunctions, but also for excess emissions during startup and shutdown. Although EPA asserts that the Proposed Standards are set at a level that should be achievable by SSI units during startup and shutdown, there is no logical reason why a source that experiences excess emissions during startup or shutdown that were not reasonably preventable (either because it experienced conditions EPA did not anticipate in setting the standards, or because EPA’s assumption about the achievability of those standards during startup and shutdown periods was wrong) should be excluded from the affirmative defense.

Additionally, many aspects of the affirmative defense would make it unavailable as a practical matter for many, if not most malfunctions. Many of these limitations on the affirmative defense also are not directly related to the question of whether an exceedance of the emission limitations due to a malfunction should be excused. EPA needs to substantially revise and streamline the proposed affirmative defense for it to be of practical value.

Several of the conditions for establishing an affirmative defense in proposed 40 C.F.R. § 60.4861(a) and 40 C.F.R. § 60.5181(a)¹⁴ list numerous items which may

¹³ Cf. 40 C.F.R. § 80.613 (stating that persons demonstrating specified defenses “will not be deemed in violation” and are not “deemed liable for a violation” of diesel fuel sulfur program regulations).

¹⁴ EPA is proposing the same affirmative defense requirements for new sources (40 C.F.R. § 60.4861) and existing sources (40 C.F.R. § 60.5181.) Our comments cite the proposed

be appropriate considerations in determining whether excess emissions during a malfunction should be considered a violation, but which ought not to be listed as mandatory criteria, all of which have to be met in order for an exceedance to be excused. For example, proposed section 60.4861(a)(1)(i) states that the excess emissions must have been “caused by a sudden, short, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner.” There is no practical reason why a sudden, infrequent, and unavoidable equipment failure should be exempted if it was “short” but considered a violation if it was not “short.” Similarly, why should a malfunction be considered a violation of the standards if it is not “infrequent,” even though it is “not part of a recurring pattern indicative of inadequate design, operation, or maintenance” (see proposed section 60.4861(a)(1)(iv))?

Several of the conditions for establishing an affirmative defense use phrases that are subject to a wide range of interpretations, and that on their face do not recognize any need for reasonableness or cost-effectiveness. How will the enforcement authority, or a judge, determine whether “proper design” or “better operation and maintenance practices” could have prevented a malfunction (section 60.4861(a)(1)(ii)), whether a recurring malfunction is a result of “inadequate design” (section 60.4861(a)(1)(iv)), whether repairs were made “as expeditiously as possible” (section 60.4861(a)(2)), whether the source took “all possible steps” to minimize the impact of the excess emissions (section 60.4861(a)(5)), *and* whether emissions control systems “were kept in operation if at all possible” (section 60.4861(a)(6))? In many, if not most cases, it may have been possible to avoid the malfunction, or to do more to reduce the magnitude of the excess emissions, if the source had spent huge amounts of money or had imposed economically impracticable constraints on its operation. The affirmative defense, as proposed, leaves open the possibility that a source will be considered to be in violation because the enforcement authority decides that in one or more respects it would have been “proper” or “possible” for the source to take further steps to prevent or minimize the malfunction. In effect, EPA or the court may impose an extreme version of MACT during malfunction periods, without any application of the beyond-the-floor factors in CAA section 129(a)(2). At a minimum, the vague and unqualified descriptors in the criteria for demonstrating the affirmative defense will inevitably lead to varying conclusions as to whether a violation has occurred, resulting in inconsistency from one jurisdiction to the next.

Proposed section 60.4861(a)(6) requires, as a condition for the affirmative defense, that all emissions “control systems were kept in operation if at all possible.” Besides the fact that “if at all possible” is an extreme term that bears no relation to good air pollution control practices, this provision, as well as proposed sections 60.4861(a)(1)(ii) and (iv), should be qualified, as EPA has qualified similar provisions in the NESHAP General Provisions in 40 C.F.R. § 63.6. For example, these

regulatory provisions for new SSI units but are equally applicable to the proposed regulatory provisions for existing SSI units.

conditions should be qualified with caveats that the operation must be consistent with safety and good air pollution control practices, that it does not require the source to make further efforts to reduce emissions below what the standards require, and that it does not require regular operation of backup or standby pollution control equipment.¹⁵ Similarly, EPA has long recognized, in the General Provisions applicable to NSPS, that it is appropriate to require sources to operate the affected facility and related air pollution control technology “to the extent practicable...consistent with good air pollution control practice for minimizing emissions” during SSM periods, not “if at all possible.” See 40 C.F.R. § 60.11(d). EPA cannot abandon those rational approaches and adopt the kind of absolute requirements implied by the Proposed Rule, without an explanation of why it is necessary and appropriate to do so.

Proposed section 60.4861(a)(4) would preclude a facility from taking advantage of the affirmative defense if the malfunction involved bypassing control equipment or a process and the bypass was not “unavoidable to prevent loss of life, severe personal injury, or severe property damage.” This language is stated in such extreme terms that it may be difficult or impossible to meet this criterion, even though bypassing the control equipment or the process was an appropriate exercise of good air pollution control practices. For example, a bypass can be the appropriate response to an upset in order to prevent excess emissions, e.g., fouling of pollution control equipment media that in turn would result in reduced pollution control equipment efficiency or increased pollution control equipment downtime. There can be substantial room for disagreement about what constitutes “severe” property damage. And what degree of injury to employees must the bypass avoid in order to qualify as avoiding “severe” personal injury? Besides the unclear and subjective nature of these criteria, there is nothing inherent to standards under CAA sections 111 and 129 that require a source to avoid bypassing control equipment to such a degree. Lastly, it is not apparent at all why the CAA would disfavor bypassing “a process” in this way.

Under proposed section 60.4861(a)(6), a source claiming the affirmative defense must prove that: “All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health.” In addition to the subjective term “all possible steps,” this provision again presents a disconnect between the absolute and extreme requirement of the affirmative defense and the provisions of the CAA designed to attain ambient air quality standards and protect human health and the environment. The CAA does not require sources to take “all possible steps” to control emissions, even to minimize the impact of hazardous air pollutant emissions on human health under CAA section 112(f). In addition, it is unclear how this criterion for qualifying for the affirmative defense

¹⁵ EPA also determined it was appropriate to include those kinds of caveats in its regulation requiring proper operation and maintenance of wastewater treatment facilities, in 40 C.F.R. § 122.41(e).

differs from proposed section 60.4861(a)(2), which requires that the frequency, amount, and duration of excess emissions “were minimized to the maximum extent practicable.” Unless EPA explains what additional showing would be needed by section 60.4861(a)(6), it should be eliminated.

The requirement proposed in section 60.4861(a)(8) that the source must show that “at all times, the facility was operated in a manner consistent with good practices for minimizing emissions” (emphasis added) could be read to go way beyond an analysis of why equipment may have malfunctioned and place an insurmountable burden on the source to meet a “good practices” standard (undefined) for the whole sewage treatment plant, industrial plant, or commercial premises. (The problem is that EPA has used “facility” in some aspects of the Proposed Rule to indicate something much larger than the SSI unit subject to the Proposed Standards. See proposed 40 C.F.R. §60.4780.) This factor could allow a regulatory enforcement official to potentially measure the entirety of operations at a site against a multitude of arbitrary “good practices” and subjectively find the source lacking, thereby denying the source the ability to assert an affirmative defense. If EPA retains this condition for the affirmative defense, of demonstrating operation consistent with good practices for minimizing emissions, EPA must clarify that this condition applies to the “affected facility” or “existing facility,” as those terms are defined in 40 C.F.R. §60.2. EPA also must not include a requirement such as this in an affirmative defense unless it defines the terms used. If EPA really does intend for this condition to apply to operation of the entire site, and not just the SSI unit, then EPA must justify why EPA has the statutory authority to shift its focus from the SSI unit to the plant as a whole.

The requirement in proposed section 60.4861(a)(9) that the source “have prepared a written root cause analysis to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue” again does not implement the statutory criteria for standard-setting under sections 111 and 129. Moreover, read literally it would mean that a source could never take advantage of the affirmative defense if the source was unable to determine the primary cause of the malfunction or was unable to correct that cause. EPA has defined a malfunction as an event that is “unavoidable” and unforeseeable. See proposed section 60.4861(a)(1)(i)-(iii). It therefore should be expected that in many cases the primary cause of the malfunction will not be ascertainable, or it will not be possible to identify a way to ensure the malfunction will not recur.¹⁶ In addition, requiring the facility to eliminate the primary causes of the malfunction, without regard to “taking into consideration the cost of achieving such” elimination and the “non-air quality health and environmental impacts and energy requirements” associated with its elimination is unreasonable and entirely

¹⁶ EPA has long acknowledged this reality in the General Provisions applicable to NSPS, which requires that written reports of excess emissions include the “nature and cause of any malfunction, if known....” 40 C.F.R. § 60.7(b)(2) (emphasis added).

inconsistent with the criteria for standards established under CAA sections 111(a)(1) and 129(a)(2).

Finally, the requirement in proposed section 60.4861(b) to notify the Administrator by telephone or fax as soon as possible, but no later than two business days after the malfunction begins, and then to submit a written report within 30 days of the initial occurrence of the malfunction that demonstrates, "with all necessary supporting documentation," that the source met all of the multitude of criteria for the affirmative defense, is unreasonable and unnecessary. It is novel at best for a person to be determined to have acted unlawfully unless the person has submitted his entire defense before he is even notified of a potential enforcement action. In many cases, it would be obvious to the enforcement authority (not "the Administrator"), based on the kind of short malfunction or deviation report that sources already submit under many air programs, that an exceedance of the Proposed Standards resulted from an unforeseen and unavoidable equipment failure or process upset. It is extremely inefficient and burdensome for both sources and regulators to require a complete justification of the affirmative defense before the enforcement authority has indicated any need for further investigation. Additionally, allowing only 30 days to provide the kind of extensive documentation required by the affirmative defense as currently written, including a completed root cause analysis, is unreasonable. Ninety days is the minimum time that should be allowed, unless EPA substantially streamlines the criteria for the affirmative defense, consistent with these comments.

6. Conclusion

In summary, the SSM Coalition urges EPA to withdraw the Proposed Rule, so that EPA can give serious consideration to alternative emission limitations, or other requirements, that would apply during startup and shutdown events or during malfunctions. EPA must consider the variety of options, as described in these comments, that it has for addressing excess emissions during SSM events, rather than merely assuming they will not occur or providing an "affirmative defense" in lieu of setting standards and other requirements that comply with the criteria for standard-setting in CAA sections 111 and 129. If EPA retains the affirmative defense in lieu of setting appropriate, achievable standards, EPA must modify it substantially so that it does not require the source to prove its innocence (before it is even charged) and does not impose unreasonable or impracticable conditions.

If you have any questions about these comments or wish to discuss these issues further with members of the SSM Coalition, please contact our counsel, Russell Frye, at 202-572-8267 or rfrye@fryelaw.com.

Sincerely,

American Chemistry Council
American Forest & Paper Association
American Home Furnishings Alliance
American Iron and Steel Institute
American Petroleum Institute
American Wood Council
Brick Industry Association
Coalition for Responsible Waste
Incineration
Council of Industrial Boiler Owners
Florida Sugar Industry
National Association of Manufacturers
National Petrochemical & Refiners
Association
Rubber Manufacturers Association
Treated Wood Council
Vegetable Oil SSM Coalition (consisting
of the Corn Refiners Association, the
National Cotton Council, the National
Cottonseed Products Association, the
National Oilseed Processors
Association, and Sessions Peanut
Company)

cc: Desk Officer for EPA

Attachment E
Residual Risk Coalition Letter

December 6, 2010

EPA Docket Center
EPA West (Air Docket)
Attention Docket ID No. EPA-HQ-OAR-2010-0600
U.S. Environmental Protection Agency
Mailcode 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
a-and-r-docket@epa.gov

Re: Comments of the Residual Risk Coalition on the National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; The Printing and Publishing Industry; and Steel Pickling – HCl Process Facilities and Hydrochloric Acid Regeneration Plants; Proposed Rule.

To Whom It May Concern:

The Residual Risk Coalition (“R2C”) appreciates this opportunity to submit comments on the above-referenced proposed rule, which was published at 75 Fed. Reg. 65068 (Oct. 21, 2010). The R2C is an ad-hoc group comprised of the American Chemistry Council, the American Forest & Paper Association, the American Petroleum Institute, the American Wood Council, the National Oilseed Processors Association, the National Petrochemical and Refiners Association, the Portland Cement Association, and the Rubber Manufacturers Association. Each R2C organization has members that are subject to “MACT” standards that will undergo residual risk review pursuant to § 112(f), including standards that are the subject of this rulemaking. The R2C is dedicated to working constructively with the Environmental Protection Agency in developing a practical and environmentally responsible approach to satisfying the Agency’s obligations under § 112(f).

We offer comments on eight specific aspects of the proposed rule. These comments address the cross-cutting issues that likely will arise in many of the residual risk assessments for rules applicable to our members. We do not provide comments on the particular details of the source categories addressed in the subject proposal. Overall, our interest is in establishing a reasonable residual risk methodology that identifies and appropriately addresses remaining risk associated with hazardous air pollutant (“HAP”) emissions from MACT-regulated source categories and subcategories, while avoiding additional emissions limitations where they are not needed to assure an ample margin of safety.

1. The “total facility” approach to conducting risk assessment exceeds EPA’s authority under § 112(f).

EPA explains in the RTR Proposal that “in contrast to past [residual risk] determinations” the Agency has decided to consider “additional measures of health information to support our decision-making,” including “[e]stimates of “total facility” cancer and non-cancer risk (risk from all HAP emissions from the facility at which the source category is located.”¹ Because the CAA requires residual risk determinations to be conducted on a category by category basis, EPA does not have authority to consider the combined emissions from entire facilities when making a § 112(f) risk assessment for a given source category.

Section 112(f)(2)(A) unambiguously requires EPA, within eight years after adopting a MACT standard for a given source category or subcategory, to “promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health.” Section 112(f)(2)(A) further dictates that, “Emissions standards promulgated under this subsection shall provide an ample margin of safety to protect public health.” It is not reasonable to construe these provisions as authorizing EPA to consider emissions from entire facilities in conducting risk assessments and potentially revising the underlying rule for the simple reason that the Congress clearly envisioned that full implementation of the MACT program would take longer than eight years. Consequently, it would be impossible for EPA to fulfill its unambiguous obligation for § 112(f) standards to protect public health with an ample margin of safety in cases where facilities contain sources in a category where the eight year deadline for conducting the § 112(f) risk review precedes the adoption of MACT standards for other sources at the facilities.

This is not mere hypothetical conjecture. The standards under review in this proposal provide a case in point. Many of the facilities containing sources affected by one of the standards under review in this proposal also contain industrial boilers that will be subject to the upcoming MACT standard for industrial boilers. As a result, EPA currently is without authority to conduct a § 112(f) risk assessment for co-located industrial boilers because those boilers are not yet subject to a MACT standard. Thus, it is impossible for EPA to assure an ample margin of safety from total facility emissions for sources affected by the standards covered by this proposal. This demonstrates why the statute cannot be interpreted to allow consideration of emissions from entire facilities when conducting a § 112(f) risk review.

In addition, § 112(f)(2)(A) further provides that, “If standards promulgated pursuant to subsection (d) of this section and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to *emissions from a source in the category or subcategory* to less than one in one million, the Administrator shall promulgate

¹ 75 Fed. Reg. at 65073.

standards under this subsection for such source category” (emphasis added). This provision unambiguously requires the § 112(f) risk assessment to be focused exclusively on “emissions from a source in the category or subcategory.” For this reason alone, EPA does not have authority to consider emissions from any sources other than those in the source category or subcategory under review at that time.

2. Demographics may not be considered in conducting risk assessments under § 112(f).

EPA explains that “in contrast to past [residual risk determinations], this notice presents and considers additional measures of health information to support our decision-making” – including “[d]emographic analyses (analyses of the distributions of HAP-related cancer risks and non-cancer risks, across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located).”² In other words, EPA proposes to consider in making § 112(f) risk determinations “the potential for any environmental justice issues that might be associated with each source category.”³

Although EPA conducted a “demographic analysis” for each of the six rules covered by this proposal, those analyses do not provide a basis for imposing additional control measures in order to assure an ample margin of safety. However, for one source category – chromium electroplating and anodizing – EPA expresses concern “that there are disparities in risks for some demographic groups” and specifically requests comment “on whether there are any cost-effective controls that may be able to reduce these risks.”⁴

Because the term “public health” cannot reasonably be interpreted to include consideration of environmental justice in the § 112(f) context, EPA’s proposal to consider demographic analyses in conducting risk reviews under § 112(f) is not a proper exercise of Agency authority. Section 112(f)(2)(A) expressly instructs EPA to impose additional emissions controls if needed to provide an ample margin of safety “to protect public health.” The term “public health” is not defined in § 112 or in EPA’s Part 63 regulations.

In the context of EPA’s national ambient air quality program (“NAAQS”), the Supreme Court has observed that the “primary definition of the term” should be applied – *i.e.*, public health means “the health of the public.”⁵ This conclusion emphasizes that the scope of the term “public health” should be dictated by the meaning of the word “public.” In relevant part, Websters Free Dictionary defines the adjective “public” to mean “of, relating to, or affecting all of the people or the whole area of a nation or state” and “of or relating to people in general.”

² *Id.*

³ *Id.* at 65080.

⁴ *Id.* at 65093.

⁵ *Whitman v. American Trucking Associations, Inc.*, 531 U.S. 457, 465 (2001).

These definition emphasize that the word “public” should be construed expansively as describing the people as a whole, and not particular demographic segments.

EPA’s established approach to assessing potential impacts on public health under the NAAQS program is consistent with this meaning. EPA reasonably interprets the term “public health” to include consideration not only of potential impacts on the population as a whole, but also on sensitive subpopulations – recognizing that the objective is to protect the group rather than any particular individual in the group.⁶ But, sensitive subpopulations are identified according to their particular health-based sensitivities (*e.g.*, asthmatics) rather than demographic classifications unrelated to particular health-based sensitivities (*e.g.*, population without a high school diploma).

With this backdrop, it is not reasonable to construe the term “public health” as used in § 112(f) as allowing consideration of demographic classifications that bear no relationship to the potential health effects presented by the HAPs at issue for the given source category or subcategory. EPA’s proposal would unreasonably inject racial, ethnic, and other policy considerations into a program designed to provide protection for the public at large. For example, EPA suggests that the population without a high school diploma should receive extra scrutiny, yet does not afford the same scrutiny to other reasonably definable educational groups, such as those with a high school diploma, those with college degrees, and those with advanced degrees. There is simply no principled way to identify and define those groups that should receive extra scrutiny from those that do not. In short, EPA’s approach would inappropriately cause arbitrary policy and political considerations to trump objective scientific analysis. This is patently unreasonable and, as such, is not a supportable interpretation of § 112(f).

3. EPA fails to provide a rational basis for using allowable emissions in conducting risk assessments under § 112(f).

EPA coins the term “MACT allowable” emissions in the preamble, and explains that this term “represents the highest emission level that could be emitted by the facility without violating the MACT standard.”⁷ The Agency asserts that considering MACT allowable emissions in determining residual risk under § 112(f) “is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards.”⁸ Without further explanation as to why it might be appropriate to determine and apply MACT allowable emissions in § 112(f) risk assessments, the Agency goes on to explain that it developed a ratio method of estimating MACT allowable emissions and “applied these ratios on a facility-by-facility basis to the maximum chronic risk values from the inhalation risk assessment to obtain

⁶ *See, e.g.*, 71 Fed. Reg., 61144, 61145 fn. 2 (Oct. 17, 2006).

⁷ 75 Fed. Reg. at 65077.

⁸ *Id.*

facility-specific maximum risk values based on MACT-allowable emissions.”⁹ The Agency considered risks based on MACT allowable emissions in its proposed risk assessments for the six subject source categories.¹⁰

EPA cannot lawfully use MACT allowable emissions in the proposed risk assessments and residual risk determinations because the Agency has failed to provide any reasoned explanation for why risk assessments based on actual emissions estimates are inadequate.¹¹ The Agency’s risk assessment methodology already is rife with conservative assumptions. For example, health benchmarks, such as acute reference doses, typically incorporate two to three orders of magnitude of conservatism to account for uncertainties, such as the extrapolation of animal toxicity testing data to humans. Similarly, the dispersion models used to predict off-site ambient HAP concentrations attributable to emissions from affected sources incorporate numerous conservative assumptions to simplify the analysis of highly complex factors, such as meteorology and atmospheric chemistry. In addition, risk assessments assume exposure to the most exposed individual on a continuous basis for an entire lifetime.

In light of the conservatism that already is inherent to EPA’s risk assessment methodology, it makes no sense to apply yet another layer of conservatism – this time based on the hypothetical assumption that affected sources should be expected to emit more than the actual data indicate – to § 112(f) risk assessments. EPA has provided no data or analyses indicating that its current methodology results in negative bias. EPA has provided no data demonstrating that affected sources actually do emit at levels significantly higher than the actual data show for any significant period of time. In short, EPA’s proposal to use hypothetical emissions levels in § 112(f) risk assessments is justified on nothing more than the bald assertion that sources *might* emit at these higher levels. The failure to provide a reasoned explanation as to why this approach is justified and the failure to provide any record evidence supporting the use of MACT allowable emissions render this proposal insupportable under the law.

⁹ *Id.*

¹⁰ *See, e.g., id.* at 65087 (risk assessment for the chromium electroplating and anodizing source category).

¹¹ Note that § 112(f)(1)(A) required EPA to report to Congress on “methods of calculating the risk to public health *remaining, or likely to remain*, from sources subject to regulation under this section after the application of standards under subsection (d) of this section” (emphasis added). Section 112(f)(1)(B) required EPA also to report on “the *actual health effects* with respect to persons living in the vicinity of” affected sources” (emphasis added). These requirements clearly signal that Congress expected EPA to focus on actual risk and not hypothetical risk in implementing the requirements of § 112(f). Thus, it is not reasonable in the first instance for EPA to construe § 112(f) as authorizing the Agency to conduct risk assessments based on hypothetical “MACT allowable” emissions.

4. EPA is without authority to eliminate the startup, shutdown, and malfunction provisions unless the underlying MACT standards accommodate emissions during those periods.

EPA observes in the preamble to the proposed rule that the startup, shutdown, and malfunction (“SSM”) provisions contained in the Part 63 General Provisions were vacated by the D.C. Circuit in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) (“*Sierra Club*”).¹² The Agency then explains that, “We are proposing to eliminate the SSM exemption in each of the six MACT standards addressed in this proposal. Consistent with *Sierra Club v. EPA*, we are proposing that the established standards in these rules apply at all times.”¹³

The proposal to eliminate the SSM provisions in the six subject rules is not based on an accurate reading of *Sierra Club*, is not supported by any rational explanation as to why the elimination of the SSM provisions is justified, and is arbitrary and capricious given that EPA fails to provide any analysis of why affected sources reasonably can be expected to meet the emissions limitations and standards that the Agency proposes to apply during periods of SSM.

To begin, EPA’s proposal “that the standards in these rules apply at all times” is not, as EPA claims, “[c]onsistent with *Sierra Club v. EPA*. The decision in that case was grounded in the court’s assertion that § 112 requires emissions standards to apply at all times.¹⁴ Based on this, the court held the SSM General Provisions do not comport with § 112 because, in the eyes of the court, the SSM provisions are not “section 112-compliant” emissions standards.¹⁵ Notably, the court did not hold that EPA is prohibited from setting separate standards for periods of SSM. It simply held that standards for such periods must be developed according to the § 112(d) MACT process.

Thus, the proposal to eliminate the SSM provisions from the six source categories subject to this proposal is not “consistent” with *Sierra Club* because there is nothing in that case that supports the conclusion that vacatur of the Part 63 General Provisions necessarily requires “the established standards in these rules [to] apply at all times.” EPA’s flawed legal analysis provides no support for the proposal to eliminate the SSM provisions in the six subject rules.

¹² 75 Fed. Reg. at 65074.

¹³ *Id.*

¹⁴ *Sierra Club* at 1027 (“Congress has required that there must be continuous section 112-compliant standards.”).

¹⁵ *Id.* at 1028 (“Because the general duty is the only standard that applies during SSM events — and accordingly no section 112 standard governs these events — the SSM exemption violates the CAA’s requirement that some section 112 standard apply continuously.”).

This fundamental legal flaw is magnified by the Agency's failure to provide any explanation whatsoever as to why it is appropriate to now apply the existing emissions standards to periods of SSM. For example, EPA made no effort to obtain emissions information from the six source categories for periods of SSM and provides no other evidence or analysis supporting its assertion that it is appropriate to apply the existing standards to periods of SSM. Moreover, EPA fails to investigate the record data developed during the promulgation of the existing standards to assess whether those data are characteristic and representative of emissions during periods of SSM. In short, the Agency simply asserts with no record basis that the existing standards should apply to periods of SSM. This unsupported assertion provides no basis for extending the existing standards to periods of SSM – this failure to seek relevant data, assess existing data, and investigate whether the existing standards should appropriately apply to periods of SSM is facially arbitrary and capricious and provide wholly inadequate support for the Agency's proposal.¹⁶

5. EPA is without authority to impose new standards under §§ 112(d)(2) and (3) for emissions sources in source categories for which a MACT standard already has been promulgated – § 112(d)(6) provides the Agency's only authority to adjust existing MACT standards.

Once EPA establishes a MACT standard for a particular source category, the Agency has the authority under § 112(d)(6) to “review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years.” In other words, EPA does not have unfettered discretion to revisit a prior MACT determination once that determination has been issued. Rather, EPA may revise a prior determination only “as necessary” according to explicit statutory criteria.¹⁷

¹⁶ In any event, we also note that EPA's proposal to provide an affirmative defense for periods of malfunction is without merit. Comments recently submitted by the “SSM Coalition” on EPA's proposed standards for Sewage Sludge Incinerators explain in detail that: (1) EPA must take malfunctions into accounts when setting § 112 emissions standards; (2) the proposed affirmative defense is not a permissible substitute for setting emissions standards for periods of malfunction; and (3) the proposed affirmative defense is unreasonable and impracticable. See Letter to EPA Docket Center (EPA/DC) from the American Chemistry Council, *et al.*, Comments on Proposed Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Docket ID No. EPA-HQ-OAR-2009-0559, at 6-20 (Nov. 29, 2010). We incorporate these comments by reference. For these reasons, EPA should set aside the proposed affirmative defense for periods of malfunction and, instead, set a work practice standard for such periods.

¹⁷ Cf. *New Jersey v. EPA*, 517 F.3d 574, 582 (D.C. Cir. 2008) (Thus, EPA can point to no persuasive evidence suggesting that section 112(c)(9)'s plain text is ambiguous. It is therefore bound by section 112(c)(9) because “for [] EPA to avoid a literal interpretation at *Chevron* step

In the proposal, EPA explains that, “For eight source categories subject to three of the MACT standards, we identified significant emission sources within the categories for which standards were not previously developed” and that, “We are proposing MACT standards for these emission sources pursuant to CAA section 112(d)(2) and (3).”¹⁸ This explanation makes it clear that EPA is not invoking § 112(d)(6) as the authority for the new proposed standards – indeed, the preamble provides no analysis of “developments in practices, processes, and control technologies” to justify the proposed standards, as would be required if EPA were relying on § 112(d)(6). And, there is no mention of § 112(d)(6) in relation to the proposed new standards. Instead, the Agency is invoking §§ 112(d)(2) and (3) directly, as if a MACT standard for these sources categories does not already exist.

EPA does not have such authority. As explained above, once EPA makes a MACT determination for a particular category, § 112(d)(6) provides the only authority for the Agency to later review and possibly revise the determination. Section 112(d)(6) expressly authorizes EPA to review existing determinations and provides specific criteria to guide and constrain the review. The existence of this express authority forecloses the Agency’s ability to directly invoke §§ 112(d)(2) and (3) for a given source category when a MACT determination has already been issued for the source category.

Notably, even if the Agency had invoked § 112(d)(6) as authority for revising the existing MACT standards, it still would not have authority to regulate the emissions points for which standards were not established in the first round of MACT rulemaking. Prior MACT determinations may be revised only “as necessary (taking into account developments in practices, processes, and control technologies).” Perceived “gaps” in the original MACT determinations are not “practices, processes, and control technologies” that are properly within the scope of a § 112(d)(6) review.

6. In any event, it is not a reasonable exercise of authority to establish new emissions limitations under existing MACT standards when there is no significant risk associated with emissions from sources in the given source category.

In the proposed rule, EPA asserts the proposition that standards must be established for “significant emissions points” not currently regulated under existing MACT standards – even in circumstances where the Agency has determined that the existing MACT standard protects

one, it must show either that, as a matter of historical fact, Congress did not mean what it appears to have said, or that, as a matter of logic and statutory structure, it almost surely could not have meant it,” *Engine Mfrs. Ass’n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996), showings EPA has failed to make.”).

¹⁸ 75 Fed. Reg. at 65074.

health and the environment with an ample margin of safety. Establishing new standards under these circumstances is patently unreasonable and cannot be justified under § 112(d)(6).

For example, in its review of the existing MACT standards for the epichlorohydrin elastomers production source category, EPA explains that, based on a detailed assessment of risk to health and the environment due to HAP emissions from this source category under the existing Polymers and Resins I MACT standard, “we continue to propose that the current MACT standard provides an ample margin of safety to protect public health and the environment, and we are proposing to re-adopt the existing MACT standard to satisfy section 112(f) of the CAA.”¹⁹ Yet, just paragraphs later in the same section of the preamble, the Agency proposes a new MACT emissions limitation for back end process operations in this source category.²⁰

As explained above, EPA has no direct authority under §§ 112(d)(2) and (3) to create new limits in source categories for which a MACT standard already has been promulgated. But, even if EPA had invoked § 112(d)(6) as authority for adopting the new standard for back end process operations, such a standard would not be justified because EPA’s own analysis demonstrates that the existing MACT standard provides an ample margin of safety to health and the environment. In fact, EPA plainly admits that “the MACT standard, prior to the implementation of the proposed emission limitation to the back-end process operations discussed in this section, provides an ample margin of safety to protect public health.”²¹

In these circumstances, it is patently unreasonable for EPA to regulate beyond the point that the standard has been found to already provide an ample margin of safety. This is regulation for the sake of regulation and, as such, contradicts Congress’s clear intent that an ample margin of safety is an appropriate stopping point for emissions limitations under § 112.²²

¹⁹ *Id.* at 65098.

²⁰ *Id.* at 65097.

²¹ *Id.* at 65099.

²² EPA also explains in the context of the proposed new limit for back end process operations that, because the existing MACT standard already provides an ample margin of safety, “we do not believe it will be necessary to conduct another residual risk review under CAA section 112(f) for this source category 8 years following promulgation of new back-end process limitations, merely due to the addition of this new MACT requirement.” Implicit in this statement is the suggestion that a residual risk review under § 112(f) may be needed for new emissions limits that are established for existing MACT standards. As with setting MACT standards in the first instance, § 112(f) provides a one-time opportunity for conducting a residual risk review of a MACT standard. There is no basis under the law for the suggestion that a revision to an existing MACT standard triggers the need for another § 112(f) residual risk review. Indeed, the proposal provides no explanation whatsoever as to why such a subsequent review could be required under the law.

7. EPA is without authority to consider non-HAP emissions reductions in conducting a review of existing MACT standards under § 112(d)(6).

In the context of the § 112(d)(6) review of the existing MACT standard for Marine Tank Vessel Loading Operations (“MTVLO”), EPA assesses the possibility of lowering the existing applicability threshold for that rule from 10 million barrels per year (bbl/yr) gasoline to a lower threshold of 5, 1, or 0.5 million bbl/yr. The Agency’s analysis shows that the cost effectiveness of establishing a 1 million bbl/yr threshold would be \$74,000 per ton of HAP controlled and \$5,500 per ton of VOC controlled.²³ Based on this analysis, the Agency proposes to lower the applicability threshold to 1 million bbl/yr on the grounds that, “While the HAP cost-effectiveness is higher than our historical values, the VOC cost-effectiveness is within the range of acceptability.”²⁴ In other words, EPA purports to expand the HAP control requirements under the existing rule based on a finding that the expanded control requirements would be cost effective for VOC control.

This conclusion cannot be supported under the CAA. When setting MACT standards in the first instance, the CAA expressly forbids EPA from considering the co-benefits of non-HAP emissions reductions – the “floor” must be based on the HAP emissions reductions achieved by the better performing sources in the category (or the best controlled similar source in the case of new source MACT) and any “above the floor” standard may be based only on consideration of “the cost of achieving such [HAP] emission reduction, and any non-air quality health and environmental impacts and energy requirements.”²⁵ It would not be reasonable to conclude that § 112(d)(6) enables consideration of non-HAP emissions reductions in making control requirements when such reductions cannot be considered in setting the standard in the first instance. Congress unambiguously designed § 112 to provide the authority and obligation for EPA to regulate HAP emissions. There is no indication in §§ 112(d)(2), (3), or (6) that EPA may impose HAP emissions limitation based solely on an assessment of collateral non-HAP emissions reductions.

Therefore, in the case of the MTVLO standard, EPA has no cognizable basis for changing the existing 10 million-bbl/yr applicability threshold.

²³ 75 Fed. Reg. at 65115.

²⁴ *Id.*

²⁵ CAA §§ 112(d)(2) and (3).

8. EPA has not provided justification or any rational basis for departing from the risk assessment methods established in prior § 112(f) residual risk determinations.

As explained in detail above, EPA proposes at least three significant departures from its established methods of conducting risk analyses in support of § 112(f) determinations: (1) EPA seeks to include consideration of total facility HAP emissions at a given site, and has expressed the belief that region-wide analyses would be appropriate if adequate data were available; (2) the Agency proposes to consider allowable emissions from affected facilities rather than relying on quality-assured actual emissions data; and (3) EPA seeks to consider demographics in deciding whether an ample margin of safety has been achieved.

Where legal discretion otherwise exists, the Agency is not prevented from charting a new course on established regulatory principles. However, EPA must do more than outline its purported legal authority for the new approach. EPA has the additional burden of providing a rational basis for abandoning its prior approach. In this case, even assuming EPA has discretion on these key points (which, for the reasons described above, the R2C contends the Agency does not), EPA has provided no explanation at all as to why such fundamental changes to the established contours of the program are necessary or appropriate. As a result, these changes lack foundation and are not supported as a reasonable exercise of Agency discretion.

* * * * *

Thank you for the opportunity to submit these comments. Please do not hesitate to contact me if you have questions or need additional information.

Sincerely,

Matt Todd
Chair – The Residual Risk Coalition

cc: P. Tsirigotis
R. Wayland
M. Kissell

Attachment F
Reservoir Performance for Reduced Emissions
Completions

Attachment F

Reservoir Performance for Reduced Emissions Completions

By David A. Simpson, PE

EPA has proposed under 40 CFR 60.5375 that “*Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.*”

- (1) *You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.*
- (2) *You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.*
- (3) *You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”*

This regulation requires that flow-back emissions must be controlled. Industry practice has long been to flow wells back to flares where allowed by local regulations because unburned natural gas presents a safety hazard to workers on location. There is an evolving trend to flow this gas to sales where technically feasible. In effect, the regulatory language above is setting proscriptive language to require an evolving practice. The discussion below is directed at clarifying the issues surrounding the technical choices that must be made during a flow back to maximize the potential for success.

API conversations with Halliburton, Schlumberger, and BJ Services (the three largest oilfield service companies) and Aztec Well Services a regional drilling company indicates that essentially every well that is drilled is evaluated for hydraulic fracture stimulation and has been for many years. There are fields where this evaluation results in different stimulation techniques, but these fields are reasonably rare. Consequently, the population for this requirement is approximately every gas well.

To support these conversations, the online databases for Colorado¹, New Mexico², and Wyoming³ were searched for information on hydraulic fractures. Permit data is stored as scanned images and a review of a random selection of wells completed since 1960, showed that the data is mostly silent on stimulation techniques, but where such techniques were mentioned every well that was looked at had been hydraulically fractured regardless of the formation.

The benefits of Reduced Emissions Completions (REC) stated in the Regulatory Impact Analysis (RIA) depend heavily the data contained in EPA’s Natural Gas Star Program⁴. This reliance may be less justified than the EPA expects. First, the data within the Natural Gas Star Program has been carefully

¹ Website of Colorado database <http://cogcc.state.co.us/>

² Website of New Mexico database http://octane.nmt.edu/gotech/Petroleum_Data/General.aspx

³ Website of Wyoming database <http://wogcc.state.wy.us/>

⁴ EPA Energy Star Program at <http://www.energystar.gov/>

selected initially by the contributing company and finally by the EPA itself to present environmental successes in the best possible light. The success stories described within the program represent techniques that have worked on the projects referenced, and contributing companies have not claimed that the techniques reported are in any way universally applicable to the industry. To assume that a few dozen or even a few hundred successful reduced emissions completions means that 53% of all completions, fractures and re-fractures will benefit from this technique is extrapolating a limited data set far outside the parameters supported by the original sample size.

The requirements for REC are: (1) that any inert gases used in the fracture will be diluted to acceptable levels for sales gas before the end of the flow back; and (2) that the well has adequate reservoir pressure to flow at rates appropriate for transporting solids and liquids into an imposed back pressure. The first requirement is easily satisfied for hydraulic fracture stimulations using a liquid as the carrier fluid—the large number of procedures that use nitrogen or CO₂ foam will rarely meet the requirements during the flowback period. The second requirement is problematic.

First, let me clarify some terms commonly used in describing flow from a reservoir.

- **“Reservoir pressure”** is the pressure within the reservoir rock at a point where the pressure is largely undisturbed by well flow. When a well is first completed (i.e., the production casing is installed, cemented, and perforated), the pressure seen on surface is a reasonable surrogate for reservoir pressure as long as care is taken to take the static pressure gradient into account. As fluids are removed from the reservoir, surface pressure becomes progressively less representative of reservoir pressure. For determining if a well will flow into line pressure, the pressure experienced immediately after perforations (before any stimulation) is typically used for “reservoir pressure”. After that initial point, reservoir pressure is rarely known with certainty again, but can be estimated through pressure build up tests or material balance calculations.
- **“Near wellbore pressure traverse”** is an estimate of the pressure moving away from the bottom of the well to a position within the reservoir that is experiencing “reservoir pressure”. This gradient represents the resistance of the reservoir to flow, so the faster you flow the well the steeper the gradient becomes; which tends to be a limiting parameter in flow rate. This is because of the resistance of the reservoir rock to flow which can be very high. We don’t measure “resistance” to flow, but instead we measure “ability” to flow or “permeability”. The industry goes to great lengths to predict permeability in every reservoir, but permeability tends to change with time and with spatial position so it is never known with precision.
- **“Flowing bottomhole pressure”** is the pressure that can be measured on the well side of the perforations while the well is flowing. This is the “hinge” pressure that determines both the flow rate into the well and the flow rate out of the well for a given set of wellbore tubulars and a fixed surface pressure.
- **“Flowing tubinghead pressure”** is the pressure measured in the production tubing at the surface while the well is flowing. The difference between line pressure and flowing tubing pressure is the pressure drop in the flow lines and surface equipment. This pressure drop can be very large especially at high flow rates or in scaling/plugging situations. It is rare to be able to reliably substitute “line pressure” for “flowing tubing pressure”.
- **“Line pressure”** is the pressure at the sales meter and represents the pressure of the gathering line. Data from line pressure instruments is always the most accurate and available information on a wellsite, but is rarely appropriate for reservoir-flow calculations.

- “**Superficial velocity**” is the velocity that a fluid would demonstrate if it were the only fluid contained in a multiphase flow stream. The interactions between fluids in a multiphase flow conduit are extremely complex and estimating the actual velocity of any given component within the stream has proven to be impossible to date. Researchers have found that superficial velocity leads to conclusions that do an adequate job of reflecting actual performance of a multiphase line.

Velocity is required to shift liquids and solids. The magnitude of required bottom-hole superficial velocity is somewhere between 50 ft/sec and 150 ft/sec depending on the free solids that must be transported. Plotting bottom-hole superficial gas velocity vs. flowing tubing pressure for an example well with 4,000 ft of 2-3/8, 4.7 lbm/ft, J-55 tubing yields:

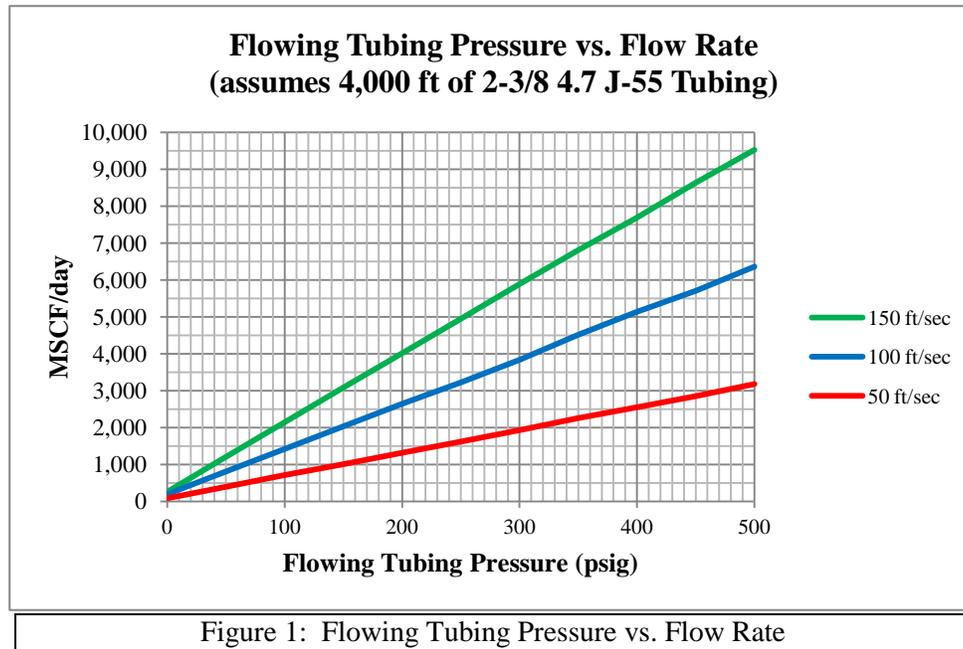
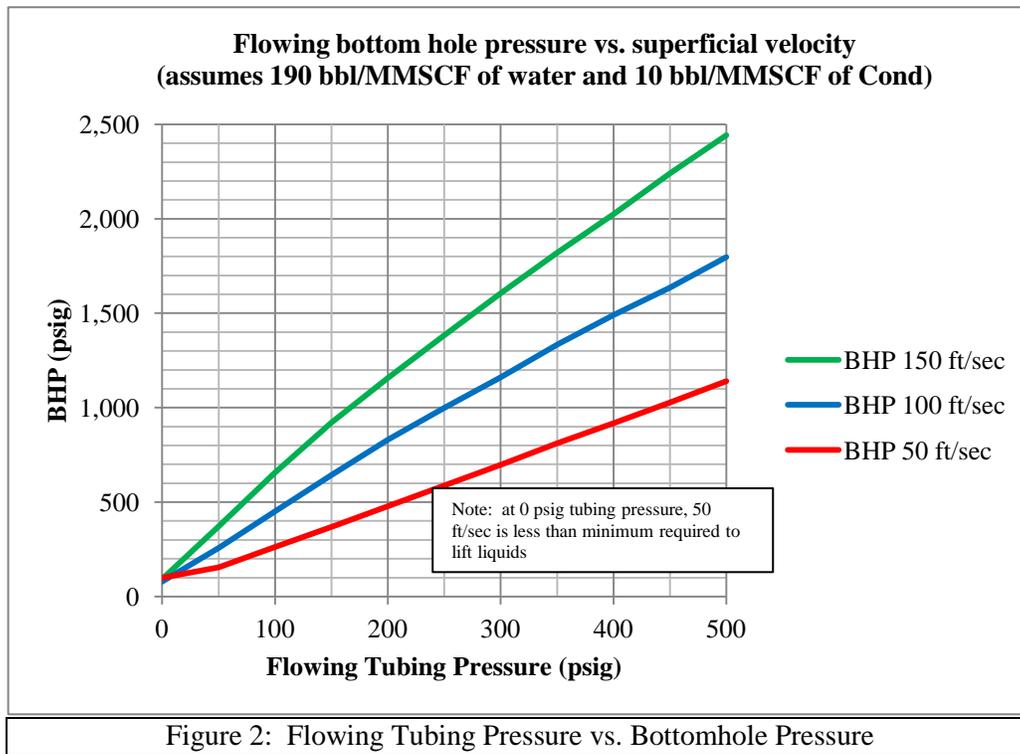


Figure 1 shows that imposed backpressure has a significant impact on velocity. If the flow back can exhaust to atmosphere, then the flow rate required to achieve adequate velocity is 200 to 264 MSCF/day depending on the amount of solids that have to be moved. This flow rate is achievable in a significant number of new wells. If the well sees 100 psig, which is often considered a “low” line pressure, then the minimum required flow rate moves up to a range of 700 to 2,100 MSCF/day which exceeds the ability of a large proportion of new wells. In the frontier Shale Gas plays, the line pressures are currently tending to be in the neighborhood of 450 psig which would require the wells to flow 2.8 to 8.6 MMSCF/d, with the sand load requiring velocities well toward the high end of that range.

The other piece of this puzzle is the flowing bottom-hole pressure required to achieve a superficial gas velocity of 50-150 ft/sec. To determine that pressure you have to assume a liquid flow rate. If you assume that while the well is cleaning up it will flow about 190 bbl water/MMSCF and 10 bbl condensate/MMSCF then you can get an example of the bottom hole pressures required:



There is no universal correlation to relate a flowing bottom hole pressure and a flow rate to reservoir pressure because the relationship is very much dependent on the efficiency of the transport paths within the near wellbore. That being said, it is not unusual for the required reservoir pressure to be more than twice the bottom hole pressure, so to flow 150 ft/sec into 450 psig gathering pressure would require reservoir pressures in the neighborhood of 4,400 psig. Reservoir pressures this high are certainly not unheard of, but at the same time they are not particularly common either.

Determining reservoir pressure is a challenge. For flowing wells, reservoir pressure is rarely known with any confidence. Sometimes a pressure build-up test is used to allow engineering tools to be applied to predict reservoir pressure, but the shut-in periods are rarely long enough to allow the near wellbore pressure to reach reservoir pressure. Occasionally, engineers have enough information to perform a reliable material balance to compute reservoir pressure. This is exceedingly rare. When a new well is drilled, the area around the wellbore will have approximate reservoir pressure because that region of the reservoir will not have been subject to any velocity or depletion effects yet. After stimulation and flowback, the reservoir pressure becomes progressively more difficult to determine with time. After setting production casing and cementing it into the well bore, the casing and cement are perforated to allow the wellbore to access the reservoir. At that point, the reservoir pressure is equal to the bottom-hole pressure and until liquids accumulate in the wellbore, surface pressure is reasonably close to flowing bottomhole and reservoir pressure. This number is generally recorded and reported to state agencies as “Initial Pressure” and is reasonable to accept as “reservoir pressure” at completion.

After stimulation, wellhead pressure is no longer a reasonable representation of reservoir pressure. Stimulation fluids add a hydrostatic component that makes determination of reservoir pressure from the surface less accurate. During the flow back, friction effects within the reservoir, through the well bore tubulars, through surface equipment, to the gathering system are very complex and change constantly. In other words, the comparison of surface pressure immediately after perforation to the line pressure prior to

flow back represent a data point that could inform a decision whether to set REC equipment or not, but it doesn't ensure that the well will clean up to sales. The decision of how to flow a well back after a stimulation procedure is generally based on the experience of the people on the ground and to dictate specific equipment or specific procedures across the board has a very high potential to lead to sub-optimum results.

If a line pressure of half the flowing bottom hole pressure and a flowing bottom hole pressure of half of reservoir pressure are required to reliably clean up a well, then the only wells that you can have confidence will clean up while flowing to sales are wells with reservoir pressure at least four times line pressure. Some wells will clean up with reservoir pressure less than that, but that decision must be based on the training and experience of the operators on the ground. A well that is too weak to flow into an imposed backpressure will rapidly accumulate liquids and solids within the wellbore that can damage the well's ability to produce gas at economic flow rates. This is a decision that can only be made after the well is completed. To require REC equipment to be set prior to perforating the casing is imposing a cost that will frequently be wasted.

Author Biography

David Simpson has 31 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2000 SPE *International Conference on Health, Safety, and the Environment in Oil & Gas Production* in Stavanger, Norway where he presented a paper on the transition from continuous bleed pneumatic controllers to intermittent vent pneumatic controllers (SPE61030). He has been a featured speaker at the bi-annual *Four Corners Oil & Gas Conference* for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 12 countries.

Peer Review. This document was peer reviewed by experienced Reservoir Engineers to ensure that the conclusions reached were consistent with the conclusions that would normally be reached by someone experienced in the field.

Roger R. Gierhart is a Professional Engineer (registered in Oklahoma and Colorado) with a BS in Industrial Science and Engineering (1975) from Oklahoma State University. He worked for Amoco Production Company and BP America (1975-2009) and was an Engineering Advisor for Unconventional Gas – Coalbed Methane from 1999-2009. Since 2009 he has been employed by Acro Service Company as an Engineering Consultant. He was a member of the Society of Petroleum Engineers (SPE) Engineering Certification Program in 2010. Engineering accomplishments include

- Corresponding author: *Spatial Variation of San Juan Basin Fruitland Coalbed Methane Pressure Dependent Permeability: Magnitude and Functional Form* with R. R. Gierhart, SPE, BP; C.R.

- Clarkson, SPE, ConocoPhillips; J.P. Seidle, SPE, MHA Petroleum Consultants, paper IPTC 11333-MS presented at International Petroleum Technology Conference Dubai, U.A.E. (12/5/07)
- Co-author: *Production Data Analysis of CBM Wells* with C.R. Clarkson, ConocoPhillips Canada; C.L. Jordan, Apache; R.R. Gierhart, BP Amoco PLC; J.P. Seidle, MHA Petroleum Consultants, paper SPE 107705-MS presented at Rocky Mountain Oil and Gas Technology Symposium, Denver, Colorado (4/17/07)
- Steering Committee member, SPE Applied Technology Workshop on Coalbed Methane, Durango, Colorado (3/27/07 – 3/29/07) BP Mentor for coalbed methane summer engineers program (2003-2009) and DAP - Challenge Development and Assessment Panel (2006-2009)
- Exhibitor and Technical Session speaker, *Mature Field Production Management of the Fruitland Coal, San Juan Basin, USA*, Petrotech 2007, New Delhi, India (1/15/07 – 1/19/07)
- Engineering Witness before the Colorado Oil and Gas Conservation Commission for BP's three 80-acre infill applications for the Colorado San Juan basin Fruitland coal (9/14/05, 6/29/06, and 12/3/08)
- SPE Advanced Technology Workshop – Unconventional Gas Speaker (Invited Presentation) - *San Juan Basin Fruitland Coal Pressure Dependent Permeability Observations* (4/19/06)
- AAPG Annual Convention Oral Program Speaker (Invited Presentation) - *Mature Field Production Management of the Fruitland Coal, San Juan Basin, USA* (4/10/06)
- Potential Gas Committee, Spring Meeting Guest Speaker - *San Juan Basin Fruitland Coalbed Methane Play* (5/2/05)
- SPE Gulf Coast Section Reservoir Study Group Guest Speaker - *San Juan Basin Fruitland Coalbed Methane Play* (1/27/05)
- Potential Gas Committee member for San Juan basin Fruitland coal resource (1996-Present)
- SPE's Professionalism (Exam Writing) Committee member (2000-2004) for NCEES National Council of Examiners for Engineering and Surveying
- SPE's Petroleum Engineering Certification (Exam Writing) Subcommittee member (2010-Present)
- Certified Reserve Estimator

John P. Seidle, Ph.D., P. E. is a Professional Engineer (Oklahoma, Wyoming, and Colorado) with a BS, Aeronautical Engineering, University of Colorado (1972), MS, Aeronautical Engineering, Stanford (1973), and Ph.D., Mechanical Engineering, University of Colorado (1981). He has been a Vice President and Senior Reservoir Engineer at MHA Petroleum Consultants, LLC in Denver, CO since 2006 with a focus primarily coalbed methane and unconventional gas reservoir and economic studies, pressure transient test analyses, reservoir evaluations, simulation studies, reserves determinations, property evaluations, litigation support, acquisition and divestiture support. From 1999-2006 he filled a similar role with Sproule Associates, Inc. in Denver, CO. From 1981 to 1999 John held various reservoir engineering and research roles with Amoco Production Company in Tulsa, OK and Denver, CO. Professional and engineering accomplishments include more than 28 years of industry experience including:

- Multiple domestic and international coalbed methane plays
- Rate and reserve calculations for coal, shale, and tight formation gas wells
- Pilot and commercial enhanced coalbed methane projects

-
- Pressure transient test design and analysis
 - Reservoir simulation studies
 - Laboratory rock and fluid tests, various coal property tests
 - Industry coalbed methane class instructor
 - Expert witness for litigation and regulatory commissions
 - Property evaluation, acquisition and divestitures
 - Reservoir and economic evaluation coal and shale gas
 - 24 technical papers, one monograph chapter, six patents

Attachment G
Review of the Regulatory Impact Analysis (RIA)
for the Well Completions Portion of the Proposed
New Source Performance Standards for the Oil
and Natural Gas Industry

Attachment G

Review of the Regulatory Impact Analysis (RIA) for the Well Completions Portion of the Proposed New Source Performance Standards for the Oil and Natural Gas Industry

By David A. Simpson, PE

EPA has proposed under 40 CFR 60.5375 that “*Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.*”

- (1) *You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.*
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- (3) *You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”*

API conversations with Halliburton, Schlumberger, and BJ Services (the three largest oilfield service companies) and Aztec Well Services, a regional drilling company, indicates that essentially every well that is drilled is evaluated for hydraulic fracture stimulation and has been for many years. There are fields where this evaluation results in different stimulation techniques, but these fields are reasonably rare. Consequently, the population for this requirement is approximately every gas well.

To support these conversations, the online databases for Colorado¹, New Mexico², and Wyoming³ were searched for information on hydraulic fractures. Permit data is stored as scanned images and a review of a random selection of wells completed since 1960, showed that the data is mostly silent on stimulation techniques, but where such techniques were mentioned every well that was looked at had been hydraulically fractured regardless of the formation.

Companies Affected: Data from IHS for 2008 showed that there were 14,289 companies with at least one producing well⁴. There were 5,873 companies with 10 or more producing wells. RIA Table 7-18 claims that this number is 128 companies. While there are a smaller number of companies that are drilling new wells, all of these companies will be subject to this rule.

¹ Website of Colorado database <http://cogcc.state.co.us/>

² Website of New Mexico database http://octane.nmt.edu/gotech/Petroleum_Data/General.aspx

³ Website of Wyoming database <http://wogcc.state.wy.us/>

⁴ Reference for IHS company data <http://www.ihs.com/products/oil-gas-information/production-data/>

Company Survey: API asked member companies to provide information about their 2012 development plans. Nine companies provided data on 29 producing areas where they expected to drill 6,159 wells in 2012. The companies that responded represented all of the largest producers in the major shale-gas plays⁵, so it is likely that this survey encompassed a significant portion of the Shale-gas development for 2012. Extrapolating the data to the population of companies is difficult and of limited value, but the best we were able to do is predict that 30% of the 2012 drilling will be shale-gas, 70% will be CBM, tight-gas, and conventional. Table G-1 summarizes the results of the API survey. Within a single play with several companies reporting, the variability was significant. The only conclusion that can be drawn is that each company has their own strategy for performing reduced emissions completions (REC) and the equipment required (and its cost and supplier) reflects that variability. A weighted average of this data puts the cost/day very close to \$5,000.

Table G-1: Summary of API Survey Results

| Type Reservoir | 2012 Well Count | Minimum Reported Cost/day | Maximum Reported Cost/day |
|-----------------------|------------------------|----------------------------------|----------------------------------|
| Conventional REC | 1,060 | \$2,150 | \$5,900 |
| CBM REC | 625 | \$4,286 | \$30,000 |
| Shale REC | 2,698 | \$1,530 | \$10,500 |
| Tight Gas REC | 74 | \$6,000 | \$15,000 |
| Non-REC | 1,702 | | |

Applicability of Reduced Emissions Completions (REC): The Table 3-2 of the RIA expects that 9,313 wells will meet the requirements for REC in 2015 (out of 17,453 new gas wells). In the same table they expect that there will be 12,050 refracs that meet the criteria for REC and 42,352 conventional wells that will not meet the criteria. The benefits of REC stated in the RIA depend heavily the data contained in EPA’s Natural Gas Star Program.

First, the data within the Natural Gas Star Program has been carefully selected initially by the contributing company and finally by the EPA itself to present environmental successes in the best possible light. The success stories described within the program represent techniques that have worked on the projects referenced, and contributing companies have not claimed that the techniques reported are in any way universally applicable to the industry. In fact, the Natural Gas Star Partner reported successes for reduced emission completions have been targeted to specific areas where the reservoir characteristics and infrastructure enable reduced emission completions. The limitations on use of reduced emission techniques have been clearly articulated and communicated to EPA, both through the Natural Gas Star Program and in various other communications. To ignore these limitations and assume that a few dozen

⁵ Companies responding were Anadarko Petroleum Corp, BP Production Co, Chesapeake Energy Corp., Chevron Corp., ConocoPhillips, Devon Energy, Noble Energy Inc., Shell, Talisman Energy Inc., and XTO Energy

or even a few hundred successful reduced emissions completions means that 53% of all completions, frac's, and re-frac's will benefit from this technique is extrapolating a limited data set far outside the parameters supported by the original sample size.

The technical support document (TSD) for reduced emissions completions relied heavily on data from the Wyoming Department of Environmental Quality (WYDEQ) Air Quality Division and claimed that "The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared". According to the WYDEQ's March 2010 Oil and Gas Production Facilities Permitting Guidance ⁶ this is a requirement in only 7 counties of the state.

Second, the number of refracs is assumed to be 10% of the population of gas wells each year. Data from industry puts that number well under 1%.

Third, the requirements for REC are: (1) that any gases used in the frac will decline to acceptable levels for sales gas before the end of the flow back; and (2) that the well has adequate reservoir pressure to flow at rates adequate for transporting solids and liquids into an imposed back pressure. The first requirement is easily satisfied for hydraulic fracture stimulations using a liquid as the carrier fluid—the large number of procedures that use nitrogen or CO₂ foam will never meet the requirements during the flowback period. The second requirement is very dependent on reservoir pressure and line pressure. The industry direction is to flow to sales if it is cost effective, but many wells will not clean up at observed pressures.

The TSD estimates that wellsite dehydrators and sand separators are "often" included on completions and that "many" REC wellsites will only add \$806/day (2006 estimate inflated to 2008) to the cost of completion. On sites that have to bring in temporary equipment this number increases to \$7,486 (2008 dollars) per day. They further claim that flowbacks will be done in 3-10 days (average of 7 days) and that an average incremental cost is \$4,146/day. This includes a one-time cost of \$691 for transportation, placement, and removal of equipment. This results in a total cost of \$29,713/well.

The companies who responded to API's survey described above represented the majority of the most active shale-gas operators. This group of companies is doing REC on approximately 70% of the wells they reported. This data is very much skewed toward shale-gas. Evaluating the companies that responded to the survey relative to the population of companies in the industries indicates that the industry will likely drill 30% shale gas and 70% CBM, tight-gas, and conventional wells. Data from the API member survey showed that the average cost per day is about \$5,000 (reasonably close to the EPA estimate). The EPA estimated that flow back periods will typically be 3-10 days with 7 being a reasonable average. The API survey is largely in agreement with those estimates. The problem is that the equipment does not magically appear on day one and instantly disappear on day 7. It has to be staged before the flowback can be scheduled, gas control must have advance notice to nominate the gas to the gathering system, and some contingency time is generally needed. Then at the end of the flowback, crews must be scheduled to demobilize the equipment, trucks must be scheduled to pick it up, and it has to have a place to go. The front-end/back-end non-productive time must be paid for. To account for this, the

⁶ Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

majority of flowback companies have a 30 day minimum rental period which makes the average cost per well \$150,000 plus \$30,000 for mobilization/demobilization for an average total of \$180,000. Also, the API Survey reported that the storage vessels and combustion equipment for REC costs on the order of \$2,000/day, but again requires a 30 day commitment so the rental cost per well is \$60,000 and the mobilization/demobilization costs are \$30,000.

In the TSD, the authors consistently claim that REC is only applicable to unconventional gas, then on page 4-16, they claim that every completion will recover 34 bbl of condensate at a value of \$70/bbl which adds \$2,380 to the benefit of REC—but most unconventional wells produce no condensate. They also assume that each well will recover 8.258 MMSCF during the flowback. This says that for a 7 day average flowback, wells will average 1.2 MMSCF/day. For the wells that can flow to sales, this is a reasonable assumption since only the strongest formations will be able to flow to sales.

The number of wells that can successfully be cleaned up by flowing into a gathering system is closer to 30% or 5,230 wells instead of 9,313. Evaluating reservoir pressure requirements to flow into typical gathering systems, a number around 1.2-1.4 MMCF/d is reasonable. However, the condensate recovery factor is unreasonably high. This leads to the cost per REC shown on Table G-2.

Table G-2: Cost per REC

| | RIA | API Survey |
|--|-------------------------|------------------------|
| Rental cost of equipment | \$29,022 | \$150,000 |
| Variable cost per installation | \$691 | \$30,000 |
| Total cost per job | \$33,239 | \$180,000 |
| Sales recovered per job | \$35,410 | \$32,900 |
| Net Cost (benefit) per well | (\$2,171) | \$147,100 |
| Number of jobs in 2015 | 9,313 | 5,230 |
| Total cost (benefit) in 2015 of REC | (\$20.2 million) | \$782.6 million |

EPA estimated that 53% of the wells drilled would be able to sell gas. The remainder of the population was broken into hydraulically fractured wells that could not sell gas (3%) and “conventional wells” (44%) which they mistakenly suggest are not hydraulically fractured. They estimate that the equipment and reporting requirements will add \$3,523 per well to the cost of the well. However, the requirements for non-sales wells are extensive and very expensive. EPA is requiring that companies capture gas that “can not be directed to the gathering line to a completion combustion device” with a “reliable continuous ignition source”. When the gas is not combustible, this will require supplemental fuel. Also, this prohibits the use of electronic igniters to minimize the use the waste of pilot gas. Furthermore, EPA is also requiring that for wildcat or delineation wells, that companies supply “the distance, in miles, of the nearest gathering line”, the “latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of

1983”, etc. All the new information required will require new data-storage and collection systems, which will require administrative staff to assemble several new reporting obligations, and will require environmental professionals to comply with additional strict reporting requirements. Once adequate data collection systems are in place, this rule can be expected to add 100 man-hours of administrative effort per well and 20 hours for an environmental professional. At a fully-burdened cost of administrative staff of \$50/hour and professional staff of \$110/hour, this adds \$7,200/well which will apply even to wells that can not recover sales gas. Table G-3 summarizes the cost for completions using flaring versus recover to sales. Table G-4 summarizes the overall expenditures for REC. The cost of this regulation has the potential to create the same devastation to the Oil & Gas industry as the New Mexico Pit Rule has created in New Mexico. The costs in the “API Survey” column above would not be sustainable in most of the industry and this regulation will result in a large number of wells that will not be drilled, and a large number of wells that could otherwise benefit from a production restoring “workover” to be plugged and abandoned.

Table G-3: Cost of Completions with Flaring

| | RIA | API Survey |
|---|---------------|-------------------|
| Costs of equipment and installation | \$3,523 | \$90,000 |
| Administrative cost per installation | 0 | \$7,200 |
| Total cost per job | \$3,523 | \$97,200 |
| Sales recovered | \$0 | \$0 |
| Net Cost (benefit) | \$3,523 | \$97,200 |
| Number of jobs in 2015 (Frac’d & Flared) | 446 | 12,230 |
| Total cost (benefit) in 2015 of Frac’d & Flared (\$million) | \$1.6 | \$997.0 |
| Number of Jobs in 2015 (Conventional) | 7,694 | 7,694 |
| Total cost in 2015 of Conventional (\$million) | \$27.1 | \$747.9 |

Table G-4: Summary Expenditures

| | RIA | API Survey |
|---|----------------------|--------------------------|
| REC wells | (\$20.2 million) | \$782.6 million |
| Frac’d and Combusted Wells | \$1.6 million | \$997.0 million |
| Conventional Wells (Combusted) | \$27.1 million | \$747.9 million |
| Total cost (benefit) of regulation | \$8.5 million | \$2,527.5 million |

Emissions Reductions

VOC content varies from well to well, field to field, and basin to basin. With 400,000 gas wells there are 400,000 unique gas analyses that are in place at any given time. Regulations require that each of the wells will be periodically re-sampled because the mix of components in a well stream changes. The mix will change with pressure changes, temperature changes, and with changes in the portion of the reservoir that is currently available to the wellbore (which changes minute-to-minute). The VOC content of the mix of wells on production at any given time is one of the most volatile parameters in this industry. The EPA based their rule making on 7 wells out of 400,000. These 7 wells were handpicked based on parameters other than an effort to provide a random sample.

To determine the mass of VOC in any given stream, you must first determine the mass of the stream and apply the weight percent VOC to that total mass. For the tables below, we assumed that the EPA estimate of 1.2 MMCF/day and 7 days of flowback are as reasonable an estimate as anyone is likely to develop. Collapsing 20,000 flowbacks into a single number is statistically invalid, but for the sake of this discussion we will accept EPA's number.

Table 3-3 in the RIA has detailed emissions reductions for gas wells that assume 83% (by volume) Methane and 3% (by volume) VOC. These percentages are the same for all the categories of gas wells, including conventional wells and disregard the fact that a significant portion of current and future drilling is in CBM and Shale Gas plays.

An article published in *Oil & Gas Journal* March 9, 2009 titled "Compositional variety complicated processing plans for US shale gas" written by Keith A Bullin and Peter E Kroushop both of Bryan Research and Engineering had a series of tables that are summarized on Table G-5.

Table G-5: Shale Gas Composition

| | C1 | C2 | C3+ | CO2 | N2 | Total |
|---------------------------|-----------|-----------|------------|------------|-----------|--------------|
| Barnett Average | 86.8% | 6.7% | 2.0% | 1.7% | 2.9% | 100.0% |
| Marcellus Average | 85.2% | 11.3% | 2.9% | 0.4% | 0.3% | 100.0% |
| Fayetteville Average | 97.3% | 1.0% | 0.0% | 1.0% | 0.7% | 100.0% |
| New Albany Average | 89.9% | 1.1% | 1.1% | 7.9% | 0.0% | 100.0% |
| Haynesville Shale Average | 95.0% | 0.1% | 0.0% | 4.8% | 0.1% | 100.0% |
| Shale Gas Average | 90.8% | 4.0% | 1.2% | 3.1% | 0.8% | 100.0% |

A similar analysis of CBM would show C2+ to be approximately zero. Adding the Shale Gas analysis to the GRI analysis provided in the docket yields Table G-6. The "tonne VOC/MMSCF" column is simply the density of the gas at standard temperature and pressure times 1,000,000 SCF. The "tonne VOC/flowback" column is the "tonne VOC/MMSCF" column times the 8.4 MMSCF which would have

been produced from a well making 1.2 MMSCF/day for 7 days. The “cost effectiveness” column is the cost of the flowback (\$180,000 discussed above) divided by the “tonne VOC/flowback” column.

Table G-6: Gas Composition

| | MW | SG | VOC (Vol %) | VOC (W%) | Tonne VOC/ MMSCF | Tonne VOC/ flowback | Cost Effective- ness (\$/tonne) |
|----------------------|---------------|---------------|----------------|--------------|------------------------|---------------------------|--|
| GRI1 | 16.661 | 0.5752 | 0.45% | 1.39% | 0.277 | 2.327 | \$63,214 |
| GRI2 | 17.637 | 0.6090 | 2.20% | 6.84% | 1.447 | 12.155 | \$12,102 |
| GRI3 | 18.373 | 0.6344 | 3.93% | 11.94% | 2.631 | 22.100 | \$6,656 |
| GRI4 | 29.356 | 1.0136 | 28.13% | 52.72% | 18.569 | 155.980 | \$943 |
| GRI5 | 20.509 | 0.7081 | 7.15% | 18.62% | 4.583 | 38.497 | \$3,821 |
| GRI6 | 20.911 | 0.7220 | 8.64% | 21.39% | 5.366 | 45.074 | \$3,264 |
| GRI7 | 20.665 | 0.7135 | 7.01% | 10.09% | 2.502 | 21.016 | \$8,564 |
| GRI8 | 20.665 | 0.7135 | 7.01% | 17.95% | 4.451 | 37.388 | \$4,814 |
| GRI9 | 19.558 | 0.6753 | 6.22% | 16.31% | 3.828 | 32.155 | \$4,575 |
| GRI10 | 17.791 | 0.6143 | 2.41% | 7.47% | 1.595 | 13.398 | \$10,979 |
| GRI11 | 18.565 | 0.6410 | 3.21% | 9.80% | 2.183 | 18.337 | \$8,022 |
| GRI12 | 20.550 | 0.7096 | 2.30% | 6.78% | 1.671 | 14.036 | \$10,480 |
| Barnett Avg | 18.355 | 0.6337 | 2.00% | 4.81% | 1.058 | 8.887 | \$16,552 |
| Marcellus Avg | 18.605 | 0.6424 | 2.90% | 6.87% | 1.534 | 12.886 | \$11,415 |
| Fayetteville Avg | 16.547 | 0.5713 | 0.00% | 0.00% | - | 0 | infinite |
| New Albany Avg | 18.715 | 0.6462 | 1.10% | 2.59% | 0.582 | 4.889 | \$30,088 |
| Haynesville Avg | 17.411 | 0.6012 | 0.00% | 0.00% | - | 0 | Infinite |
| Shale Gas Avg | 17.915 | 0.6186 | 1.20% | 2.95% | 0.635 | 5.334 | \$27,578 |

In Table G-6, only eight of the seventeen analyses would meet a cost effectiveness target of less than \$10,000/tonne. Further, 77% of the proposed 2012 wells from the API survey are unconventional gas; therefore, the shale gas average would be the most representative of wells being drilled.

If we look just at the group of wells that the RIA claims can sell gas, then the emissions reductions and cost effectiveness would be as shown in the API Survey VOC column of Table G-7.

Table G-7: Emissions Reduction and Cost Effectiveness

| | | RIA VOC | API Survey VOC |
|----------------------------------|---------------|--------------------|-------------------------------|
| Shale Gas Wells | tons/well | 22.0 | 5.3 |
| Number of Wells | | 7,171 | 4,027 |
| Annual Sales | BSCF | 60.2 | 33.8 |
| Annual Emissions Savings | tons/yr | 157,182 | 21,480 |
| Annual Cost | \$million | \$238.4 | \$724.9 |
| Annual Sales | \$million | (\$253.9) | (\$132.5) |
| Effectiveness (w/o sales) | \$/ton | \$1,516 | \$33,748 |
| Effectiveness (w/sales) | \$/ton | (\$99) | \$27,579 |

Finally, looking at the conventional wells where the mix of gases used in the RIA is defensible, but the assumption that they will not be frac'd is not defensible. It is curious to note in the RIA that while conventional wells are not required to conform to Subpart OOOO, the EPA is claiming significant VOC reductions in Table 3-3 of the RIA as shown here on Table G-8.

Table G-8: RIA Table 3-3

| | | RIA | | |
|----------------------------------|---------------|-----------------|-------|-------|
| | | VOC | CH4 | HAP |
| Conventional Wells | tons/well | 0.11 | 0.76 | 0.01 |
| Number of Wells | | 7,694 | 7,694 | 7,694 |
| Annual Sales | BSCF | 0 | 0 | 0 |
| Annual Emissions Savings | tons/yr | 857 | 5,875 | 62 |
| Annual Cost | \$million | \$27.1 | | |
| Annual Sales | \$million | 0 | | |
| Effectiveness (w/o sales) | \$/ton | \$31,619 | | |

From this data, it is not cost effective to do REC on conventional wells even at EPA’s understated cost/procedure, but the wells are hydraulically fractured so they would be subject to Subpart OOOO and would be required to do REC.

Author Biography

David Simpson has 31 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master’s degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2000 SPE *International Conference on Health, Safety, and the Environment in Oil & Gas Production* in Stavanger, Norway where he presented a paper on the transition from continuous bleed pneumatic controllers to intermittent vent pneumatic controllers (SPE61030). He has been a featured speaker at the bi-annual *Four Corners Oil & Gas Conference* for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled “Managing the Performance of Low Pressure Gas Wells and Associated Facilities” held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 12 countries.

Attachment H

WCI Fuel Gas Metering

**Technical Review of Western Climate Initiative Proposals to
Meter Fuel and Control Gas**

**Prepared by: David A. Simpson, P.E.
MuleShoe Engineering**

Prepared: February 16, 2010

Table of Contents

| | | |
|------|--|----|
| I. | Executive Summary | 1 |
| A. | Summary Expenditures | 1 |
| B. | Author Biography | 1 |
| II. | Discussion | 3 |
| A. | Magnitude of Gas Consumed..... | 3 |
| 1. | Engine Fuel | 3 |
| 2. | Separator/Tank Heaters..... | 3 |
| 3. | Dehydrator Reboilers, Heater/Treaters, and Line Heaters..... | 4 |
| 4. | Pneumatic devices..... | 5 |
| B. | Gas Measurement Technologies..... | 8 |
| 1. | Gas Analysis | 10 |
| 2. | Square Edged Orifice Meters..... | 10 |
| 3. | V-Cone Meters..... | 10 |
| 4. | Turbine Meters..... | 11 |
| 5. | Coriolis Meters..... | 11 |
| 6. | Ultrasonic Meters..... | 11 |
| 7. | Roots Rotary Meters | 11 |
| 8. | Diaphragm Meters | 12 |
| 9. | Exotic/Laboratory instruments..... | 12 |
| 10. | Conclusion | 12 |
| C. | Wellsite Configurations | 13 |
| III. | Costs of Implementation | 15 |
| A. | RTU costs..... | 16 |
| B. | Host/Database costs | 16 |
| C. | Installation costs..... | 16 |
| D. | Operating costs..... | 17 |
| IV. | Conclusion | 17 |

Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the “most accurate” volumes if the gas was metered as a “fuel” stream and a “control” stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to “provide the rigor required for either cap-and-trade or offset programs”. The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer’s numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The “Per Company” column below assumes 2,000 wells per company, “Total WCI” column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under “Cost of Implementation” below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

| | Per well (\$k) | Per Company (\$million) | Total WCI (\$million) |
|------------------------|----------------|-------------------------|-----------------------|
| RTU Replacement | \$3.5 | \$7 | \$350 |
| Host/Database | | \$15 | \$750 |
| Site Modifications | \$30.0 | \$60 | \$3,000 |
| Total Capital | \$33.5 | \$82 | \$4,100 |
| | | | |
| Annual Operating Costs | \$1.5 | \$3 | \$150 |

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 *SPE Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas Conference* for the last 6 years and is a regular instructor at short courses at the annual *ALRDC Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate “accuracy” in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different “emissions factor” on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as “on demand” in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators

take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 “turndown ratio”. Turndown ratio is a measure of ability of a measurement device to provide similar “accuracy” over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from “off “ to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer’s estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since “rich” liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

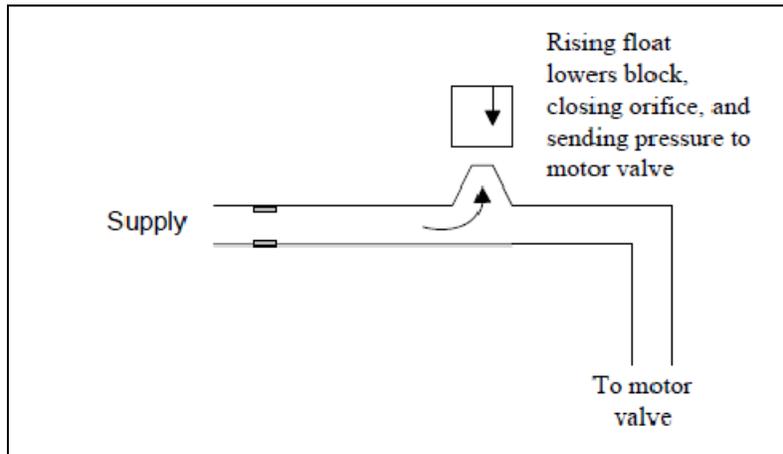
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

4. *Pneumatic devices*

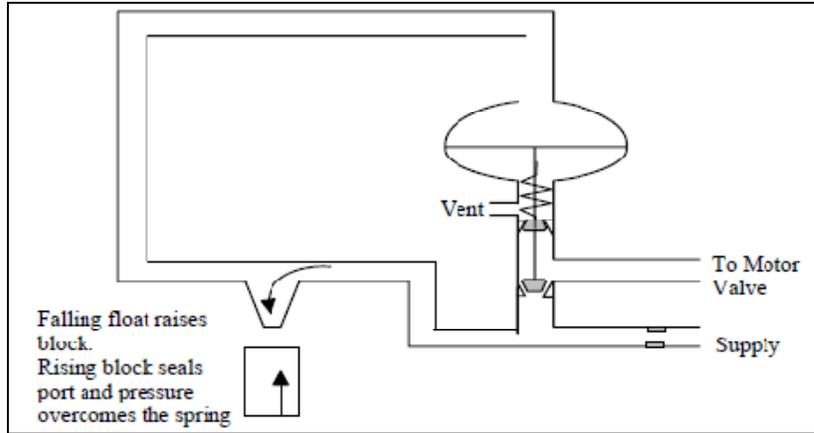
I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either “Throttling” or “Snap Acting”. Bleed characteristic is either “continuous bleed” or “no bleed”. An example of a Continuous Bleed, Throttling controller is shown below



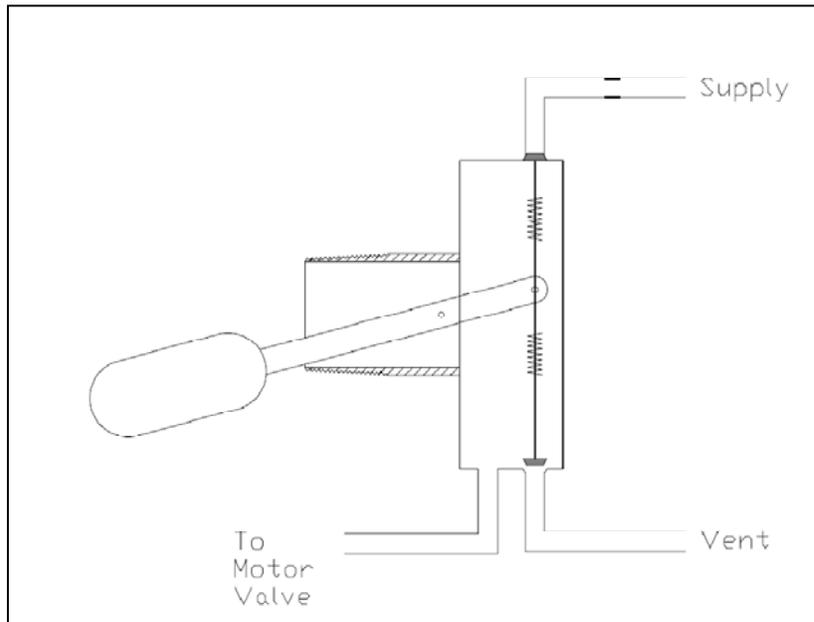
In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled

devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A “No Bleed” controller would look something like:



This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the

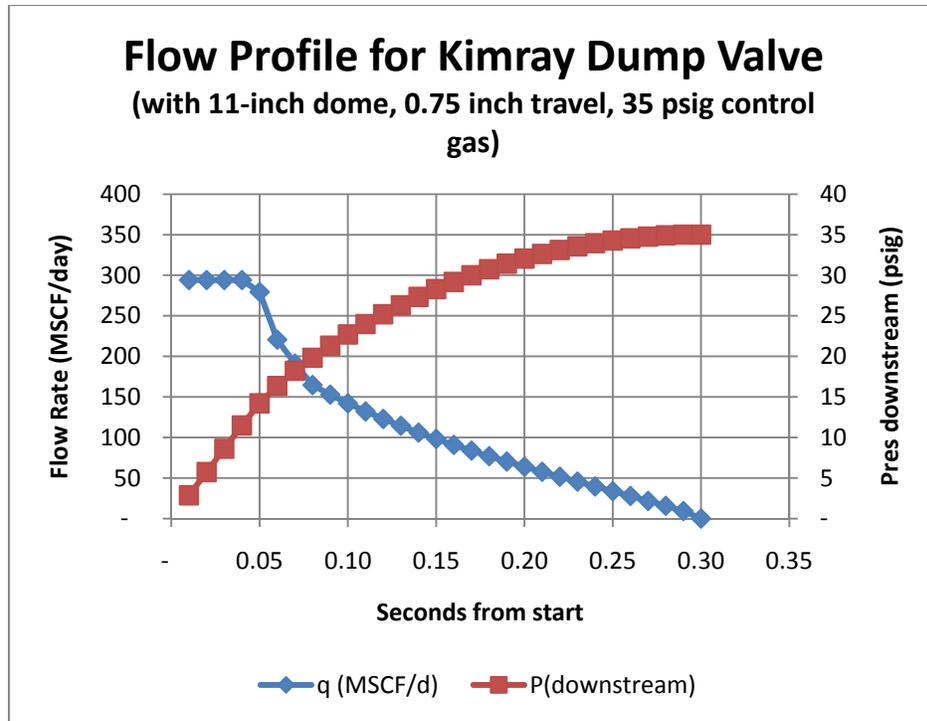
vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it “snaps” open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas is used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing “bleeding” of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can't be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a “jerky” action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft³) and the diaphragm dome is 0.04 ft³ (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft³. At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about “meter accuracy” above I always said “accuracy”. “Accuracy” is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of “accuracy” is encompassed in the terms “repeatability” and “uncertainty” which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

“Repeatability” is a measure of a device’s ability to report the same output for a given set of inputs. Many things can impact a device’s repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable

repeatability occurs when the standard deviation of the sample data is within $\pm 0.05\%$ of the mean value.

“Uncertainty” is the “dead band” of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device’s calibrated span. For example, a digital pressure transducer may have a stated uncertainty of $\pm 0.5\%$ which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices’ uncertainty is less than $\pm 2.0\%$ (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is “latency”. Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are “inferential” technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli’s development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. *Gas Analysis*

Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed $\pm 25\%$.

These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

This device has potential, but the smallest meter (1/2" ID) would register zero during pilot flow and would have a dP less than 7 inH₂O (0.25 psi)

while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

The operating principle is to relate a rotor’s angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

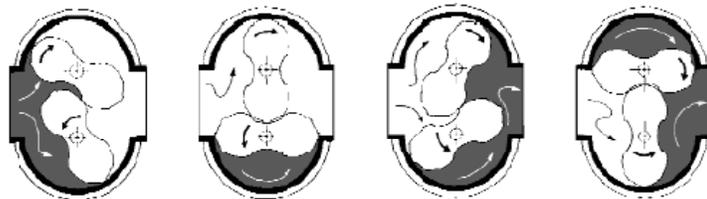
The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to “measuring” gas volumes instead of “inferring” a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. *Diaphragm Meters*

The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. “Household quality” meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H₂S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). “Industrial quality” meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or “yellow metal” is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

The volume of gas discussed in this application kept leading me to devices like “Thermal Dispersion Meters” (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

- a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.
- b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a “valve open” clock on the supply line, which (in conjunction with manufacturer’s data and Engineering analysis) would result in a better volume than attempting to meter the gas.

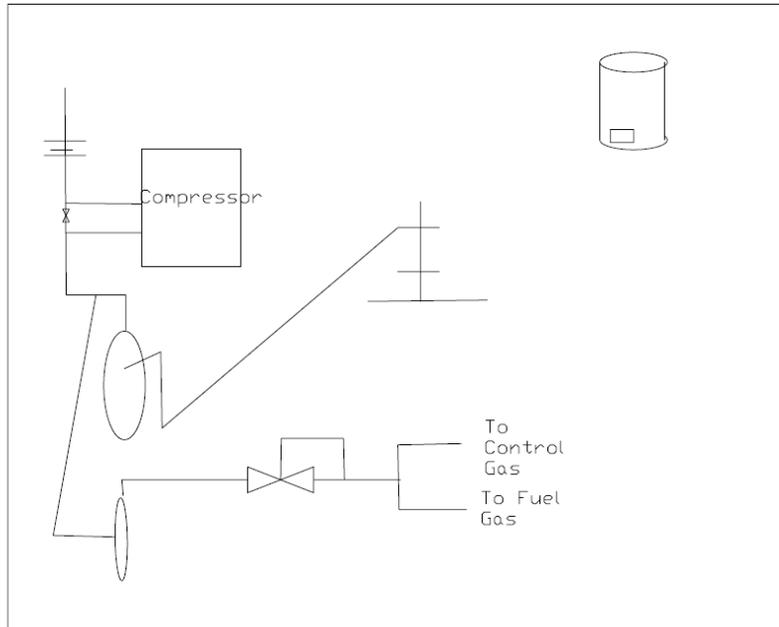
- c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Coriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.
- d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can’t be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

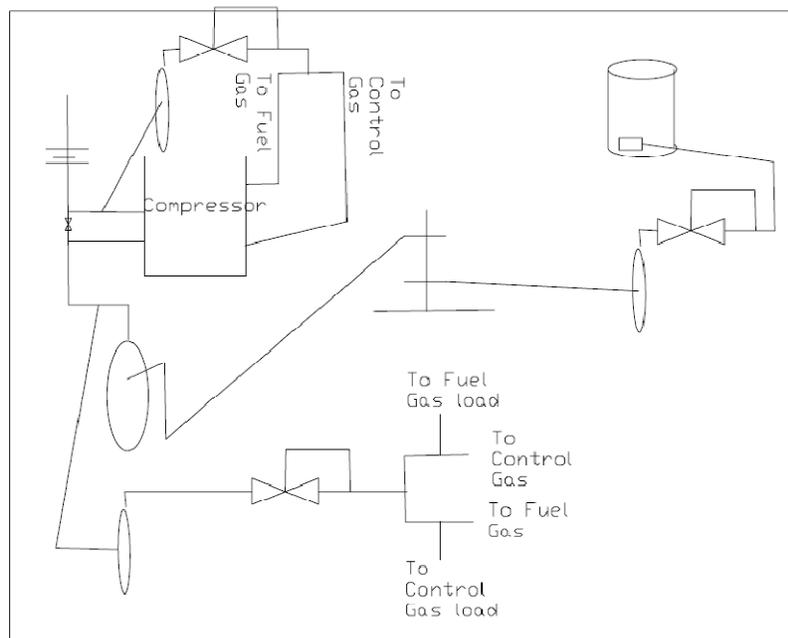
On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a “standard” wellsite where fuel-gas measurement equipment can be “relatively easily” installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since

compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a “typical” wellsite, “typical” automation system, or “typical” host/database modification because there is no such thing. There are companies within the WCI area of operation that don’t have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I’ve worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at

http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at <http://www.capp.ca/GetDoc.aspx?DocID=146286> for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

| | Gas | Oil | Total |
|------------|--------|--------|---------|
| New Mexico | 36,202 | 15,456 | 51,658 |
| California | 3,692 | 16,197 | 19,889 |
| Utah | 5,259 | 2,574 | 7,833 |
| Montana | 6,207 | 4,199 | 10,406 |
| BC | 6,608 | 1,122 | 7,730 |
| Manitoba | 0 | 2,692 | 2,692 |
| | | | 100,208 |

For the economic analysis I’ll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of \$4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately \$3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data polling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost \$15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend \$750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At \$1,200/day that is \$12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be \$30,000/well—100,000 wells would cost \$3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a \$5/MMBTU sales price the cost of this lost production is \$600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is \$150,000/year which works out to about \$750/meter/year or \$1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.

Attachment I
Applicability Determinations for NSPS D, Da, Db,
and Dc



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0100016

Category: NSPS
EPA Office: Region 3
Date: 02/13/2001
Title: Approval of Derate Proposal
Recipient: Charles Bennett
Author: Judith Katz

Subparts: Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40c

Abstract:

Q: Will EPA approve a boiler deration proposal from a company to limit the size of boilers at two facilities?

A: Yes. EPA Region III approves the deration proposal because it meets EPA's Policy on boiler deration for limiting the steam generation capacity of the boilers.

Letter:

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

In Reply Refer To: 3AP12

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Charles A. Bennett
Manager, Environmental Affairs
Knouse Foods Cooperative, Inc.
53 East Hanover Street
P.O. Box 709
Biglerville, Pennsylvania 17307-0709

Re: Derate Proposal for Company Boilers

Dear Mr. Bennett:

The Philadelphia Regional Office of the U.S. Environmental Protection Agency (Region III) has received and reviewed your information submittals, dated August 22, 2000, September 21, 2000, and January 19, 2001 proposing an alternative boiler deration method for the Biglerville and Gardners plant boilers of Knouse Foods in Adams County, Pennsylvania under the New Source Performance Standards (NSPS) program, 40 CFR Part 60, Subpart Dc. EPA had previously approved a different deration method for Knouse Foods back in 1991 which entailed modifying the cam on the oil flow control valve to limit the oil fuel flow to the boilers, therefore, limiting the heat input capacity of the boilers to less than 30 million BTUs per hour, thereby, avoiding certain NSPS requirements such as the installation of continuous monitors etc. Currently, Knouse Foods has applied for a different deration procedure involving the use of the "Autoflame " combustion management system which is supposed to be able to improve the combustion efficiency of the boilers and, through the use of a microprocessor, be able to limit the heat input capacity of these emission sources. Also, Knouse is proposing to replace the generic oil flow valve with a specially-fabricated control valve specific to Knouse's flow limitation needs to reduce the maximum design heat input capacity of the Biglerville and Gardner plant boilers to less than 30 million BTUs per hour.

EPA's Policy on boiler deration in connection with the NSPS program has always required that a physical/design change be made that is both permanent and as close to impossible to modify as is technically achievable. Based on our review of the submitted materials by Knouse Foods, to date, EPA, hereby, approves Knouse's deration proposal consisting of the following elements, at a minimum:

1. Installation of two (2) Autoflame microprocessor-based burner control systems to replace the mechanical linkage systems currently in use per previous EPA approval. One is to be retrofitted onto the 1000 horsepower Johnston boiler at the Biglerville, Pennsylvania facility and one onto the 1000 horsepower Johnston boiler at the Gardners, Pennsylvania facility. The Autoflame system is comprised of two major components, namely, the Control Module containing the microcomputer and power supply and the individual servomotors for modulating the fuel valves and air damper. The commissioning mode of the computer can only be accessed by entering a proprietary password which is unknown to the facility personnel and maintained by CSI Services, the technology vendor being used to install the technology.
2. Installation of a specially fabricated oil flow control valve having an orifice manufactured by Autoflame which will only pass a compliant volume of oil and effectively limit the operation of the boilers to a compliant high end heat input of less than 30 million BTUs per hour.

This deration will physically make it impossible for these boilers to combust fuel at a rate of 30 million BTUs per hour or greater meeting EPA's current policies on boiler derating and the Company will maintain monthly records of fuel usage and fuel quality/heat content for the regulatory agencies to be able to assess Company compliance with the heat input limit. All physical changes will be made in conformance with the plans/specifications contained in the information submitted to EPA, to date.

If you should have any comments or questions in regard to this matter, do not hesitate to contact James W. Hagedorn, of my staff, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Rick Copland, RTP
Ron Davis, PaDEP



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0100055

Category: NSPS
EPA Office: Region 3
Date: 07/31/2001
Title: Boiler Derate Proposal
Recipient: J. Nelson Weaver
Author: Judith Katz

Subparts: Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40c

Abstract:

Q: Will EPA approve a boiler deration proposal under Subpart Dc?

A: EPA will approve a boiler deration proposal that meets federal policy on being a permanent change to the steam output capacity of the boiler which cannot be easily reversed.

Letter:

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

In Reply Refer To: 3AP12

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. J. Nelson Weaver
General Manager
Keystone Protein Company
P.O. Box 37
U.S. Route 22
Fredericksburg, Pennsylvania 17026

Re: Johnston Boiler Derate Proposal

Dear Mr. Weaver:

The Philadelphia Regional Office of the U.S. Environmental Protection Agency (Region III) has received and reviewed your most recent boiler derating proposal, dated July 11, 2001, for your new Johnston boiler at your Lebanon County, Pennsylvania facility consisting of two elements; (1) Installation of Autoflame Control System Technology which utilizes a computer control scenario for fuel flow to the boiler burner limiting the maximum design heat input capacity and (2) a redesigned, resized control valve specifically machined to only allow enough oil flow to the burner to maintain a heat input capacity of 30 million BTUs per hour or less. The Company desired to do this based on the New Source Performance Standards program regulations for small boilers, codified at 40 C.F.R. Part 60, Subpart Dc, which specify certain requirements, such as the installation of a continuous opacity monitor, to be complied with if the heat input capacity to the boiler is greater than 30 million BTUs per hour.

Based on EPA's review of the proposal, and the fact that it meets the conditions provided in existing EPA Policy on the matter requiring that a permanent, physical change be made to limit the boiler steam generation capability, Region III has decided to approve the deration proposal as submitted by Keystone Protein in conjunction with the boiler manufacturer representative, CSI Services. The approved plan consists of the described equipment and procedures as delineated in Keystone Protein's submissions to the Agency dated July 11, 2001 and April 30, 2001. This response was coordinated with both Pennsylvania DEP and EPA Research Triangle Park personnel.

If you should have any comments or questions in regard to this matter, do not hesitate to contact James W. Hagedorn, of my staff, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Ranjan Roy, PaDEP
Rick Copland, EPA-RTP



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0100080

Category: NSPS
EPA Office: Region 4
Date: 01/07/1999
Title: Boiler Derate
Recipient: Alan Klimek
Author: R. Douglas Neeley

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.40c

Abstract:

Q: A boiler derate is proposed for a unit subject to Subpart Db which will include the replacement of an existing burner with a new burner rated at 95 mmBtu/hr. Is the proposed derate acceptable?

A: Yes. The proposed derate is consistent with criteria used in past boiler derates.

Letter:

January 7, 1999

4APT-ARB

Mr. Alan Klimek, P.E.
Director
Division of Air Quality
North Carolina Department of Environment,
Health, and Natural Resources
P.O. Box 29580
Raleigh, NC 27626-0580

SUBJ: Proposed Boiler Derate for U.S. Marine Corps Base, Camp Lejeune, NC

Dear Mr. Klimek:

We have received a letter dated October 28, 1998, from the Marine Corps Base in Camp Lejeune which requests approval of a method for derating a boiler. The proposed method is described in an October 12, 1998, letter from the Coen Company. A copy of these letters is enclosed. The proposed derate is for Boiler No. 5 at the Main Street Plant (Building HP-17), and the purpose for the derate is to exempt the boiler from the requirements of 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The boiler presently has a maximum heat input of 121 mmBtu/hr. Camp Lejeune proposes to physically reduce the capacity of the boiler by removing the existing burner and installing a new burner to permanently limit the boiler heat input capacity to 95 mmBtu/hr. Following the boiler derate, the boiler would be subject to the requirements of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The boiler is primarily used as an auxiliary boiler to supplement loads during start-ups and peak sharing and typically operates at 50 percent of its rated capacity. EPA has determined that the derating method proposed by Camp Lejeune, as described below, would be acceptable.

The method proposed to derate boiler no. 5 involves the removal of the existing Coen CPF-32 burner and replacement with a new burner rated at 95 mmBtu/hr. The burner will be designed to use No. 2 fuel oil or natural gas. The existing Coen windbox will be used, and the new burner will be designed to bolt to the same studs on the existing windbox. The proposed derate method also includes changes to the fuel feed systems. The new burner will provide the same or lower NOx emission levels as the existing burner, using the same induced flue gas recirculation system currently installed.

Each proposal for a boiler derate is evaluated on a case-by- case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. However, changes which are made only to fuel feed systems are not acceptable for derates. Based on these criteria, the modification proposed by Camp Lejeune is acceptable for a derate. The heat input of the boiler will be limited by the installation of a new burner, which is considered part of the steam generating unit affected facility. The maximum heat input capacity should be demonstrated by operating the boiler at maximum capacity for a 24 hour period with each fuel.

Steam generating units that have a design firing rate of 90 to 100 mmBtu/hr should be required to continuously monitor fuel feed rates and maintain information regarding the fuel heat content in order to ensure that the unit does not exceed 100 mmBtu/hr of heat input. We recommend that fuel feed rates be reported as hourly averages. If any hourly fuel feed rate and corresponding heat content indicate a heat input of greater than 100 mmBtu/hr, then the steam generating unit would be considered subject to Subpart Db from the date a heat input of 100 mmBtu/hr is exceeded.

This approval of the derate method for Boiler No. 5 will become void if Camp Lejeune fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA.

If there are any questions regarding the contents of this letter, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch Air, Pesticides, and Toxics Management Division

Enclosure

cc: Dennis Abell
Marine Corps Base; Camp Lejeune, NC

Scott A. Brewer
Marine Corps Base; Camp Lejeune, NC



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0100082

Category: NSPS
EPA Office: Region 4
Date: 12/14/1998
Title: Boiler Derate
Recipient: James A. Joy
Author: R. Douglas Neeley

Subparts: Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40c
60.47c

Abstract:

Q: A derate method is proposed which will limit the capacity of a boiler by reducing the air volume into the boiler. Will the proposed method be acceptable?

A: Yes. The proposed derate is consistent with criteria used in past boiler derates.

Letter:

December 14, 1998

4APT-ARB

Mr. James A. Joy, III, P.E.
Chief
Bureau of Air Quality
South Carolina Department of Health and
Environmental Control
2600 Bull Street
Columbia, SC 29201-1708

SUBJ: Proposed Boiler Derate for Wellman, Inc. - Johnsonville, SC

Dear Mr. Joy:

This is to acknowledge receipt of the letter from Mr. Joe Eller of your office dated July 29, 1998, and the July 21, 1998, submittal from Wellman, Inc. which proposes a boiler derate method. The proposed derate is for a Clever Brooks boiler (Boiler No. 3), which was installed in 1994 and is rated at 29.3 mmBtu/hr. The boiler is fueled by natural gas with propane or fuel oil as backup fuel. The boiler is subject to 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial- Commercial-Institutional Steam Generating Units. During a periodic source test, one test run resulted in actual boiler operation at 30.49 mmBtu/hr, which is above the rated capacity. In order to be exempt from the opacity standard in Sec. 60.43(c)c and the requirement in Sec. 60.47c to monitor opacity by using a continuous emission monitoring system (CEMS), Wellman proposes to derate the boiler to less than 30.0 mmBtu/hr. The opacity standard applies to the boiler during oil-fired operation. As a result of the proposed derate, the boiler heat input rating would be 25.1 mmBtu/hr. EPA has determined that the derating method proposed by Wellman, as described below, would be acceptable.

The method proposed by Wellman to derate Boiler No. 3 includes the installation of one 20 horsepower (hp) 600 volt blower motor with base spacer, one 600 hp combustion air impeller with mounting hardware, one 600 hp oil metering stem, three fuse blocks with properly sized fuses, three thermal over loads for the starter, and revised wiring diagrams. A new nameplate will be provided to relate the new reduced boiler input rating (i.e., 25.1 mmBtu/hr). The relative motor horsepower and the fixed impeller size will limit the maximum capacity of the boiler by reducing the air volume into the boiler. The modification will reduce the capacity during both natural gas and oil-fired operation, and a complete combustion tune up with both natural gas and oil will be performed.

Each proposal for a boiler derate is evaluated on a case-by- case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. However, changes which are made only to fuel feed systems are not acceptable for derates. Based on these criteria, the modification proposed by Wellman is acceptable for a derate. The maximum heat input capacity should be demonstrated by operating the boiler at maximum capacity for a 24 hour period with each fuel. An ongoing program will also need to be implemented to monitor the actual heat input of the boilers by maintaining records of fuel consumption (as already required by Sec. 60.48c(g)) and fuel heating value.

This approval of the derate method for Boiler No. 3 will become void if Wellman fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA.

If there are any questions regarding the contents of this letter, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch Air, Pesticides, and Toxics Management Division

cc: Joe Eller
SC DHEC



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0300001

Category: NSPS
EPA Office: Region 10
Date: 01/18/2001
Title: Boiler Derate Criteria
Recipient: Robert Bloom
Author: Douglas Hardesty

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units

References: 60.14
60.15

Abstract:

Q: Is Lamb-Weston's boiler #1 subject to NSPS Subpart Db after its capacity was changed to below 100 million Btu/hour?

A: No. The boiler is no longer subject to NSPS Subpart Db.

Letter:

Reply To
Attn Of: OAQ-107

Certified Mail - Return Receipt Requested

Mr. Robert G. Bloom
Accounting and Services Manager
Lamb-Weston, Inc.
2975 Lamb Weston Road
P.O. Box 489
American Falls, Idaho 83211

Re: Non Applicability to NSPS Subpart Db

Dear Mr. Bloom:

This letter responds to your letters dated September 19, 2000, and January 8, 2001, which request EPA's applicability determination on Lamb-Weston's Boiler #1 at American Falls, Idaho.

Based on the information you have provided, the 133 million Btu/hour burner in the boiler had been replaced with a new low-NOx burner whose manufacturer's rating is 98 million Btu/hour. Results from performance tests conducted by Lamb-Weston also confirm that the boiler's heat input does not exceed 98 million Btu/hour. EPA has determined that NSPS Subpart Db ceases to apply to this boiler due to this change in heat input and because the boiler has met the following boiler derate criteria:

1. Be accomplished through a permanent physical change which will preclude it from operating at a capacity greater than the derated value;
2. Be a change that cannot be easily undone;
3. Requires a system shutdown to make the change or to reverse the change; and,
4. Reduced the capacity of the boiler without the installation of a feed rate governor.

In addition, information you have provided indicates this boiler was installed in 1986, and has not been "modified" within the meaning of 40 C.F.R. Sec. 60.14, or "reconstructed" within the meaning of 40 C.F.R. Sec. 60.15. Therefore, EPA also determines that this boiler is not subject to NSPS, Subpart Dc.

In summary, based on information you have provided, EPA has determined that Lamb-Weston's Boiler #1 at American Falls, Idaho, is no longer subject to NSPS Subpart Db, and is also not subject to NSPS Subpart Dc. In the event Lamb-Weston changes the boiler's capacity to above 100 million Btu/hour, then this applicability determination becomes invalid.

If you have any questions regarding this response, please contact Mr. Kai Hon Shum of my staff at (206) 553-2117.

Sincerely,

Douglas E. Hardesty, Manager
Federal and Delegated Air Programs Unit

KHS:DEH:cb

cc: Harbi Elshafei (IDEQ)
Mike Silver (IDEQ)



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0300021

Category: NSPS
EPA Office: Region 4
Date: 12/30/2002
Title: Boiler Derate Proposal
Recipient: Mike Aldridge
Author: Beverly Banister

Subparts: Part 60, D, Fossil Fuel Fired Steam Gen. (post 8/17/71)

Abstract:

Q: Will EPA allow a facility to derate a boiler to less than 250 mmBtu/hr by limiting the feed rate of coal and fuel oil?

A: No. Changes which are made only to fuel feed systems are not acceptable for derating boilers.

Letter:

December 30, 2002

4APT-ATMB

Mr. Mike Aldridge
Environmental Engineering Supervisor
Technical Services Division
North Carolina Department of Environment
and Natural Resources
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

Dear Mr. Aldridge:

We have received a November 4, 2002, letter from Weyerhaeuser Company in Plymouth, North Carolina requesting approval of a method for derating a boiler. The proposed derate is for Hog Fuel Boiler (HFB) No. 1 at the Weyerhaeuser pulp and paper manufacturing facility. Approval of the derate would prevent applicability of New Source Performance Standards (NSPS) Subpart D - "Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971." The boiler is presently permitted to fire coal, No. 6 fuel oil, waste oil and sludge, hog fuel (wood) and High Volume Low Concentration non-condensable gases. Hog fuel is the primary fuel, and coal and oil are auxiliary fuels. The maximum heat input rate from fossil fuel is greater than 250 million Btu/hour. Based on our review of Weyerhaeuser's request, the proposed method of derating the boiler, as described below, is not acceptable. Guidance concerning an acceptable derate is provided in this letter.

Weyerhaeuser's proposed derate is based on limiting the fossil fuel heat input to HFB No.1 by using the following methods. The coal feeder rate (tons/hour) is now variable depending on the speed of the feeder, which is controlled by a variable speed drive. The company proposes to make the drive a constant speed drive, which would limit the coal feed to a constant rate. The change can be completed in about two weeks. Weyerhaeuser has indicated that the pumps used to deliver No. 6 fuel oil to HFB No. 1 are positive displacement pumps, which deliver fuel to the boiler at a constant flow rate regardless of the pressure in the system, up to the point of pump failure. The company plans to change the pumps to restrict the flow through the oil guns. The change to the oil pumps may take three to five months to complete. The company may also reduce the number of oil guns in the boiler from six to two or three, depending on the outcome of engineering design work.

Based on previous determinations concerning boiler derates, an acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. As indicated in previous determinations concerning derates, changes which are made only to fuel feed systems are not acceptable. It has previously been determined that changes in system capacity such as switching to smaller fans with smaller capacity in combination with the use of smaller pipes and pumps to control fuel feed rate would be acceptable. Based on these criteria, we have determined that the method proposed by Weyerhaeuser for derating HFB No. 1 is not acceptable since it only results in changes to fuel feed systems.

This determination has been provided with assistance from the United States Environmental Protection Agency's Office of Enforcement and Compliance Assurance (OECA). If there are any questions regarding this letter, please contact Keith Goff of the EPA Region 4 staff at (404) 562-9137.

Sincerely,

Beverly H. Banister
Director
Air, Pesticides & Toxics Management Division

cc: Dan Chadwick; OECA



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0300040

Category: NSPS
EPA Office: Region 10
Date: 02/07/2000
Title: Boiler Derate through Burner Replacement
Recipient: Bob Bloom
Author: Douglas E. Hardesty

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b

Abstract:

Q: May a facility derate a boiler whose burner has been replaced with a new natural gas burner such that the boiler's heat input capacity is now less than 100 mmBtu/hr?

A: Yes. The facility is eligible to derate the boiler's heat input capacity. A performance test shall be conducted to determine the derated value and a test plan submitted to EPA for approval.

Letter:

Reply To
Attn Of: OAQ-107

Mr. Bob Bloom
Lamb-Weston, Inc.
2975 Lamb Weston Road
American Falls, Idaho 83211

Re: NSPS Subpart Db Applicability

Dear Mr. Bloom:

This letter responds to your January 21, 2000, request to the United States Environmental Protection Agency, Region 10 (Region 10), to derate Boiler No. 1. The boiler commenced construction after June 19, 1984, and its heat input capacity is greater than 100 MMBtu/hr. Thus, the requirements of 40 C.F.R. Part 60, Subpart Db - Standards of Performance for Industrial - Commercial - Institutional Steam Generating Units currently apply. You indicate, however, that the replacement of the original burner with a Forney Corporation NOx Miser natural gas burner has decreased the boiler's heat input capacity such that it is now less than 100 MMBtu/hr. You propose to conduct a performance test to determine the boiler's new maximum heat input capacity.

It is our understanding that the installation of the Forney burner is a permanent physical change which will preclude the boiler from operating at a capacity greater than 98 MMBtu/hr. The burner installation is a change that cannot be easily undone, and requires a system shutdown to accomplish or reverse. Therefore, Region 10 has determined that you are eligible to derate the boiler's heat input capacity. The derated value shall be determined by conducting a performance test in accordance with procedures approved by Region 10.

Submit a test plan to Region 10 for approval prescribing the methods to determine the boiler's heat input capacity. Region 10 shall act upon your test plan within 30 calendar days of receipt.

If you have any questions regarding our response, please contact Dan Meyer of my staff at (206) 553-4150.

Sincerely,

Douglas E. Hardesty, Manager Federal and Delegated Air Programs Unit

cc: Harbi Elshafei, IDEQ
Jim Greaves, Region 10 - Idaho Operations Office
Mike Silver, IDEQ



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0300076

Category: NSPS
EPA Office: Region 10
Date: 12/27/1999
Title: Boiler Derate
Recipient: Dave Kubosumi
Author: Douglas Hardesty

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units

Abstract:

Q: Due to a permanent physical change to a boiler, its heat input capacity decreased to less than 100 MMBtu/hr. Will the boiler be subject to the requirements of NSPS Subpart Db?

A: No. The boiler is no longer subject to the requirements of NSPS Subpart Db. However, given that the boiler commenced construction after June 9, 1989, the requirements of NSPS Subpart Dc apply.

Letter:

Reply To
Attn Of: OAQ-107

Mr. Dave Kubosumi
Engineering Manager
Lamb Weston, Inc.
856 Russet Street
Twin Falls, Idaho 83303-0128

Re: NSPS Subpart Db Applicability

Dear Mr. Kubosumi:

This letter responds to your November 8, 1999, request to the United States Environmental Protection Agency, Region 10 (Region 10), for an applicability determination for Boiler No. 1. The boiler commenced construction after June 19, 1984, and its heat input capacity is greater than 100 MMBtu/hr. Thus, the requirements of 40 C.F.R. Part 60, Subpart Db - Standards of Performance for Industrial - Commercial - Institutional Steam Generating Units applied. Subsequent to a recent permanent physical change to the boiler, its heat input capacity decreased such that it is now less than 100 MMBtu/hr. For the reasons discussed below, Region 10 has determined that the boiler is no longer subject to the requirements of 40 C.F.R. Part 60, Subpart Db.

Lamb Weston has successfully demonstrated that the boiler's heat input capacity is less than 100 MMBtu/hr. On November 3, 1999, the boiler was operated at full load during four 15- minute periods. The draft fan motor was operating at full speed and air inlet dampers were fully open. Maximum natural gas flow rates were maintained so as to optimize combustion efficiency. The highest 15-minute heat input value recorded by the facility was 96.6 MMBtu/hr.

Lamb Weston has also successfully documented that the boiler's heat input capacity has been reduced by replacing a 200 horsepower (hp) draft fan motor with a 75 hp motor, effectively reducing fan speed from 1725 revolutions per minute (rpm) to 840 rpm. As prescribed in our June 30, 1999, letter to Lamb-Weston, a boiler derate must be accomplished in accordance with the following criteria:

1. Be accomplished through a permanent physical change which will preclude it from operating at a capacity greater than the derated value.
2. Be a change that cannot be easily undone
3. Require a system shutdown to make the change or to reverse it
4. Reduce the capacity, not the feed rate, of the boiler.

The replacement of the draft fan motor satisfies all four criteria.

Pursuant to the conditions of our June 30, 1999, letter, you shall continue to monitor and maintain records of the natural gas flow rate on a continuous basis. Read and record natural gas flow rate (ft³/min), no less frequently than on a continuous basis. Report to Region 10 and the Idaho Division of Environmental Quality on a quarterly basis the natural gas fired heat input of the boiler (MMBtu/hr) for each boiler operating day.

Given that the boiler commenced construction after June 9, 1989, the boiler is subject to the requirements of 40 C.F.R. Part 60, Subpart Dc - Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units, effective the date of this letter. Please note the monitoring and recordkeeping requirements for natural gas fired boilers in 40 C.F.R. Sec. 60.48c(g).

In summary, Region 10 has determined that Boiler No. 1 is no longer subject to the requirements of NSPS Subpart Db. In the event you ever intend to undo the aforementioned physical change such that the boiler's capacity increases above 100 MMBtu/hr, then this applicability determination becomes invalid.

If you have any questions regarding our response, please contact Dan Meyer of my staff at (206) 553-4150.

Sincerely,

Douglas E. Hardesty, Manager Federal and Delegated Air Programs Unit

cc: Harbi Elshafei, IDEQ
Jim Greaves, Region 10 - Idaho Operations Office
Mike Silver, IDEQ
Brian Stoddard, Lamb Weston



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0400003

Category: NSPS
EPA Office: Region 4
Date: 10/27/2003
Title: Boiler Derate
Recipient: Robert R. Fulp
Author: Beverly Banister
Comments: Compare with prior determination filed as ADI Control No. 0100082.

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.40c

Abstract:

Q: Will EPA approve a proposal under New Source Performance Standards (NSPS) subpart Db to derate a boiler at North Carolina Baptist Hospital which consists of limiting the combustion air flow by welding a mechanical stop to limit the travel of the inlet valve dampers?

A: No. The proposed derate does not meet the criteria specified in other proposals approved by EPA. In order to be an acceptable derate, a permanent physical change must be made. The proposed method is not considered permanent and could be reversed rather easily.

Letter:

October 27, 2003

4APT-ARB

Mr. Robert R. Fulp
Director
Forsyth County Environmental Affairs Department
537 North Spruce Street
Winston-Salem North Carolina 27101

Dear Mr. Fulp:

We have received the enclosed September 30, 2003, request from North Carolina Baptist Hospital in Winston-Salem, North Carolina for approval of a proposed method for derating a boiler. The proposed derate is for a boiler which has a heat input capacity of 105 million Btu/hour and is subject to New Source Performance Standards (NSPS) Subpart Db - "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units." As indicated in conversations with Mr. Greg Nichols, from North Carolina Baptist Hospital, the primary fuel for the boiler is natural gas, and fuel oil is used as a backup fuel. By derating the boiler to less than 100 million Btu/hour, it would no longer be subject to NSPS Subpart Db but would be subject to NSPS Subpart Dc - "Standards of Performance for Small Industrial-Commercial- Institutional Steam Generating Units." Based on our review of the proposed boiler derate, we have determined that it is not acceptable. Guidance concerning an acceptable derate is provided in this letter.

Based on previous determinations concerning boiler derates, an acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. As indicated in previous determinations, changes which are made only to fuel feed systems are not acceptable. It has previously been determined that changes in system capacity such as switching to smaller fans with smaller capacity in combination with the use of smaller pipes and pumps to control fuel feed rate would be acceptable.

The boiler derate proposed by North Carolina Baptist Hospital is based on limiting the combustion air flow to the boiler to reduce the capacity. The facility has proposed to do so by welding a mechanical stop to limit the travel of the inlet valve dampers. The proposal indicates that along with the mechanical stop, the control span of the actuator will be adjusted. To support their proposal, the facility enclosed with their request a previous Environmental Protection Agency (EPA) Region 4 determination dated December 14, 1998. That determination approved a boiler derate proposal which was also based on limiting the capacity of the boiler by reducing the combustion air volume. While limiting the combustion air flow is an acceptable method of derating a boiler, the particular method described by North Carolina Baptist Hospital is not acceptable. Since the method proposed by North Carolina Baptist Hospital does not constitute a permanent physical change to the affected facility, it is not acceptable. The proposed changes to the boiler could also be reversed rather easily, unlike the changes approved in the December 14, 1998, determination.

If there are any questions regarding this letter, please contact Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely yours,

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

cc: Greg Nichols, North Carolina Baptist Hospital

Enclosure



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0500017

Category: NSPS
EPA Office: CAMPD
Date: 12/21/2004
Title: Autoflame Control System Technology for Boiler Derate
Recipient: R. Douglas Neeley
Author: Michael S. Alushin
Comments: This comment supercedes previous determinations filed as ADI Control Nos. 0100016 and 0100055.

Subparts: Part 60, D, Foss. Fuel Fired Steam Gen. (post 8/17/71)
Part 60, Da, Elec. Util. Steam Gen. Units (post 9/18/78)
Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40a
60.40b
60.40c

Abstract:

Q: Will EPA approve the Autoflame Control System Technology to derate a boiler for purposes of determining applicability of the NSPS subparts for boilers (40 CFR part 60, subparts D, Da, Db, and Dc)?

A: No. EPA will not approve the Autoflame Control System Technology because derate methods that are based solely on fuel feedrate control, as the Autoflame Control System Technology is, are not acceptable derate methods for determining the rated capacity of a boiler under NSPS subparts D, Da, Db, and Dc.

Letter:

MEMORANDUM

SUBJECT: New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units - Use of Autoflame for Boiler Derates

FROM: Michael S. Alushin, Director Compliance Assessment and Media Program Division
Office of Compliance

TO: R. Douglas Neeley, Chief
Air Toxics and Monitoring Branch
EPA Region 4

This memorandum is in response to a request for assistance from Keith Goff of your staff regarding a letter received on December 22, 2003, from the North Carolina Baptist Hospital (NCBH) located in Winston-Salem, North Carolina. NCBH seeks approval for the use of the Autoflame Control System Technology as a boiler derate method to avoid compliance requirements under the New Source Performance Standards (NSPS) for steam generating units. In their request, NCBH relies upon prior approval of the Autoflame Control System Technology given by EPA Region 3.

According to information provided to us by EPA Region 3, the Autoflame Control System Technology consists of two elements: 1) the installation of a control module (microcomputer and power supply) to control fuel flow to the boiler burner limiting the maximum design heat input capacity; and 2) the installation of a redesigned, resized control valve specifically machined to limit the maximum fuel flow to the boiler. The combination of these two elements limits the fuel feedrate to a boiler.

Beginning in 1977, EPA policy regarding boiler derates has been communicated in several applicability determinations. According to these applicability determinations, approval of a boiler derate is based on the following requirements. The derate must:

- 1) Be accomplished through a permanent physical change which will preclude it from operating at a capacity greater than the derated value;
- 2) Be a change that can not be easily undone;
- 3) Require a system shutdown to make the change or to reverse the change;
- 4) Reduce the capacity of the boiler, not the fuel feedrate to the boiler.

Based on these requirements, the Autoflame Control System Technology would not qualify as an acceptable derate since this system is solely used for fuel feedrate control. In addition, existing EPA applicability determinations have concluded that the installation of a weld plate or orifice, such as a resized control valve, to control fuel flow, would not be an acceptable derate method because it is neither permanent, nor difficult to reverse. Therefore, EPA cannot approve the use of the Autoflame Control System Technology, as described above, as a method for derating boilers to avoid requirements under any of the NSPS for steam generating units (i.e., Subparts D, Da, Db, and Dc).

The two EPA Region 3 determinations approving the use of the Autoflame Control System

Technology as a derate method were based on erroneous technical advise and are in conflict with our current EPA policy regarding boiler derates. Since we have no intention of changing our current boiler derate policy, the EPA Region 3 applicability determinations are not precedence for the NCBH request or any future requests.

The two EPA Region 3 applicability determinations will remain available through the EPA Applicability Determination Index (ADI). However, a statement will be added to these applicability determinations indicating that they were issued erroneously and do not represent official EPA policy.

If you have any questions concerning this response, please contact Gregory Fried at (202) 564-7016.

cc: Mamie Miller, Air Compliance Branch, USEPA
Keith Goff, EPA Region 4
James Hagedorn, EPA Region 3
Christopher Pilla, EPA Region 3
Jan Tierney, Office of General Counsel, USEPA



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0500029

Category: NSPS
EPA Office: Region 4
Date: 02/07/2005
Title: Boiler Derate Proposal
Recipient: Robert Fulp
Author: Beverly Banister
Comments: See referenced determinations filed as ADI Control Nos. 0400003 and 0500017.

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.40c

Abstract:

Q: Will EPA approve a boiler derate proposal, under 40 CFR part 60, subpart Db, which is based on changes made to limit the fuel feed rate?

A: No. EPA will not approve this boiler derate proposal under NSPS subpart Db because it is based only on a reduction in the fuel feed rate and does not result in a reduction in boiler capacity, thus failing to comply with EPA's policy on derates.

Letter:

4APT-ATMB

Mr. Robert R. Fulp
Director
Forsyth County Environmental Affairs Department
537 North Spruce Street
Winston-Salem North Carolina 27101

Dear Mr. Fulp:

We have received the enclosed December 1, 2003, request from North Carolina Baptist Hospital (NCBH) in Winston-Salem, North Carolina for approval of a proposed method for derating a boiler. The proposal is for a boiler which has a heat input capacity of 105 million Btu/hour and is subject to New Source Performance Standards (NSPS) Subpart Db - "Standards of Performance for industrial-Commercial- Institutional Steam Generating Units." The primary fuel for the boiler is natural gas, and fuel oil is used as a backup fuel. By derating the boiler to less than 100 million Btu/hour, it would no longer be subject to NSPS Subpart Db but would be subject to NSPS Subpart Dc - "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." Based on a review of the NCBH proposal, we have determined that it does not comply with the Environmental Protection Agency's (EPA's) policy on derates and is not acceptable.

The derate method proposed by NCBH consists of the installation of two Autoflame microprocessor- based burner control systems to replace the mechanical linkage systems currently in use. The Autoflame system is comprised of two major components, which are the control module containing the microcomputer and power supply and the individual servomotors for modulating the fuel valves and air damper. The commissioning mode of the computer can only be accessed by entering a proprietary password which is unknown to the facility personnel and maintained by CSI Services, the vendor which would install the technology. The proposed derate also consists of the installation of a specially fabricated oil flow control valve having an orifice manufactured by Autoflame. The oil flow control valve will restrict the volume of oil and limit the operation of the boilers to a heat input of less than 100 million BTUs per hour. As justification for their proposal, NCBH has referenced previous EPA Region 3 determinations approving this method for derating boilers.

EPA's policy concerning boiler derates has been described in prior EPA determinations and in our October 27, 2003, response to a previous NCBH proposal for a derate. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable.

Since the NCBH proposal is based only on a reduction in the fuel feed rate and does not result in a reduction in boiler capacity, it does not comply with EPA's policy on derates. To ensure compliance with EPA's policy, this determination is being provided with assistance from EPA's Office of Enforcement and Compliance Assurance (OECA). Enclosed with this letter is a December 21, 2004, memorandum from OECA regarding their review of the NCBH proposal and EPA's policy on derates.

If there are any questions regarding this determination, please contact Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely yours,

Beverly H. Banister

Director
Air, Pesticides, and Toxics
Management Division

cc: Michael F. Mahan
North Carolina Baptist Hospital



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0500051

Category: NSPS
EPA Office: Region 4
Date: 05/23/2005
Title: Boiler Derate Proposal
Recipient: Robert R. Fulp
Author: Beverly Banister
Comments:

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.40c

Abstract:

Q: Will EPA approve under 40 CFR part 60, subparts Db and Dc, a boiler derate proposal from North Carolina Baptist Hospital in Winston-Salem, North Carolina, which is based on changes made to the natural gas burner?

A: Yes. EPA approves the proposed derate method under NSPS subparts Db and Dc, as it will reduce the capacity of the boiler and will comply with EPA's policy on derates.

Letter:

4APT-ARB

Mr. Robert R. Fulp
Director
Forsyth County Environmental Affairs Department
537 North Spruce Street
Winston-Salem North Carolina 27101

Dear Mr. Fulp:

We have received the enclosed April 26, 2005, request for a boiler derate from North Carolina Baptist Hospital (NCBH) in Winston-Salem, North Carolina. The proposal is for a boiler which has a heat input capacity of 105 million Btu/hour and is subject to New Source Performance Standards (NSPS) Subpart Db - "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units." The primary fuel for the boiler is natural gas, and fuel oil is used as a backup fuel. By derating the boiler to less than 100 million Btu/hour, it would no longer be subject to NSPS Subpart D b but would be subject to NSPS Subpart Dc - "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." NCBH proposes to modify the gas burner in the boiler by installing new burner tips, which will limit the heat input capacity to less than 100 mmBtu/hr. The oil supply to the boiler and the oil burner will be removed, so the boiler will no longer be capable of burning fuel oil. We have determined that the NCBH proposal complies with the Environmental Protection Agency's (EPA's) policy on derates and is acceptable.

The proposal is described in more detail in the enclosed May 5, 2005, letter from the Coen Company, the manufacturer of the boiler. As described in the proposal, new gas burner tips will be provided which will limit the flow of natural gas to the burner to less than 100 mmBtu/hr. The burner tips will be redesigned with smaller orifices. To replace the burner tips, the boiler will need to be shutdown and then cooled for about two days. A contractor will enter the furnace to replace the old burner tips with the new ones. The unit will then be re-calibrated by a Coen service engineer to adjust the new air/fuel ratio curves based on the new maximum capacity, which can take up to five more days. To eliminate the capability of firing fuel oil, the oil supply and the oil burner will be removed from the boiler.

Each proposal for a boiler derate is evaluated on a case-by-case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable. Based on these criteria, the modification proposed by NCBH is acceptable for a derate. The heat input of the boiler will be limited by modifying the burner, which is considered part of the steam generating unit affected facility. The maximum heat input capacity should be demonstrated by operating the boiler at maximum capacity for a 24 hour period.

Steam generating units that have a design firing rate of 90 to 100 mmBtu/hr should be required to continuously monitor fuel feed rates and maintain information regarding the fuel heat content in order to ensure that the unit does not exceed a heat input of 100 mmBtu/hr. We recommend that fuel feed rates be reported as hourly averages. If any hourly fuel feed rate and corresponding heat content indicate a heat input of greater than 100 mmBtu/hr, the steam generating unit would then be considered subject to Subpart Db from the date a heat input of 100 mmBtu/hr is exceeded.

This approval of the derate method will become void if NCBH fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a

notification of the proposed modifications must be submitted to EPA.

This determination has been provided with assistance from the EPA's Office of Enforcement and Compliance Assurance (OECA). If there are any questions regarding this determination, please contact Mr. Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely yours,

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

cc: Michael F. Mahan; North Carolina Baptist Hospital Greg Fried; OECA

Enlosures (2)



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0500122

Category: NSPS
EPA Office: Region 4
Date: 05/23/2005
Title: Boiler Derate Proposal
Recipient: Fulp, Robert R.
Author: Banister, Beverly H.
Comments:

Subparts: Part 60, Db, Indust.-Comm.-Inst. Steam Gen. Units
Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.40c

Abstract:

Q: Does EPA approve a boiler derate proposal, under 40 CFR part 60, subpart Db, based on changes made to the natural gas burner at North Carolina Baptist Hospital in Winston-Salem, North Carolina?

A: Yes. EPA approves this proposal under NSPS subpart Db because it has determined that the proposed derate method, which includes installing new boiler tips limiting the heat input capacity to 100mmBtu/hr and eliminating the burning of fuel oil, will reduce the capacity of the boiler and will comply with EPA's policy on derates.

Letter:

4APT-ARB

Mr. Robert R. Fulp
Director
Forsyth County Environmental Affairs Department
537 North Spruce Street

Winston-Salem North Carolina 27101

Dear Mr. Fulp:

We have received the enclosed April 26, 2005, request for a boiler derate from North Carolina Baptist Hospital (NCBH) in Winston-Salem, North Carolina. The proposal is for a boiler which has a heat input capacity of 105 million Btu/hour and is subject to New Source Performance Standards (NSPS) Subpart Db - "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units." The primary fuel for the boiler is natural gas, and fuel oil is used as a backup fuel. By derating the boiler to less than 100 million Btu/hour, it would no longer be subject to NSPS Subpart Db but would be subject to NSPS Subpart Dc - "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." NCBH proposes to modify the gas burner in the boiler by installing new burner tips, which will limit the heat input capacity to less than 100 mmBtu/hr. The oil supply to the boiler and the oil burner will be removed, so the boiler will no longer be capable of burning fuel oil. We have determined that the NCBH proposal complies with the Environmental Protection Agency's (EPA's) policy on derates and is acceptable.

The proposal is described in more detail in the enclosed May 5, 2005, letter from the Coen Company, the manufacturer of the boiler. As described in the proposal, new gas burner tips will be provided which will limit the flow of natural gas to the burner to less than 100 mmBtu/hr. The burner tips will be redesigned with smaller orifices. To replace the burner tips, the boiler will need to be shut down and then cooled for about two days. A contractor will enter the furnace to replace the old burner tips with the new ones. The unit will then be re-calibrated by a Coen service engineer to adjust the new air/fuel ratio curves based on the new maximum capacity, which can take up to five more days. To eliminate the capability of firing fuel oil, the oil supply and the oil burner will be removed from the boiler.

Each proposal for a boiler derate is evaluated on a case-by-case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable. Based on these criteria, the modification proposed by NCBH is acceptable for a derate. The heat input of the boiler will be limited by modifying the burner, which is considered part of the steam generating unit affected facility. The maximum heat input capacity should be demonstrated by operating the boiler at maximum capacity for a 24 hour period.

Steam generating units that have a design firing rate of 90 to 100 mmBtu/hr should be required to continuously monitor fuel feed rates and maintain information regarding the fuel heat content in order to ensure that the unit does not exceed a heat input of 100 mmBtu/hr. We recommend that fuel feed rates be reported as hourly averages. If any hourly fuel feed rate and corresponding heat content indicate a heat input of greater than 100 mmBtu/hr, the steam generating unit would then be considered subject to Subpart Db from the date a heat input of 100 mmBtu/hr is exceeded.

This approval of the derate method will become void if NCBH fails to follow the proposed

procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA.

This determination has been provided with assistance from the EPA's Office of Enforcement and Compliance Assurance (OECA). If there are any questions regarding this determination, please contact Mr. Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely yours,

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

cc: Michael F. Mahan; North Carolina Baptist Hospital Greg Fried; OECA

Enclosures (2)

requirements as provided in Part 60 of the Code of Federal Regulations. This policy requires that any boiler deration must be done thru physical changes to the boiler that are permanent in nature and cannot be reversed easily without the need for a source shutdown of extended duration. Each proposal for a boiler derate is evaluated on a case-by-case basis. Changes which are made only to the fuel feed systems are not acceptable. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value.

Based on internal discussions here at Region III and discussions with EPA Headquarters in Washington, D.C., EPA approves the Sunsweet derate proposal to decrease the heat input capacity of the boiler to less than 30 million BTUs per hour through the installation of a new burner. The burner currently in place has a maximum natural gas firing rate of 33,480,000 BTUs per hour and the new burner will have a firing rate of 29,600,000 BTUs per hour. This approval of the derate method will become void if Sunsweet fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA.

Thank you for your notification on this matter and should you have any further comments or questions in regard to boiler derations, do not hesitate to contact James Hagedorn, of the Air Enforcement Branch, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Ken Hartzler, PaDEP
Greg Fried, EPA OECA

have made do not constitute an acceptable boiler derate. The details of our response are provided below.

In your April 5, 2006 request, you indicated that the original design capacity of the boiler as stated by the manufacturer is 63.9 million (mm) British Thermal Units (BTUs) (gas) and 61.0 mmBTU (oil). You state that electronic and mechanical modifications have been made to the boiler to limit the fuel input capacity to a maximum of 29.9 mmBTU. The changes include using computer software to limit the fuel/air actuator (to 41 percent of it's original nominal range) and welded stops to physically limit the cam drive rotation of the fuel oil control valve thereby limiting fuel and air input to the boiler.

EPA policy on boiler derates requires that the derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. In addition, changes which are made only to fuel feed systems are not acceptable for derates.

Based on the information you have provided, we have determined that the changes you have made do not satisfy our policy on boiler derates. Electronic controls designed to limit fuel and air feed rates are not permanent and constitute only a change to the fuel feed system. See letter from Beverly Bannister, Director, Air, Pesticides, and Toxics Management Division to Robert Fulp, Director Forsyth County Environmental Affairs Department, February 7, 2005, Applicability Determination Index #0500029, <http://cfpub2.epa.gov/adi/>. Welded stops to limit the cam rotation of the fuel oil control valve are not permanent and can be easily undone. See letter from Douglas Neeley, Chief, Air and Radiation Technology Branch, to James A. Joy, Chief, Bureau of Air Quality, South Carolina Department of Health and Environmental Control, July 25, 1997, Applicability Determination Index #9800043, <http://cfpub2.epa.gov/adi/>.

Therefore, we have determined that the changes made to the boiler in question are not acceptable for a boiler derate. Temple University is still subject to all regulatory requirements that accompany the installation of a new 63.9 million BTU (gas) and 61.0 mmBTU (oil) boiler which may include testing, monitoring, and reporting mandates on the boiler operation. Please work with Philadelphia Air Management Services permitting personnel to assure that Temple University has the correct permit conditions in this federally-enforceable document especially under the federal NSPS program.

This response has been coordinated with the EPA Office of Enforcement and Compliance Assurance. If you should have any comments or questions in regard to this matter, do not hesitate to contact James W. Hagedorn, of the EPA Air Enforcement Branch, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Joe Sheehan, Philadelphia AMS
Greg Fried, EPA OECA

we have determined that the proposal complies with the Environmental Protection Agency's (EPA's) policy on derates and is acceptable.

The method proposed by Biogen to derate boilers ES-026 and ES-027 is described in their letter and in the enclosures from C&C Boiler Sales & Service, Inc. As described in the derate proposal, the forced draft fans on each of the two boilers will be replaced with smaller fans and smaller motors. The current fans are powered by 50 HP motors, and the boilers are each rated at 33.6 million Btu/hour (800 HP). The new smaller fans to be installed will be powered by 30 HP motors and will limit the boilers to a heat input capacity of 29.3 million Btu/hour (700 HP) each. The fuel oil flow capacity will also be reduced by using a smaller oil metering stem and orifice block, and adjustments will be made to reduce the flow of natural gas to correspond with the reduced combustion air volume. The combustion fuel-to-air ratios will be set to coincide with the new maximum firing rate.

Each proposal for a boiler derate is evaluated on a case-by-case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable. Based on these criteria, the derate method proposed by Biogen is acceptable. The installation of new fans in the boilers to reduce the flow of combustion air would be acceptable for reducing the heat input capacity of the boilers. The maximum heat input capacity should be demonstrated by operating the boilers at maximum capacity for a 24-hour period for each fuel. An ongoing program will also need to be implemented to monitor the actual heat input of the boilers by maintaining records of fuel consumption (as already required by 60.48c(g)) and fuel heating value.

The approval of the derate method will become void if Biogen fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to the EPA.

If there are any questions regarding this determination, please contact Mr. Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely,

G. Alan Farmer
Acting Director
Air, Pesticides, and Toxics
Management Division

Enclosure

cc: Keith Gibson, Biogen Idec Inc.

company's proposal includes the replacement of the forced draft fans with smaller fans and motors, which will reduce the heat input capacity of each boiler to 29.3 million Btu/hour. Based on our review, we have determined that the proposal complies with the Environmental Protection Agency's (EPA's) policy on derates and is acceptable.

The method proposed by Premium Standard Farms to derate boilers B-4 and B-5 is described in their February 22, 2006, letter, and additional details concerning the procedure are described in a February 10, 2006, letter and enclosures from C&C Boiler Sales & Service, Inc. As described in the derate proposal, the forced draft fans on each of the two boilers will be replaced with smaller fans and smaller motors. The current fans are powered by 50 HP motors, and the boilers are each rated at 33.6 million Btu/hour (800 HP). The new smaller fans to be installed will be powered by 30 HP motors and will limit the boilers to a heat input capacity of 29.3 million Btu/hour (700 HP) each. The fuel oil flow capacity will also be reduced by using a smaller oil metering stem and orifice block, and adjustments will be made to reduce the flow of natural gas and propane to correspond with the reduced combustion air volume. The combustion fuel-to-air ratios will be set to coincide with the new maximum firing rate.

Each proposal for a boiler derate is evaluated on a case-by-case basis. An acceptable derate must consist of a permanent physical change which prevents the boiler from operating at a capacity greater than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable. Based on these criteria, the derate method proposed by Premium Standard Farms is acceptable. The installation of new fans in the boilers to reduce the flow of combustion air would be acceptable for reducing the heat input capacity of the boilers. The maximum heat input capacity should be demonstrated by operating the boilers at maximum capacity for a 24-hour period for each fuel. An ongoing program will also need to be implemented to monitor the actual heat input of the boilers by maintaining records of fuel consumption (as already required by 60.48c(g)) and fuel heating value.

The approval of the derate method will become void if Premium Standard Farms fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to the EPA.

If there are any questions regarding this determination, please contact Mr. Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely,

G. Alan Farmer
Acting Director
Air, Pesticides, and Toxics
Management Division

cc: Michael Aldridge, NC Department of Environment & Natural Resources



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0700029

Category: NSPS
 EPA Office: Region 10
 Date: 07/14/2005
 Title: Boiler De-rating
 Recipient: Nel, Jan
 Author: KenKnight, Jeff
 Comments:

| | | |
|-------------|---|---|
| Part 60, Db | Indust.-Comm.-Inst. Steam Gen. Units | |
| | Dc | Small Indust.-Comm.-Inst. Steam Gen. Units |

Abstract:

Q: Has Blaine Larsen Farms's (BLF) boiler, located at the Dehydration Division potato processing plant, in Dubois, Idaho, been derated and made subject to the requirements of 40 CFR part 60, subpart Dc, rather than 40 CFR part 60, subpart Db?

A: Yes. EPA determines that BLF's boiler has been derated and is now subject to NSPS subpart Dc, because the burner has been replaced with one that will limit the boiler capacity to less than 100 MMBtu/hr, as verified by testing, and thus meeting the four derate criteria.

Letter:

Reply To
 Attn Of: AWT - 107

Jan Nel
 Vice President,
 Dehydration Operations
 Blaine Larsen Farms
 P.O. Box 188
 Hamer, Idaho 83425

Re: Confirmation of Boiler De-rating from NSPS Subpart Db to NSPS Subpart Dc

Dear Jan Nel:

This letter responds to your submittal of a boiler derating test report to the United States Environmental Protection Agency (EPA) to finalize a derate of a boiler owned and operated by Blaine Larsen Farms (BLF). The initial request and test protocol, which was not acceptable, was submitted October 21, 2004, and followed up with more information in a letter dated November 30, 2004. A revised test protocol was submitted in a letter dated January 3, 2005. The method of derating described in the letter dated January 3, 2005, consisting of replacing the burner, was approved by EPA as an acceptable

approach to derate the boiler, in a letter to BLF from EPA dated March 11, 2005.

As described below, based on the fact that the burner has been replaced with one that will limit the boiler capacity to less than 100 MMBtu/hr, EPA approves the derate. The boiler is now subject to the requirements of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The boiler is located at the Dehydration Division potato processing plant, in Dubois, Idaho. It commenced construction after June 19, 1984, and its heat input capacity, before the derate, was 143 MMBtu/hr. Thus, the requirements of 40 C.F.R. Part 60, Subpart Db - Standards of Performance for Industrial - Commercial - Institutional Steam Generating Units applied before the derate. You indicate that BLF has replace the existing 143 MMBTU/hr oil and gas burner with a new Todd - burner designed to limit the boiler capacity for both oil and gas to less than 100 MMBtu/hr.

In order for a boiler to be derated, certain criteria must be met. The derate must: 1. Be accomplished through a permanent physical change which will preclude it from operating at a capacity greater than the derated value; 2. Be a change that cannot be easily undone; 3. Require a system shutdown to make the change or to reverse the change; and, 4. Reduce the capacity of the boiler without the installation of a feed rate governor. Changes which are made only to fuel feed systems are not acceptable.

BLF has stated that, with the installation of the new Todd? burner, all four of the above criteria are met. The test results, which followed ASME standards, show that the capacities for the different fuels are 96.208 MMBtu/hr for #6 fuel oil and 85.594 MMBtu/hr for propane. BLF has also submitted a copy of the burner name plate for the boiler which states that the maximum capacity is 99MMBtu/hr. Based on this information, EPA agrees that the four criteria describe above are met and the derate is therefore approved.

If you have any questions regarding our response, please contact Heather Valdez of my staff at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Dan Heiser, JBR Environmental
Dan Pitman, IDEQ



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0700034

Category: NSPS
 EPA Office: Region 10
 Date: 04/04/2007
 Title: Final Boiler Derating
 Recipient: Porter, Ellen
 Author: Helm, Nancy
 Comments:

Part 60, D Foss. Fuel Fired Steam Gen. (post 8/17/71)

References: 60.40(a)
 60.40(c)

Abstract:

Q1: Does EPA approve Roseburg Forest Products (RFP)'s proposal to derate two 40 CFR part 60, subpart D boilers by eliminating the capacity of both boilers to burn oil and replacing the burners with burners that are limited to burning less than 250 MMBtu/hr of natural gas, provided that the natural gas pressure delivered to the boilers is monitored?

A1: Yes. EPA believes that the changes made by RFP meet the derate criteria. Installation of a new burner is a permanent change to the boiler, which requires a system shutdown, cannot be easily undone, and is not just a change to the fuel feed system. The changes RFP has made to the boilers, however, are only expected to reduce the capacity of the boilers to slightly under the 250 MMBtu/hr applicability threshold, and information initially provided by RFP raised a question regarding whether, if the pressure of the fuel delivered to a burner exceeded 7.5 psig, the burner could operate at a capacity greater than 245.7 MMBtu/hr for natural gas. Thus, EPA required submission of performance test data verifying that the capacity of the RFP boilers had been reduced to at or below 250 MMBtu/hr at a documented pressure before EPA would issue an applicability determination.

Q2: After approving a source test protocol and reviewing the source test results, will EPA finalize the derate of two of Roseburg Forest Products (RFP)'s boilers under 40 CFR part 60, subpart D?

A2: Yes. EPA has concluded that the boilers will not exceed 250 MMBtu/hr, provided the pressures do not exceed 9.16 psig for Boiler No. 2 and 7.33 psig for Boiler No. 6. EPA has concluded that Boilers No. 2 and No. 6 are no longer subject to Subpart D provided RFP continues to monitor gas pressure to verify that the system is maintaining an average gas pressure below 9.16 psig for Boiler No. 2 and 7.33 psig for Boiler No. 6 (calculated using a three hour average) and provided the limits on gas pressure are included in RFP's Title V permit to insure that the physical restrictions in place to limit gas pressure are not degrading or failing.

Letter:

Reply To
 Attn Of: AWT - 107

Ellen Porter
Manager, Environmental Affairs
Roseburg Forest Products
P.O. Box 1088
Roseburg, OR 97470

Subject: NSPS Subpart D Final Boiler De-rating for Roseburg Forest Products

Dear Ms Porter:

This letter is in response to an applicability request and boiler de-rating source test results that were submitted to the Environmental Protection Agency (EPA) by Stoel Rives LLP, Attorneys at Law, for Roseburg Forest Products (RFP), in letters dated December 22, 2005, September 11, 2006, and February 27, 2007. The test results were submitted to finalize the de-rating of two boilers, Boilers No. 2 and No. 6, at RFP's facility in Dillard, Oregon. EPA has reviewed the information provided by RFP, including the source test results. EPA has determined that, based on the information provided by RFP, Boilers No. 2 and No. 6 are no longer subject to 40 CFR Part 60, Subpart D, New Source Performance Standards (NSPS) for "Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971." Subpart D provided that the natural gas pressure delivered to the boilers is monitored as described below.

Background:

Subpart D applies to each fossil-fuel-fired steam generating unit, and each fossil-fuel-fired and wood-residue-fired steam generating unit, capable of firing fossil fuels at a heat input rate of more than 250 million Btu per hour and that commenced construction or modification on or after August 17, 1971. (See 40 CFR 60.40(a) and (c)). RFP operates two boilers at its Dillard facility that were installed in 1974 and 1976, Boilers No. 2 and No. 6. These units are co-fired fossil fuel/wood waste units that were both rated above 250 million Btu per hour (250 MMBtu/hr) heat input for fossil fuels. Therefore, these boilers were both subject to Subpart D when they were installed at RFP.

RFP has stated in a letter to ODEQ dated October 31, 2005 that they have eliminated the capacity of both boilers to burn oil. RFP further stated that over the July 4, 2005 shutdown, they made changes to the boilers that reduce the total heat input capacity for both boilers to less than 245.7 MMBtu/hr for natural gas. In addition, in a letter dated August 18, 2005, from RFP to Oregon Department of Environmental Quality (ODEQ), which was later provided to EPA, RFP enclosed a copy of the burner vendor's letter and burner loading curve stating that the burners in Dillard Boilers #2 and #6 were replaced with burners that are limited to burning less than 250 MMBtu/hr of natural gas. If each boiler's ability to fire natural gas is reduced (that is, "de-rated") to below 250 MMBtu/hr, both boilers would no longer be subject to regulation under Subpart D because Subpart D only applies to units capable of firing fossil fuels at a heat input rate of more than 250 MMBtu/hr.¹ RFP proposed to monitor gas pressure to verify that the system is maintaining an hourly average gas pressure below a level determined to keep the heat input below 250MMBtu/hr. RFP also proposed to maintain this documentation as a permit condition under its Title V permit to ensure that the physical restrictions in place to limit gas pressure are not degrading or failing. RFP further proposed to demonstrate, through a performance test, the maximum pressure that corresponds to a maximum heat input capacity of the boilers at 250 MMBtu/hr or less.

Criteria for De-rating Boilers

EPA has previously stated that for EPA to consider the capacity of a boiler to be "de-rated," the reduction in capacity must:

1. Be accomplished through a permanent physical change, which will preclude it from operating at a capacity greater than the de-rated value;
2. Be a change that cannot be easily undone;
3. Require a system shutdown to make the change or to reverse the change; and,
4. Reduce the capacity of the boiler, not the feed rate of the boiler (EPA does not consider changes that are made only to fuel feed systems to derate boiler capacity).

Review of Changes to RFP Boilers

Based on the information provided by ODEQ and RFP, including information from the boiler vendor, and the recent source test results, EPA believes that the changes made by RFP meet the above criteria. Installation of a new burner is a permanent change to the boiler, which required a system shutdown, cannot be easily undone, and is not just a change to the fuel feed system. The changes RFP has made to the boilers, however, are only expected to reduce the capacity of the boilers to 245.7 MMBtu/hr, just under the 250 MMBtu/hr applicability threshold. Moreover, information initially provided by RFP raised a question regarding whether, if the pressure of the fuel delivered to a burner exceeded 7.5 psig, the burner could operate at a capacity greater than 245.7 MMBtu/hr for natural gas.

As described in EPA's letter to RFP of March 8, 2006, EPA therefore required submission of performance test data verifying that the capacity of the RFP boilers had been reduced to at or below 250 MMBtu/hr at a documented pressure before EPA would issue an applicability determination. On September 11, 2006, RFP submitted a test protocol to Region 10 for making such a determination. EPA approved this test protocol by letter dated October 6, 2006. Consistent with that test protocol, RFP performed the testing on December 19, 2006. Gary Andes of ODEQ attended the test. This testing demonstrated that the maximum heat input capacity attributed to fossil fuel for Boiler No. 2, at an average gas pressure 8.825 psig, is 245 MMBtu/hr. For Boiler No. 6, the maximum heat input capacity attributed to fossil fuel was demonstrated, at an average gas pressure of 6.516 psig, to be 236 MMBtu/hr. Scaling the pressures up to correspond to a heat input of 250 MMBtu/hr, EPA has concluded that the boilers will not exceed 250 MMBtu/hr, provided the pressures do not exceed 9.16 psig for Boiler No. 2 and 7.33 psig for Boiler No. 6.

Conclusion

Based on a review of the source test results and other information provided by RFP, EPA has concluded that Boilers No. 2 and No. 6 are no longer subject to Subpart D provided RFP continues to monitor gas pressure to verify that the system is maintaining an average gas pressure below 9.16 psig for Boiler No. 2 and 7.33 psig for Boiler No. 6 (calculated using a three hour average) and provided the limits on gas pressure are included in RFP's Title V permit to ensure that the physical restrictions in place to limit gas pressure are not degrading or failing.

If you have any questions regarding our response, please contact Heather Valdez at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Nancy Helm, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Thomas R. Wood, Stoel Rives LLP
Gary Andes, ODEQ
Kerri Nelson, ODEQ
Andy Ginsburg, ODEQ

¹ The ability to combust wood, a non-fossil fuel, is not relevant for purposes of applicability under Subpart D. Both RFP boilers were constructed prior to the applicability dates for the NSPS that apply to smaller size boilers, 40 CFR Part 60, Subparts Db and Dc, which do have limits for wood combustion.

Jan Nel
Vice President
Dehydration Operations
Blaine Larsen Farms
P.O. Box 188
Hamer, Idaho 83425

Re: Boiler De-rating from NSPS Subpart Db to NSPS Subpart Dc

Dear Jan Nel:

This letter responds to your requests to the United States Environmental Protection Agency (EPA) to derate a boiler owned and operated by Blaine Larsen Farms (BLF). The initial request and test protocol was submitted October 21, 2004, and followed up with more information in a letter dated November 30, 2004. The original proposal would not be a valid method to accomplish a boiler derate, as described in more detail below. You submitted a new method and test protocol for derating in a letter dated January 3, 2005. This method of derating, consisting of replacing the burner, is eligible for consideration.

The boiler is located at the Dehydration Division potato processing plant, in Dubois, Idaho. It commenced construction after June 19, 1984, and its heat input capacity is currently greater than 100 MMBtu/hr. Thus, the requirements of 40 C.F.R. Part 60, Subpart Db - Standards of Performance for Industrial - Commercial - Institutional Steam Generating Units currently apply. You indicate, however, that BLF will replace the existing 143 MMBTU/hr oil and gas burner with one designed to limit the boiler capacity to approximately 97 MMBTU/hr. The test protocol submitted by BLF describes the performance test you propose to conduct to determine the boiler's new maximum heat input capacity. As you have stated, following the boiler derate, the boiler would be subject to the requirements of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

In order for a boiler to be derated, certain criteria must be met. The derate must:

1. Be accomplished through a permanent physical change which will preclude it from operating at a capacity greater than the derated value;
2. Be a change that cannot be easily undone;
3. Require a system shutdown to make the change or to reverse the change; and,
4. Reduce the capacity of the boiler without the installation of a feed rate governor. Changes which are made only to fuel feed systems are not acceptable.

In your initial request you proposed to modify the boilers fuel delivery system by restricting the fuel-metering valves. You stated this was to be accomplished with an adjustment to the valve "by repositioning the adjustment screw to limit the travel of the fuel valves through their full travel". You also suggested that the adjustment screws would be locked into place with a locking device that would require a special tool to undo or by sealing it with epoxy. EPA determined that this approach would not be valid based on criteria number four above. Furthermore, EPA also determined that neither proposed method for locking the screws would be considered permanent.

In your January 3, 2005, letter you proposed a different method for derating, consisting of replacing the burner. It is our understanding that the installation of the new burner is a permanent physical change which will preclude the boiler from operating at a capacity greater than 100 MMBtu/hr. The burner installation is a change that cannot be easily undone, requires a system shutdown to accomplish or reverse and is not just a change to the fuel feed system. The boiler burner name plate will be replaced to reflect the maximum input capacity at less than 100 MMBtu/hr. Based on these criteria, this modification proposed by BLF can be considered for a derate.

BLF proposes to use ASME Performance Test, Code 4-1998, as the verification test method. You state that the input/output method will be utilized to record the BTU input to the boiler. BLF has indicated that the same fuels, #6 fuel oil or LP gas, will be fired in the boiler once derated. The maximum heat input capacity should be demonstrated by operating the boiler at maximum capacity for a 24 hour period with each fuel. Steam generating units that have a design firing rate of 90 to 100 mmBtu/hr should be required to continuously monitor fuel feed rates and maintain information regarding the fuel

heat content in order to ensure that the unit does not exceed 100 mmBtu/hr of heat input. We recommend that fuel feed rates be reported as hourly averages. If any hourly fuel feed rate and corresponding heat content indicate a heat input of greater than 100 mmBtu/hr, then the steam generating unit would be considered subject to Subpart Db from the date a heat input of 100 mmBtu/hr is exceeded.

Once BLF has completed a performance test verifying that the heat input capacity is less than 100 MMBtu/hr, that information can be submitted to EPA for final approval of the derate. The derate will not be approved if BLF fails to follow the proposed procedure. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA.

If you have any questions regarding our response, please contact Heather Valdez of my staff at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Dan Heiser, JBR Environmental
Dan Pitman, IDEQ
Doug Cole, EPA - IOO



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0700042

Category: NSPS
 EPA Office: Region 10
 Date: 03/08/2006
 Title: Boiler Derating
 Recipient: Thomas R. Wood
 Author: Jeff KenKnight
 Comments:

| | | |
|------------|--------------------|---|
| Part 60, A | General Provisions | |
| | D | Foss. Fuel Fired Steam Gen. (post 8/17/71) |

| | |
|-------------|----------|
| References: | 60.40(a) |
| | 60.40(c) |

Abstract:

Q: Do changes proposed by Roseburg Forest Products (RFP) to two large boilers result in the boilers being derated under 40 CFR part 60, subpart D? (RFP has eliminated the capacity of both boilers to burn oil and made changes to the boilers that reduce the total heat input capacity for both boilers to less than 245.7 MMBtu/hr for natural gas. RFP proposed to conduct additional monitoring and performance testing to verify that the capacity of the boilers has been reduced.)

A: Although the changes RFP has made to its boilers appear to meet many of the criteria for derating boilers, EPA will require submission of source test data verifying that the capacity of the boilers has been reduced before EPA will determine that the RFP boilers have been derated. Any such verification testing should be conducted while each boiler is operating at its maximum capacity for a 24-hour period for each fossil fuel that the boiler has the capability of burning. EPA expects RFP to monitor the gas pressure during the performance test to verify the correlation of gas pressure to heat input. In addition, to ensure reliability of the performance test results, RFP should submit a performance test plan to EPA for approval prior to the test and follow the general provisions of 40 CFR part 60, subpart A, for performance tests, such as notifying EPA in advance of the test.

Letter:

Reply To
 Attn Of: AWT - 107

Gary Andes
 Oregon Department of Environmental Quality
 750 Front Street NE
 Salem OR 97301

Thomas R. Wood
 Stoel Rives LLP

Attorneys at Law
900 SW Fifth Avenue, Suite 2600
Portland, OR 97204

Subject: NSPS Subpart D Boiler Derating for Roseburg Forest Products

Dear Mr. Andes and Mr. Wood:

This applicability determination is in response to a request sent to the United States Environmental Protection Agency (EPA) by the Oregon Department of Environmental Quality (ODEQ) regarding the Roseburg Forest Products (RFP) facility in Dillard, Oregon. In the original request from ODEQ dated July 1, 2005, EPA was asked to determine if changes proposed by RFP to two large boilers at the Dillard facility would result in the boilers no longer being subject to 40 CFR Part 60, Subpart D, New Source Performance Standards (NSPS) for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 (Subpart D). This is referred to as "derating" the boilers.

This request was followed up with further information regarding the changes RFP has in fact made to their boilers in a letter from ODEQ to EPA dated October 7, 2005. That letter included as an attachment a letter from RFP to ODEQ dated August 18, 2005 and a letter from RFP's boiler vendor to RFP dated July 11, 2005, including a burner loading curve for the new burners. Additional information was also submitted to EPA by Stoel Rives LLP, attorney for RFP, in a letter dated December 22, 2005. In that letter, RFP proposed to conduct additional monitoring and performance testing to verify that the capacity of the boilers has been reduced.

As discussed in more detail below, although the changes RFP has made to their boilers appear to meet many of the criteria for derating boilers, EPA will require submission of source test data verifying that the capacity of the boilers has been reduced before EPA will determine that the RFP boilers have been derated.

Background

Subpart D applies to each fossil-fuel-fired steam generating unit, and each fossil-fuel-fired and wood-residue-fired steam generating unit, capable of firing fossil fuels at a heat input rate of more than 250 million Btu per hour and that commenced construction or modification on or after August 17, 1971 (see 40 CFR 60.40(a) and (c)). RFP operates two boilers at its Dillard facility that were installed in 1974 and 1976. These units are co-fired fossil fuel/wood waste units rated above 250 million Btu per hour (250 MMBtu/hr) heat input for fossil fuels. Therefore, these boilers were both subject to Subpart D when they were installed at RFP.

RFP has stated in a letter to ODEQ dated October 31, 2005 that they have eliminated the capacity of both boilers to burn oil. RFP further stated that over the July 4, 2005 shutdown, they made changes to the boilers that reduce the total heat input capacity for both boilers to less than 245.7 MMBtu/hr for natural gas. In addition, in a letter dated August 18, 2005 from RFP to ODEQ, which was later provided to EPA, RFP enclosed a copy of the burner vendor's letter and burner loading curve stating that the burners in Dillard Boilers #2 and #6 were replaced with burners that are limited to burning less than 250 MMBtu/hr of natural gas. If each boiler's ability to fire natural gas is reduced (that is, derated) to below 250 MMBtu/hr, both boilers would no longer be subject to regulation under Subpart D because Subpart D only applies to units capable of firing fossil fuels at a heat input rate of more than 250 MMBtu/hr.¹

Criteria for Derating Boilers

EPA has previously stated that for EPA to consider the capacity of a boiler to be "derated," the reduction in capacity must:

1. Be accomplished through a permanent physical change, which will preclude it from operating at a capacity greater than the derated value;
2. Be a change that cannot be easily undone;
3. Require a system shutdown to make the change or to reverse the change; and,
4. Reduce the capacity of the boiler, not the feed rate of the boiler (EPA does not consider changes

that are made only to fuel feed systems to derate boiler capacity).

Review of Changes to RFP Boilers

Based on the information provided by ODEQ and RFP, including information from the boiler vendor, the changes made by RFP appear to meet most of the above criteria. Installation of a new burner is a permanent change to the boiler, which required a system shutdown, cannot be easily undone and is not just a change to the fuel feed system.

EPA believes that a legitimate question remains, however, regarding whether the capacity of the boilers has in fact been reduced to at or below the 250 MMBtu/hr applicability threshold in Subpart D. The changes RFP has made to the boilers are only expected to reduce the capacity of the boilers to 245.7 MMBtu/hr, just under the 250 MMBtu/hr applicability threshold. Moreover, information initially provided by RFP raised a question regarding whether, if the pressure of the fuel delivered to a burner exceeded 7.5 psig, the burner could operate at a capacity greater than 245.7 MMBtu/hr for natural gas. In their December 22, 2005 letter, RFP explained why they believe the pressure of the fuel delivered to the burner would not exceed 7.5 psig, even though the burners installed on their boilers could theoretically consume more than 250 MMBtu/hr of natural gas if they were installed on a boiler whose gas supply system operated at pressures greater than 7.5 psig.²

As additional assurance that the pressure of the fuel delivered to a burner does not exceed 7.5 psi, RFP proposes to monitor gas pressure to verify that the system is maintaining an hourly average gas pressure below 7.5 psi. RFP also proposes to maintain this documentation as a permit condition under their Title V permit to insure that the physical restrictions in place to limit gas pressure are not degrading or failing. RFP further proposed to demonstrate through a performance test that the maximum heat input capacity of the boilers at 7.5 psi is 250 MMBtu/hr or less. RFP has asked that EPA require such a test be conducted, however, only if either boiler is operated for any material length of time on natural gas because natural gas is rarely fired in the boilers for more than 24 hours at a time, the boilers can go for months between gas burning events, and the periods of gas burning are not typically scheduled in advance.

Because the physical changes made by RFP to the boilers are designed to result in a reduction of the capacity of the boilers to just below the applicability threshold and because of the question regarding boiler operation at pressures greater than 7.5 psig, EPA will require submission of performance test data verifying that the capacity of the RFP boilers has been reduced to at or below 250 MMBtu/hr before EPA will issue an applicability determination. ASME Performance Test, Code 4-1998, has generally been used as the verification test method for boilers similar to the RFP boilers in connection with derating requests, although RFP may elect to propose an alternate test for determining heat input of the boilers. Any such verification testing should be conducted while each boiler is operating at its maximum capacity for a 24-hour period for each fossil fuel that the boiler has the capability of burning. EPA will also expect RFP to monitor the gas pressure during the performance test to verify the correlation of gas pressure to heat input. In addition, to ensure reliability of the performance test results, RFP should submit a performance test plan to EPA for approval prior to the test and follow the general provisions of 40 CFR Part 60, Subpart A, for performance tests, such as notifying EPA in advance of the test. Once RFP has completed performance tests verifying that the heat input capacity is less than 250 MMBtu/hr, EPA will consider RFP's applicability request.

Once derated, EPA expects boilers or other steam generating units that have a design firing rate of 225 to 250 MMBtu/hr to continuously monitor fuel feed rates and maintain information regarding the fuel heat content in order to ensure that the unit does not exceed 250 MMBtu/hr of heat input. Fuel feed rates should generally be reported as hourly averages. If any hourly fuel feed rate and corresponding heat content, or any other available information, indicate a heat input of greater than 250 MMBtu/hr, then the steam generating unit would be considered subject to Subpart D from the date the unit exceeded a heat input of 250 MMBtu/hr. Also note that if RFP ever wants to increase the capacity of either boiler after it has been derated, a notification of the proposed modifications must be submitted to EPA as required under the NSPS modification provisions of 40 CFR Sec. 60.14.

If you have any questions regarding our response, please contact Heather Valdez at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Kerri Nelson, Administrator, ODEQ Western Region, Eugene Ady Ginsburg, Administrator, Air Quality Division, Portland

1 The ability to combust wood, a non-fossil fuel, is not relevant for purposes of applicability under Subpart D. Both RFP boilers were constructed prior to the applicability dates for the NSPS that apply to smaller size boilers, 40 CFR Part 60, Subparts Db and Dc, which do have limits for wood combustion.

2 RFP states that the possibility of the pressure exceeding 7.5 psig, resulting in heat input greater than 250 MMBtu/hr, is purely theoretical in relation to the actual boiler fuel feed system at their facility. RFP further states that if the pressure increased materially over 7.5 psig, the system would not function properly and the boiler operator would experience a gas header trip, which cuts off the gas supply. For this reason, RFP has the gas pressure monitor alarmed so that it alerts the operator if any pressure irregularities occur. Instantaneous loss of gas when the boilers are depending upon the fuel is an upset condition that RFP actively avoids. This is the reason, RFP states, that RFP specified and the boiler vendor designed the new burner installation based on a 7.5 psig maximum design capacity.



U.S. Environmental Protection Agency Applicability Determination Index

Control Number: 0700050

Category: NSPS
EPA Office: Region 10
Date: 10/06/2006
Title: Boiler Derating
Recipient: Ellen Porter
Author: KenKnight, Jeff
Comments:

Part 60, D Foss. Fuel Fired Steam Gen. (post 8/17/71)

Abstract:

Q: Does EPA approve a source test protocol for determinations of the maximum heat input for use in a boiler derate demonstration, under 40 CFR part 60, subpart D, at the Roseburg Forest Products (RFP) facility in Roseburg, Oregon?

A: Yes. Based upon a review of the source test protocol and the piping and instrument Diagram for the natural gas systems for both boilers, EPA concludes that, under NSPS subpart D, if the source test is conducted according to the protocol, it should provide the information required to verify the maximum heat input, namely, gas flow rate, calorific value, and supply pressure.

Letter:

Reply To
Attn Of: AWT - 107

Ellen Porter
Manager, Environmental Affairs
Roseburg Forest Products
P.O. Box 1088
Roseburg, OR 97470

Subject: Source Test for NSPS Subpart D Boiler Derating for Roseburg Forest Products

Dear Ms Porter:

This letter is in response to a source test protocol that was submitted to the Environmental Protection Agency (EPA) by Roseburg Forest Products (RFP) dated September 11, 2006. Based on a review of the source test protocol and looking at the Piping and Instrument Diagram for the natural gas systems for both boilers, EPA believes that, if the source test is conducted according to the protocol, the source test should provide the information we need to verify the maximum heat input, namely, the gas flow rate, calorific value, and supply pressure.

As stated in a previous determination issued by EPA to RFP dated March 8, 2006, once RFP has completed source tests verifying that the heat input capacity is less than 250 MMBtu/hr for boilers No. 2 and No. 6 at the Dillard facility for all fossil-fuels that can be fired in the boilers, RFP should submit

those results to EPA, along with an applicability request to officially de-rate the boilers. If EPA determines that the information provided by RFP is sufficient to establish that the boilers are below the size threshold for NSPS Subpart D for all fossil fuels, the boilers will be considered officially de-rated and no longer be subject to NSPS Subpart D.

If you have any questions regarding our response, please contact Heather Valdez at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Thomas R. Wood, Stoel Rives LLP Attorneys at Law, Portland, OR Gary Andes, ODEQ, Western Region, Salem
Kerri Nelson, ODEQ Administrator, Eugene Office
Andy Ginsburg, ODEQ Administrator, Air Quality Division, Portland

than the derated value. The physical change cannot be easily undone, and a system shutdown must be required to make the change or to reverse it. The capacity of the boiler must be reduced to constitute an appropriate derate. Changes which are made only to fuel feed systems are not acceptable.

Based on the criteria described above, the physical changes proposed by HSR to derate the boiler are acceptable. The replacement of the oil burner and modification of the natural gas fuel system are permanent in nature and will take several days to complete. Therefore, those changes, in combination with the modifications to the air/fuel mixture settings on the burner controller, are acceptable for derating the heat input capacity of the boiler. However, HSR will need to demonstrate the reduced maximum heat input capacity by operating the boilers at a maximum capacity for a 24 hour period using each fuel. HSR will also need to implement an ongoing program to monitor the actual heat input of the boilers by maintaining records of fuel consumption (as already required by 60.48c(g)) and fuel heating value.

This approval of HSR's derate proposal will become void if HSR fails to follow the proposed procedures. In the future, if the facility wants to increase the capacity of the boiler after it has been derated, HSR must submit to EPA a notification of the proposed modifications.

Thank you for your notification of this matter and should you have any further comments or questions in regard to boiler derating, do not hesitate to contact Steve Rapp, of the Air Technical Unit, at (617) 918-1551.

Sincerely,

Susan Studien, Director
Office of Environmental Stewardship

Cc: Mr. Albert Wasko, The Hospital of Saint Raphael Bob Girard, CT DEP
Keith Hill, CT DEP

capacity of the boiler must be reduced to constitute an appropriate derate, changes which are made only to fuel feed systems are not acceptable. Based on these criteria, the derate method proposed by Bosch is acceptable.

The approval of the derate method will become void if Bosch fails to follow the procedure described in the company's request. If the facility wants to increase the capacity of the boiler after it has been derated, a notification of the proposed modifications must be submitted to the EPA.

If there are any questions regarding this determination, please contact Mr. Keith Goff of the EPA Region 4 staff at (404) 562-9137.

Sincerely,

Carol L. Kemker
Acting Director
Air, Pesticides, and Toxics
Management Division

cc: Diane Humphries, DHEC

Attachment J
Proposed Recordkeeping Requirements for
Storage Vessels under NSPS OOOO

Attachment J
Proposed Recordkeeping Requirements for
Storage Vessels under NSPS OOOO

| Proposed Regulatory Citation | Recordkeeping Requirement | Comment |
|---|---|---|
| §60.5420(c)(5)(i) (Proposed NSPS OOOO) | If required to reduce emissions by complying with §63.766, the records specified in §63.774(b)(2) through (8) of this chapter. | Refer to the recommended regulatory revisions found in the Storage Vessels comments, Section 16.8 |
| §63.774(b)(2) (NESHAP Subpart HH) | Records specified in <u>§63.10(b)(2)</u> ; | If justified, the General Provisions, 60.7, should be used as a reference. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2) (NESHAP Subpart A via reference from HH) | The owner or operator of an affected source subject to the provisions of this part shall maintain relevant records for such source of - | |
| §63.10(b)(2)(i) (NESHAP Subpart A via reference from HH) | The occurrence and duration of each startup or shutdown when the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards; | See General Comments Sections 10.1.2 and 10.3; If justified, the General Provisions, 60.7(b) addresses records required for SSM. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(ii) (NESHAP Subpart A via reference from HH) | The occurrence and duration of each malfunction of operation (<i>i.e.</i> , process equipment) or the required air pollution control and monitoring equipment; | See General Comments Sections 10.1.2 and 10.3; If justified, the General Provisions, 60.7(b) addresses records required for SSM. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(iii) (NESHAP Subpart A via reference from HH) | All required maintenance performed on the air pollution control and monitoring equipment; | |
| §63.10(b)(2)(iv)(A) (NESHAP Subpart A via reference from HH) | Actions taken during periods of startup or shutdown when the source exceeded applicable emission limitations in a relevant standard and when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see <u>§63.6(e)(3)</u>); or | Since this references 63.6(e)(3), Does it mean a SSM Plan is required? See General Comments Sections 10.1.2 and 10.3; If justified, The General Provisions, 60.7(b) addresses records required for SSM. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(iv)(B) (NESHAP Subpart A via reference from HH) | Actions taken during periods of malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see | See General Comments Sections 10.1.2 and 10.3; If justified, The General Provisions, 60.7(b) addresses records required for SSM. The reference to a NESHAP requirement is not appropriate and should be removed. |

| Proposed Regulatory Citation | Recordkeeping Requirement | Comment |
|---|---|---|
| | §63.6(e)(3); | |
| §63.10(b)(2)(v) (NESHAP Subpart A via reference from HH) | All information necessary, including actions taken, to demonstrate conformance with the affected source's startup, shutdown, and malfunction plan (see §63.6(e)(3)) when all actions taken during periods of startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), and malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. (The information needed to demonstrate conformance with the startup, shutdown, and malfunction plan may be recorded using a "checklist," or some other effective form of recordkeeping, in order to minimize the recordkeeping burden for conforming events); | See General Comments Sections 10.1.2 and 10.3; If justified, The General Provisions, 60.7(b) addresses records required for SSM. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(vi) (NESHAP Subpart A via reference from HH) | Each period during which a CMS is malfunctioning or inoperative (including out-of-control periods); | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7 and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(vii) (NESHAP Subpart A via reference from HH) | All required measurements needed to demonstrate compliance with a relevant standard (including, but not limited to, 15-minute averages of CMS data, raw performance testing measurements, and raw performance evaluation measurements, that support data that the source is required to report); | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7 and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(vii)(A) (NESHAP Subpart A via reference from HH) | This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7 and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |

| Proposed Regulatory Citation | Recordkeeping Requirement | Comment |
|---|--|---|
| | In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. | |
| §63.10(b)(2)(vii)(B) (NESHAP Subpart A via reference from HH) | This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7 and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(vii)(C) (NESHAP Subpart A via reference from HH) | The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (b)(2)(vii), if the administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source. | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(viii) (NESHAP Subpart A via reference from HH) | All results of performance tests, CMS performance evaluations, and opacity and visible emission observations; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, 60.8, 60.11, and 60.13 contain requirements for CMS, performance tests, and opacity and visible emission observations. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(ix) (NESHAP Subpart A via reference from HH) | All measurements as may be necessary to determine the conditions of performance tests and performance evaluations; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, 60.8, 60.11, and |

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| | | 60.13 contain requirements for CMS, performance tests, and opacity and visible emission observations. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(x) (NESHAP Subpart A via reference from HH) | All CMS calibration checks; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(xi) (NESHAP Subpart A via reference from HH) | All adjustments and maintenance performed on CMS; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(b)(2)(xii) (NESHAP Subpart A via reference from HH) | Any information demonstrating whether a source is meeting the requirements for a waiver of recordkeeping or reporting requirements under this part, if the source has been granted a waiver under paragraph (f) of this section; | |
| §63.10(b)(2)(xiii) (NESHAP Subpart A via reference from HH) | Any information demonstrating whether a source is meeting the requirements for a waiver of recordkeeping or reporting requirements under this part, if the source has been granted a waiver under paragraph (f) of this section; | |
| §63.10(b)(2)(xiv) (NESHAP Subpart A via reference from HH) | All documentation supporting initial notifications and notifications of compliance status under <u>§63.9</u> . | This is specific for a MACT source and does not apply to NSPS. |
| §63.774(b)(3) (NESHAP Subpart HH) | Records specified in §63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of §63.773(d). Notwithstanding the requirements of §63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through(b)(3)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all | EPA is proposing an amendment to this provision. The proposed amendment is shown in the recordkeeping requirement column. This amendment appears to be a duplication of requirements already identified in other recordkeeping requirements. See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General |

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| | such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data. | Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c) (NESHAP Subpart A via reference from HH) | <i>Additional recordkeeping requirements for sources with continuous monitoring systems.</i> In addition to complying with the requirements specified in paragraphs (b)(1) and (b)(2) of this section, the owner or operator of an affected source required to install a CMS by a relevant standard shall maintain records for such source of-- | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(1) (NESHAP Subpart A via reference from HH) | All required CMS measurements (including monitoring data recorded during unavoidable CMS breakdowns and out-of-control periods); | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(2) – (4) | [Reserved] | |
| §63.10(c)(5) (NESHAP Subpart A via reference from HH) | The date and time identifying each period during which the CMS was inoperative except for zero (low-level) and high-level checks; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(6) (NESHAP Subpart A via reference from HH) | The date and time identifying each period during which the CMS was out of control, as defined in §63.8(c)(7); | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(7) | The specific identification (i.e., the date and time of commencement and completion) of each period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during startups, shutdowns, and malfunctions of the affected source; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be |

| Proposed Regulatory Citation | Recordkeeping Requirement | Comment |
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| | | removed. |
| §63.10(c)(8) (NESHAP Subpart A via reference from HH) | The specific identification (i.e., the date and time of commencement and completion) of each time period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during periods other than startups, shutdowns, and malfunctions of the affected source | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(9) | [Reserved] | |
| §63.10(c)(10) (NESHAP Subpart A via reference from HH) | The nature and cause of any malfunction (if known); | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(11) (NESHAP Subpart A via reference from HH) | The corrective action taken or preventive measures adopted; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(12) (NESHAP Subpart A via reference from HH) | The nature of the repairs or adjustments to the CMS that was inoperative or out of control; | See Storage Vessels Comments Section 16.13. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(13) (NESHAP Subpart A via reference from HH) | The total process operating time during the reporting period; and | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(14) (NESHAP Subpart A via reference from HH) | All procedures that are part of a quality control program developed and implemented for CMS under §63.8(d). | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain |

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| | | requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.10(c)(15) (NESHAP Subpart A via reference from HH) | In order to satisfy the requirements of paragraphs (c)(10) through (c)(12) of this section and to avoid duplicative recordkeeping efforts, the owner or operator may use the affected source's startup, shutdown, and malfunction plan or records kept to satisfy the recordkeeping requirements of the startup, shutdown, and malfunction plan specified in §63.6(e), provided that such plan and records adequately address the requirements of paragraphs (c)(10) through (c)(12). | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(3)(i) (NESHAP Subpart HH) | Monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments; | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(3)(ii) (NESHAP Subpart HH) | [Reserved] | EPA is proposing an amendment to this provision. The proposed amendment strikes the current requirement from the rule. Amendment is shown in the recordkeeping requirement column. |
| §63.774(b)(3)(iii) (NESHAP Subpart HH) | Periods of non-operation resulting in cessation of the emissions to which the monitoring applies; and | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(3)(iv) (NESHAP Subpart HH) | Excursions due to invalid data as defined in §63.773(d)(6)(iv). | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(4) (NESHAP | Each owner or operator using a control | See Storage Vessels Comments |

| Proposed Regulatory Citation | Recordkeeping Requirement | Comment |
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| Subpart HH) | device to comply with §63.764 of this subpart shall keep the following records up-to-date and readily accessible: | Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(4)(i) (NESHAP Subpart HH) | Continuous records of the equipment operating parameters specified to be monitored under §63.773(d) or specified by the Administrator in accordance with §63.773(d)(3)(iii). For flares, the hourly records and records of pilot flame outages specified in paragraph (e) of this section shall be maintained in place of continuous records. | See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(4)(ii) (NESHAP Subpart HH) | Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in §63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section. | EPA is proposing an amendment to this provision. The proposed amendment is shown in the recordkeeping requirement column. See Storage Vessels Comments Section 16.13 and General Comments Section 8.3 and 8.5.2. If justified, the NSPS General Provisions 60.7, and 60.13 contain requirements for CMS. The reference to a NESHAP requirement is not appropriate and should be removed. |
| §63.774(b)(4)(iii) (NESHAP Subpart HH) | Hourly records of whether the flow indicator specified under §63.771(c)(3)(i)(A) was operating and whether flow was detected at any time during the hour, as well as records of the times and durations of all periods when the vent stream is diverted from the control device or the monitor is not operating. | |
| §63.774(b)(4)(iv) (NESHAP Subpart HH) | Where a seal or closure mechanism is used to comply with §63.771(c)(3)(i)(B), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanism has been done, and shall record the duration of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has | |

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| | broken. | |
| §63.774(b)(5) (NESHAP Subpart HH) | Records identifying all parts of the cover or closed-vent system that are designated as unsafe to inspect in accordance with <u>§63.773(c)(5)</u> , an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment. | |
| §63.774(b)(6) (NESHAP Subpart HH) | Records identifying all parts of the cover or closed-vent system that are designated as difficult to inspect in accordance with <u>§63.773(c)(6)</u> , an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment. | |
| §63.774(b)(7) (NESHAP Subpart HH) | For each inspection conducted in accordance with <u>§63.773(c)</u> , during which a leak or defect is detected, a record of the information specified in paragraphs (b)(7)(i) through (b)(7)(viii) of this section. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(i) (NESHAP Subpart HH) | The instrument identification numbers, operator name or initials, and identification of the equipment. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(ii) (NESHAP Subpart HH) | The date the leak or defect was detected and the date of the first attempt to repair the leak or defect. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(iii) (NESHAP Subpart HH) | Maximum instrument reading measured by the method specified in <u>§63.772(c)</u> after the leak or defect is successfully repaired or determined to be nonrepairable. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(iv) (NESHAP Subpart HH) | "Repair delayed" and the reason for the delay if a leak or defect is not repaired within 15 calendar days after discovery of the leak or defect. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(v) (NESHAP Subpart HH) | The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(vi) (NESHAP Subpart HH) | The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(vii) (NESHAP Subpart HH) | Dates of shutdowns that occur while the equipment is unrepaired. | It doesn't appear the cost for instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(viii) (NESHAP | The date of successful repair of the leak or | It doesn't appear the cost for |

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| Subpart HH) | defect. | instrument leak detection, repair, and recordkeeping was included in the cost-benefit analysis. |
| §63.774(b)(7)(ix) (NESHAP Subpart HH) | Records identifying the carbon replacement schedule under §63.771(d)(5) and records of each carbon replacement. | EPA is proposing an amendment to this provision. The proposed amendment is shown in the recordkeeping requirement column. |
| §63.774(b)(8) (NESHAP Subpart HH) | For each inspection conducted in accordance with §63.773(c) during which no leaks or defects are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks or defects were detected. | |
| §60.5420(c)(5)(ii) (Proposed NSPS OOOO) | Records of the determination that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under §60.5395(a)(1) and (a)(2). | Refer to Storage Vessels comment Section 16.6. |

Attachment K
Pneumatic Controller Technical Review

Attachment K

Technical Review of Pneumatic Controllers

by David A Simpson, P.E.

Comments by EPA in the preamble to proposed 40 CFR §60, Subpart OOOO indicate that the agency may not have a good fundamental understanding of the variability in pneumatic controller design and operation. Preamble comments, combined with proposed rule text, lead to uncertainty in industry with regard to EPA's intent in regulating gas-driven pneumatic controller emissions. In comments, API seeks to clarify what it believes is EPA's intent, which is that applicability of the rule is limited

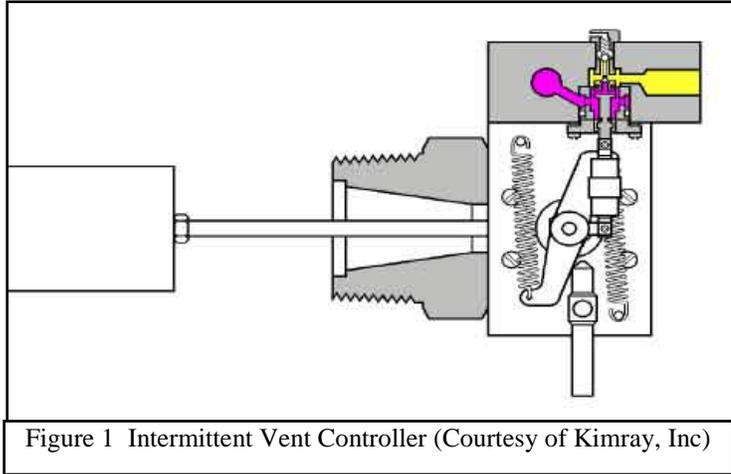


Figure 1 Intermittent Vent Controller (Courtesy of Kimray, Inc)

only to continuous bleed pneumatic controllers. The technical discussion that follows provides EPA with the necessary information on pneumatic controller design and operation, to support limiting regulation only to continuous bleed gas-driven pneumatic controllers.

Pneumatic controllers are devices that can detect the value of physical parameter of a process variable and send a pressure signal to an end-device to change the value of that process variable. Common process variables are liquid level, system pressure, differential pressure across a known restriction (often a surrogate for flow rate), and temperature. There are many ways to classify pneumatic controllers, but you can completely define one with two parameters: (1) is it used for on/off control or does it throttle the process (on/off vs. throttle); and (2) does it bleed control gas continuously or does it vent control gas at the end of the on cycle (continuous bleed vs. intermittent vent).

We often discuss controllers as “snap acting” vs. “variable opening”. A snap acting controller will never send a partial signal, it will wait until the signal has reached a maximum value and then snap open and stay in that fully-open position until the input parameter reaches a minimum value and then will snap shut. A variable-open controller will send a throttled

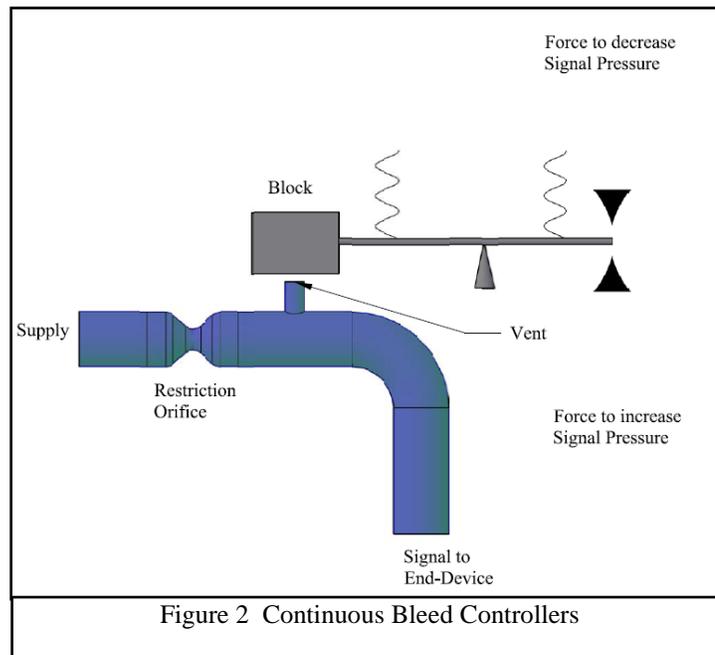


Figure 2 Continuous Bleed Controllers

signal as soon as the input value increases above a minimum and as the input continues to increase the signal will strengthen. Either on/off or throttle controllers can be either snap-acting or variable-input and this is not a defining characteristic.

Service (On/Off vs. Throttle)

On/Off controllers are often used to control on/off “dump valves” in level-control service. These level controllers (see Figure 1) have a float that senses the fluid level. When the level increases to the set point (usually when the float is at its maximum upward travel), a spring-loaded valve within the controller is forced open which sends a pressure signal to a “dump valve”. The valve opens to drain the liquid. When the condition is satisfied (e.g., when the float is at the bottom end of its travel), the spring-loaded valve shuts off supply pressure to the end-device and vents the gas that was used to operate the end-device to atmosphere (through the top port in Figure 1). The time required for the end-device to go shut is a function of control gas pressure, the volume of gas in the piping and valve bonnet, and the size of the vent orifice.

Throttling controllers are used to maintain a process variable within a defined range. For example, if it was important to maintain a particular-component pressure in a narrow range by operating a control valve some distance away from the component, a throttling controller could be used. Figure 2 shows a simplified version of a throttling controller. In this version, the restriction orifice is slightly smaller than the vent opening, so when the block is off the vent, all of the gas that can get through the orifice exits through the vent and releases the pressure to the end device. As the system calls for an increased signal, the block is forced onto the vent to restrict flow. This increases the pressure in the line going to the end device and operates it. As the signal to increase pressure moves toward a maximum, the block moves down on the vent to completely seal the vent flow and send maximum pressure to the end device.

Depressurization Method (Continuous Bleed vs. Intermittent Vent)

Any pneumatic controller must release pressure when it needs to lower the signal. This pressure release can be more or less continuous or can be intermittent. A device like Figure 2 that does not have any mechanical barrier to isolate the supply from the load is considered a “continuous-bleed” device. The amount that it bleeds off is controlled by the position of the block over the vent. At times the amount of vented gas is nearly zero and pressure builds in the supply line to operate the end device. At the end of the pressurization cycle, the gas that was used to operate the end device is vented at a rate similar to the vent rate seen by an intermittent vent controller for a short period, this is sometimes called the “strong stream”

When the block is fully off the vent, the amount of vented gas will approximately equal the amount that enters the controller through the inlet orifice—this is sometimes called the “weak

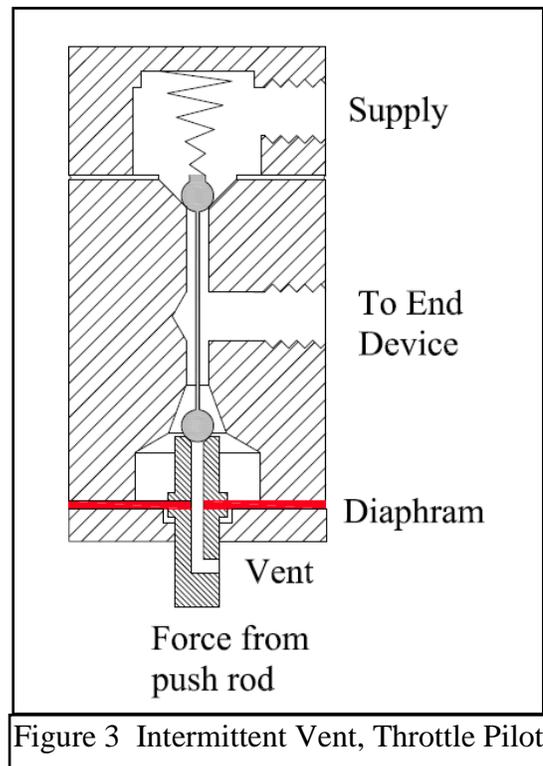


Figure 3 Intermittent Vent, Throttle Pilot

stream” because the pressure difference between the supply piping and atmosphere is at a minimum. The weak stream represents the maximum continuous bleed rate.

Intermittent-Vent controllers are usually associated with on/off service, but that is certainly not the only use. The device shown in Figure 3 is an intermittent venting controller in throttle service. During steady operation, both valve balls are tight in their seat. If less pressure is required for the end-device, then the push rod will move downward which pulls the seat away from the bottom ball and gas is vented. When the condition is satisfied, the push rod pushes the seat back against the ball and venting stops. When more pressure is required to the end device, the push rod pushes the top ball off the seat against spring pressure (while holding the vent tightly closed) and allows supply pressure to increase to the end device.

Continuous-Bleed controllers such as the device in Figure 2 are always allowing some amount of pressure to bleed off (except for the short period when they are fully against the block). The distinction between “venting” and “bleeding” is often subtle, but a clear line can be drawn—if there is a mechanical barrier between the supply pressure and the end device, then it is a “vent”. If the pressure is maintained by bleeding off gas with the supply open then it is a “bleed”

Controller Exhaust Volumes

With the categorization above, all controllers can be broken into one of four groups: (1) Intermittent vent controller in on/off service; (2) Intermittent vent controller in throttle service; (3) Continuous bleed controller in on/off service; and (4) Continuous bleed controller in throttle service. The method for calculating the vented volume is different for each group.

Intermittent vent controller in on/off service

Control gas is sent to the end-device when an “on” condition is called for. The pressure on the end-device quickly reaches control-system pressure and remains there until it receives the signal to shift to the “off” condition. At that time the controller shuts off pressure to the end device and opens a vent to allow the trapped gas to exit to atmosphere. Every single time the device shifts from “on” to “off”, the same volume of gas is vented. This volume can be calculated by:

$$Vol_{system} = Vol_{pipe} + Vol_{bonnet} = \frac{\pi}{4} ID_{pipe}^2 \square L_{pipe} + Vol_{bonnet} \quad (1.1)$$

Where:

- ID_{pipe} Inside diameter of the tubing (ft)
- L_{pipe} Length of the tubing (ft)
- Vol_{bonnet} Volume of the bonnet at the end of full travel (ft³)

This volume is only useful with regard to standard conditions which allow gas volumes at different pressures and temperatures to be aggregated. Since control gas is at relatively low pressure, the conversion to standard conditions in this case can generally disregard changes in temperature and compressibility, so the standard volume becomes:

$$Vol_{SCF} = \left(\frac{\pi}{4} ID_{pipe}^2 \square L_{pipe} + Vol_{bonnet} \right) \square \frac{P_{control} + P_{atm}}{P_{std}} \quad (1.2)$$

Where:

- P_{cntl} Control gas supply pressure (psig)

- P_{atm} Local atmospheric pressure (psia)
- P_{std} Standard pressure (generally 14.73 psia in Oil & Gas operations)

For example, if a control gas system is operating at 25 psig at sea level (P_{atm} equal to 14.7 psia), using 3/8 inch ID tubing (0.03125 ft) that is 10 ft long to operate an end device with a 0.03 ft³ bonnet, then the volume per cycle is 0.079 SCF/cycle which would be the “characteristic volume” of this piping configuration at 25 psig at sea level.

For a “Venting Controller in On/Off Service” this calculation provides results that are both accurate and repeatable. It is reasonable to generalize the system volume and to convert the generalized volume into a “typical” pressure to get a generalized exhaust SCF per cycle, but it is not reasonable to convert that into a typical vented volume per unit time.

Far better results would be realized by estimating the effect of each cycle on the total result. For example, if the controller is in level-control service, then it is often possible to determine how much volume is removed in each dump-cycle by counting dumps and measuring the accumulated volume. Combining this calculation with equation 1.2, yields:

$$Vol_{SCF/month} = \left(\frac{\pi}{4} ID_{pipe}^2 L_{pipe} + \Delta Vol_{bonnet} \right) \left(\frac{P_{control} + P_{atm}}{P_{std}} \right) \left(\frac{cycle}{Vol_{liquid}} \right) \left(\frac{Vol_{liquid}}{month} \right) \quad (1.3)$$

If a facility accumulates 1 bbl (42 gal) in a day and observations show that it cycled 11 times in the day, then the average volume per cycle is 3.82 gal/cycle (0.091 bbl/cycle). If the liquid accumulation in a month was 10 bbl (420 gal) then you know the controller cycled 110 times. In the 25 psig control gas pressure example above, the exhaust volume is 8.6 SCF/month.

In the Barnett Shale (4.81% VOC by weight on average), the VOC emissions for the example above would be 0.000109 tonne of VOC/year. If it costs \$72/controller to fill out the paperwork to report the emissions on this controller then the cost effectiveness for regulating intermittent vent controllers in on/off service is on the order of \$659,304/VOC tonne just for the administrative costs.

Intermittent Vent controller in throttle service

These devices vent so little gas, so irregularly, that it is impossible to either measure or estimate the vented volume. For example, this type of controller can be used to control the flow on a secondary cooling loop on an oil-flooded screw compressor to maintain the discharge temperature of the compressor. In this service, the controller will often vent a tiny fraction of an SCF of gas 2-3 times per day. Trying to estimate this volume as other than zero would create a great burden on users of the device that will tend to drive users away from this truly environmentally responsible technology in favor of one that exhausts more gas, but is easier to comply with reporting requirements.

Continuous Bleed controller in on/off service

When the device in Figure 2 is in the “off” position (i.e., the block is clear of the vent), then the flow rate out the vent is [Ref: GPSA Engineering Data Book, eq 3-12 converted to SCF/day]:

$$Vol_{scf} = 16330 \cdot \left[1 + \left(\frac{d}{D} \right)^4 \right] \cdot d^2 \cdot \left[(H_{cntl})(29.32 + 0.3 \cdot H_{cntl}) \cdot \left(\frac{SG_{ref}}{SG_{cntl}} \right) \cdot \left(\frac{T_{std}}{T_{cntl}} \right) \right]^{0.5} \cdot \frac{(P_{cntl} + P_{atm})}{P_{std}} \quad (1.4)$$

Where:

- d Inside diameter of bleed restriction orifice (inches)
- D Inside diameter of tubing (inches)
- H_{cntl} Control gas gauge pressure (inches of mercury, 1 psig = 2.036 inHg)
- P_{cntl} Control gas gauge pressure (psig)
- P_{std} Standard Pressure (14.73 psia)
- P_{atm} Local atmospheric pressure (psia)
- T_{cntl} Control gas temperature in Rankine ($^{\circ}\text{F} + 460^{\circ} = \text{R}$)
- T_{std} Standard temperature ($60^{\circ}\text{F} = 520\text{R}$)
- SG_{ref} Reference specific gravity (0.6)
- SG_{cntl} Specific gravity of control gas (air = 1.0)

In the example used above for a *Venting controller in on/off service* with gas from the Barnett Shale:

- d 0.03 inches
- D 0.375 inches
- H_{cntl} 25 psig = 50.9 inHg
- P_{std} 14.73 psia
- P_{atm} 14.7 psia (sea level)
- T_{cntl} $80^{\circ}\text{F} + 460^{\circ} = 540\text{R}$
- T_{std} $60^{\circ}\text{F} + 460^{\circ} = 520\text{R}$
- SG_{ref} 0.6
- SG_{cntl} 0.6337

Equation 1.4 works out to a weak stream of 1,800 SCF/day for 25 psig control gas at sea level (the strong stream is irrelevant since the gas that flows to the end device during the operation cycle will be vented at the end of the cycle and the net result is approximately the same as if the weak stream was never interrupted). Using the Barnett Shale example above (VOC 4.81% by weight) results in this stream venting 0.66 MMCF/year of natural gas (0.7 tonne VOC/year). The net heating value of this gas stream is 0.944 MMBTU/MCF so selling this stream has a benefit of \$660/year at \$4/MMBTU. The cost effectiveness of capturing a high-bleed stream for sales (assuming \$72/year administrative cost) is -\$840/tonne.

Continuous Bleed controller in throttle service

In throttle service, bleed rate is difficult to determine. Pressure in the line after the restriction orifice will always be at an intermediate pressure between supply pressure and local atmospheric pressure. Further, the vent diameter (“d” in equation 1.4) is the exhaust orifice (instead of the restriction orifice) which is larger than the restriction orifice, but partially closed by the block. The most accurate way to calculate this flow rate is to use the flow from the control-gas system

through the restriction orifice, with “ H_{cntl} ” equal to the difference between control gas pressure and pressure to the end device and P_{cntl} equal to control gas pressure.

For example, if the end device is controlling its parameter at a steady value with 15 psig on a 25 psig control gas system, then you would need to use 10 psig (20.4 inHg) as H_{cntl} in Equation 1.4 to get a daily vent volume of 632 SCF/day instead of 1,802 SCF/day. For a given controller, this value could change many times in a 24 hour period and changes are significant to exhaust calculations. For estimating fugitive emissions, it is reasonable to assume that flow rate is 1/3 to 2/3 the on/off flow rate.

After Market Retrofit Kits

Several manufacturers have retrofit kits that convert a *Continuous Bleed On/Off Controller* into an *Intermittent Vent On/Off Controller*. One example is the MIZER[®] from WellMark Company, LLC. This device uses the mechanical movement of the block in Figure 2 to operate an “actuation poppet” on an on/off controller. A *Continuous Bleed On/Off Controller* with this sort of kit installed becomes an *Intermittent Vent On/Off Controller* and the emissions factors should be calculated based on the revised category.

Many *Continuous Bleed Controllers in On/Off Service* try to take advantage of the fact that most on/off services spend significantly more time at idle than actuated. To capitalize on this observation, operators can turn the controller upside down (so that at idle the block is hard on the vent and in the actuated position the block is off the vent) and actuate an external pilot. The external pilot is set up to send an actuation signal on loss of pressure. These devices reduce vented/bleed emissions, but not by much.

High Bleed vs Low Bleed

In the calculations above, the restriction orifice was assumed to be 0.03 inch diameter. This value results in a flow rate of 75 SCF/hr at 25 psig control gas pressure. EPA is drawing a hard line at 6 SCF/hr as the difference between high bleed and low bleed. To reach this value at 25 psig would require a 0.00848 inch orifice (8% of the size of a standard orifice). In the Barnett Shale example we’ve been using, going to 6 SCF/hr would lower the VOC from 0.7 tonne VOC/yr to 0.06 tonne/VOC/yr.

If control gas pressure is 45 psig (standard orifice flow rate 171 SCF/hr), then to reach 6 SCF/hr would require an orifice size of 0.00562 inches (3.5% of the flow area of the standard orifice). Using orifices this small significantly reduces the operating speed of end devices (which can increase overshoot and lead to control instabilities).

Also, orifices this small have a significant risk of plugging. The 45 psig orifice above is 143 microns across—this is the beginning of the range of the class of equipment called “filters” instead of flow orifices. The possibility of an opening this small plugging in any given year is approximately 100%.

Achieving a bleed rate of <6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller. Achieving 6 SCF/hr with a continuous bleed pneumatic controller is fraught with operational difficulties and hidden costs. Encouraging the use of such devices is not recommended.

Conclusion

If each controller were placed in a category based on Service (on/off vs. throttle) and Depressurization Method (Intermittent Vent vs. Continuous Bleed) then the emissions impact of that device can be easily calculated. Determining either the VOC emissions or the gas lost to sales is reasonably straight forward. The key to achieving emissions targets is to develop clarity and precision in the definitions and categorization of the various controllers so that recognition of what controller technology is appropriate to meet these targets is possible.

With a requirement for a bleed rate of <6 SCF/h, it is more likely that an operator will use an intermittent vent type controller to ensure reliable controller operation, rather than using a continuous bleed controller with a low bleed orifice.

Author Biography

David Simpson has 31 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2000 SPE *International Conference on Health, Safety, and the Environment in Oil & Gas Production* in Stavanger, Norway where he presented a paper on the transition from continuous bleed pneumatic controllers to intermittent vent pneumatic controllers (SPE61030). He has been a featured speaker at the bi-annual *Four Corners Oil & Gas Conference* for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 12 countries.

Attachment L
Kimray, Inc. Technical Bulletin Y09201
“Pilot Bleed Rate”



We are occasionally asked to furnish information concerning the "bleed rate" of our controllers. Our pilots or controllers do not have a continuous bleed rate. There are basically three kinds of pneumatic controllers: continuous bleed, actuating or intermittent bleed, and self-contained.

The continuous bleed type uses a stream of gas which is constantly flowing through a tiny nozzle to atmosphere. Near the set point a small flapper moves close to the nozzle causing back pressure which works internally to actuate the device being controlled.

The intermittent bleed controller utilizes a tiny three-way valve which is closed at both ports when conditions are as required, open to the actuator when an output is required, or open to atmosphere when pressure at the actuator needs to be relieved.

With intermittent bleed, the question of the rate at which gas is emitted to the atmosphere has no easy answer. Other questions must be answered first.

Is the controller throttling, or is it an on / off device? If it is throttling, then only very small amounts of gas will be vented as the controller makes minute adjustments on the actuator's position. This will vary with the size of the actuator and the stability of the system.

If the controller is operating in on / off service then the following questions are vital: How often does the controller switch? What is the capacity of the actuator? What is the volume of the tubing which runs from the controller to the actuator? What is the pressure of the actuating gas?

In either case with an intermittent bleed pilot, the only information that can come from the manufacturer is the capacity of the actuators. That information is the subject of the table in the next column.

Kimray Intermittent Bleed Pilot

The key to accurate, consistent control in every Kimray pilot is the Pilot Plug. It functions as the plug in a tiny three-way valve, either communicating supply pressure to the actuator of a controlled device, or venting pressure from that actuator. The balls at either end of the plug are stainless steel. The seats which these balls act to close are also stainless steel.

Metal to metal seat

The use of steel for both the seats and plugs produces a metal to metal seat. A metal to metal seat is used in order to eliminate hysteresis, which would be seen as a lag or "dead-band" in the controlled process. Due to the nature of the design of the pilot, the plug is only lightly pressed into either seat. This also is done to eliminate hysteresis.

Seepage

The very elements of design which allow the pilot to operate without any detectable dead-band or lag in control, do not allow for the necessary elements for tight shut-off. For this reason a small amount of gas will normally seep from the vent of the pilot. This does not affect the action of the pilot.

Kimray describes the pilots as "intermittent bleed pilots". This is to contrast them with the "continuous bleed pilots" which are found in some control devices of other manufacture. Unlike the continuous stream of gas characteristic in these devices the small amount which seeps from a Kimray pilot is considered normal.

Valve Actuator Gas Capacity

Following is a simple table listing the capacity of the actuator of various Kimray valves and regulators. Of course the limitations of this information need to be recognized. There is additional information which must be supplied :

- The frequency of actuation of the valves
- The extent of actuation travel that regulators may require. (Often almost no movement is required)
- The pressure of the actuating gas supplied
- The volume of the tubing involved

| DEVICE | SIZE | ACTUATOR CAPACITY CU. IN. | |
|---------------------------------------|------|---------------------------|----|
| Regulator Catalog Section A | 1" | 1.1 | |
| | 2" | 9 | |
| | 3" | 31 | |
| | 4" | 73 | |
| | 6" | 244 | |
| Regulator Catalog Section E1 | 1" | 30 | |
| | 2" | 110 | |
| | 3" | 225 | |
| | 4" | 243 | |
| | 6" | 650 | |
| Regulator Catalog Section E2 | 1" | 1.1 | |
| | 2" | 9 | |
| | 3" | 31 | |
| | 4" | 73 | |
| | 6" | 244 | |
| Regulator Catalog Section E3 | | PO | PC |
| | 2" | 6 | 8 |
| | 3" | 22 | 31 |
| | 4" | 27 | 36 |
| | 6" | 40 | 54 |

Attachment M
Reserved

Attachment N
Comments on the EPA Draft Residual Risk
Assessment for the Oil and Gas Production and
Natural Gas Transmission and Storage Source
Categories

Attachment N
Comments on the EPA Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories

Background

As part of EPA's proposal to amend the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) for natural gas processing plants, EPA conducted separate risk assessments for two source categories, oil and gas production, and natural gas transmission and storage units. EPA used the results of this risk assessment to determine whether or not the emissions from these sectors and resulting health risks were acceptable, or if additional controls were warranted.

EPA estimated the emissions from 990 oil and natural gas production facilities and 321 natural gas transmission and storage facilities based on emissions data reported in the 2005 National Exposure Index (NEI). EPA termed these "actual" emissions. EPA also evaluated emissions based on the highest emissions allowed under the MACT standard for these categories. EPA termed these "allowed" emissions.

EPA conducted dispersion modeling to estimate the individual and population exposure resulting from emissions from these sources. The dispersion model used AERMOD which was coupled with EPA's Human Exposure Model (HEM) version 3. EPA estimated both short-term and long-term inhalation exposure to individuals and populations residing within 50 km of the modeled sources.

For carcinogenic hazardous air pollutants (HAPs), EPA estimated for each facility the maximum individual risk (MIR) associated with continuous lifetime exposure to the maximum concentration at the centroid of an inhabited census block. EPA calculated individual cancer risk by multiplying the estimated lifetime exposure for each HAP by the corresponding unit risk estimate (URE). EPA used UREs from its own IRIS database and from California EPA (CalEPA). EPA then calculated overall incremental individual lifetime cancer risks by summing the risk for each HAP. EPA also developed the cancer incidence and the distribution of individual cancer risks for the population residing within 50 km of any sources.

To assess non-cancer health effects, EPA summed the hazard quotient (HQ) for each HAP that affects a common target organ. The HQ for chronic exposure is the estimated chronic exposure divided by the chronic reference level. EPA used chronic reference concentrations from IRIS or CalEPA.

To assess acute effects, EPA compared short-term concentrations to Acute Exposure Guidelines developed by the EPA in conjunction with the National Research Council. EPA also used Emergency Planning Guidelines developed by the American Industrial Hygiene Association, and Acute Reference Concentrations developed by CalEPA.

In addition to evaluating the health impact of the two source categories alone, EPA also examined the risks of the "entire facility" where the facility included all HAP-emitting sources. EPA used these "facility-wide" estimates to determine the portion of facility-wide risks that could be attributed to the source categories addressed in the proposal.

Summary of Results and EPA Conclusions

Oil and Natural Gas Production Units

Based on actual emissions data, EPA estimated that maximum individual lifetime cancer risk (MIR) from emissions from oil and natural gas production units could be as high as 40-in-1- million, with polycyclic organic matter (POM) driving the highest risk, and benzene driving the risk overall. EPA noted that this risk is below the 100-in-1 million criteria EPA used in the benzene NESHAP. The total estimated cancer incidence from this source category was estimated to be 0.02 excess cancer cases per year based on the upper end of the benzene URE, equating to one additional cancer case in every 50 years. Based on the lower end of the benzene URE, EPA estimated the cancer risk from this source category as 0.007 excess cancer cases per year. EPA estimated that approximately 160,000 people are estimated to have cancer risk at or above 1-in-1 million as a result of the emissions from 89 facilities (based on use of the upper bound benzene URE). EPA determined that the maximum HI was 0.1, which resulted from emissions of naphthalene. EPA considered this low HI to indicate that there was no significant non-carcinogenic risk to health.

Based on maximum allowable emission data under the MACT, EPA estimated the MIR to be as high as 400-in-1 million based on the upper end of the benzene URE (or 100-in-1 million based on the lower end of the benzene URE). EPA stated that the 400-in-1 million risk “greatly exceeds” the “presumptive limit” of 100-in-1 million in the benzene NESHAP and is therefore unacceptable. Since the MACT-allowable emissions are driven by the allowable emissions of 0.9 Mg/yr benzene under the MACT as a compliance option, EPA is proposing to eliminate the 0.9 Mg/yr benzene option as a compliance option from the existing glycol dehydrator MACT requirements.

Natural Gas Transmission and Storage Units

Based on actual and maximum allowable emissions data, EPA estimated the maximum individual lifetime cancer risk (MIR) from exposure to emissions from natural gas transmission and storage units could be as high as 90-in-1 million, based on the upper end of the benzene URE, or 30-in-1 million, based on the lower end of the benzene URE. EPA noted that these risks are below the 100-in-1 million criteria EPA used in the benzene NESHAP and proposed that these risks are acceptable. The total estimated cancer incidence from this source category was estimated to be 0.001 excess cancer cases per year based on the upper end of the benzene URE, equating to one case in every 1000 years. Based on the lower end of the benzene URE, EPA estimated the cancer risk from this source category as 0.0003 excess cancer cases per year. EPA estimated that approximately 2,500 people have cancer risk at or above 1-in-1 million as a result of the emissions from 15 natural gas transmission and storage facilities (based on use of the upper bound benzene URE). EPA determined the maximum HI was 0.4, resulting from emissions of benzene. Since the HI was far less than 1.0, EPA also considered the non-cancer risks to be acceptable and to not present a significant risk to health.

However, under a section entitled “ample margin of safety,” EPA reached a completely different conclusion concerning natural gas transmission and storage units. In this section, EPA investigated how various control options would reduce the risks associated with emissions from this source category. EPA estimated that if the 0.9 Mg/year benzene limit compliance alternative was removed for the glycol dehydrator MACT standard in the current NESHAP, the risks would be lowered from 90-in-1 million to

20-in-1 million. EPA considered the costs for any additional controls resulting from elimination of the above benzene limit compliance option to be cost effective. Therefore, EPA is proposing to eliminate the 0.9 Mg/yr benzene limit for large glycol dehydrator units. EPA considered this approach was needed to provide “an ample margin of safety to protect public health.”

Comments on EPA’s Risk Assessment Approach

EPA’s risk assessment approach includes a number of default assumptions that directionally result in a significant over-estimate of risks. Table N-1 provides a list of some of the key default assumptions and their approximate impact on the risk assessment. Overall, we estimate that EPA’s use of these default assumptions results in an approximately 100- to 1000-fold over-estimate of the true risks currently posed by these source categories. In addition to the approach of considering only the maximum exposed individual using a series of worst case defaults, we encourage EPA to also consider results using more central assumptions.

In various places in the risk assessment, EPA states that use of the various default assumptions is justified based on the concept of protecting public health. Conceptually, we agree that EPA must place high priority on the protection of public health. However, in our view, it is not appropriate to build the public health protection into the risk assessment through use of a series of conservative default assumptions. This approach makes it difficult for risk managers to gauge the true level of health protection provided by the proposed rule. Rather, we suggest that EPA consider the appropriate health protection required at the end of the process, after completion of a risk assessment that incorporates reasonable central assumptions of exposure and health effects. With this goal in mind, we include in Table N-1 recommendations on how EPA can improve the accuracy of their draft risk assessment.

For purposes of decision making, EPA places sole reliance on the maximum MACT allowable emissions versus the actual emissions from natural gas operations. In the case of natural gas production facilities, the maximum allowable emissions are approximately 50-fold higher than the actual emissions. While we understand the concept of including both sets of emission data for purposes of decision-making, we recommend placing more emphasis on the results using actual emissions data, since these values can be used to estimate the current real-world risks posed by emissions from these facilities.

EPA assumes that the target population is exposed continually during their lifetime, i.e., there is no migration in or out of the area of exposure. As noted by EPA, this assumption does not bias the estimate of the theoretical MIR nor does it affect the estimate of cancer incidence, assuming that there is migration both in and out of the target area and that the total number of people exposed remains the same. However, this default and unrealistic assumption results in a significant upward shift of the distribution of individual risks, increasing the number of people at specific risks levels. We recommend that EPA incorporate population mobility data from their Exposure Factor Handbook into their draft risk assessment (EPA, 1997). For example, the average residence time for the U.S. population is on the order of 10.56 years (see Table 12-163 of the EFH).

EPA does not consider time-activity data in their risk assessment. Rather, EPA assumes the exposed individuals are outdoors for their lifetime receiving the maximum modeled exposure to emissions from the regulated facilities. As noted by EPA, consideration of time activity data would result in an approximate 25% decrease in exposure to particulates, including polycyclic organic matter, a HAP driving the peak results in this risk assessment. Consideration of time activity data would also reduce

exposure to gaseous HAPs albeit somewhat less than 25%. We recommend that EPA incorporate time-activity data from the EPA Exposure Factor Handbook (EPA, 1997) into their risk assessment. Some factors relevant for this assessment include time indoors/outdoors and time at home/away from home (see Table 15-6 of the EFH).

EPA uses only the high end UREs for purposes of decision-making. This results in a significant upward bias in the risk estimates. For example, in the case of benzene, the impact is a 3.5-fold increase in risks versus use of the low end URE. The URE for benzene represents a 95% upper confidence limit bound on the risk associated with exposure to benzene. As noted by EPA, the true risks could be zero. However, EPA excludes not only the zero risk case but also the low end of the plausible risk estimate from consideration. We recommend that EPA at least consider the full range of the benzene URE for purposes of decision-making. This recommendation is consistent with the advice from EPA's Science Advisory Board, who recommended that EPA avoid using high-end estimates for benefits analyses (SAB, 2002).

In the absence of IRIS values, EPA uses UREs and Inhalation Reference Concentrations developed by CalEPA. It is well known that many CalEPA health criteria are very conservative. EPA states in their draft risk assessment that they will consider risk assessment criteria from other sources if they are developed using a scientifically valid methodology. However, no other criteria are used. For example the Texas Commission of Environmental Quality has developed health criteria (URE and Reference Concentrations) for a wide variety of carcinogenic and non-carcinogenic HAP. The TCEQ criteria were developed using valid and well documented procedures. The EPA risk assessment for this proposed rule is national in scale. By excluding other valid state criteria and considering only those from CalEPA, EPA is biasing the risk assessment in an upward manner. We therefore recommend that EPA incorporate the TCEQ criteria and other valid criteria from other states into their risk assessment.

Comments on EPA's Conclusions

Oil and Natural Gas Production Units

We disagree with EPA's conclusion that the risks from emissions from this source category are unacceptable and that removal of the 0.9 Mg/yr benzene compliance option from glycol dehydrators is warranted based on EPA's risk assessment. Even using the myriad of conservative default assumptions described above, the risks estimated from *actual* emission data are acceptable (100-in-1 million) according to the EPA approach used in the benzene NESHAP. If EPA incorporated more central assumptions such as using the full range of the benzene URE and incorporating population mobility and time activity data in their risk assessment, the risks would be reduced further below the 100-in-1 million benchmark.

Natural Gas Transmission and Storage Units

We agree with EPA's conclusion that the risks from emissions from this category are acceptable. EPA estimates the MIR for this category is in the range of 30- to 90-in-1 million, which is below the MIR benchmark EPA used in the benzene NESHAP. Furthermore, as noted above, this risk range is based on a series of conservative default assumptions and the true risks are much lower than 30- to 90-in-1 million. Accordingly, we recommend that EPA conclude that no modifications to this source category are required.

We strongly disagree with EPA’s rationale to remove the 0.9 Mg/yr benzene limit for glycol dehydrators for these facilities under the MACT. EPA’s rationale is based on achieving an incremental reduction in exposure and risk and corresponding incremental increase in margin of safety. Essentially, EPA is concluding that a risk of 90-in-1 million does not provide an adequate margin of safety whereas a risk of 20-in-1 million does. If one simply uses the lower end of the benzene URE versus the high end range, one achieves a risk change similar to this order of magnitude.

As another example, EPA estimates that the total estimated cancer incidence from this source category under existing conditions is estimated to be 0.001 excess cancer cases per year based on the upper end of the benzene URE, equating to one case in every 1000 years. With removal of the benzene limit option, these incremental risks would change to 0.0002 excess cancer cases per year, equating to one case in every 4500 years. Again, we see no logical reason why 0.001 excess cancer cases per year or one case in 1000 years, does not provide an adequate margin of safety whereas 0.0002 excess cancer cases per year equating to one case in every 4500 years, does provide such a margin. In our view, EPA’s rationale is arbitrary and, in reality, all of the above risk estimates are indistinguishable from a public health perspective given the myriad of assumptions used to derive the underlying risk estimates. We question EPA’s conclusion that the additional control measures required in the proposed rule, which will result in an incremental decrease of an already *de minimis* risk, are “cost effective.”

Table N-1. Key EPA Default Assumptions

| Default Assumption | Impact | Recommendation |
|---|--|---|
| Use maximum allowable emissions instead of actual for decision-making | 50-fold increase in exposure and risks versus actual | Use both actual and maximum allowable emissions, but place greater emphasis on actual emissions for decision-making |
| Assume all members of the population are continuously exposed for their lifetimes | Significant (2-3 fold) increase in the estimated number of people at specific risk levels | Incorporate population mobility data from EPA Exposure Factor Handbook |
| Do not consider time-activity patterns | Approximate 25% or 1.25-fold increase in exposure to particulates including POM; somewhat less for VOC | Incorporate time-activity data from EPA Exposure Factor Handbook |
| Use only high end URE for decision-making | Significant increase in risks e.g., 3.5-fold in the case of benzene | Consider full range of URE for decision-making |
| Use only ultra conservative URE from CalEPA in the absence of IRIS values | Significant (estimated 3-fold) increase in risk estimates versus use of other criteria | Incorporate valid URE from other state sources such as those published by TCEQ |
| Overall | Estimate 100- to 1000-fold over-estimate in risks versus use of more central factors | |

Attachment O
Comments on the Risk-Based Proposed Decision to
Remove the 0.9 Mg/yr Benzene Alternative for
Glycol Dehydrators in the MACT Standards for
the Oil and Gas Production and Natural Gas
Transmission and Storage Source Categories

Attachment O
Comments on the Risk-Based Proposed Decision to Remove the 0.9 Mg/yr Benzene Alternative for Glycol Dehydrators in the MACT Standards for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories

Background

The Oil and Gas Production MACT (Subpart HH) currently includes two compliance options for glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr. These options are to reduce organic HAP emissions by 95% or to reduce benzene emissions to less than 0.9 Mg/yr. Similarly, the Natural Gas Transmission and Storage MACT (subpart HHH) requires glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr to reduce HAP emissions by 95% or benzene emissions to less than 0.9 Mg/yr. EPA is proposing to eliminate the 0.9 Mg/yr benzene emissions compliance alternative for both source categories.

In the August 23, 2011 proposal, EPA explains that the reason for this is that this compliance option results in an unacceptable level of risk.

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we find that the current levels of emissions allowed by the MACT reflect acceptable levels of risk; however, the level of emissions allowed by the alternative compliance option for glycol dehydrator MACT (i.e., the option of reducing benzene emissions to less than 0.9 Mg/yr in lieu of the MACT standard of 95-percent control) reflects an unacceptable level of risk. We are, therefore, proposing to eliminate the 0.9 Mg/yr alternative compliance option. (76 FR 52747)

We disagree with this conclusion and maintain that the evidence provided by EPA to support these conclusions is incorrect. For the Oil and Natural Gas Production source category (subpart HH), the analyses that resulted in the risk estimate that EPA determined to be unacceptable is seriously flawed. For the Natural Gas Transmission and Storage source category (subpart HHH), not only are EPA's statements regarding risk acceptability inconsistent throughout the preamble, there are serious errors and inaccuracies in the ample margin of safety analyses.

Oil and Natural Gas Production

EPA proposes that the risks from the Oil and Natural Gas Production source category are unacceptable based on the MACT allowable emission level.

For the Oil and Natural Gas Production source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 40-in-1 million due to actual emissions and as high as 400-in-1 million due to MACT-allowable emissions (100-in-1 million, based on the lower end of the benzene URE range). While the 40-in-1 million risk due to actual emissions is considerably less than 100-in-1 million, which is the presumptive limit of acceptability, the 400-in-1 million risk due to allowable emissions is considerably higher and is considered unacceptable. (76 FR 52779)

Specifically, EPA assumes that glycol dehydrators which control benzene emissions to levels less than 0.9 Mg/yr could increase benzene emissions to 0.9 Mg/yr, and that this increase in benzene emissions could result in a cancer MIR of 400-in-1 million.¹ While the basic premise of this analysis is not unreasonable, there are problems in the data, and errors in the analysis, that make this conclusion entirely incorrect. In fact, the evidence clearly supports a cancer MIR based on MACT allowable emissions that is well within the levels that EPA generally considers to be acceptable.

In EPA’s analysis, there are two facilities with a cancer MIR greater than 100-in-1 million based on MACT allowable emissions. Tables O-1 and O-2 provide profiles of these two facilities using information in the appendix to EPA’s risk assessment document.²

Table O-1. Hawkins Gas Plant, FM 1795, Hawkins, TX (NEI 8007)
Cancer MIR Based on Actual Emissions: 1-in-1 million
Cancer MIR Based on MACT Allowable Emissions: 400-in-1 million
Number of Dehydrators in NEI Dataset: 8

| Dehydrator ID | Controlled? | Benzene Emissions (tpy) | Included in MACT Allowable Analysis? |
|----------------------|--------------------|--------------------------------|---|
| DN0004 | YES | 0.000043 | NO* |
| DN0005 | YES | 0.0129 | YES |
| DN0037 | YES | 0.000017 | NO* |
| DN0051 | YES | 0.03 | YES |
| DN0052 | YES | 0.005 | NO* |
| DU0006 | NO | 0.00029 | NO |
| DU0008 | NO | 0.00064 | NO |
| DU0015 | NO | 0.004 | NO |

* While these points met the criteria for being considered (controlled to < 1 tpy benzene), they were not included in EPA’s MACT Allowable analysis. It is presumed that their risks from actual emission levels were not significant enough for consideration.

¹ Memorandum. From Heather Brown, P.E., EC/R Incorporated and Lesley Stobert, EC/R Incorporated, to Bruce Moore, EPA/OAQPS/SPPD/FIG. “Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT – MACT Allowable Emissions and Risks.” July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0055)

² “Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories.” EPA, Office of Air Quality Planning and Standards, Office of Air and Radiation. July 2011. (Docket Item EPA-HQ-OAR-2010-0505-0032)

**Table O-2. Kathleen Tharp 2, 1.5 Mi S Huffman Off Hwy FM 2100, Huffman, TX
(NEITXRHX1519)**

Cancer MIR Based on Actual Emissions: 0.03-in-1 million
Cancer MIR Based on MACT Allowable Emissions: 300-in-1 million
Number of Dehydrators in NEI Dataset: 1

| Dehydrator ID | Controlled? | Benzene Emissions (tpy) | Included in MACT Allowable Analysis? |
|----------------------|--------------------|--------------------------------|---|
| DN0001 | YES | 0.114 | YES |

There are two fundamental problems with EPA’s analysis. First, there are basic errors in the analysis that, if corrected, cause the MIR for each of these facilities to be well below 100-in-1 million. This alone is sufficient to compel EPA to reverse its decision to eliminate the 0.9 Mg/yr benzene alternative for subpart HH. However, even if this were not the case, the tremendous uncertainty associated with the data sets for these two “high risk” facilities call into question the integrity of the analysis to the degree that EPA should not base a major decision on its results.

Errors in EPA Analysis

Table O-3, which is taken from Table A-1 in the MACT allowable memo,¹ contains the information and calculations used to estimate the MACT allowable risks for the two facilities discussed above. A comparison of the benzene emissions from the model input files shown above in Tables O-1 and O-2, with the benzene emissions used in the MACT allowable analysis and shown in the upper portion of Table O-3, reveals that incorrect values were used in the MACT allowable calculations. These incorrect emissions resulted in adjustment factors that were significantly overstated (by several orders of magnitude). This caused the calculation of MACT allowable risk estimates that are also orders of magnitude too high. The lower portion of Table O-3 shows the calculations conducted using the correct benzene emissions for each dehydrator. To clarify, in this analysis API is not changing EPA’s data or approach. Rather, API is only correcting errors in EPA’s analysis. As can be seen, the corrected MACT allowable cancer MIRs are 3-in-1 million for the Hawkins Gas Plant and 0.1-in-1 million for the Kathleen Tharp 2 facility. After the MACT allowable MIRs are corrected for these two facilities, the highest MACT allowable MIR is 50-in-1 million for the Seneca Resources Corporation facility in Ojai, CA.

**Table O-3. Recreation of EPA's MACT Allowable Risk Calculations for Facilities
Predicted to Have a Cancer MIR > 100-in-1 million**

| A | B | C | D | E | F | G | H | I | J |
|--------------------------------------|-----------|---------|------------------------------------|--------------------------------------|-------------------------------------|---|---|--|---|
| Facility ID | Source ID | HAP | Facility MIR | Cancer Risk from Source ID/HAP | Cancer Risk From Other Points | Controlled Dehydrator Benzene Emissions (tpy) | Factor for 1 tpy Benzene Adjustment | Adjusted Cancer Risk From Overcontrolled Point | MACT Allowable MIR at Facility Due to Dehy 1 tpy Limit |
| | | | (from risk modeling results) | (from risk modeling results) | (Column D - Column E) | (from NEI data) | (1/Column G) | (Column E * Column H) | (Column F * Column I) |
| FROM EPA ANALYSIS¹ | | | | | | | | | |
| ONG_NEI8007 | DN0051 | Benzene | 1.05E-06 | 2.99E-08 | 1.02E-06 | 0.0129 | 77.52 | 2.32E-06 | 3.56E-04 |
| ONG_NEI8007 | DN0005 | Benzene | 1.05E-06 | 1.53E-08 | 1.03E-06 | 0.00004 | 23071.24 | 3.53E-04 | |
| ONG_NEITXRHX1519 | DN0001 | Benzene | 2.86E-08 | 2.76E-08 | 1.04E-09 | 0.0001 | 10000.00 | 2.76E-04 | 2.76E-04 |
| CORRECTED | | | | | | | | | |
| ONG_NEI8007 | DN0051 | Benzene | 1.05E-06 | 2.99E-08 | 1.02E-06 | 0.0300 | 33.33 | 9.96E-07 | 3.18E-06 |
| ONG_NEI8007 | DN0005 | Benzene | 1.05E-06 | 1.53E-08 | 1.03E-06 | 0.01290 | 77.52 | 1.18E-06 | |
| ONG_NEITXRHX1519 | DN0001 | Benzene | 2.86E-08 | 2.76E-08 | 1.04E-09 | 0.1140 | 8.77 | 2.42E-07 | 2.43E-07 |

Data Set Uncertainties

The issues associated with the data for the two facilities with cancer MIRs greater than 100-in-1 million based on MACT allowable emissions are sufficient to invalidate the results and EPA’s conclusion that risks from the Oil and Natural Gas Production source category are unacceptable. The highest risk facility, with a cancer MIR of 400-in-1 million based on MACT allowable emissions, is the Hawkins Gas Plant in Hawkins, Texas. A review of the background data in EPA’s dataset for this facility has found significant errors. For example, the EPA data set includes data for eight dehydrators when in fact there are only three dehydrators at the plant. The Hawkins Gas Plant operates three glycol dehydrators, with a fourth dehydrator on site that has been shut down for more than 10 years. In addition, one of these dehydrators (DehyRod) falls into EPA’s definition of “small dehydrator” and should not have been considered in the large dehydrator analysis, as its throughput is less than 60,000 m³/day. For the past 10 or more years, only emissions data for the three operating glycol dehydrators has been submitted to the TCEQ for the annual emissions inventory.

There are no emissions during normal operation of these three dehydrators as the still vent vapors are routed through a vapor recovery compressor (VRC) and back into the process. There is no emissions point. However, as a backup for times when the vapor recovery compressor is down, dehydrator still vent emissions are routed first through a BTEX condenser, then to the low pressure flare. Emissions only occur during VRC downtime which is reported to the TCEQ each year in the emissions inventory. The table below lists the annual emissions reported to the TCEQ for the emissions inventory for 2005-2009.

Table O-4. Hawkins Plant Dehydrator Emissions

| Hawkins Plant Dehy | Annual Emissions (tons/yr) | | | | | | | | | |
|-----------------------------------|-----------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| | 2005 | | 2006 | | 2007 | | 2008 | | 2009 | |
| | VOC | BTEX | VOC | BTEX | VOC | BTEX | VOC | BTEX | VOC | BTEX |
| DehyHP | 0.05 | 0.009 | 0.15 | NA | 0.024 | NA | 0.01 | NA | 0.004 | NA |
| Dehy80 | 0.86 | 0.03 | 0.027 | NA | 0.21 | NA | 0.045 | NA | 0.023 | NA |
| DehyRod | 0.005 | 0.005 | 0.33 | NA | 0.057 | NA | 0.003 | NA | 0.004 | NA |

The facility with the second highest MACT Allowable risk (200-in-1 million) is the Kathleen Tharp 2 facility in Huffman, Texas. API has confirmed with the Texas Commission on Environmental Quality (TCEQ) that this facility does not have a Title V permit and is not a major source of HAP.³ API has also obtained documentation that a Form PI-8 has been filed for this facility. A Form PI-8 certifies emissions below the minor source limit of 25 tons/yr VOC, and makes the certified emissions enforceable. Therefore, it should not be considered in this analysis.

EPA must reverse its proposed decision to eliminate the 0.9 Mg/yr benzene compliance alternative in subpart HH for glycol dehydrators with actual annual average natural gas flow rates greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr. The analysis that resulted in risks determined by EPA to be unacceptable, and the data used in the analysis, has significant errors. Correction of these errors leads to risk estimates well within the ranges that EPA determines to be acceptable.

³ Personal Communication. Norwood, P., ERM, and Moore, S., TCEQ Houston Regional Office. October 13, 2011.

Natural Gas Transmission and Storage

As quoted above, EPA states the following in the preamble:

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we find that the current levels of emissions allowed by the MACT reflect acceptable levels of risk; however, the level of emissions allowed by the alternative compliance option for glycol dehydrator MACT (i.e., the option of reducing benzene emissions to less than 0.9 Mg/yr in lieu of the MACT standard of 95-percent control) reflects an unacceptable level of risk. We are, therefore, proposing to eliminate the 0.9 Mg/yr alternative compliance option. (76 FR 52747)

For the Natural Gas Transmission and Storage source category, this contradicts the statements made later in the preamble where EPA concludes that risks from the Natural Gas Transmission and Storage source category are acceptable.

For the Natural Gas Transmission and Storage source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 90-in-1 million due to actual and allowable emissions (30-in-1 million, based on the lower end of the benzene URE range). These risks are near 100-in-1 million, which is the presumptive limit of acceptability. On the other hand, the risk analysis shows low cancer incidence (1 case in every 1,000 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic and acute noncancer health impacts are unlikely. We conclude that acute noncancer health impacts are unlikely for reasons similar to those described in section VII.C.2.b.i of this preamble.

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In determining whether risk is acceptable, we considered the available health information, as described above. In this case, because the MIR is approaching, but still less than 100-in-1 million risk, and because a number of other factors indicate relatively low risk concern (e.g., low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, chronic and acute noncancer health impacts unlikely), we are proposing to determine that the risks are acceptable. (76 FR 52783)

It appears that the first statement (p. 52747) is incorrect and that EPA's decision to eliminate the 0.9 Mg/yr benzene compliance alternative for the Natural Gas Transmission and Storage source category was based on the second step of their risk decision, the ample margin of safety determination.

We next considered whether the existing MACT standard provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information, along with all of the health risks and other health information considered in the risk acceptability determination. The estimated MIR of 90-in-1 million discussed above is driven by the 0.9 Mg/year benzene limit compliance alternative for the glycol dehydrator MACT standard in the current NESHAP. Removal of this compliance alternative would lower the MIR for the source category to 20-in-1 million. We, therefore, considered removing this compliance alternative as an option for reducing risk and assessed the cost of such alternative. Without the compliance alternative, affected glycol dehydrators (i.e., those units with annual average benzene emissions of 0.9 Mg/yr

or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary. (76 FR 52783)

However, as we will outline below, EPA’s ample margin of safety analyses do not support this conclusion.

First, EPA indicates that removal of the 0.9 Mg/yr compliance alternative would “lower the MIR for the source category to 20-in-1 million.” The technical memorandum analyzing the impacts of the regulatory alternatives under consideration for glycol dehydrators⁴ very clearly indicates that removal of the 0.9 Mg/yr benzene compliance option has **NO** impact on the cancer MIR. Following is the table from this memorandum. This directly contradicts the statement in the preamble.

Estimated Impacts of Removing the Glycol Dehydrator Alternative Compliance Option

| Source Category | Source Category Max Cancer Risk if Controlled Glycol Dehydrators Use 0.9 Mg/yr Alternative | Source Category Max Cancer Risk Without the 0.9 Mg/yr Alternative | Control Cost Effectiveness (\$/Mg HAP) ^a |
|--------------------------------------|--|---|---|
| Oil and Natural Gas Production | 400 | 40 | \$14,000 |
| Natural Gas Transmission and Storage | 90 | 90 ^b | \$3,300 |

^aAssumes the control cost is twice that of the control cost for small glycol dehydrators

^bThe maximum cancer risk is from a facility without controlled glycol dehydrators, **so removing the alternative compliance alternative alone would not reduce the maximum cancer risk from this category.** Although not investigated specifically as a risk reduction option, the requirement for small glycol dehydrators proposed under CAA section 112(d)(2) for the Natural Gas Transmission and Storage source category is expected to reduce risks to 20-in-1 million.

Second, as shown below, EPA’s analysis concludes that the cancer MIR of 90-in-1 million is due to “small dehydrators” (i.e., dehydrators with actual annual average natural gas flow rates less than 283,000 m³/day). Since these small dehydrators are not subject to any standards in the current MACT, the 0.9 Mg/yr benzene standard for large dehydrators is unrelated to these maximum risk values.

There are two natural gas transmission and storage facilities with a cancer MIR of 90-in-1 million. These are the Danville Compressor Station in Danville, West Virginia (NEIW0050020) and the Bradley Compressor Station in Brenton, West Virginia (NEI WV1090017). The data set shows that each of these facilities has a single uncontrolled dehydrator. For both facilities, the dehydrator is the only emission source in the database. The total emissions from the Danville Compressor Station are around 29.5 tpy total HAP, with 5.8 tpy of benzene. For the Bradley Compressor Station, the total HAP emissions are 30.4 tpy with 5.75 tpy of benzene.

⁴ Memorandum. From Heather Brown, P.E., EC/R Inc. to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. “Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options.” July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0047)

Glycol dehydration units with uncontrolled benzene emissions less than 1 tpy or with natural gas throughputs less than 10 MMscf/day are by definition considered to be small dehydrators. EPA's data set did not identify each dehydrator as large or small, requiring them to make assumptions. In assessing the impacts of MACT review options for glycol dehydrators,⁵ EPA classified dehydrators with any of the following characteristics as a "small" dehydrator:

- (1) *Uncontrolled benzene emissions less than 1 tpy.* These dehydrators are by definition small dehydrators.
- (2) *Uncontrolled benzene emissions greater than 1 tpy.* EPA's database did not have throughput information. EPA assumed that if a dehydrator had benzene emissions greater than 1 tpy and a throughput of 10 MMscf/day or greater, that the dehydrator emissions would need to be controlled to comply with subpart HHH. Therefore, they assumed that any dehydrator with uncontrolled benzene emissions greater than 1 tpy must have a throughput less than 10 MMscf/day, thus making them a small dehydrator.
- (3) *Controlled benzene emissions less than 0.05 tpy.* A dehydrator with controlled benzene emissions less than 0.05 tpy would have uncontrolled benzene emissions less than 1 tpy, thus making it a small dehydrator by definition.

Since both the dehydrator at the Danville and Bradley compressor stations have uncontrolled emissions greater than 1 tpy, they would be classified as small dehydrators. This is confirmed in Attachment 2 of the Glycol Dehydrator review options technical memorandum,⁶ which specifically identifies these dehydrators as small dehydrators (Attachment 2, page 1). Therefore, EPA has clearly assumed that these dehydrators are NOT subject to the dehydrator standards in subpart HHH.

EPA estimates that these two dehydrators would need to install controls to meet the proposed standards for small dehydrators, and that these controls would reduce the emissions (and MIR) by 95%. Therefore, these facilities would no longer be the highest risk facilities in the source category. In fact, the maximum cancer MIR for the source category would then be 20-in-1 million, which is at a different facility due to an emissions source other than dehydrators (equipment leaks). This risk reduction would be due to the proposed standard for small dehydrators, and would have no connection to the 0.9 Mg/yr benzene limitation for large dehydrators that EPA is proposing to eliminate.

In conclusion, the rationale used by EPA in the preamble to support the removal of the 0.9 Mg/yr compliance alternative for large dehydrators at natural gas transmission and storage facilities is not supported by any of the background technical documentation and analyses. The high risks that EPA appears to claim will be reduced by removal of the 0.9 Mg/yr benzene alternative are, by EPA's own estimation, attributable to small dehydrators that are not even subject to the current 0.9 Mg/yr benzene alternative in the regulation.

Therefore, EPA has demonstrated no valid risk-based rationale for removing this 0.9 Mg/yr benzene alternative for large dehydrators at natural gas transmission and storage facilities. Since there is no justification for the proposed change, EPA must maintain it in subpart HHH.

⁵ Reference 4.

⁶ Reference 4.

Attachment P
Analysis of Cost Effectiveness for Compliance with
Proposed Small Dehydrator Emission Limitation
at Oil and Gas Production Facilities

Attachment P
Analysis of Cost Effectiveness for Compliance with Proposed
Small Dehydrator Emission Limitation at Oil and Gas Production Facilities

On August 23, 2011, EPA proposed revisions to the NESHAP for oil and natural gas production facilities (40 CFR 63 subpart HH) and the NESHAP for natural gas transmission and storage facilities (40 CFR 63 subpart HHH). For both NESHAP, EPA proposed standards for “small” dehydrators. For subpart HH, small dehydrators are defined as those with either an annual average flow rate less than 85,000 m³/day (3 million ft³/day) OR actual annual benzene emissions less than 0.9 Mg/yr (1 ton/yr). For subpart HHH, small dehydrators are defined as those with either an annual average flow rate less than 283,000 m³/day (10 million ft³/day) OR actual annual benzene emissions less than 0.9 Mg/yr (1 ton/yr).

The proposed standards were in the form of an equation, where an allowable BTEX emissions level would be calculated for each dehydrator based on the inputs of BTEX inlet concentration and annual throughput. EPA estimated that the cost effectiveness of the application of this equation to small dehydrators in the oil and gas production source category to be \$8,360/Mg HAP (76 FR 52768).

API obtained information for actual dehydrators across the country to evaluate the true impacts of this equation at oil and natural gas production facilities. This analysis is shown in Table P-1. As can be seen in this table, the cost effectiveness of these actual situations ranges from around \$6,600 per ton of HAP reduction to over \$2 million/ton.

Table P-1. Small Dehydrator Control Evaluation Examples

| Facility Name | Inlet BETX Content ppmv (Ci,BETX) | Throughput SM ³ /Day | Inlet BETX Tons | Equation #1 BETX Allowable | | | GlyCalc Emissions tons/yr | | | | Cost/Ton Control ² | | | | | |
|---|-----------------------------------|---------------------------------|-----------------|----------------------------|---------------|------------|---------------------------|--------|--------|---------|--------------------------------------|------------------|-------------|---------------|-------------|----------------|
| | | | | Mg | Tons per Year | % of Inlet | VOC | HAPS | BETX | Benzene | Annualized Control Cost ¹ | Control % (BETX) | VOC \$/Ton | HAPS \$/Ton | BETX \$/Ton | Benzene \$/Ton |
| N. San Juan Basin Gas Treating and Compression Facility Dehy #1 | 0.9 | 2,406,935 | 3.5619 | 0.0508 | 0.0560 | 1.57% | 1.2896 | 0.9424 | 0.9347 | 0.0308 | \$30,409 | 94.0% | \$25,082 | \$34,322 | \$34,605 | \$1,050,173 |
| N. San Juan Basin Comp. Station M Dehy #1 | 1 | 849,506 | 1.3294 | 0.0199 | 0.0219 | 1.65% | 0.9128 | 0.7739 | 0.7682 | 0.0145 | \$30,409 | 97.1% | \$34,294 | \$40,449 | \$40,749 | \$2,158,838 |
| N. San Juan Basin Comp. Station WP Dehy | 0 | 56,634 | 0.0000 | 0 | 0.0000 | Undefined | 0.0045 | 0.0002 | 0 | 0 | \$30,409 | Undefined | \$6,757,556 | \$152,045,000 | Undefined | Undefined |
| N. San Juan Basin Comp. Station WP Dehy - 2 Test | 1 | 56,634 | 0.0886 | 0.0013 | 0.0015 | 1.65% | 0.0189 | 0.0146 | 0.0144 | 0 | \$30,409 | 89.8% | \$1,790,874 | \$2,318,324 | \$2,350,522 | Undefined |
| N. San Juan Basin Comp. Station Q Dehy | 16 | 424,753 | 10.3313 | 0.1593 | 0.1755 | 1.70% | 5.0482 | 1.6736 | 1.63 | 0.2448 | \$30,409 | 89.2% | \$6,751 | \$20,363 | \$20,907 | \$139,212 |
| Barnett Shale Comp. Station Dehy - uncontrolled | 12 | 580,213 | 9.9277 | 0.1632 | 0.1798 | 1.81% | 1.5546 | 1.2171 | 1.2129 | 0.5424 | \$30,409 | 85.2% | \$22,965 | \$29,333 | \$29,435 | \$65,821 |
| Barnett Shale Comp. Station Dehy - flash tank & condenser | 12 | 580,213 | 9.9277 | 0.1632 | 0.1798 | 1.81% | 1.2555 | 1.0177 | 1.0136 | 0.4627 | \$30,409 | 82.3% | \$29,444 | \$36,323 | \$36,470 | \$79,893 |
| Arkoma Basin Gas Treating and Compression Facility SB Dehy | 0 | 849,506 | 0.0000 | 0 | 0.0000 | Undefined | 0.3614 | 0 | 0 | 0 | \$30,409 | Undefined | \$84,142 | Undefined | Undefined | Undefined |
| Haynesville Shale Generic Dehydrator | 77 | 212,377 | 22.9588 | 0.3832 | 0.4224 | 1.84% | 3.3644 | 1.8721 | 1.7997 | 0.9951 | \$30,409 | 76.5% | \$11,810 | \$21,225 | \$22,079 | \$39,931 |
| GGRB Basin Generic Well Site Dehy 1.5 MMSCFD | 404 | 42,475 | 25.8916 | 0.4021 | 0.4433 | 1.71% | 8.0399 | 5.034 | 4.929 | 0.9439 | \$30,409 | 91.0% | \$4,156 | \$6,638 | \$6,779 | \$35,400 |
| GGRB Basin Generic Well Site Dehy 1.0 MMSCFD | 404 | 28316.88 | 17.2611 | 0.2681 | 0.2955 | 1.71% | 5.3599 | 3.356 | 3.286 | 0.6293 | \$30,409 | 91.0% | \$6,234 | \$9,956 | \$10,169 | \$53,097 |
| GGRB Basin Generic Well Site Dehy 0.5 MMSCFD | 404 | 14,158 | 8.6305 | 0.1340 | 0.1478 | 1.71% | 2.68 | 1.678 | 1.643 | 0.3146 | \$30,409 | 91.0% | \$12,468 | \$19,913 | \$20,337 | \$106,210 |
| GGRB Basin Generic Well Site Dehy 0.2 MMSCFD | 404 | 5,663 | 3.4522 | 0.0536 | 0.0591 | 1.71% | 1.072 | 0.6712 | 0.6572 | 0.1259 | \$30,409 | 91.0% | \$31,170 | \$49,782 | \$50,843 | \$265,400 |

¹Annualized Cost from page 3-26; Table 3-7 of RIA; With control % above ~20% the only viable option is to use a combustion device which is the basis for the Table 3-7 cost. Hence, the control cost does not go down with incrementally lower control %.

²For sites with no BETX and undefined BETX control % the control cost uses total emissions for species present.

Attachment Q
Analysis of Illustration of Impacts of Application
of the Proposed Small Dehydrator Emission
Limitation Equation for Oil and Gas Production
Facilities

Attachment Q
Sensitivity of the Proposed Subpart HH Proposed Equation 1
for Small Dehydrators to Throughput Rates

On August 23, 2011, EPA proposed revisions to the NESHAP for oil and natural gas production facilities (40 CFR 63 subpart HH) and the NESHAP for natural gas transmission and storage facilities (40 CFR 63 subpart HHH). For both NESHAP, EPA proposed standards for “small” dehydrators. For subpart HH, small dehydrators are defined as those with either an annual average flow rate less than 85,000 m³/day (3 million ft³/day) OR actual annual benzene emissions less than 0.9 Mg/yr (1 ton/yr). For subpart HHH, small dehydrators are defined as those with either an annual average flow rate less than 283,000 m³/day (10 million ft³/day) OR actual annual benzene emissions less than 0.9 Mg/yr (1 ton/yr).

The proposed standards were in the form of the following equation:

$$EL_{\text{BTEX}} = \text{CONSTANT} * \text{Throughput} * C_{i,\text{BTEX}} * 365 \text{ days/yr} * 1 \text{ Mg}/1 \times 10^6 \text{ grams}$$

where:

$$\begin{aligned} EL_{\text{BTEX}} &= \text{Unit-specific BTEX emission limit, Mg/yr} \\ \text{CONSTANT} &= 1.10 \times 10^{-4} \text{ grams BTEX/scm-ppmv [subpart HH],} \\ &= 6.42 \times 10^{-5} \text{ grams BTEX/scm-ppmv [subpart HHH],} \\ \text{Throughput} &= \text{Annual average daily natural gas throughput, scm/day} \\ C_{i,\text{BTEX}} &= \text{BTEX concentration of the natural gas at the inlet to the glycol dehydrator unit,} \\ &\text{ppmv.} \end{aligned}$$

Since throughput and inlet BTEX concentration are entered into this equation, it could be assumed that the equation is sensitive to both of these variables. However, API conducted an analysis to evaluate the sensitivity of the equations to these parameters.

Specifically, API obtained actual BTEX concentrations entering dehydrators at oil and gas production facilities from API member companies in different types of formations across the United States. Using this information, API calculated the uncontrolled BTEX emissions at varying throughputs using GRI–GLYCalc™. API then calculated the BTEX emissions that would be allowed based on the proposed equation in subpart HH for each scenario, along with the emission reduction (%) that would be required. Table Q-1 shows the results of this analysis.

As can be seen in Table Q-1, the equation will result in the same percent reduction in BTEX emissions for a given inlet BTEX concentration regardless of the dehydrator throughput. Another interesting observation from this analysis is that, while the % reduction does vary with inlet BTEX concentration, the results can be that a higher % reduction is required for lower inlet concentrations and uncontrolled emissions.

Table Q-1. Small Dehydrator Control - Sensitivity of Proposed Subpart HH Equation To Throughput Rate Evaluation

| Facility Name | Inlet BTEX Content ppmv (Ci,BTEX) | Throughput SM ³ /Day | Inlet BTEX Tons | Equation #1 BTEX Allowable | | | GlyCalc Emissions tons/yr | | | | Cost/Ton Control ³ | | | | | |
|--|-----------------------------------|---------------------------------|-----------------|----------------------------|---------------|------------|---------------------------|--------|--------|---------|--------------------------------------|------------------|-------------|-------------|-------------|----------------|
| | | | | Mg | Tons per Year | % of Inlet | VOC | HAPS | BTEX | Benzene | Annualized Control Cost ¹ | Control % (BTEX) | VOC \$/Ton | HAPS \$/Ton | BTEX \$/Ton | Benzene \$/Ton |
| Coal Bed Methane - North San Juan Basin - SW Colorado | | | | | | | | | | | | | | | | |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 1 MMSCFD | 0.9 | 28,317 | 0.0419 | 0.0006 | 0.0007 | 1.57% | 0.0152 | 0.0111 | 0.011 | 0.0004 | \$30,409 | 94.0% | \$2,127,938 | \$2,913,934 | \$2,940,424 | \$80,861,661 |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 10 MMSCFD | 0.9 | 283,169 | 0.4191 | 0.0060 | 0.0066 | 1.57% | 0.1517 | 0.1109 | 0.11 | 0.0036 | \$30,409 | 94.0% | \$213,215 | \$291,656 | \$294,042 | \$8,984,629 |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 50 MMSCFD | 0.9 | 1,415,844 | 2.0953 | 0.0299 | 0.0329 | 1.57% | 0.7586 | 0.5543 | 0.5498 | 0.0181 | \$30,409 | 94.0% | \$42,638 | \$58,354 | \$58,831 | \$1,787,039 |
| N. San Juan Basin Gas Treating and Compression Facility Dehy 100 MMSCFD ² | 0.9 | 2,831,688 | 4.1905 | 0.0597 | 0.0658 | 1.57% | 1.5171 | 1.1087 | 1.0996 | 0.0362 | \$30,409 | 94.0% | \$21,321 | \$29,174 | \$29,416 | \$893,520 |
| Haynesville Shale - East Texas Basin - East Texas | | | | | | | | | | | | | | | | |
| Haynesville Shale 1 MMSCFD | 77 | 28,317 | 3.0612 | 0.0511 | 0.0563 | 1.84% | 0.4486 | 0.2496 | 0.24 | 0.1327 | \$30,409 | 76.5% | \$88,571 | \$159,187 | \$165,555 | \$299,421 |
| Haynesville Shale 2 MMSCFD | 77 | 56,634 | 6.1223 | 0.1022 | 0.1126 | 1.84% | 0.8972 | 0.4992 | 0.4799 | 0.2654 | \$30,409 | 76.5% | \$44,289 | \$79,599 | \$82,800 | \$149,720 |
| Haynesville Shale 4 MMSCFD | 77 | 113,268 | 12.2447 | 0.2044 | 0.2253 | 1.84% | 1.7943 | 0.9984 | 0.9598 | 0.5307 | \$30,409 | 76.5% | \$22,146 | \$39,799 | \$41,400 | \$74,874 |
| Haynesville Shale 7.5 MMSCFD | 77 | 212,377 | 22.9588 | 0.3832 | 0.4224 | 1.84% | 3.3644 | 1.8721 | 1.7997 | 0.9951 | \$30,409 | 76.5% | \$11,810 | \$21,225 | \$22,079 | \$39,931 |
| Haynesville Shale 8 MMSCFD (Large Dehy) | 77 | 226,535 | 24.4894 | 0.4087 | 0.4506 | 1.84% | 3.5887 | 1.9969 | 1.9196 | 1.0615 | \$30,409 | 95.0% | \$8,920 | \$16,030 | \$16,675 | \$30,155 |
| Tight Sand Gas - Greater Green River Basin - SW Wyoming | | | | | | | | | | | | | | | | |
| GGRB Basin Generic Well Site Dehy 0.2 MMSCFD | 404 | 5,663 | 3.4522 | 0.0536 | 0.0591 | 1.71% | 1.072 | 0.6712 | 0.6572 | 0.1259 | \$30,409 | 91.0% | \$31,170 | \$49,782 | \$50,843 | \$265,400 |
| GGRB Basin Generic Well Site Dehy 0.5 MMSCFD | 404 | 14,158 | 8.6305 | 0.1340 | 0.1478 | 1.71% | 2.68 | 1.678 | 1.643 | 0.3146 | \$30,409 | 91.0% | \$12,468 | \$19,913 | \$20,337 | \$106,210 |
| GGRB Basin Generic Well Site Dehy 1.0 MMSCFD | 404 | 28316.88 | 17.2611 | 0.2681 | 0.2955 | 1.71% | 5.3599 | 3.356 | 3.286 | 0.6293 | \$30,409 | 91.0% | \$6,234 | \$9,956 | \$10,169 | \$53,097 |
| GGRB Basin Generic Well Site Dehy 1.5 MMSCFD | 404 | 42,475 | 25.8916 | 0.4021 | 0.4433 | 1.71% | 8.0399 | 5.034 | 4.929 | 0.9439 | \$30,409 | 91.0% | \$4,156 | \$6,638 | \$6,779 | \$35,400 |
| GGRB Basin Generic Well Site Dehy 2 MMSCFD | 404 | 56,634 | 34.5221 | 0.5361 | 0.5910 | 1.71% | 10.7199 | 6.7121 | 6.5719 | 1.2586 | \$30,409 | 91.0% | \$3,117 | \$4,978 | \$5,084 | \$26,548 |
| GGRB Basin Generic Well Site Dehy 3 MMSCFD (Large Dehy) | 404 | 84,951 | 51.7832 | 0.8042 | 0.8865 | 1.71% | 16.0798 | 10.068 | 9.8579 | 1.8879 | \$30,409 | 95.0% | \$1,991 | \$3,179 | \$3,247 | \$16,955 |
| ¹ Annualized Cost from page 3-26; Table 3-7 of RIA; With control % above ~20% the only viable option is to use a combustion device which is the basis for the Table 3-7 cost. Hence, the control cost does not go down with incrementally lower control %. ² 100 MMSCFD is about the maximum throughput limit for a dehydration system ³ For sites with no BTEX and undefined BTEX control % the control cost uses total emissions for species present. | | | | | | | | | | | | | | | | |

Attachment R
EPA's Small Dehydrator Data Set

Attachment R

Small Dehydrator MACT Floor Analysis

This document includes tables providing various analyses related to the data used by EPA to determine their proposed MACT floor for small dehydrators.¹ EPA defined small dehydrators as those dehydrators with an actual annual average natural gas flow rate less than 85,000 scmd at oil and natural gas production sites or 283,000 scmd at natural gas transmission and storage sites, or actual average benzene emissions less than 0.9 Mg/yr.

Following are descriptions of these tables.

- Table R-1 shows the EPA small dehydrator data set for the oil and natural gas production category sorted by uncontrolled BTEX emissions. For the few controlled dehydrators, the uncontrolled emissions were calculated by assuming a control efficiency of 98%.
- Table R-2a shows this same data set sorted by inlet BTEX concentration, and Table R-2b provides average BTEX and benzene emissions for different ranges of the BTEX concentrations.
- Table R-3a shows this same data set sorted by daily dehydrator throughput, and Table R-3b provides average BTEX and benzene emissions for different ranges of daily throughput.
- Figure 1 shows the relationship between the BTEX inlet concentration and BTEX emissions. Figure 2 shows the relationship between the daily throughput and BTEX emissions, and Figure 3 shows the relationship between the product of BTEX inlet concentration and daily throughput.
- Table R-4 separates the small oil and natural gas production dehydrators into two subcategories: (1) dehydrators with uncontrolled benzene emissions < 0.9 Mg/yr and (2) dehydrators with uncontrolled benzene emissions \geq 0.9 Mg/yr and annual average throughputs < 85,000 SCMD. It also calculates the MACT floor for this second subcategory.
- Table R-5 separates the small natural gas transmission and storage dehydrators into two subcategories: (1) dehydrators with uncontrolled benzene emissions < 0.9 Mg/yr and (2) dehydrators with uncontrolled benzene emissions \geq 0.9 Mg/yr and annual average throughputs < 283,000 SCMD. It also calculates the MACT floor for this second subcategory.

¹ Memorandum. From Heather Brown, P.E, EC/R Incorporated, to Bruce Moore and Greg Nizich., EPA/OAQPS/SPPD/FIG. "Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options". July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0047)

Table R-1. Small Oil and Gas Production Dehydrator Data Sorted by Uncontrolled BTEX Emissions

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) |
|-------------|-----------------|--------------------|-------------|--------------------------|-------------------------|-----------------------|----------------|---------------------|
| G | 4 | 0.02 | | 0.02 | 0.02 | 0.02 | 5 | 1.6 |
| E | 1 | 0.1 | | 0.1 | 0 | 0 | 39 | 1.5 |
| A | 1 | 0.004 | C* | 0.2 | 0.001 | 0.05 | 116 | 0.62 |
| R | 6 | 0.2 | | 0.2 | 0.1 | 0.1 | 150 | 0.1 |
| D | 1 | 0.6 | | 0.6 | 0.6 | 0.6 | 140 | 3.5 |
| F | 1 | 0.9 | | 0.9 | 0.4 | 0.4 | 308 | 1.04 |
| B | 1 | 1.1 | | 1.1 | 0.1 | 0.1 | 69 | 20 |
| W | 3 | 1.2 | | 1.2 | 0.3 | 0.3 | 102 | 0.65 |
| HH | 1 | 1.5 | | 1.5 | 0.7 | 0.7 | 410 | 0.09 |
| GG | 3 | 1.9 | | 1.9 | 0.2 | 0.2 | 39 | 1.34 |
| Y | 1 | 2.4 | | 2.4 | 0.2 | 0.2 | 157 | 0.75 |
| DD | 1 | 3 | | 3 | 0.2 | 0.2 | 19 | 6.34 |
| Q | 1 | 3.5 | | 3.5 | 0 | 0 | 50 | 5.8 |
| M | 1 | 3.8 | | 3.8 | 1.2 | 1.2 | 400 | 1.2 |
| T | 3 | 3.9 | | 3.9 | 0.4 | 0.4 | 216 | 1.2 |
| C | 5 | 0.084 | C* | 4.2 | 0.007 | 0.35 | 60 | 1.6 |
| J | 1 | 4.4 | | 4.4 | 3 | 3 | 823 | 0.7 |
| S | 1 | 4.5 | | 4.5 | 1.5 | 1.5 | 400 | 0.8 |
| EE | 1 | 4.6 | | 4.6 | 1.2 | 1.2 | 500 | 0.32 |
| O | 2 | 4.71 | | 4.71 | 0.99 | 0.99 | 348 | 1.3 |
| U | 30 | 4.8 | | 4.8 | 0.5 | 0.5 | 316 | 1 |
| I | 1 | 5.02 | | 5.02 | 0.64 | 0.64 | 40 | 17.5 |
| BB | 2 | 5.3 | | 5.3 | 0.7 | 0.7 | 198 | 1.21 |
| Z | 2 | 5.4 | | 5.4 | 0.7 | 0.7 | 2560 | 0.1 |
| K | 1 | 6.5 | | 6.5 | 4.6 | 4.6 | 1499 | 0.55 |
| AA | 3 | 6.9 | | 6.9 | 1.3 | 1.3 | 320 | 1 |
| H | 3 | 7.9 | | 7.9 | 4.9 | 4.9 | 1560 | 1 |
| P | 1 | 10.4 | | 10.4 | 0.8 | 0.8 | 174 | 5.11 |
| V | 2 | 11.7 | | 11.7 | 1.3 | 1.3 | 329 | 2 |

Table R-1. Small Oil and Gas Production Dehydrator Data Sorted by Uncontrolled BTEX Emissions

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BTEX Inlet ppm | Thruput (mmscf/day) |
|--------------------|------------------------|---------------------------|--------------------|---------------------------------|--------------------------------|------------------------------|-----------------------|----------------------------|
| X | 1 | 13.8 | | 13.8 | 0.6 | 0.6 | 668 | 1.1 |
| L | 2 | 17.7 | | 17.7 | 1.7 | 1.7 | 1400 | 1.6 |
| FF | 1 | 2.5 | C* | 125 | 0.2 | 10 | 32 | 2.3 |
| N | 1 | 7.5 | C* | 375 | 5.1 | 255 | 340 | 2.2 |
| CC | 2 | 59.3 | C* | 2965 | 10.5 | 525 | 920 | 2.7 |

* - To calculate the uncontrolled emissions from the actual/controlled emissions, a reduction efficiency of 98% was assumed.

Table R-2a. Small Oil and Gas Production Dehydrator Data Sorted by Inlet BTEX Concentration

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) |
|-------------|-----------------|--------------------|-------------|--------------------------|-------------------------|-----------------------|----------------|---------------------|
| G | 4 | 0.02 | | 0.02 | 0.02 | 0.02 | 5 | 1.6 |
| DD | 1 | 3 | | 3 | 0.2 | 0.2 | 19 | 6.34 |
| E | 1 | 0.1 | | 0.1 | 0 | 0 | 39 | 1.5 |
| GG | 3 | 1.9 | | 1.9 | 0.2 | 0.2 | 39 | 1.34 |
| I | 1 | 5.02 | | 5.02 | 0.64 | 0.64 | 40 | 17.5 |
| Q | 1 | 3.5 | | 3.5 | 0 | 0 | 50 | 5.8 |
| C | 5 | 0.084 | C | 4.2 | 0.007 | 0.35 | 60 | 1.6 |
| B | 1 | 1.1 | | 1.1 | 0.1 | 0.1 | 69 | 20 |
| W | 3 | 1.2 | | 1.2 | 0.3 | 0.3 | 102 | 0.65 |
| A | 1 | 0.004 | C | 0.2 | 0.001 | 0.05 | 116 | 0.62 |
| D | 1 | 0.6 | | 0.6 | 0.6 | 0.6 | 140 | 3.5 |
| R | 6 | 0.2 | | 0.2 | 0.1 | 0.1 | 150 | 0.1 |
| Y | 1 | 2.4 | | 2.4 | 0.2 | 0.2 | 157 | 0.75 |
| P | 1 | 10.4 | | 10.4 | 0.8 | 0.8 | 174 | 5.11 |
| BB | 2 | 5.3 | | 5.3 | 0.7 | 0.7 | 198 | 1.21 |
| T | 3 | 3.9 | | 3.9 | 0.4 | 0.4 | 216 | 1.2 |
| F | 1 | 0.9 | | 0.9 | 0.4 | 0.4 | 308 | 1.04 |
| U | 30 | 4.8 | | 4.8 | 0.5 | 0.5 | 316 | 1 |
| AA | 3 | 6.9 | | 6.9 | 1.3 | 1.3 | 320 | 1 |
| V | 2 | 11.7 | | 11.7 | 1.3 | 1.3 | 329 | 2 |
| O | 2 | 4.71 | | 4.71 | 0.99 | 0.99 | 348 | 1.3 |
| M | 1 | 3.8 | | 3.8 | 1.2 | 1.2 | 400 | 1.2 |
| S | 1 | 4.5 | | 4.5 | 1.5 | 1.5 | 400 | 0.8 |
| HH | 1 | 1.5 | | 1.5 | 0.7 | 0.7 | 410 | 0.09 |
| EE | 1 | 4.6 | | 4.6 | 1.2 | 1.2 | 500 | 0.32 |
| X | 1 | 13.8 | | 13.8 | 0.6 | 0.6 | 668 | 1.1 |
| J | 1 | 4.4 | | 4.4 | 3 | 3 | 823 | 0.7 |
| L | 2 | 17.7 | | 17.7 | 1.7 | 1.7 | 1400 | 1.6 |

Table R-2a. Small Oil and Gas Production Dehydrator Data Sorted by Inlet BTEX Concentration

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BTEX Inlet ppm | Thruput (mmscf/day) |
|--------------------|------------------------|---------------------------|--------------------|---------------------------------|--------------------------------|------------------------------|-----------------------|----------------------------|
| K | 1 | 6.5 | | 6.5 | 4.6 | 4.6 | 1499 | 0.55 |
| H | 3 | 7.9 | | 7.9 | 4.9 | 4.9 | 1560 | 1 |
| Z | 2 | 5.4 | | 5.4 | 0.7 | 0.7 | 2560 | 0.1 |
| Outliers | | | | | | | | |
| FF | 1 | 2.5 | C | 125 | 0.2 | 10 | 32 | 2.3 |
| N | 1 | 7.5 | C | 375 | 5.1 | 255 | 340 | 2.2 |
| CC | 2 | 59.3 | C | 2965 | 10.5 | 525 | 920 | 2.7 |

Table R-2b. Small Oil and Gas Production Dehydrator Analysis by Inlet BTEX Concentration

| | Emissions (tpy) | | | | | |
|---------------------------|-----------------|------|-------|---------|------|------|
| | BTEX | | | Benzene | | |
| | max | min | avg | max | min | avg |
| all dehydrators | 2965 | 0.02 | 106.1 | 525 | 0 | 24.1 |
| removing outliers | | | | | | |
| all dehydrators | 17.7 | 0.02 | 4.6 | 4.9 | 0 | 0.9 |
| lowest 25% of inlet BTEX | 5.02 | 0.02 | 2.5 | 0.64 | 0 | 0.2 |
| highest 75% of inlet BTEX | 17.7 | 0.2 | 5.2 | 4.9 | 0.05 | 1.2 |
| lowest 50% of inlet BTEX | 10.4 | 0.02 | 2.7 | 0.8 | 0 | 0.3 |
| highest 50% of inlet BTEX | 17.7 | 0.9 | 6.6 | 4.9 | 0.4 | 1.6 |

Table R-3a. Small Oil and Gas Production Dehydrator Data Sorted by Daily Throughput

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) |
|-------------|-----------------|--------------------|-------------|--------------------------|-------------------------|-----------------------|----------------|---------------------|
| HH | 1 | 1.5 | | 1.5 | 0.7 | 0.7 | 410 | 0.09 |
| R | 6 | 0.2 | | 0.2 | 0.1 | 0.1 | 150 | 0.1 |
| Z | 2 | 5.4 | | 5.4 | 0.7 | 0.7 | 2560 | 0.1 |
| EE | 1 | 4.6 | | 4.6 | 1.2 | 1.2 | 500 | 0.32 |
| K | 1 | 6.5 | | 6.5 | 4.6 | 4.6 | 1499 | 0.55 |
| A | 1 | 0.004 | C | 0.2 | 0.001 | 0.05 | 116 | 0.62 |
| W | 3 | 1.2 | | 1.2 | 0.3 | 0.3 | 102 | 0.65 |
| J | 1 | 4.4 | | 4.4 | 3 | 3 | 823 | 0.7 |
| Y | 1 | 2.4 | | 2.4 | 0.2 | 0.2 | 157 | 0.75 |
| S | 1 | 4.5 | | 4.5 | 1.5 | 1.5 | 400 | 0.8 |
| U | 30 | 4.8 | | 4.8 | 0.5 | 0.5 | 316 | 1 |
| AA | 3 | 6.9 | | 6.9 | 1.3 | 1.3 | 320 | 1 |
| H | 3 | 7.9 | | 7.9 | 4.9 | 4.9 | 1560 | 1 |
| F | 1 | 0.9 | | 0.9 | 0.4 | 0.4 | 308 | 1.04 |
| X | 1 | 13.8 | | 13.8 | 0.6 | 0.6 | 668 | 1.1 |
| M | 1 | 3.8 | | 3.8 | 1.2 | 1.2 | 400 | 1.2 |
| T | 3 | 3.9 | | 3.9 | 0.4 | 0.4 | 216 | 1.2 |
| BB | 2 | 5.3 | | 5.3 | 0.7 | 0.7 | 198 | 1.21 |
| O | 2 | 4.71 | | 4.71 | 0.99 | 0.99 | 348 | 1.3 |
| GG | 3 | 1.9 | | 1.9 | 0.2 | 0.2 | 39 | 1.34 |
| E | 1 | 0.1 | | 0.1 | 0 | 0 | 39 | 1.5 |
| G | 4 | 0.02 | | 0.02 | 0.02 | 0.02 | 5 | 1.6 |
| C | 5 | 0.084 | C | 4.2 | 0.007 | 0.35 | 60 | 1.6 |
| L | 2 | 17.7 | | 17.7 | 1.7 | 1.7 | 1400 | 1.6 |
| V | 2 | 11.7 | | 11.7 | 1.3 | 1.3 | 329 | 2 |
| D | 1 | 0.6 | | 0.6 | 0.6 | 0.6 | 140 | 3.5 |
| P | 1 | 10.4 | | 10.4 | 0.8 | 0.8 | 174 | 5.11 |
| Q | 1 | 3.5 | | 3.5 | 0 | 0 | 50 | 5.8 |

Table R-3a. Small Oil and Gas Production Dehydrator Data Sorted by Daily Throughput

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) |
|--------------------|------------------------|---------------------------|--------------------|---------------------------------|--------------------------------|------------------------------|-----------------------|----------------------------|
| DD | 1 | 3 | | 3 | 0.2 | 0.2 | 19 | 6.34 |
| I | 1 | 5.02 | | 5.02 | 0.64 | 0.64 | 40 | 17.5 |
| B | 1 | 1.1 | | 1.1 | 0.1 | 0.1 | 69 | 20 |
| Outliers | | | | | | | | |
| FF | 1 | 2.5 | C | 125 | 0.2 | 10 | 32 | 2.3 |
| N | 1 | 7.5 | C | 375 | 5.1 | 255 | 340 | 2.2 |
| CC | 2 | 59.3 | C | 2965 | 10.5 | 525 | 920 | 2.7 |

Table R-3b. Small Oil and Gas Production Dehydrator Analysis by Daily Throughput

| | Emissions (tpy) | | | | | |
|----------------------------|------------------------|------------|------------|----------------|------------|------------|
| | BTEX | | | Benzene | | |
| | max | min | avg | max | min | avg |
| all dehydrators | 2965 | 0.02 | 106.1 | 525 | 0 | 24.1 |
| removing outliers | | | | | | |
| all dehydrators | 17.7 | 0.02 | 4.6 | 4.9 | 0 | 0.9 |
| lowest 25% of throughputs | 6.5 | 0.2 | 3.0 | 4.6 | 0.05 | 1.3 |
| highest 75% of throughputs | 17.7 | 0.02 | 5.1 | 4.9 | 0 | 0.8 |
| lowest 50% of throughputs | 13.8 | 0.2 | 4.3 | 4.9 | 0.05 | 1.3 |
| highest 50% of throughputs | 17.7 | 0.02 | 4.9 | 1.7 | 0 | 0.5 |

Figure 1. Relationship of BTEX Inlet Conc and BTEX Emissions

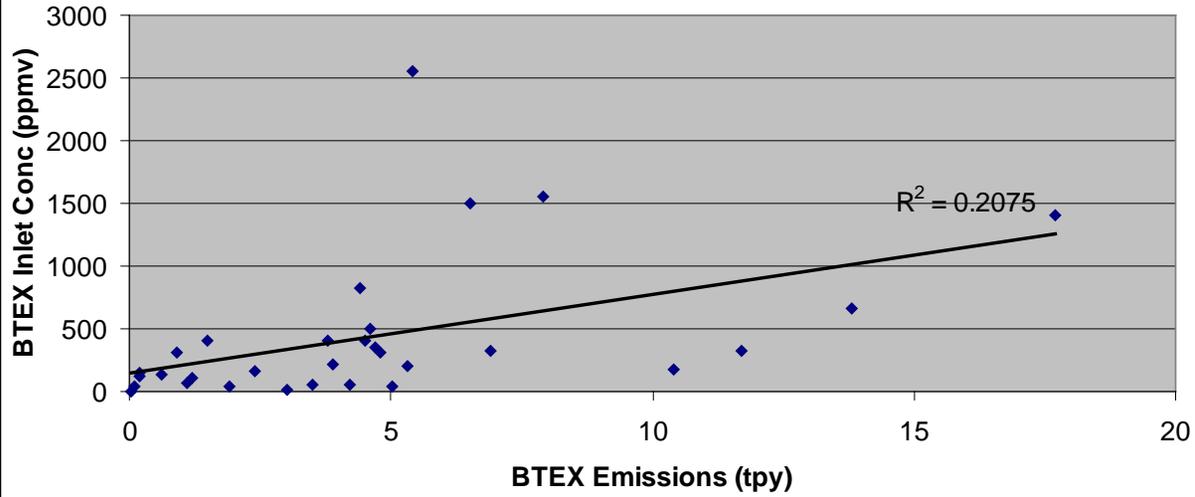


Figure 2. Relationship of Throughput and BTEX Emissions

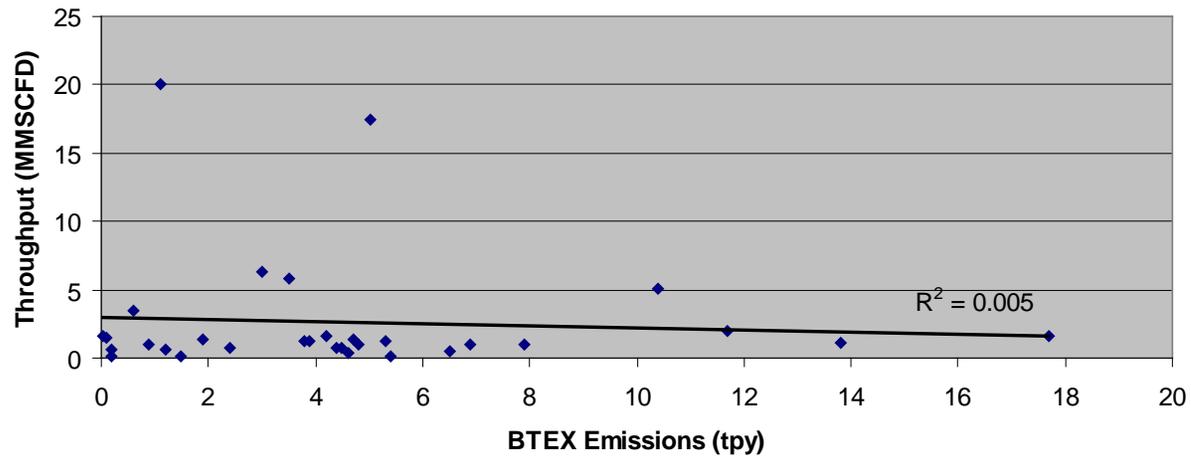


Figure 3. Relationship of Throughput*BTEX Conc and BTEX Emissions

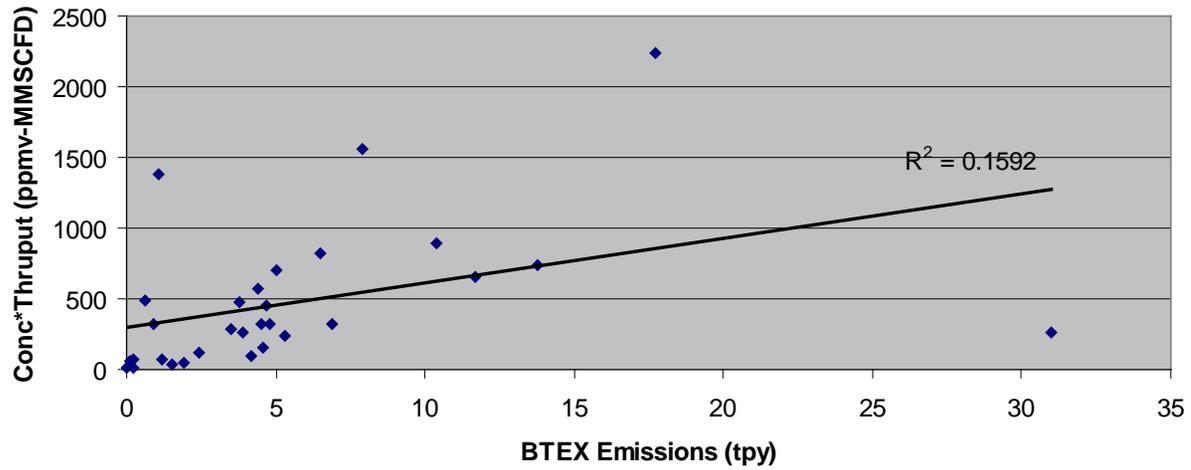


Table R-4. Oil and Natural Gas Production Small Dehydrator MACT Floor Analysis

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) | |
|-------------|-----------------|--------------------|-------------|--------------------------|-------------------------|-----------------------|----------------|---------------------|---|
| A | 1 | 0.004 | C | 0.2 | 0.001 | 0.05 | 116 | 0.62 | Subcategory with uncontrolled benzene emissions < 0.9 Mg/yr (1 tpy) |
| G | 4 | 0.02 | | 0.02 | 0.02 | 0.02 | 5 | 1.6 | |
| C | 5 | 0.084 | C | 4.2 | 0.007 | 0.35 | 60 | 1.6 | |
| E | 1 | 0.1 | | 0.1 | 0 | 0 | 39 | 1.5 | |
| R | 6 | 0.2 | | 0.2 | 0.1 | 0.1 | 150 | 0.1 | |
| D | 1 | 0.6 | | 0.6 | 0.6 | 0.6 | 140 | 3.5 | |
| F | 1 | 0.9 | | 0.9 | 0.4 | 0.4 | 308 | 1.04 | |
| B | 1 | 1.1 | | 1.1 | 0.1 | 0.1 | 69 | 20 | |
| W | 3 | 1.2 | | 1.2 | 0.3 | 0.3 | 102 | 0.65 | |
| HH | 1 | 1.5 | | 1.5 | 0.7 | 0.7 | 410 | 0.09 | |
| GG | 3 | 1.9 | | 1.9 | 0.2 | 0.2 | 39 | 1.34 | |
| Y | 1 | 2.4 | | 2.4 | 0.2 | 0.2 | 157 | 0.75 | |
| DD | 1 | 3 | | 3 | 0.2 | 0.2 | 19 | 6.34 | |
| Q | 1 | 3.5 | | 3.5 | 0 | 0 | 50 | 5.8 | |
| T | 3 | 3.9 | | 3.9 | 0.4 | 0.4 | 216 | 1.2 | |
| O | 2 | 4.71 | | 4.71 | 0.99 | 0.99 | 348 | 1.3 | |
| U | 30 | 4.8 | | 4.8 | 0.5 | 0.5 | 316 | 1 | |
| I | 1 | 5.02 | | 5.02 | 0.64 | 0.64 | 40 | 17.5 | |
| BB | 2 | 5.3 | | 5.3 | 0.7 | 0.7 | 198 | 1.21 | |
| Z | 2 | 5.4 | | 5.4 | 0.7 | 0.7 | 2560 | 0.1 | |
| P | 1 | 10.4 | | 10.4 | 0.8 | 0.8 | 174 | 5.11 | |
| X | 1 | 13.8 | | 13.8 | 0.6 | 0.6 | 668 | 1.1 | |

Table R-4. Oil and Natural Gas Production Small Dehydrator MACT Floor Analysis

| Unit ID No. | Number of Units | BTEX emissions tpy | Controlled? | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | BETX Inlet ppm | Thruput (mmscf/day) |
|--|-----------------|--------------------|-------------|--------------------------|-------------------------|-----------------------|----------------|---------------------|
| FF | 1 | 2.5 | C | 125 | 0.2 | 10 | 32 | 2.3 |
| M | 1 | 3.8 | | 3.8 | 1.2 | 1.2 | 400 | 1.2 |
| J | 1 | 4.4 | | 4.4 | 3 | 3 | 823 | 0.7 |
| S | 1 | 4.5 | | 4.5 | 1.5 | 1.5 | 400 | 0.8 |
| EE | 1 | 4.6 | | 4.6 | 1.2 | 1.2 | 500 | 0.32 |
| K | 1 | 6.5 | | 6.5 | 4.6 | 4.6 | 1499 | 0.55 |
| AA | 3 | 6.9 | | 6.9 | 1.3 | 1.3 | 320 | 1 |
| N | 1 | 7.5 | C | 375 | 5.1 | 255 | 340 | 2.2 |
| H | 3 | 7.9 | | 7.9 | 4.9 | 4.9 | 1560 | 1 |
| V | 2 | 11.7 | | 11.7 | 1.3 | 1.3 | 329 | 2 |
| L | 2 | 17.7 | | 17.7 | 1.7 | 1.7 | 1400 | 1.6 |
| CC | 2 | 59.3 | C | 2965 | 10.5 | 525 | 920 | 2.7 |
| MACT Floor: Average of lowest 5 in subcategory | | 3.96 tpy | | 3.6 Mg/yr | | | | |

Subcategory with uncontrolled benzene emissions ≥ 0.9 Mg/yr (1 tpy) and annual throughputs < 85,000 m³/day (3 million ft³/day)

Table R-5. Natural Gas Transmission and Storage Small Dehydrator MACT Floor Analysis

| Unit ID No. | Number of Units | BTEX emissions tpy | BTEX unc emissions (tpy) | Benzene emissions (tpy) | Benzene unc emissions | Thruput (mmscf/day) | |
|--|-----------------|--------------------|--------------------------|-------------------------|-----------------------|---------------------|---|
| A | 1 | 0.4 | 0.4 | 0.1 | 0.1 | 20 | Subcategory with uncontrolled benzene emissions < 0.9 Mg/yr (1 tpy) |
| H | 1 | 1.7 | 1.7 | 0.2 | 0.2 | 5.3 | |
| B | 1 | 0.7 | 0.7 | 0.2 | 0.2 | 30 | |
| C | 1 | 0.8 | 0.8 | 0.2 | 0.2 | 35 | |
| I | 1 | 1.1 | 1.1 | 0.2 | 0.2 | 5.7 | |
| J | 1 | 2.8 | 2.8 | 0.3 | 0.3 | 7 | |
| N | 1 | 2.3 | 2.3 | 0.3 | 0.3 | 4 | |
| O | 1 | 1.8 | 1.8 | 0.3 | 0.3 | 3 | |
| P | 1 | 1.3 | 1.3 | 0.3 | 0.3 | 0.9 | |
| G | 1 | 2.8 | 2.8 | 0.4 | 0.4 | 12.5 | |
| F | 1 | 5.8 | 5.8 | 0.5 | 0.5 | 50 | |
| M | 1 | 7.0 | 7.0 | 0.6 | 0.6 | 15 | |
| L | 1 | 7.2 | 7.2 | 0.6 | 0.6 | 15 | |
| E | 1 | 2.4 | 2.4 | 0.8 | 0.8 | 60 | |
| D | 1 | 3.0 | 3.0 | 1.0 | 1.0 | 120 | |
| K | 1 | 5.6 | 5.6 | 1.2 | 1.2 | 7 | Subcategory with uncontrolled benzene emissions ≥ 0.9 Mg/yr (1 tpy) and annual throughputs < 283,000 m3/day (3 million ft3/day) |
| MACT Floor: Emissions of only dehydrator in subcategory | | | | | | | |
| | | 5.6 tpy | | | | | |
| | | 5.1 Mg/yr | | | | | |

Petroleum and Natural Gas Systems Emissions Reporting Guidance for California's Mandatory Greenhouse Gas Reporting Regulation

This document describes the requirements for facility operators of petroleum and natural gas systems for reporting greenhouse gas (GHG) emissions data under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 *et seq*) (MRR).

The petroleum and natural gas systems sector consists of eight industry segments as defined in section 95150 of MRR. This guidance document does not, and cannot, create or vary any legal requirements of MRR.

This document discusses how facility definitions are applied to each industry segment, describes updated reporting requirements that became effective January 1, 2015, and provides answers to frequently asked questions from this sector.

This guidance does not discuss reporting requirements related to covered product data. For additional information about covered product data reporting for petroleum and natural gas systems see the [Petroleum and Natural Gas Systems Covered Product Data Reporting and Verification Guidance](#) document.

1 Identifying and Defining Facility Industry Segments

Section 95101(e) of MRR includes eight industry segments for petroleum and natural gas systems. Of these segments, two industry segments—natural gas distribution, and onshore petroleum and natural gas production—have specific, more specialized “facility” definitions within MRR. All other industry segments use the definition of “facility” in section 95102(a)(170) of MRR.

1.1 Natural Gas Distribution Facility Definition

Section 95102(a)(171) of MRR includes a specialized facility definition for natural gas distribution facilities as follows:

“‘Facility,’ with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, means the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.”

1.2 Onshore Petroleum and Natural Gas Production Facility Definition

Section 95102(a)(172) of MRR includes a specialized facility definition for onshore petroleum and natural gas production facilities as follows:

“Facility,’ with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single basin as defined in section 95102(a). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.”

1.2.1 Application of the Term “Associated with”

Onshore petroleum and natural gas system emissions sources are considered “associated with” the hydrocarbon stream produced from the well pad. This includes steam generators, dehydrators, amine treaters, and other equipment (portable and stationary) that are associated with the production and treatment of the hydrocarbon stream produced at the well pad. The “associated with” term is also inclusive of cogeneration facilities that supply steam and/or electricity to the well pad.

1.2.2 California Geologic Provinces (Basins)

Onshore petroleum and natural gas production facilities in California are required to aggregate and report applicable GHG emissions using the “basin” footprint as defined in the following publication:

AAPG-CSD Geologic Provinces Code Map, R.F. Meyer, L.G. Wallace, and F. J. Wagner, Jr., *The American Association of Petroleum Geologists Bulletin*, V. 75, No. 10 (October 1991), pgs., 1644 – 1651, 1991.

This journal article is copyright protected and cannot be freely distributed by the California Air Resources Board (ARB). Reporters may access the complete article free of charge at many California public libraries. To aid reporters in the determination of their reporting footprint and correct basin name and number, ARB staff have constructed Table 1, which lists each California county or counties included in each basin by name and number (as defined in the reference publication). Note that, in many cases, a basin may contain multiple California counties. Offshore basins do not necessarily correspond to individual onshore California counties.

Table 1: Basin IDs Defining Oil and Natural Gas Production Facility Reporting Footprint

| Basin Name | Basin Number | California County(ies) |
|---------------------------------|--------------|--|
| Onshore Basins | | |
| Southern Oregon | 620 | Lassen, Modoc |
| Great Basin | 625 | Inyo, Mono |
| Mojave | 640 | San Bernardino |
| Salton | 645 | Imperial, Riverside |
| Sierra | 650 | Alpine, Amador, Calaveras, El Dorado, Mariposa, Nevada, Placer, Plumas, Sierra, Tuolumne, Yuba |
| Klamath Mountain | 715 | Del Norte, Shasta, Siskiyou, Trinity |
| Eel River | 720 | Humboldt |
| Northern Coast Range | 725 | Alameda, Lake, Mendocino, Napa, Santa Clara, Sonoma |
| Sacramento | 730 | Butte, Colusa, Contra Costa, Glenn, Sacramento, San Joaquin, Solano, Sutter, Tehama, Yolo |
| Santa Cruz | 735 | Marin, Santa Clara, Santa Cruz, San Francisco, San Mateo |
| Coastal | 740 | Monterey, San Luis Obispo |
| San Joaquin | 745 | Fresno, Kern, Kings, Madera, Merced, San Benito, Stanislaus, Tulare |
| Santa Maria | 750 | Santa Barbara |
| Ventura | 755 | Ventura |
| Los Angeles | 760 | Los Angeles, Orange |
| Capistrano | 765 | San Diego |
| Offshore Basins | | |
| Eel River | 945 | Not applicable |
| Point Arena | 948 | |
| Santa Cruz (Bodega) | 950 | |
| Santa Maria | 953 | |
| Santa Barbara Channel | 955 | |
| Pacific Coast (Outer) | 956 | |
| Southern California borderlands | 957 | |

1.3 Definition of “Facility” for all Other Industry Segments

The “facility” definition in section 95102(a)(170) of MRR applies to the other industry segments listed in section 95101(e) including offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, import, and export facilities. The definition is as follows:

“Facility,’ unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.”

Operators of natural gas distribution facilities and onshore petroleum and natural gas production facilities must use the definitions described in Sections 1.1 and 1.2 of this guidance document instead of this facility definition.

Note: Onshore natural gas processing facilities that fractionate or that do not fractionate but have a throughput of 25 million standard cubic feet (MMscf) per day or greater must report according to the general facility definition in section 95102(a)(170).

1.4 Examples for Applying Facility Definitions for Oil and Gas Facilities

Example 1: An onshore petroleum production operator in a single hydrocarbon basin owns greater than a 50 percent share in a cogeneration plant, which supplies steam to some of the wells for production. How many ARB facility IDs does this owner need?

Answer: One. The cogeneration plant is associated with the onshore petroleum production facility and emissions from the cogeneration plant must be reported with the other emissions associated with the well pad within the geologic basin because the operator owns greater than a 50 percent share in the cogeneration plant as specified in the definition of “onshore petroleum and natural gas production facility” in section 95102(a).

Example 2: An oil company operates a natural gas processing plant that has a throughput of 35 MMscf/day in an oil field that consists of multiple well pads (not necessarily under common ownership) in a single hydrocarbon basin. How many ARB facility IDs are needed?

Answer: At least two. The natural gas processing facility has a separate facility ID from the well pads. However, depending on how many owners or operators of the well pads there are in the single hydrocarbon basin, the onshore natural gas production facility may consist of one ARB facility ID or multiple ARB facility IDs.

Example 3: A liquefied natural gas storage facility is located contiguous to a commonly owned cogeneration plant. How many ARB facility IDs do the facility and plant need?

Answer: One. The liquefied natural gas storage facility is contiguous to the cogeneration facility. Because MRR does not include a specific, specialized facility

definition for liquefied natural gas storage facilities, the general facility definition in section 95102(a) of MRR applies, so this is considered a single facility.

1.5 Reporting by Sub-facility

MRR specifies that emissions and product data must be disaggregated within the basin reporting footprint to the sub-facility level when reported via the California Electronic Greenhouse Gas Reporting Tool (Cal e-GGRT). Sub-facility is defined in terms of single townships or a group of contiguous or adjacent townships, as identified in the Public Land Survey System of the United States. Sub-facilities may be further disaggregated according to similar operational, geological, or geographical characteristics. Reporters should refer to the definition of sub-facility found in section 95102(a) of MRR for additional information. Entities that have already been reporting emissions and product data at the sub-facility level should continue reporting with the same subdivision of information; however the facility's GHG Monitoring Plan must provide a map or a list identifying the townships, ranges, and section numbers that comprise the geographic boundaries of the sub-facilities. Production data must be further disaggregated between thermal and other-than-thermal (i.e., non-thermal) production processes at the sub-facility level.

2 New and Modified Requirements for 2014 Data Reported in 2015, and for Subsequent Years

This section discusses new requirements that became effective in MRR January 1, 2015.

2.1 Requirements for Quantifying Emissions from Centrifugal Compressor Venting

A new requirement for quantifying emissions from centrifugal compressor venting was added to section 95153(m)(1)(A) of MRR. All facility operators that have centrifugal compressors that use spin-up gas to start their compressors must report these emissions. In cases where natural gas is used as spin-up or starting gas, vented emissions of this spin-up gas must be included in operating mode emissions calculations for affected compressors as per Equation 20 of section 95153(m)(1)(A) of MRR. Spin-up gas is gas that is used to start a compressor with the kinetic energy of the gas stream, and subsequently vented rather than being combusted in the compressor. If spin-up gas is captured and subsequently used as a fuel or flared, these emissions must be reported using the appropriate methods found in section 95153.

2.2 Requirements for Reporting Emissions from Customer Meters

Beginning in 2015, operators of natural gas distribution facilities must report carbon dioxide (CO₂) and methane (CH₄) emissions from customer meters pursuant to section 95152(i)(10) of MRR. Default emission factors for three types of customer meters (residential, commercial, and industrial) have been added to MRR's Appendix A, Table 7. These emission factors are listed in units of standard cubic feet (scf)/meter-

hour. Operators must use the equations in section 95153(p) and the emission factors in Table 7 of Appendix A to calculate emissions from customer meters. N₂O emissions are excluded from this reporting requirement.

2.3 Requirements for Reporting Emissions from Pipeline Dig-ins

Operators of natural gas distribution facilities must also report the number and emissions from pipeline dig-ins pursuant to section 95152(i)(11) of MRR, using the methodology specified in section 95153(w).

Pipeline dig-in is defined in section 95152(a) to mean the following:

“Pipeline dig-in’ means unintentional puncture or rupture to a buried natural gas transmission and distribution pipeline during excavation activities.”

Operators may use either measured data or engineering calculations based on the best available data to quantify the volume of natural gas released from pipeline dig-ins and subsequently convert and report this volumetric information as mass CH₄ and CO₂ emissions. N₂O emissions are excluded from this reporting requirement. Combustion emissions from a natural gas leak that ignites after a pipeline dig-in are not required to be reported under MRR.

2.4 Requirements to Report Sorbent Emissions

Onshore petroleum and natural gas production and natural gas distribution facilities must report sorbent emissions from fluidized bed boilers with flue gas desulfurization along with stationary combustion emissions (95153(y) of MRR). Reporters must use the methods found in United States Environmental Protection Agency (US EPA) Mandatory GHG Reporting Rule (section 40 CFR §98.33(d)) to calculate sorbent related emissions.

2.5 Requirements for Local Distribution Companies

Pursuant to sections 95157(c)(16)(U) and (V) of MRR, local distribution companies (LDC) must report CO₂ and CH₄ emissions from customer meters and pipe-line dig-ins. LDCs must also report the number of customer meters at residential, commercial, and industrial customers they serve, and the number of pipe-line dig-ins, as set-forth in sections 95157(c)(16)(W) and (X), respectively.

2.6 Voluntary Reporting of Renewable Resources to Produce Steam for EOR Operations

Section 95157(c)(19)(I) of MRR allows onshore petroleum and natural gas production facilities to voluntarily report the amount of thermal energy (in units of MMBtu) input to EOR wells that is produced using renewable energy source(s), as defined in section 95102(a).

3 Frequently Asked Questions

This section provides answers to frequently asked questions from facility operators of petroleum and natural gas systems.

3.1 If an operator does not have a certain source at its facility, can the fields in Cal e-GGRT be left blank for those sources?

No. Operators of all petroleum and natural gas facilities should report zero (0) in Cal e-GGRT where individual source emissions can be demonstrated to be zero (i.e., no emissions occurred from the source in question for the entire reporting period). This will allow ARB and the verifier to know that the operator did not have emissions associated with the specific sources instead of failing to insert data for those sources. The operator must demonstrate to the satisfaction of the verifier that no emissions occurred.

Additionally, in cases where the emissions are less than one-thousandth of a ton, the user should enter '0' into Cal e-GGRT. As mentioned above, the user should retain the records of the actual emissions for verification purposes.

3.2 Do operators have to report emissions from the blowdown of very small volumes?

Section 95153(g) of MRR requires all facility operators, except operators of offshore petroleum and natural gas production facilities, to report emissions resulting from the depressurization of equipment and pipelines caused by human intervention or taking equipment out of service for maintenance (excluding depressurizing to a flare, overpressure relief, operating pressure control and venting and blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading). A provision has been added to section 95153(g)(1) of MRR which exempts reporting blowdown emissions from physical volumes less than 50 cubic feet (cf).

Reporters must calculate the unique physical volume for each blowdown incident. Pursuant to section 95153(g)(1) this volume shall be determined by engineering estimates based on best available data. Actual measurements of variables such as tubing diameter and pipe length would also be acceptable.

In addition to physical blowdown volume, the following variables must also be determined:

N = number of occurrences of blowdowns for each unique physical volume in the calendar year. Reporters should maintain a list and record the number of blowdowns per calendar year.

T_a = Temperature at actual conditions. Reporters should be able to determine this variable from any number of sources: e.g., System Control and Data Acquisition (SCADA) systems, thermometer.

P_a = Absolute pressure at actual conditions in the unique physical volume. Reporters should be able to determine this value from a SCADA system or via an engineering estimate based on system standard operating parameters when actual pressure measurements are not available.

Reporters should always use the most accurate data available when deriving the variables required as inputs to this emissions calculation methodology. The verifier must review the data sources during verification to ensure that the input data meet accuracy requirements.

3.3 How do operators report emissions in cases where the compressor was in the non-operating and depressurized mode during the reporting period?

The monitoring requirements for compressors in the “not operating, depressurized mode” are detailed in sections 95153(m)(1)(C) and 95153(n)(1)(C) of MRR. If no measurement data has yet been acquired within the three year monitoring period, the operator may use an engineering estimate or best available data to determine the MT_m variable for compressors in the “not operating, depressurized mode,” until the required measurement is collected.

3.4 What if sampling required under MRR exposes facility personnel to hazardous concentrations of H₂S in compressor emissions? Are operators still required to conduct sampling under these circumstances?

Activities undertaken to collect and acquire data reported under MRR should never be conducted in a manner which puts personnel safety at risk. ARB staff believes that the reporting requirements include sufficient safeguards to prevent harm to personnel involved in sampling of compressor emissions. Reporters should refer to sections 95154(a)(3) and (4) of MRR (Monitoring and QA/QC Requirements) where personnel are directed to use either an infrared laser or an optical gas imaging instrument “for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.” ARB staff believes this text covers sources which are inaccessible due to safety concerns.

Sections 95153(m) and 95153(n) of MRR describe emissions measurement and quantification methodologies for centrifugal and reciprocating compressors, respectively. These two sections specify the methods used to quantify vent emissions, which include calibrated bagging, high volume sampler, or a permanent or temporary meter.”

3.5 How do operators apportion fugitive emissions measurements over the five-year period mentioned in section 95153(o)(8)(A) of MRR?

U.S. EPA has issued guidance concerning this issue and this guidance is reproduced below. Operators are directed to follow this guidance in quantifying and reporting emissions covered in section 95153(o) of MRR.

Reporter inquiry to U.S. EPA:

“Q651. Under Section 98.233(q)(8)(i), a company may elect to conduct leak detection on a multiple year cycle, up to a maximum of five years, with the number of stations monitored ‘approximately equal across all years in the cycle.’ The preamble to the final rule says ‘a minimum of 20%’ per year (76 FR 80569). Would a monitoring plan that results in 10% of stations being monitored in each of the first two years, followed by 40% of stations in year 3, 20% in year 4 and 20% in year five, be consistent with the rule language of ‘approximately equal across all years in the cycle.’”

U.S. EPA response:

“A651. Yes. According to 98.233(q)(8)(i), ‘Natural gas distribution facilities may choose to conduct leak detection at T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option, then the number of T-D transfer stations monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.’ EPA confirms that an approach of conducting monitoring at 10% of the facilities in each of the first two years, followed by 40%, 20% and 20% in years three, four and five would be consistent with the rule language that the number of stations monitored be ‘approximately equal’ over the number of years surveyed.”

This text can be found at the following web-link:

[http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=118587545.](http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=118587545)

3.6 In what cases should an operator use the “common pipe” method for reporting combustion emissions?

A “common pipe” method, as described in section 95115 of MRR, is still applicable for most fuels as described in section 95153(y)(1)(A). For combustion units that combust field gas, process vent gas, non-pipeline quality natural gas or a blend of field and process vent gas, the “common pipe” method, also applies. Section 95153(y)(2)(A) indicates that company records may be used to determine the volume of fuel combusted, and for purposes of the fuels listed in section 95153(y)(2), company records may include records related to the common pipe that transfers fuel to particular units. For reporting emissions from units downstream of the common pipe, please follow the [Guidance for Aggregation of Emitting Units](#) document.

3.7 What are the verification requirements for activity data reported pursuant to section 95157?

Facility operators for every industry segment are required to report activity data contained in section 95157 of MRR. Activity data reported under section 95157 must be verified for conformance by a third-party verification body pursuant to section 95131(b)(10). The activity data reported pursuant to section 95157 are not part of a facility's covered emissions, and as such, are not subject to material misstatement assessment.

3.8 When determining whether a natural gas source is "pipeline quality natural gas," is it acceptable for the operator to make the determination based on the annual weighted averages of monthly measurements for CH₄, CO₂, and HHV?

Yes, if the annual weighted averages of monthly measurements for CH₄, CO₂, and HHV meet the "pipeline quality natural gas" criteria for those parameters (i.e., at least 90% CH₄ by volume, less than 5 percent CO₂ by volume, and HHV between 970 and 1,100 btu/scf, inclusively), the gas may be considered "pipeline quality" for the entire data year.

3.9 Since the CO₂ emissions method in section 95153(y)(2) of MRR is based on carbon content (similar to a "Tier 3" method) and not based on a default emission factor, is it acceptable to use section 95153(y)(2) for a natural gas source that does meet the definition of "pipeline quality" natural gas?

Yes, the operator may choose to use the method in §95153(y)(2) to quantify combustion emissions for natural gas that does meet the "pipeline quality" definition.

3.10 If an operator follows the method in section 95153(y)(1) of MRR, because the fuel is a standard fuel or is pipeline quality natural gas, and selects an applicable Tier method from section 95115, does the operator need to follow all of the quality assurance and reporting requirements described in section 95115?

If a Tier method from section 95115 is selected to quantify combustion emissions based on the application of section 95153(y)(1), the reporter *must* follow all of the Tier selection, monitoring, sampling frequency, and other quality assurance requirements in section 95115 that are associated with quantifying emissions. For facilities in the oil and gas sector, the additional reporting requirements of section 95115 (e.g., reporting fuel use by device type for a common pipe source) are optional.

3.11 Do vented emissions from “rotary vane” compressors need to be reported?

Vented emissions from “rotary vane” compressors, and any other compressors that operate on the principle of a rotating shaft, should be reported as emissions from centrifugal compressors.

3.12 If the vented emissions from compressors are reported as *de minimis*, is it acceptable to modify or omit the vent testing requirements described in sections 95153(m) and (n) of MRR?

If the vented emissions from compressors meet the *de minimis* thresholds, and the chosen method for quantifying vented emissions is reasonable, the vent testing requirements described in sections 95153(m) and (n) may be modified or omitted. Verifiers must ensure that the methods used by the operator to quantify emissions reported as *de minimis* are reasonable, unlikely to be biased high or low, and that the actual emissions are unlikely to exceed the *de minimis* threshold.

3.13 How should compressor venting emissions be reported if the compressors are completely self-contained and have no vents or vent stacks, or if the vented emissions from vents are captured to a vapor recovery system?

If compressors have no vents or vent stacks, or if 100 percent of the vented emissions are routed to a vapor recovery system, the operator should quantify and report the vented emissions from such compressors as zero (0). Such compressors would still be subject to the reporting requirements for leaks and for fuel combustion, as described in Subarticle 5 of MRR.

3.14 How should emissions from unmetered, natural gas-powered intermittent-bleed pneumatic devices be quantified and reported, if the operator has documentation demonstrating that the actual bleed rate for the devices is less than six scf per hour?

Pursuant to MRR, “intermittent bleed devices which bleed at a cumulative rate of six standard cubic feet per hour or greater are considered high bleed devices” (section 95102(a)(252)), therefore, emissions from devices that exceed this limit must be reported as high-bleed in Cal e-GGRT and are subject to a compliance obligation under the Cap-and-Trade Program. A low-bleed pneumatic device is defined in MRR as a device that “vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour” (section 95102(a)). Low-bleed pneumatic devices must be reported as low-bleed in Cal e-GGRT and emissions from such devices are not subject to a compliance obligation under the Cap-and-Trade Program.

Emissions from all unmetered, natural gas-powered intermittent-bleed pneumatic devices must be quantified using the “intermittent bleed” emission factor of

13.5 scf/hour/component listed in Table 1A of Appendix A of MRR, using Equation 2 (section 95153(b)), regardless of bleed rate. If the operator has documentation that demonstrates that the devices bleed at an actual rate of less than six scf/hour/component, such as original equipment manufacturer's specifications, or measurement data, the operator must still quantify the emissions using the 13.5 scf/hour/component emission factor; however, the emissions may be reported as "low bleed" pneumatic emissions in Cal e-GGRT. If the device bleeds at a rate of six scf/hour/component or greater, or there is no documentation available that demonstrates that the actual bleed rate of a device is less than or equal to six scf/hour/component, the emissions for such devices must be reported as "high bleed" pneumatic device emissions in Cal e-GGRT.

Verifiers must evaluate pneumatic device emissions as a part of their risk analysis during verification, including the determination of whether on-site pneumatic devices are continuous-bleed or intermittent-bleed devices. Verifiers should identify emissions from intermittent bleed devices that are reported in the "low bleed" category in Cal e-GGRT as high risk. When emissions from intermittent-bleed devices are reported in the low-bleed category in Cal e-GGRT, verifiers should review documented evidence that the actual bleed rate from the devices is less than or equal to six scf/hour.

3.15 What value should an operator use for the "Fraction of gas combusted" (η or "eta"), when using Equations 35 and 36 to quantify combustion emissions for "external" combustion devices, such as heaters or boilers?

The operator must use the default value of 0.995 for the term " η " in Equations 35 and 36 for all combustion unit types, including both "internal" and "external" combustion devices, unless the operator can provide objective evidence to the verification team to substantiate the use of a value other than the default factor of 0.995. An example of such evidence could include a gas composition analysis of a combustion unit's exhaust that demonstrates the validity of an alternative engineering estimate.

3.16 A prior version of MRR required actual component counts (methodology 1) after the 2012 data year when quantifying leaks data under section 95153(p), but the current version of MRR allows an alternate "default" component count method. If an operator chooses to use the default component count method (methodology 2), does the operator need to submit notification of a change in method to ARB, pursuant to section 95103(m)(1)?

Yes. If the operator switches from methodology 1 to methodology 2 for quantifying leaks data pursuant to section 95153(p) the operator must notify ARB of the method change pursuant to section 95103(m)(1).

3.17 Are “sulfatreat” systems, and other types of systems that use a solid iron oxide medium to remove sulfur gases, subject to emissions reporting under the “acid gas removal vent” source category?

No. The emissions quantification methods required pursuant to the “acid gas removal vent” source category are intended to quantify CO₂ emissions from systems that routinely remove CO₂ from the fuel gas stream, and then vent this CO₂ directly to the atmosphere upon regeneration of the system media (e.g., an amine solvent). Systems that use an iron oxide or other solid medium to remove sulfur gases from an enclosed stream of natural or associated gas, and that do not routinely vent CO₂ to the atmosphere, are not subject to emissions reporting under the acid gas removal vent source category in section 95153(c) because the media from these systems do not remove CO₂ from the fuel stream. However, the vessels of such systems would be subject to blowdown emissions reporting, as applicable, according to section 95153(g).

3.18 Do combustion emissions from small compressors (less than 130 horsepower) need to be reported? If so, how should those emissions be quantified if the compressor engine is powered by the gas it is compressing, and there is no fuel meter?

Yes. Combustion emissions from all compressors operated by an internal combustion engine, regardless of the rated heat capacity, must be reported as covered emissions, using the appropriate quantification method. If the fuel for such devices is not metered, the operator may quantify the fuel usage using the number of operating hours for the devices, and the demonstrated hourly fuel use rate, per the device manufacturer’s specifications. However, the hours of operation and the hourly fuel use rate data (e.g., the “load” rate for the device under actual operating conditions) must meet the measurement accuracy requirements of section 95103(k). If the accuracy of the number of operating hours and/or the actual hourly fuel use rate cannot be demonstrated to the verifier, the operator may report the emissions in the de minimis category, if the requirements for de minimis reporting are met. If the operator cannot or does not wish to report the emissions in the de minimis category, the operator must use the missing data provisions to quantify the fuel use. The operator must use the maximum hourly fuel use rate for the device from the manufacturer’s specifications to quantify missing fuel use rate data. If the hours of operation data are also missing, the operator must use the maximum number of hours during the data year for which the device may have been operating.

Pursuant to section 95153(y)(3), emissions from external fuel combustion sources (e.g., heaters and boilers) with a rated heat capacity of less than or equal to five MMBtu/hour do not need to be reported. Likewise, pursuant to 95153(y)(4), emissions from internal combustion sources, except compressor drivers, with a rated heat capacity equal to or less than one MMBtu/hour (or 130 horsepower) do not need to be reported.

3.19 How are de minimis emissions reported for oil and gas facilities in Cal e-GGRT?

To simplify reporting and ensure accurate categorization of de minimis emissions operators must report Subarticle 5 (Subpart W) de minimis emissions in the Petroleum and Natural Gas Systems – Emissions Reporting Workbook, beginning with 2015 data reported in 2016. Operators should no longer use the De Minimis Workbook to report Subpart W emissions. Operators may aggregate petroleum and natural gas systems de minimis emissions on one line of the workbook, or may choose to disaggregate the de minimis emissions by sub-facility. Operators must still disaggregate emissions that are not categorized as de minimis by sub-facility. See Figure 1 below for an example of a reporting configuration in Cal e-GGRT.

Figure 1: Example input for the Cal e-GGRT Subarticle 5 workbook “Onshore Petroleum and Natural Gas Production” section.

| Does Entire Row Contain Standard or De Minimis Emissions? (any de minimis emissions must be reported in separate row(s)). | Contiguous Property/Sub-Facility Name: | Metered natural gas high bleed pneumatic device and pneumatic pump venting | | |
|--|--|--|---|-------------------------|
| | | CO ₂ Emissions (tCO ₂) | CH ₄ Emissions (tCH ₄) | Total CO ₂ e |
| | Total - Standard Emissions | 805.0 | 7.0 | 952.0 |
| | Total - De Minimis Emissions | 125.0 | 2.6 | 179.6 |
| Standard | Watson Shale 25 | 250.0 | 5.0 | 355.0 |
| De Minimis | Watson Shale 25 - De Minimis | 2.0 | 0.3 | 8.3 |
| Standard | East Hill 23X | 555.0 | 2.0 | 597.0 |
| De Minimis | De Minimis Aggregation | 123.0 | 2.3 | 171.3 |

Inventory of U.S. Greenhouse Gas Emissions and Sinks:

1990 – 2014

APRIL 15, 2016

U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
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All data tables of this document are available for the full time series 1990 through 2014, inclusive, at the internet site mentioned above.

FOR FURTHER INFORMATION

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For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www3.epa.gov/climatechange>.

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Preface

The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15.

In an effort to engage the public and researchers across the country, the EPA has instituted an annual public review and comment process for this document. The availability of the draft document is announced via Federal Register Notice and is posted on the EPA web site. Copies are also mailed upon request. The public comment period is generally limited to 30 days; however, comments received after the closure of the public comment period are accepted and considered for the next edition of this annual report.

Table of Contents

| | |
|--|-------------|
| ACKNOWLEDGMENTS | I |
| PREFACE | III |
| TABLE OF CONTENTS | V |
| LIST OF TABLES, FIGURES, AND BOXES | VIII |
| EXECUTIVE SUMMARY | ES-1 |
| ES.1. Background Information | ES-2 |
| ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks | ES-4 |
| ES.3. Overview of Sector Emissions and Trends | ES-17 |
| ES.4. Other Information | ES-22 |
| 1. INTRODUCTION | 1-2 |
| 1.1 Background Information | 1-4 |
| 1.2 National Inventory Arrangements | 1-11 |
| 1.3 Inventory Process | 1-14 |
| 1.4 Methodology and Data Sources | 1-15 |
| 1.5 Key Categories | 1-16 |
| 1.6 Quality Assurance and Quality Control (QA/QC) | 1-19 |
| 1.7 Uncertainty Analysis of Emission Estimates | 1-21 |
| 1.8 Completeness | 1-23 |
| 1.9 Organization of Report | 1-23 |
| 2. TRENDS IN GREENHOUSE GAS EMISSIONS | 2-1 |
| 2.1 Recent Trends in U.S. Greenhouse Gas Emissions and Sinks | 2-1 |
| 2.2 Emissions by Economic Sector | 2-22 |
| 2.3 Indirect Greenhouse Gas Emissions (CO, NO _x , NMVOCs, and SO ₂) | 2-32 |
| 3. ENERGY | 3-1 |
| 3.1 Fossil Fuel Combustion (IPCC Source Category 1A) | 3-4 |
| 3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A) | 3-39 |
| 3.3 Incineration of Waste (IPCC Source Category 1A1a) | 3-46 |
| 3.4 Coal Mining (IPCC Source Category 1B1a) | 3-50 |

| | | |
|-----------|---|------------|
| 3.5 | Abandoned Underground Coal Mines (IPCC Source Category 1B1a) | 3-55 |
| 3.6 | Petroleum Systems (IPCC Source Category 1B2a)..... | 3-58 |
| 3.7 | Natural Gas Systems (IPCC Source Category 1B2b)..... | 3-68 |
| 3.8 | Energy Sources of Indirect Greenhouse Gas Emissions..... | 3-84 |
| 3.9 | International Bunker Fuels (IPCC Source Category 1: Memo Items) | 3-85 |
| 3.10 | Wood Biomass and Ethanol Consumption (IPCC Source Category 1A) | 3-90 |
| 4. | INDUSTRIAL PROCESSES AND PRODUCT USE | 4-1 |
| 4.1 | Cement Production (IPCC Source Category 2A1) | 4-7 |
| 4.2 | Lime Production (IPCC Source Category 2A2) | 4-10 |
| 4.3 | Glass Production (IPCC Source Category 2A3)..... | 4-14 |
| 4.4 | Other Process Uses of Carbonates (IPCC Source Category 2A4)..... | 4-17 |
| 4.5 | Ammonia Production (IPCC Source Category 2B1)..... | 4-21 |
| 4.6 | Urea Consumption for Non-Agricultural Purposes | 4-24 |
| 4.7 | Nitric Acid Production (IPCC Source Category 2B2)..... | 4-27 |
| 4.8 | Adipic Acid Production (IPCC Source Category 2B3) | 4-30 |
| 4.9 | Silicon Carbide Production and Consumption (IPCC Source Category 2B5)..... | 4-33 |
| 4.10 | Titanium Dioxide Production (IPCC Source Category 2B6) | 4-36 |
| 4.11 | Soda Ash Production and Consumption (IPCC Source Category 2B7) | 4-38 |
| 4.12 | Petrochemical Production (IPCC Source Category 2B8)..... | 4-42 |
| 4.13 | HCFC-22 Production (IPCC Source Category 2B9a) | 4-47 |
| 4.14 | Carbon Dioxide Consumption (IPCC Source Category 2B10) | 4-50 |
| 4.15 | Phosphoric Acid Production (IPCC Source Category 2B10) | 4-53 |
| 4.16 | Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production..... | 4-56 |
| 4.17 | Ferroalloy Production (IPCC Source Category 2C2) | 4-66 |
| 4.18 | Aluminum Production (IPCC Source Category 2C3) | 4-70 |
| 4.19 | Magnesium Production and Processing (IPCC Source Category 2C4) | 4-75 |
| 4.20 | Lead Production (IPCC Source Category 2C5)..... | 4-79 |
| 4.21 | Zinc Production (IPCC Source Category 2C6) | 4-82 |
| 4.22 | Semiconductor Manufacture (IPCC Source Category 2E1) | 4-86 |
| 4.23 | Substitution of Ozone Depleting Substances (IPCC Source Category 2F) | 4-96 |
| 4.24 | Electrical Transmission and Distribution (IPCC Source Category 2G1) | 4-103 |
| 4.25 | Nitrous Oxide from Product Uses (IPCC Source Category 2G3) | 4-110 |
| 4.26 | Industrial Processes and Product Use Sources of Indirect Greenhouse Gases | 4-113 |
| 5. | AGRICULTURE | 5-1 |
| 5.1 | Enteric Fermentation (IPCC Source Category 3A) | 5-2 |
| 5.2 | Manure Management (IPCC Source Category 3B)..... | 5-8 |
| 5.3 | Rice Cultivation (IPCC Source Category 3C)..... | 5-15 |

| | | |
|------------|--|-------------|
| 5.4 | Agricultural Soil Management (IPCC Source Category 3D) | 5-20 |
| 5.5 | Field Burning of Agricultural Residues (IPCC Source Category 3F) | 5-34 |
| 6. | LAND USE, LAND-USE CHANGE, AND FORESTRY | 6-1 |
| 6.1 | Representation of the U.S. Land Base | 6-6 |
| 6.2 | Forest Land Remaining Forest Land | 6-21 |
| 6.3 | Land Converted to Forest Land (IPCC Source Category 4A2) | 6-36 |
| 6.4 | Cropland Remaining Cropland (IPCC Source Category 4B1) | 6-40 |
| 6.5 | Land Converted to Cropland (IPCC Source Category 4B2)..... | 6-54 |
| 6.6 | Grassland Remaining Grassland (IPCC Source Category 4C1) | 6-60 |
| 6.7 | Land Converted to Grassland (IPCC Source Category 4C2) | 6-66 |
| 6.8 | Wetlands Remaining Wetlands (IPCC Source Category 4D1) | 6-72 |
| 6.9 | Land Converted to Wetlands (IPCC Source Category 4D2) | 6-78 |
| 6.10 | Settlements Remaining Settlements | 6-79 |
| 6.11 | Land Converted to Settlements (IPCC Source Category 4E2) | 6-86 |
| 6.12 | Other Land Remaining Other Land (IPCC Source Category 4F1) | 6-86 |
| 6.13 | Land Converted to Other Land (IPCC Source Category 4F2)..... | 6-86 |
| 6.14 | Other (IPCC Source Category 4H)..... | 6-87 |
| 7. | WASTE..... | 7-1 |
| 7.1 | Landfills (IPCC Source Category 5A1)..... | 7-3 |
| 7.2 | Wastewater Treatment (IPCC Source Category 5D)..... | 7-16 |
| 7.3 | Composting (IPCC Source Category 5B1)..... | 7-29 |
| 7.4 | Waste Incineration (IPCC Source Category 5C1) | 7-32 |
| 7.5 | Waste Sources of Indirect Greenhouse Gases | 7-32 |
| 8. | OTHER | 8-1 |
| 9. | RECALCULATIONS AND IMPROVEMENTS..... | 9-1 |
| 10. | REFERENCES | 10-1 |

List of Tables, Figures, and Boxes

Tables

| | |
|---|-------|
| Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report..... | ES-3 |
| Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO ₂ Eq.) | ES-5 |
| Table ES-3: CO ₂ Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO ₂ Eq.)..... | ES-11 |
| Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO ₂ Eq.) | ES-17 |
| Table ES-5: U.S. Greenhouse Gas Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry (MMT CO ₂ Eq.) | ES-21 |
| Table ES-6: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO ₂ Eq.)..... | ES-23 |
| Table ES-7: U.S. Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (MMT CO ₂ Eq.)..... | ES-24 |
| Table ES-8: Recent Trends in Various U.S. Data (Index 1990 = 100) | ES-25 |
| Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime of Selected Greenhouse Gases | 1-5 |
| Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report | 1-9 |
| Table 1-3: Comparison of 100-Year GWP values | 1-10 |
| Table 1-4: Key Categories for the United States (1990-2014) | 1-17 |
| Table 1-5: Estimated Overall Inventory Quantitative Uncertainty (MMT CO ₂ Eq. and Percent) | 1-22 |
| Table 1-6: IPCC Sector Descriptions..... | 1-23 |
| Table 1-7: List of Annexes | 1-24 |
| Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO ₂ Eq.) | 2-4 |
| Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (kt)..... | 2-6 |
| Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO ₂ Eq.)... .. | 2-8 |
| Table 2-4: Emissions from Energy (MMT CO ₂ Eq.)..... | 2-11 |
| Table 2-5: CO ₂ Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO ₂ Eq.)..... | 2-12 |
| Table 2-6: Emissions from Industrial Processes and Product Use (MMT CO ₂ Eq.) | 2-15 |
| Table 2-7: Emissions from Agriculture (MMT CO ₂ Eq.)..... | 2-18 |
| Table 2-8: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry (MMT CO ₂ Eq.) | 2-19 |
| Table 2-9: Emissions from Waste (MMT CO ₂ Eq.) | 2-21 |
| Table 2-10: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO ₂ Eq. and Percent of Total in 2014)..... | 2-23 |
| Table 2-11: Electricity Generation-Related Greenhouse Gas Emissions (MMT CO ₂ Eq.) | 2-24 |
| Table 2-12: U.S. Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (MMT CO ₂ Eq.) and Percent of Total in 2014..... | 2-26 |
| Table 2-13: Transportation-Related Greenhouse Gas Emissions (MMT CO ₂ Eq.) | 2-28 |

| | |
|---|------|
| Table 2-14: Recent Trends in Various U.S. Data (Index 1990 = 100)..... | 2-31 |
| Table 2-15: Emissions of NO _x , CO, NMVOCs, and SO ₂ (kt) | 2-33 |
| Table 3-1: CO ₂ , CH ₄ , and N ₂ O Emissions from Energy (MMT CO ₂ Eq.) | 3-2 |
| Table 3-2: CO ₂ , CH ₄ , and N ₂ O Emissions from Energy (kt) | 3-3 |
| Table 3-3: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion (MMT CO ₂ Eq.)..... | 3-4 |
| Table 3-4: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion (kt)..... | 3-5 |
| Table 3-5: CO ₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO ₂ Eq.) | 3-5 |
| Table 3-6: Annual Change in CO ₂ Emissions and Total 2014 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO ₂ Eq. and Percent) | 3-6 |
| Table 3-7: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion by Sector (MMT CO ₂ Eq.) | 3-10 |
| Table 3-8: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO ₂ Eq.) | 3-11 |
| Table 3-9: CO ₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO ₂ Eq.) | 3-12 |
| Table 3-10: CH ₄ Emissions from Stationary Combustion (MMT CO ₂ Eq.)..... | 3-13 |
| Table 3-11: N ₂ O Emissions from Stationary Combustion (MMT CO ₂ Eq.)..... | 3-13 |
| Table 3-12: CO ₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMT CO ₂ Eq.) .. | 3-19 |
| Table 3-13: CH ₄ Emissions from Mobile Combustion (MMT CO ₂ Eq.)..... | 3-22 |
| Table 3-14: N ₂ O Emissions from Mobile Combustion (MMT CO ₂ Eq.) | 3-23 |
| Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO ₂ Eq./Qbtu) | 3-28 |
| Table 3-16: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO ₂ Eq. and Percent)..... | 3-31 |
| Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO ₂ Eq. and Percent) | 3-35 |
| Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Mobile Sources (MMT CO ₂ Eq. and Percent) | 3-38 |
| Table 3-19: CO ₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO ₂ Eq. and percent) | 3-40 |
| Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (Tbtu)..... | 3-40 |
| Table 3-21: 2014 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions..... | 3-41 |
| Table 3-22: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Non-Energy Uses of Fossil Fuels (MMT CO ₂ Eq. and Percent) | 3-43 |
| Table 3-23: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent) | 3-43 |
| Table 3-24: CO ₂ , CH ₄ , and N ₂ O Emissions from the Incineration of Waste (MMT CO ₂ Eq.)..... | 3-46 |
| Table 3-25: CO ₂ , CH ₄ , and N ₂ O Emissions from the Incineration of Waste (kt) | 3-47 |
| Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted (BioCycle data set) | 3-48 |
| Table 3-27: Approach 2 Quantitative Uncertainty Estimates for CO ₂ and N ₂ O from the Incineration of Waste (MMT CO ₂ Eq. and Percent)..... | 3-49 |
| Table 3-28: Coal Production (kt) | 3-50 |
| Table 3-29: CH ₄ Emissions from Coal Mining (MMT CO ₂ Eq.) | 3-51 |
| Table 3-30: CH ₄ Emissions from Coal Mining (kt)..... | 3-51 |

| | |
|--|------|
| Table 3-31: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Coal Mining (MMT CO ₂ Eq. and Percent) | 3-54 |
| Table 3-32: CH ₄ Emissions from Abandoned Coal Mines (MMT CO ₂ Eq.)..... | 3-55 |
| Table 3-33: CH ₄ Emissions from Abandoned Coal Mines (kt) | 3-56 |
| Table 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins in 2014, grouped by Class according to Post-Abandonment State | 3-57 |
| Table 3-35: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Abandoned Underground Coal Mines (MMT CO ₂ Eq. and Percent) | 3-58 |
| Table 3-36: CH ₄ Emissions from Petroleum Systems (MMT CO ₂ Eq.)..... | 3-59 |
| Table 3-37: CH ₄ Emissions from Petroleum Systems (kt) | 3-60 |
| Table 3-38: CO ₂ Emissions from Petroleum Systems (MMT CO ₂ Eq.)..... | 3-60 |
| Table 3-39: CO ₂ Emissions from Petroleum Systems (kt) | 3-60 |
| Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Petroleum Systems (MMT CO ₂ Eq. and Percent)..... | 3-63 |
| Table 3-41: CH ₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO ₂ Eq.)..... | 3-64 |
| Table 3-42: CH ₄ Emissions from Pneumatic Controllers (MMT CO ₂ Eq.)..... | 3-65 |
| Table 3-43: CH ₄ Emissions from Oil Well Completions and Workovers (C&W) (MMT CO ₂ Eq.)..... | 3-65 |
| Table 3-44: Potential Emissions from CO ₂ Capture and Extraction for EOR Operations (MMT CO ₂ Eq.)..... | 3-67 |
| Table 3-45: Potential Emissions from CO ₂ Capture and Extraction for EOR Operations (kt) | 3-68 |
| Table 3-46: CH ₄ Emissions from Natural Gas Systems (MMT CO ₂ Eq.) ^a | 3-69 |
| Table 3-47: CH ₄ Emissions from Natural Gas Systems (kt) ^a | 3-70 |
| Table 3-48: Calculated Potential CH ₄ and Captured/Combusted CH ₄ from Natural Gas Systems (MMT CO ₂ Eq.)... .. | 3-70 |
| Table 3-49: Non-combustion CO ₂ Emissions from Natural Gas Systems (MMT CO ₂ Eq.) | 3-70 |
| Table 3-50: Non-combustion CO ₂ Emissions from Natural Gas Systems (kt) | 3-70 |
| Table 3-51: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and Non-energy CO ₂ Emissions from Natural Gas Systems (MMT CO ₂ Eq. and Percent)..... | 3-74 |
| Table 3-52: CH ₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO ₂ Eq.)..... | 3-76 |
| Table 3-53: CH ₄ Emissions from Pneumatic Controllers (MMT CO ₂ Eq.)..... | 3-76 |
| Table 3-54: CH ₄ Emissions from Gathering and Boosting (MMT CO ₂ Eq.)..... | 3-77 |
| Table 3-55: CH ₄ Emissions from Transmission Stations (MMT CO ₂ Eq.) | 3-78 |
| Table 3-56: CH ₄ Emissions from Storage Stations (MMT CO ₂ Eq.)..... | 3-78 |
| Table 3-57: CH ₄ Emissions from Transmission Segment Pneumatic Controllers (MMT CO ₂ Eq.)..... | 3-79 |
| Table 3-58: CH ₄ Emissions from Storage Segment Pneumatic Controllers (MMT CO ₂ Eq.)..... | 3-79 |
| Table 3-59: CH ₄ Emissions from M&R Stations (MMT CO ₂ Eq.) | 3-80 |
| Table 3-60: CH ₄ Emissions from Pipeline Leaks (MMT CO ₂ Eq.)..... | 3-80 |
| Table 3-61: CH ₄ Emissions for Other Distribution Sources (MMT CO ₂ Eq.)..... | 3-81 |
| Table 3-62: NO _x , CO, and NMVOC Emissions from Energy-Related Activities (kt)..... | 3-84 |
| Table 3-63: CO ₂ , CH ₄ , and N ₂ O Emissions from International Bunker Fuels (MMT CO ₂ Eq.) | 3-86 |

| | |
|---|------|
| Table 3-64: CO ₂ , CH ₄ , and N ₂ O Emissions from International Bunker Fuels (kt) | 3-87 |
| Table 3-65: Aviation CO ₂ and N ₂ O Emissions for International Transport (MMT CO ₂ Eq.) | 3-87 |
| Table 3-66: Aviation Jet Fuel Consumption for International Transport (Million Gallons)..... | 3-88 |
| Table 3-67: Marine Fuel Consumption for International Transport (Million Gallons) | 3-89 |
| Table 3-68: CO ₂ Emissions from Wood Consumption by End-Use Sector (MMT CO ₂ Eq.) | 3-91 |
| Table 3-69: CO ₂ Emissions from Wood Consumption by End-Use Sector (kt) | 3-91 |
| Table 3-70: CO ₂ Emissions from Ethanol Consumption (MMT CO ₂ Eq.)..... | 3-91 |
| Table 3-71: CO ₂ Emissions from Ethanol Consumption (kt) | 3-91 |
| Table 3-72: Woody Biomass Consumption by Sector (Trillion Btu) | 3-92 |
| Table 3-73: Ethanol Consumption by Sector (Trillion Btu) | 3-92 |
| Table 4-1: Emissions from Industrial Processes and Product Use (MMT CO ₂ Eq.) | 4-3 |
| Table 4-2: Emissions from Industrial Processes and Product Use (kt) | 4-4 |
| Table 4-3: CO ₂ Emissions from Cement Production (MMT CO ₂ Eq. and kt)..... | 4-7 |
| Table 4-4: Clinker Production (kt)..... | 4-8 |
| Table 4-5: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Cement Production (MMT CO ₂ Eq. and Percent)..... | 4-9 |
| Table 4-6: CO ₂ Emissions from Lime Production (MMT CO ₂ Eq. and kt)..... | 4-10 |
| Table 4-7: Potential, Recovered, and Net CO ₂ Emissions from Lime Production (kt)..... | 4-11 |
| Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (kt) | 4-12 |
| Table 4-9: Adjusted Lime Production (kt)..... | 4-12 |
| Table 4-10: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Lime Production (MMT CO ₂ Eq. and Percent)..... | 4-13 |
| Table 4-11: CO ₂ Emissions from Glass Production (MMT CO ₂ Eq. and kt) | 4-15 |
| Table 4-12: Limestone, Dolomite, and Soda Ash Consumption Used in Glass Production (kt) | 4-16 |
| Table 4-13: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Glass Production (MMT CO ₂ Eq. and Percent)..... | 4-16 |
| Table 4-14: CO ₂ Emissions from Other Process Uses of Carbonates (MMT CO ₂ Eq.) | 4-18 |
| Table 4-15: CO ₂ Emissions from Other Process Uses of Carbonates (kt) | 4-18 |
| Table 4-16: Limestone and Dolomite Consumption (kt) | 4-19 |
| Table 4-17: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Other Process Uses of Carbonates (MMT CO ₂ Eq. and Percent) | 4-20 |
| Table 4-18: CO ₂ Emissions from Ammonia Production (MMT CO ₂ Eq.) | 4-22 |
| Table 4-19: CO ₂ Emissions from Ammonia Production (kt)..... | 4-22 |
| Table 4-20: Ammonia Production and Urea Production (kt)..... | 4-23 |
| Table 4-21: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Ammonia Production (MMT CO ₂ Eq. and Percent)..... | 4-24 |
| Table 4-22: CO ₂ Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO ₂ Eq.)..... | 4-25 |
| Table 4-23: CO ₂ Emissions from Urea Consumption for Non-Agricultural Purposes (kt) | 4-25 |

| | |
|---|------|
| Table 4-24: Urea Production, Urea Applied as Fertilizer, Urea Imports, and Urea Exports (kt) | 4-26 |
| Table 4-25: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO ₂ Eq. and Percent) | 4-26 |
| Table 4-26: N ₂ O Emissions from Nitric Acid Production (MMT CO ₂ Eq. and kt N ₂ O) | 4-27 |
| Table 4-27: Nitric Acid Production (kt) | 4-29 |
| Table 4-28: Approach 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from Nitric Acid Production (MMT CO ₂ Eq. and Percent) | 4-30 |
| Table 4-29: N ₂ O Emissions from Adipic Acid Production (MMT CO ₂ Eq. and kt N ₂ O)..... | 4-31 |
| Table 4-30: Adipic Acid Production (kt) | 4-32 |
| Table 4-31: Approach 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from Adipic Acid Production (MMT CO ₂ Eq. and Percent) | 4-33 |
| Table 4-32: CO ₂ and CH ₄ Emissions from Silicon Carbide Production and Consumption (MMT CO ₂ Eq.)..... | 4-34 |
| Table 4-33: CO ₂ and CH ₄ Emissions from Silicon Carbide Production and Consumption (kt) | 4-34 |
| Table 4-34: Production and Consumption of Silicon Carbide (Metric Tons) | 4-35 |
| Table 4-35: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and CO ₂ Emissions from Silicon Carbide Production and Consumption (MMT CO ₂ Eq. and Percent)..... | 4-35 |
| Table 4-36: CO ₂ Emissions from Titanium Dioxide (MMT CO ₂ Eq. and kt) | 4-36 |
| Table 4-37: Titanium Dioxide Production (kt) | 4-37 |
| Table 4-38: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Titanium Dioxide Production (MMT CO ₂ Eq. and Percent) | 4-38 |
| Table 4-39: CO ₂ Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (MMT CO ₂ Eq.)..... | 4-39 |
| Table 4-40: CO ₂ Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt) | 4-40 |
| Table 4-41: Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt)..... | 4-40 |
| Table 4-42: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Soda Ash Production and Consumption (MMT CO ₂ Eq. and Percent)..... | 4-41 |
| Table 4-43: CO ₂ and CH ₄ Emissions from Petrochemical Production (MMT CO ₂ Eq.)..... | 4-43 |
| Table 4-44: CO ₂ and CH ₄ Emissions from Petrochemical Production (kt) | 4-43 |
| Table 4-45: Production of Selected Petrochemicals (kt) | 4-46 |
| Table 4-46: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Petrochemical Production and CO ₂ Emissions from Carbon Black Production (MMT CO ₂ Eq. and Percent)..... | 4-46 |
| Table 4-47: HFC-23 Emissions from HCFC-22 Production (MMT CO ₂ Eq. and kt HFC-23) | 4-48 |
| Table 4-48: HCFC-22 Production (kt)..... | 4-49 |
| Table 4-49: Approach 2 Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (MMT CO ₂ Eq. and Percent) | 4-49 |
| Table 4-50: CO ₂ Emissions from CO ₂ Consumption (MMT CO ₂ Eq. and kt) | 4-50 |
| Table 4-51: CO ₂ Production (kt CO ₂) and the Percent Used for Non-EOR Applications | 4-52 |
| Table 4-52: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from CO ₂ Consumption (MMT CO ₂ Eq. and Percent)..... | 4-52 |
| Table 4-53: CO ₂ Emissions from Phosphoric Acid Production (MMT CO ₂ Eq. and kt)..... | 4-53 |

| | |
|---|------|
| Table 4-54: Phosphate Rock Domestic Consumption, Exports, and Imports (kt) | 4-54 |
| Table 4-55: Chemical Composition of Phosphate Rock (Percent by weight)..... | 4-55 |
| Table 4-56: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Phosphoric Acid Production (MMT CO ₂ Eq. and Percent) | 4-56 |
| Table 4-57: CO ₂ Emissions from Metallurgical Coke Production (MMT CO ₂ Eq.) | 4-57 |
| Table 4-58: CO ₂ Emissions from Metallurgical Coke Production (kt) | 4-58 |
| Table 4-59: CO ₂ Emissions from Iron and Steel Production (MMT CO ₂ Eq.)..... | 4-58 |
| Table 4-60: CO ₂ Emissions from Iron and Steel Production (kt) | 4-58 |
| Table 4-61: CH ₄ Emissions from Iron and Steel Production (MMT CO ₂ Eq.)..... | 4-58 |
| Table 4-62: CH ₄ Emissions from Iron and Steel Production (kt) | 4-59 |
| Table 4-63: Material Carbon Contents for Metallurgical Coke Production..... | 4-60 |
| Table 4-64: Production and Consumption Data for the Calculation of CO ₂ and CH ₄ Emissions from Metallurgical Coke Production (Thousand Metric Tons) | 4-60 |
| Table 4-65: Production and Consumption Data for the Calculation of CO ₂ Emissions from Metallurgical Coke Production (Million ft ³) | 4-61 |
| Table 4-66: CO ₂ Emission Factors for Sinter Production and Direct Reduced Iron Production | 4-61 |
| Table 4-67: Material Carbon Contents for Iron and Steel Production | 4-61 |
| Table 4-68: CH ₄ Emission Factors for Sinter and Pig Iron Production | 4-62 |
| Table 4-69: Production and Consumption Data for the Calculation of CO ₂ and CH ₄ Emissions from Iron and Steel Production (Thousand Metric Tons)..... | 4-63 |
| Table 4-70: Production and Consumption Data for the Calculation of CO ₂ Emissions from Iron and Steel Production (Million ft ³ unless otherwise specified)..... | 4-64 |
| Table 4-71: Approach 2 Quantitative Uncertainty Estimates for CO ₂ and CH ₄ Emissions from Iron and Steel Production and Metallurgical Coke Production (MMT CO ₂ Eq. and Percent)..... | 4-65 |
| Table 4-72: CO ₂ and CH ₄ Emissions from Ferroalloy Production (MMT CO ₂ Eq.)..... | 4-67 |
| Table 4-73: CO ₂ and CH ₄ Emissions from Ferroalloy Production (kt)..... | 4-67 |
| Table 4-74: Production of Ferroalloys (Metric Tons)..... | 4-68 |
| Table 4-75: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Ferroalloy Production (MMT CO ₂ Eq. and Percent)..... | 4-69 |
| Table 4-76: CO ₂ Emissions from Aluminum Production (MMT CO ₂ Eq. and kt)..... | 4-70 |
| Table 4-77: PFC Emissions from Aluminum Production (MMT CO ₂ Eq.)..... | 4-71 |
| Table 4-78: PFC Emissions from Aluminum Production (kt) | 4-71 |
| Table 4-79: Production of Primary Aluminum (kt) | 4-74 |
| Table 4-80: Approach 2 Quantitative Uncertainty Estimates for CO ₂ and PFC Emissions from Aluminum Production (MMT CO ₂ Eq. and Percent)..... | 4-74 |
| Table 4-81: SF ₆ , HFC-134a, FK 5-1-12 and CO ₂ Emissions from Magnesium Production and Processing (MMT CO ₂ Eq.) | 4-75 |
| Table 4-82: SF ₆ , HFC-134a, FK 5-1-12 and CO ₂ Emissions from Magnesium Production and Processing (kt) ... | 4-75 |
| Table 4-83: SF ₆ Emission Factors (kg SF ₆ per metric ton of magnesium) | 4-77 |

| | |
|--|-------|
| Table 4-84: Approach 2 Quantitative Uncertainty Estimates for SF ₆ , HFC-134a and CO ₂ Emissions from Magnesium Production and Processing (MMT CO ₂ Eq. and Percent)..... | 4-79 |
| Table 4-85: CO ₂ Emissions from Lead Production (MMT CO ₂ Eq. and kt) | 4-80 |
| Table 4-86: Lead Production (Metric Tons) | 4-81 |
| Table 4-87: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Lead Production (MMT CO ₂ Eq. and Percent)..... | 4-81 |
| Table 4-88: Zinc Production (Metric Tons)..... | 4-83 |
| Table 4-89: CO ₂ Emissions from Zinc Production (MMT CO ₂ Eq. and kt) | 4-84 |
| Table 4-90: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Zinc Production (MMT CO ₂ Eq. and Percent)..... | 4-86 |
| Table 4-91: PFC, HFC, SF ₆ , NF ₃ , and N ₂ O Emissions from Semiconductor Manufacture (MMT CO ₂ Eq.) | 4-87 |
| Table 4-92: PFC, HFC, SF ₆ , NF ₃ , and N ₂ O Emissions from Semiconductor Manufacture (kt) | 4-87 |
| Table 4-93: Approach 2 Quantitative Uncertainty Estimates for HFC, PFC, SF ₆ , NF ₃ and N ₂ O Emissions from Semiconductor Manufacture (MMT CO ₂ Eq. and Percent)..... | 4-95 |
| Table 4-94: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO ₂ Eq.) | 4-96 |
| Table 4-95: Emissions of HFCs and PFCs from ODS Substitution (Metric Tons) | 4-97 |
| Table 4-96: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO ₂ Eq.) by Sector | 4-97 |
| Table 4-97: Approach 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (MMT CO ₂ Eq. and Percent) | 4-100 |
| Table 4-98: U.S. HFC Consumption (MMT CO ₂ Eq.) | 4-101 |
| Table 4-99: Averaged U.S. HFC Demand (MMT CO ₂ Eq.)..... | 4-102 |
| Table 4-100: SF ₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (MMT CO ₂ Eq.) | 4-104 |
| Table 4-101: SF ₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (kt) | 4-104 |
| Table 4-102: Transmission Mile Coverage and Regression Coefficients for Large and Non-Large Utilities | 4-107 |
| Table 4-103: Approach 2 Quantitative Uncertainty Estimates for SF ₆ Emissions from Electrical Transmission and Distribution (MMT CO ₂ Eq. and Percent)..... | 4-109 |
| Table 4-104: N ₂ O Production (kt) | 4-110 |
| Table 4-105: N ₂ O Emissions from N ₂ O Product Usage (MMT CO ₂ Eq. and kt) | 4-111 |
| Table 4-106: Approach 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from N ₂ O Product Usage (MMT CO ₂ Eq. and Percent)..... | 4-112 |
| Table 4-107: NO _x , CO, and NMVOC Emissions from Industrial Processes and Product Use (kt) | 4-113 |
| Table 5-1: Emissions from Agriculture (MMT CO ₂ Eq.) | 5-2 |
| Table 5-2: Emissions from Agriculture (kt)..... | 5-2 |
| Table 5-3: CH ₄ Emissions from Enteric Fermentation (MMT CO ₂ Eq.)..... | 5-3 |
| Table 5-4: CH ₄ Emissions from Enteric Fermentation (kt) | 5-3 |
| Table 5-5: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Enteric Fermentation (MMT CO ₂ Eq. and Percent)..... | 5-6 |
| Table 5-6: CH ₄ and N ₂ O Emissions from Manure Management (MMT CO ₂ Eq.)..... | 5-9 |
| Table 5-7: CH ₄ and N ₂ O Emissions from Manure Management (kt) | 5-10 |

| | |
|--|------|
| Table 5-8: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O (Direct and Indirect) Emissions from Manure Management (MMT CO ₂ Eq. and Percent)..... | 5-13 |
| Table 5-9: IPCC (2006) Implied Emission Factor Default Values Compared with Calculated Values for CH ₄ from Manure Management (kg/head/year)..... | 5-14 |
| Table 5-10: CH ₄ Emissions from Rice Cultivation (MMT CO ₂ Eq.) | 5-16 |
| Table 5-11: CH ₄ Emissions from Rice Cultivation (kt)..... | 5-16 |
| Table 5-12: Rice Area Harvested (1,000 Hectares) | 5-17 |
| Table 5-13: Average Ratooned Area as Percent of Primary Growth Area (Percent)..... | 5-18 |
| Table 5-14: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Rice Cultivation (MMT CO ₂ Eq. and Percent)..... | 5-19 |
| Table 5-15: N ₂ O Emissions from Agricultural Soils (MMT CO ₂ Eq.)..... | 5-22 |
| Table 5-16: N ₂ O Emissions from Agricultural Soils (kt)..... | 5-22 |
| Table 5-17: Direct N ₂ O Emissions from Agricultural Soils by Land Use Type and N Input Type (MMT CO ₂ Eq.) | 5-22 |
| Table 5-18: Indirect N ₂ O Emissions from Agricultural Soils (MMT CO ₂ Eq.)..... | 5-23 |
| Table 5-19: Quantitative Uncertainty Estimates of N ₂ O Emissions from Agricultural Soil Management in 2014 (MMT CO ₂ Eq. and Percent) | 5-32 |
| Table 5-20: CH ₄ and N ₂ O Emissions from Field Burning of Agricultural Residues (MMT CO ₂ Eq.)..... | 5-35 |
| Table 5-21: CH ₄ , N ₂ O, CO, and NO _x Emissions from Field Burning of Agricultural Residues (kt)..... | 5-35 |
| Table 5-22: Agricultural Crop Production (kt of Product) | 5-38 |
| Table 5-23: U.S. Average Percent Crop Area Burned by Crop (Percent) | 5-38 |
| Table 5-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues | 5-38 |
| Table 5-25: Greenhouse Gas Emission Ratios and Conversion Factors | 5-38 |
| Table 5-26: Approach 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Field Burning of Agricultural Residues (MMT CO ₂ Eq. and Percent) | 5-39 |
| Table 6-1: Net C Stock Change from Land Use, Land-Use Change, and Forestry (MMT CO ₂ Eq.)..... | 6-2 |
| Table 6-2: Emissions from Land Use, Land-Use Change, and Forestry by Gas (MMT CO ₂ Eq.)..... | 6-2 |
| Table 6-3: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry by Land Use and Land-Use Change Category (MMT CO ₂ Eq.) | 6-3 |
| Table 6-4: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry by Gas (MMT CO ₂ Eq.) | 6-4 |
| Table 6-5: Emissions and Removals (Flux) from Land Use, Land-Use Change, and Forestry by Gas (kt) | 6-5 |
| Table 6-6: Managed and Unmanaged Land Area by Land-Use Categories for All 50 States (Thousands of Hectares) | 6-7 |
| Table 6-7: Land Use and Land-Use Change for the U.S. Managed Land Base for All 50 States (Thousands of Hectares)..... | 6-8 |
| Table 6-8: Data Sources Used to Determine Land Use and Land Area for the Conterminous United States, Hawaii, and Alaska | 6-14 |
| Table 6-9: Total Land Area (Hectares) by Land-Use Category for U.S. Territories | 6-20 |
| Table 6-10: Net CO ₂ Flux from Forest Pools in <i>Forest Land Remaining Forest Land</i> and Harvested Wood Pools. (MMT CO ₂ Eq.)..... | 6-24 |

| | |
|--|------|
| Table 6-11: Net C Flux from Forest Pools in <i>Forest Land Remaining Forest Land</i> and Harvested Wood Pools (MMT C) | 6-24 |
| Table 6-12: Forest Area (1,000 ha) and C Stocks in <i>Forest Land Remaining Forest Land</i> and Harvested Wood Pools (MMT C) | 6-25 |
| Table 6-13: Estimates of CO ₂ (MMT year ⁻¹) Emissions from Forest Fires in the Conterminous 48 States and Alaska ^a | 6-27 |
| Table 6-14: Quantitative Uncertainty Estimates for Net CO ₂ Flux from <i>Forest Land Remaining Forest Land</i> : Changes in Forest C Stocks (MMT CO ₂ Eq. and Percent) | 6-30 |
| Table 6-15: Estimated Non-CO ₂ Emissions from Forest Fires (MMT CO ₂ Eq.) for U.S. Forests | 6-32 |
| Table 6-16: Estimated Non-CO ₂ Emissions from Forest Fires (kt) for U.S. Forests | 6-33 |
| Table 6-17: Quantitative Uncertainty Estimates of Non-CO ₂ Emissions from Forest Fires in <i>Forest Land Remaining Forest Land</i> (MMT CO ₂ Eq. and Percent)..... | 6-33 |
| Table 6-18: N ₂ O Fluxes from Soils in <i>Forest Land Remaining Forest Land</i> (MMT CO ₂ Eq. and kt N ₂ O) | 6-34 |
| Table 6-19: Quantitative Uncertainty Estimates of N ₂ O Fluxes from Soils in <i>Forest Land Remaining Forest Land</i> (MMT CO ₂ Eq. and Percent) | 6-36 |
| Table 6-20: Net CO ₂ Flux from Soil C Stock Changes in <i>Land Converted to Forest Land</i> by Land Use Change Category (MMT CO ₂ Eq.) | 6-37 |
| Table 6-21: Net C Flux from Soil C Stock Changes in <i>Land Converted to Forest Land</i> by Land Use Change Category (MMT C)..... | 6-37 |
| Table 6-22: Quantitative Uncertainty Estimates for Mineral Soil C Stock Changes (MMT CO ₂ Eq. per yr) in 2014 Occurring Within <i>Land Converted to Forest Land</i> | 6-38 |
| Table 6-23: Net CO ₂ Flux from Soil C Stock Changes in <i>Cropland Remaining Cropland</i> (MMT CO ₂ Eq.) | 6-41 |
| Table 6-24: Net CO ₂ Flux from Soil C Stock Changes in <i>Cropland Remaining Cropland</i> (MMT C)..... | 6-41 |
| Table 6-25: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Cropland Remaining Cropland</i> (MMT CO ₂ Eq. and Percent)..... | 6-47 |
| Table 6-26: Emissions from Liming (MMT CO ₂ Eq.)..... | 6-49 |
| Table 6-27: Emissions from Liming (MMT C) | 6-49 |
| Table 6-28: Applied Minerals (MMT)..... | 6-50 |
| Table 6-29: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Liming (MMT CO ₂ Eq. and Percent)..... | 6-51 |
| Table 6-30: CO ₂ Emissions from Urea Fertilization (MMT CO ₂ Eq.) | 6-52 |
| Table 6-31: CO ₂ Emissions from Urea Fertilization (MMT C)..... | 6-52 |
| Table 6-32: Applied Urea (MMT)..... | 6-53 |
| Table 6-33: Quantitative Uncertainty Estimates for CO ₂ Emissions from Urea Fertilization (MMT CO ₂ Eq. and Percent)..... | 6-53 |
| Table 6-34: Net CO ₂ Flux from Soil C Stock Changes in <i>Land Converted to Cropland</i> by Land Use Change Category (MMT CO ₂ Eq.) | 6-55 |
| Table 6-35: Net CO ₂ Flux from Soil C Stock Changes in <i>Land Converted to Cropland</i> (MMT C)..... | 6-55 |
| Table 6-36: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Land Converted to Cropland</i> (MMT CO ₂ Eq. and Percent) | 6-59 |
| Table 6-37: Net CO ₂ Flux from Soil C Stock Changes in <i>Grassland Remaining Grassland</i> (MMT CO ₂ Eq.)..... | 6-61 |
| Table 6-38: Net CO ₂ Flux from Soil C Stock Changes in <i>Grassland Remaining Grassland</i> (MMT C) | 6-61 |

| | |
|--|------|
| Table 6-39: Approach 2 Quantitative Uncertainty Estimates for C Stock Changes Occurring Within <i>Grassland Remaining Grassland</i> (MMT CO ₂ Eq. and Percent) | 6-65 |
| Table 6-40: Net CO ₂ Flux from Soil and Biomass C Stock Changes for <i>Land Converted to Grassland</i> (MMT CO ₂ Eq.) | 6-66 |
| Table 6-41: Net CO ₂ Flux from Soil and Biomass C Stock Changes for <i>Land Converted to Grassland</i> (MMT C) | 6-67 |
| Table 6-42: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Land Converted to Grassland</i> (MMT CO ₂ Eq. and Percent) | 6-71 |
| Table 6-43: Emissions from <i>Peatlands Remaining Peatlands</i> (MMT CO ₂ Eq.) | 6-73 |
| Table 6-44: Emissions from <i>Peatlands Remaining Peatlands</i> (kt) | 6-74 |
| Table 6-45: Peat Production of Lower 48 States (kt) | 6-75 |
| Table 6-46: Peat Production of Alaska (Thousand Cubic Meters) | 6-75 |
| Table 6-47: Approach 2 Quantitative Uncertainty Estimates for CO ₂ , CH ₄ , and N ₂ O Emissions from <i>Peatlands Remaining Peatlands</i> (MMT CO ₂ Eq. and Percent) | 6-77 |
| Table 6-48: Net C Flux from Urban Trees (MMT CO ₂ Eq. and MMT C) | 6-79 |
| Table 6-49: Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m ² -yr) for 50 states plus the District of Columbia (2014) | 6-82 |
| Table 6-50: Approach 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (MMT CO ₂ Eq. and Percent) | 6-83 |
| Table 6-51: N ₂ O Fluxes from Soils in <i>Settlements Remaining Settlements</i> (MMT CO ₂ Eq. and kt N ₂ O) | 6-84 |
| Table 6-52: Quantitative Uncertainty Estimates of N ₂ O Emissions from Soils in <i>Settlements Remaining Settlements</i> (MMT CO ₂ Eq. and Percent) | 6-85 |
| Table 6-53: Net Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills (MMT CO ₂ Eq.) | 6-87 |
| Table 6-54: Net Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills (MMT C) | 6-87 |
| Table 6-55: Moisture Contents, C Storage Factors (Proportions of Initial C Sequestered), Initial C Contents, and Decay Rates for Yard Trimmings and Food Scraps in Landfills | 6-90 |
| Table 6-56: C Stocks in Yard Trimmings and Food Scraps in Landfills (MMT C) | 6-90 |
| Table 6-57: Approach 2 Quantitative Uncertainty Estimates for CO ₂ Flux from Yard Trimmings and Food Scraps in Landfills (MMT CO ₂ Eq. and Percent) | 6-91 |
| Table 7-1: Emissions from Waste (MMT CO ₂ Eq.) | 7-2 |
| Table 7-2: Emissions from Waste (kt) | 7-2 |
| Table 7-3: CH ₄ Emissions from Landfills (MMT CO ₂ Eq.) | 7-5 |
| Table 7-4: CH ₄ Emissions from Landfills (kt) | 7-5 |
| Table 7-5: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Landfills (MMT CO ₂ Eq. and Percent) | 7-10 |
| Table 7-6: Materials Discarded in the Municipal Waste Stream by Waste Type from 1990 to 2013 (Percent) | 7-15 |
| Table 7-7: CH ₄ and N ₂ O Emissions from Domestic and Industrial Wastewater Treatment (MMT CO ₂ Eq.) | 7-17 |
| Table 7-8: CH ₄ and N ₂ O Emissions from Domestic and Industrial Wastewater Treatment (kt) | 7-18 |
| Table 7-9: U.S. Population (Millions) and Domestic Wastewater BOD ₅ Produced (kt) | 7-20 |
| Table 7-10: Domestic Wastewater CH ₄ Emissions from Septic and Centralized Systems (2014, MMT CO ₂ Eq. and Percent) | 7-20 |

| | |
|---|------|
| Table 7-11: Industrial Wastewater CH ₄ Emissions by Sector (2014, MMT CO ₂ Eq. and Percent)..... | 7-20 |
| Table 7-12: U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (MMT) | 7-21 |
| Table 7-13: Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (percent) | 7-22 |
| Table 7-14: Wastewater Flow (m ³ /ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production..... | 7-23 |
| Table 7-15: U.S. Population (Millions), Population Served by Biological Denitrification (Millions), Fraction of Population Served by Wastewater Treatment (percent), Available Protein (kg/person-year), Protein Consumed (kg/person-year), and Nitrogen Removed with Sludge (kt-N/year)..... | 7-26 |
| Table 7-16: Approach 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Wastewater Treatment (MMT CO ₂ Eq. and Percent)..... | 7-27 |
| Table 7-17: CH ₄ and N ₂ O Emissions from Composting (MMT CO ₂ Eq.) | 7-29 |
| Table 7-18: CH ₄ and N ₂ O Emissions from Composting (kt)..... | 7-29 |
| Table 7-19: U.S. Waste Composted (kt)..... | 7-31 |
| Table 7-20: Approach 1 Quantitative Uncertainty Estimates for Emissions from Composting (MMT CO ₂ Eq. and Percent)..... | 7-31 |
| Table 7-21: Emissions of NO _x , CO, and NMVOC from Waste (kt)..... | 7-32 |
| Table 9-1: Revisions to U.S. Greenhouse Gas Emissions (MMT CO ₂ Eq.)..... | 9-4 |
| Table 9-2: Revisions to Total Net Flux from Land Use, Land-Use Change, and Forestry (MMT CO ₂ Eq.) | 9-6 |

Figures

| | |
|---|-------|
| Figure ES-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO ₂ Eq.)..... | ES-4 |
| Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions Relative to the Previous Year..... | ES-5 |
| Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990 (1990=0, MMT CO ₂ Eq.) | ES-5 |
| Figure ES-4: 2014 U.S. Greenhouse Gas Emissions by Gas (Percentages based on MMT CO ₂ Eq.)..... | ES-8 |
| Figure ES-5: 2014 Sources of CO ₂ Emissions (MMT CO ₂ Eq.) | ES-9 |
| Figure ES-6: 2014 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO ₂ Eq.)..... | ES-10 |
| Figure ES-7: 2014 End-Use Sector Emissions of CO ₂ from Fossil Fuel Combustion (MMT CO ₂ Eq.) | ES-10 |
| Figure ES-8: 2014 Sources of CH ₄ Emissions (MMT CO ₂ Eq.) | ES-13 |
| Figure ES-9: 2014 Sources of N ₂ O Emissions (MMT CO ₂ Eq.) | ES-15 |
| Figure ES-10: 2014 Sources of HFCs, PFCs, SF ₆ , and NF ₃ Emissions (MMT CO ₂ Eq.)..... | ES-16 |
| Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO ₂ Eq.)..... | ES-17 |
| Figure ES-12: 2014 U.S. Energy Consumption by Energy Source (Percent)..... | ES-19 |
| Figure ES-13: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO ₂ Eq.)..... | ES-22 |
| Figure ES-14: U.S. Greenhouse Gas Emissions with Electricity-Related Emissions Distributed to Economic Sectors (MMT CO ₂ Eq.)..... | ES-24 |
| Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product (GDP).. | ES-25 |
| Figure ES-16: 2014 Key Categories (MMT CO ₂ Eq.)..... | ES-26 |

| | |
|---|------|
| Figure 1-1: National Inventory Arrangements Diagram..... | 1-13 |
| Figure 1-2: U.S. QA/QC Plan Summary | 1-21 |
| Figure 2-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO ₂ Eq.) | 2-1 |
| Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions Relative to the Previous Year | 2-2 |
| Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990 (1990=0, MMT CO ₂ Eq.) | 2-2 |
| Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO ₂ Eq.) | 2-8 |
| Figure 2-5: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 2-10 |
| Figure 2-6: 2014 U.S. Fossil Carbon Flows (MMT CO ₂ Eq.) | 2-10 |
| Figure 2-7: 2014 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO ₂ Eq.) | 2-12 |
| Figure 2-8: 2014 End-Use Sector Emissions of CO ₂ from Fossil Fuel Combustion (MMT CO ₂ Eq.) | 2-13 |
| Figure 2-9: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 2-15 |
| Figure 2-10: 2014 Agriculture Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 2-17 |
| Figure 2-11: 2014 Waste Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 2-21 |
| Figure 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO ₂ Eq.) | 2-22 |
| Figure 2-13: U.S. Greenhouse Gas Emissions with Electricity-Related Emissions Distributed to Economic Sectors (MMT CO ₂ Eq.) | 2-26 |
| Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product | 2-32 |
| Figure 3-1: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 3-1 |
| Figure 3-2: 2014 U.S. Fossil Carbon Flows (MMT CO ₂ Eq.) | 3-2 |
| Figure 3-3: 2014 U.S. Energy Consumption by Energy Source (Percent) | 3-7 |
| Figure 3-4: U.S. Energy Consumption (Quadrillion Btu) | 3-7 |
| Figure 3-5: 2014 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO ₂ Eq.) | 3-8 |
| Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2014, Index Normal = 100) | 3-9 |
| Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2014, Index Normal = 100) | 3-9 |
| Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2014, Percent) | 3-10 |
| Figure 3-9: Electricity Generation Retail Sales by End-Use Sector (Billion kWh) | 3-14 |
| Figure 3-10: Industrial Production Indices (Index 2007=100) | 3-16 |
| Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2014 (miles/gallon) | 3-19 |
| Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2014 (Percent) | 3-19 |
| Figure 3-13: Mobile Source CH ₄ and N ₂ O Emissions (MMT CO ₂ Eq.) | 3-22 |
| Figure 3-14: U.S. Energy Consumption and Energy-Related CO ₂ Emissions Per Capita and Per Dollar GDP | 3-29 |
| Figure 4-1: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.) | 4-2 |
| Figure 5-1: 2014 Agriculture Chapter Greenhouse Gas Emission Sources (MMT CO ₂ Eq.) | 5-1 |
| Figure 5-2: Sources and Pathways of N that Result in N ₂ O Emissions from Agricultural Soil Management | 5-21 |

| | |
|--|------|
| Figure 5-3: Crops, 2014 Annual Direct N ₂ O Emissions Estimated Using the Tier 3 DAYCENT Model (MMT CO ₂ Eq./year) | 5-24 |
| Figure 5-4: Grasslands, 2014 Annual Direct N ₂ O Emissions Estimated Using the Tier 3 DAYCENT Model (MMT CO ₂ Eq./year)..... | 5-24 |
| Figure 5-5: Crops, 2014 Average Annual N Losses Leading to Indirect N ₂ O Emissions Estimated Using the Tier 3 DAYCENT Model (kt N/year) | 5-25 |
| Figure 5-6: Grasslands, 2014 Average Annual N Losses Leading to Indirect N ₂ O Emissions Estimated Using the Tier 3 DAYCENT Model (kt N/year)..... | 5-25 |
| Figure 5-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model and IPCC Tier 1 Approach (kg N ₂ O per ha per year) | 5-33 |
| Figure 6-1: Percent of Total Land Area for Each State in the General Land-Use Categories for 2014..... | 6-10 |
| Figure 6-2: Changes in Forest Area by Region for <i>Forest Land Remaining Forest Land</i> in the conterminous United States and coastal Alaska (1990-2014, Million Hectares) | 6-23 |
| Figure 6-3: Estimated Net Annual Changes in C Stocks for Major C Pools in <i>Forest Land Remaining Forest Land</i> in the Conterminous U.S. and Coastal Alaska (MMT C year ⁻¹) | 6-26 |
| Figure 6-4: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2014, <i>Cropland Remaining Cropland</i> | 6-42 |
| Figure 6-5: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2014, <i>Cropland Remaining Cropland</i> | 6-43 |
| Figure 6-6: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2014, <i>Land Converted to Cropland</i> | 6-56 |
| Figure 6-7: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2014, <i>Land Converted to Cropland</i> | 6-57 |
| Figure 6-8: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2014, <i>Grassland Remaining Grassland</i> | 6-62 |
| Figure 6-9: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2014, <i>Grassland Remaining Grassland</i> | 6-62 |
| Figure 6-10: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2014, <i>Land Converted to Grassland</i> | 6-68 |
| Figure 6-11: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2014, <i>Land Converted to Grassland</i> | 6-69 |
| Figure 7-1: 2014 Waste Chapter Greenhouse Gas Sources (MMT CO ₂ Eq.)..... | 7-1 |
| Figure 7-2: Management of Municipal Solid Waste in the United States, 2013..... | 7-14 |
| Figure 7-3: MSW Management Trends from 1990 to 2013 | 7-14 |
| Figure 7-4: Percent of Recovered Degradable Materials from 1990 to 2013 (Percent)..... | 7-15 |
| Figure 7-5: CH ₄ and N ₂ O Emitted from Composting Operations between 1990 and 2014 (kt or million tons) | 7-30 |

Boxes

| | |
|---|-------|
| Box ES-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks | ES-1 |
| Box ES-2: Use of Ambient Measurements Systems for Validation of Emission Inventories | ES-12 |
| Box ES-3: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data | ES-24 |
| Box ES-4: Recalculations of Inventory Estimates | ES-27 |

| | |
|---|------|
| Box 1-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks | 1-3 |
| Box 1-2: The <i>IPCC Fifth Assessment Report</i> and Global Warming Potentials | 1-10 |
| Box 1-3: IPCC Reference Approach | 1-16 |
| Box 2-1: Methodology for Aggregating Emissions by Economic Sector | 2-30 |
| Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data | 2-31 |
| Box 2-3: Sources and Effects of Sulfur Dioxide | 2-34 |
| Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks | 3-3 |
| Box 3-2: Energy Data from the Greenhouse Gas Reporting Program | 3-4 |
| Box 3-3: Weather and Non-Fossil Energy Effects on CO ₂ from Fossil Fuel Combustion Trends | 3-8 |
| Box 3-4: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from Industrial Sector Fossil Fuel Combustion | 3-27 |
| Box 3-5: Carbon Intensity of U.S. Energy Consumption | 3-28 |
| Box 3-6: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in Energy Sector | 3-45 |
| Box 3-7: Carbon Dioxide Transport, Injection, and Geological Storage | 3-67 |
| Box 4-1: Industrial Processes Data from EPA’s Greenhouse Gas Reporting Program | 4-6 |
| Box 5-1: Tier 1 vs. Tier 3 Approach for Estimating N ₂ O Emissions | 5-27 |
| Box 5-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach | 5-36 |
| Box 6-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks | 6-5 |
| Box 6-2: Preliminary Estimates of Land Use in U.S. Territories | 6-20 |
| Box 6-3: CO ₂ Emissions from Forest Fires | 6-26 |
| Box 6-4: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches | 6-44 |
| Box 6-5: Comparison of the Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach | 6-49 |
| Box 6-6: Progress on Inclusion of Managed Coastal Wetlands in the U.S. Greenhouse Gas Inventory | 6-78 |
| Box 7-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks | 7-1 |
| Box 7-2: Waste Data from the Greenhouse Gas Reporting Program | 7-3 |
| Box 7-3: Nationwide Municipal Solid Waste Data Sources | 7-13 |
| Box 7-4: Overview of the Waste Sector | 7-13 |
| Box 7-5: Description of a Modern, Managed Landfill | 7-16 |

Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic¹ sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, “The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner.”²

Parties to the Convention, by ratifying, “shall develop, periodically update, publish and make available... national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies...”³ The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2014. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the *2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.⁴

Box ES-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the gross emissions total presented in this report for the United States excludes emissions and sinks from LULUCF. The net emissions total presented in this report for the United States includes emissions and sinks from LULUCF. All emissions and sinks are calculated using internationally-accepted methods provided by the

¹ The term “anthropogenic,” in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC 2006).

² Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <<http://unfccc.int>>.

³ Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <<http://unfccc.int>>.

⁴ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

IPCC.⁵ Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.⁶ The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject carbon dioxide (CO₂) underground for sequestration or other reasons.⁷ Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective methodological and planned improvements sections in this report's chapters, EPA is using the data, as applicable, to improve the national estimates presented in this Inventory.

ES.1. Background Information

Greenhouse gases trap heat and make the planet warmer. The most important greenhouse gases directly emitted by humans include CO₂, methane (CH₄), nitrous oxide (N₂O), and several other fluorine-containing halogenated substances. Although the direct greenhouse gases CO₂, CH₄, and N₂O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2014, concentrations of these greenhouse gases have increased globally by 43, 160, and 21 percent, respectively (IPCC 2013 and NOAA/ESRL 2016). This annual report estimates the total national greenhouse gas emissions and removals associated with human activities across the United States.

Global Warming Potentials

Gases in the atmosphere can contribute to climate change both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).⁸ The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2013). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO₂, and therefore GWP-

⁵ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

⁶ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>>.

⁷ See <<http://www.epa.gov/ghgreporting>> and <<http://ghgdata.epa.gov/ghgp/main.do>>.

⁸ Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

weighted emissions are measured in million metric tons of CO₂ equivalent (MMT CO₂ Eq.).^{9,10} All gases in this Executive Summary are presented in units of MMT CO₂ Eq. Emissions by gas in unweighted mass tons are provided in the Trends chapter of this report.

UNFCCC reporting guidelines for national inventories require the use of GWP values from the *IPCC Fourth Assessment Report (AR4)* (IPCC 2007).¹¹ To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using AR4 GWP values, which have replaced the previously required use of *IPCC Second Assessment Report (SAR)* (IPCC 1996) GWP values in the Inventory. All estimates are provided throughout the report in both CO₂ equivalents and unweighted units. A comparison of emission values using the AR4 GWP values versus the SAR (IPCC 1996), and the *IPCC Fifth Assessment Report (AR5)* (IPCC 2013) GWP values can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

| Gas | GWP |
|--------------------------------|--------|
| CO ₂ | 1 |
| CH ₄ ^a | 25 |
| N ₂ O | 298 |
| HFC-23 | 14,800 |
| HFC-32 | 675 |
| HFC-125 | 3,500 |
| HFC-134a | 1,430 |
| HFC-143a | 4,470 |
| HFC-152a | 124 |
| HFC-227ea | 3,220 |
| HFC-236fa | 9,810 |
| HFC-4310mee | 1,640 |
| CF ₄ | 7,390 |
| C ₂ F ₆ | 12,200 |
| C ₄ F ₁₀ | 8,860 |
| C ₆ F ₁₄ | 9,300 |
| SF ₆ | 22,800 |
| NF ₃ | 17,200 |

Source: IPCC (2007)

^a The CH₄ GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to production of CO₂ is not included.

⁹ Carbon comprises 12/44 of carbon dioxide by weight.

¹⁰ One teragram is equal to 10¹² grams or one million metric tons.

¹¹ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2014, total U.S. greenhouse gas emissions were 6,870.5 MMT or million metric tons CO₂ Eq. Total U.S. emissions have increased by 7.4 percent from 1990 to 2014, and emissions increased from 2013 to 2014 by 1.0 percent (70.5 MMT CO₂ Eq.). In 2014, relatively cool winter conditions led to an increase in fuels for the residential and commercial sectors for heating. Additionally, transportation emissions increased as a result of a small increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes. There also was an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions. Lastly, since 1990, U.S. emissions have increased at an average annual rate of 0.3 percent. Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Overall, net emissions in 2014 were 8.6 percent below 2005 levels as shown in Table ES-2.

Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2014.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO₂ Eq.)

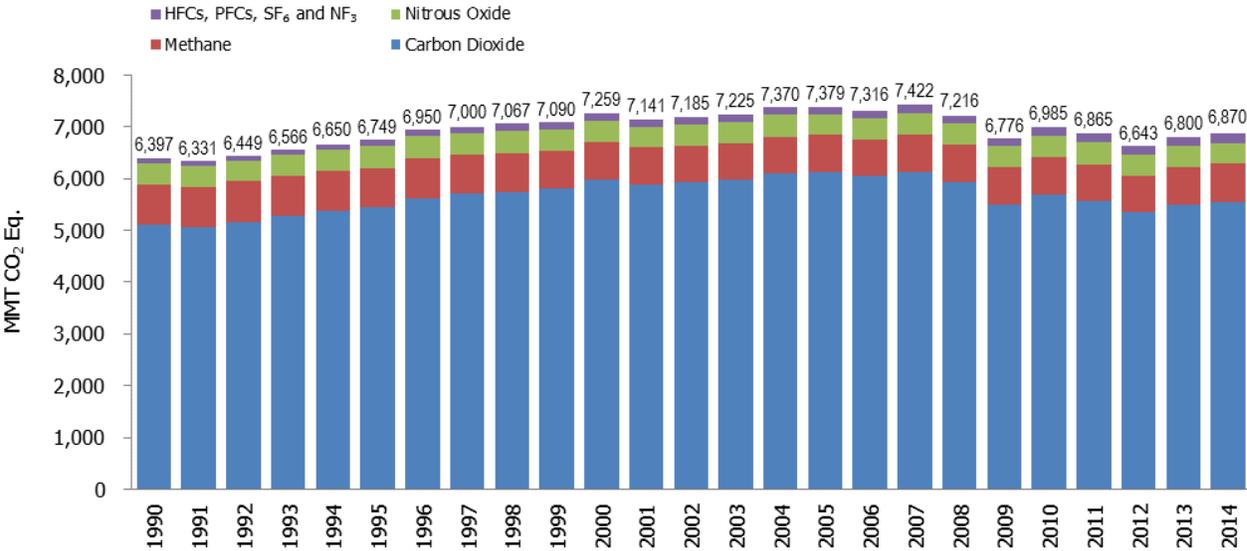


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions Relative to the Previous Year

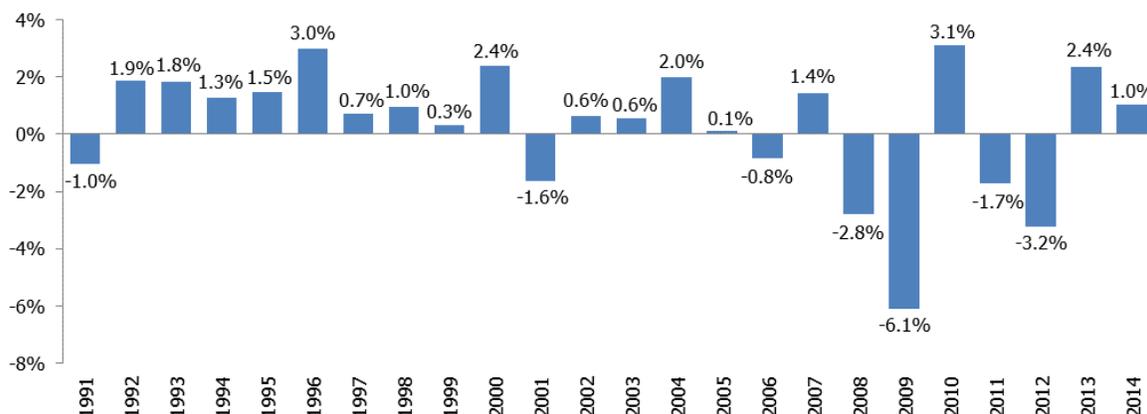


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990 (1990=0, MMT CO₂ Eq.)

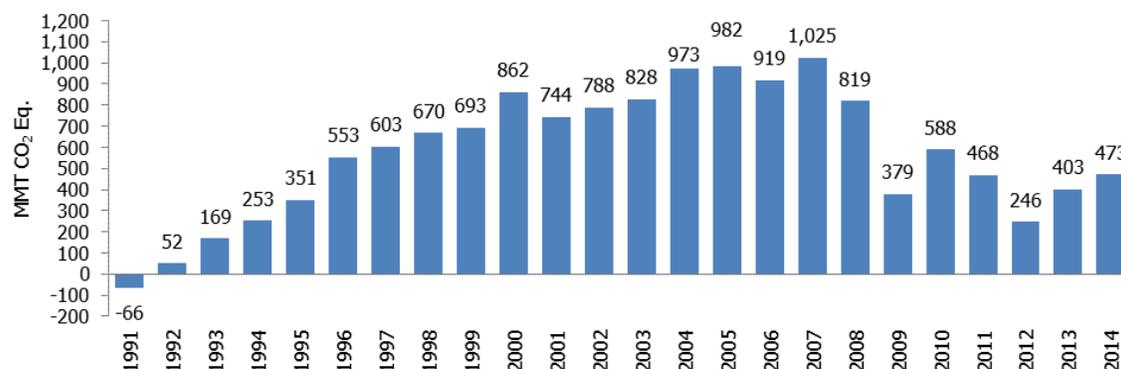


Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 5,115.1 | 6,122.7 | 5,688.8 | 5,559.5 | 5,349.2 | 5,502.6 | 5,556.0 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| <i>Electricity Generation</i> | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| <i>Transportation</i> | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| <i>Industrial</i> | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| <i>Residential</i> | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| <i>Commercial</i> | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| <i>U.S. Territories</i> | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.5 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| Natural Gas Systems | 37.7 | 30.1 | 32.4 | 35.7 | 35.2 | 38.5 | 42.4 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.6 | 27.4 | 27.2 | 26.3 | 26.5 | 26.4 | 26.5 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |

| | | | | | | | |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Incineration of Waste | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Petroleum Systems | 3.6 | 3.9 | 4.2 | 4.2 | 3.9 | 3.7 | 3.6 |
| Aluminum Production | 6.8 | 4.1 | 2.7 | 3.3 | 3.4 | 3.3 | 2.8 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Magnesium Production and Processing | + | + | + | + | + | + | + |
| Wood Biomass and Ethanol Consumption ^a | 219.4 | 229.8 | 265.1 | 268.1 | 267.7 | 286.3 | 293.7 |
| International Bunker Fuels ^b | 103.5 | 113.1 | 117.0 | 111.7 | 105.8 | 99.8 | 103.2 |
| CH₄ | 773.9 | 717.4 | 722.4 | 717.4 | 714.4 | 721.5 | 730.8 |
| Natural Gas Systems | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Petroleum Systems | 38.7 | 48.8 | 54.1 | 56.3 | 58.4 | 64.7 | 68.1 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Manure Management | 37.2 | 56.3 | 60.9 | 61.5 | 63.7 | 61.4 | 61.2 |
| Wastewater Treatment | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Stationary Combustion | 8.5 | 7.4 | 7.1 | 7.1 | 6.6 | 8.0 | 8.1 |
| Abandoned Underground Coal Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |
| Composting | 0.4 | 1.9 | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 |
| Mobile Combustion | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| Field Burning of Agricultural Residues | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Petrochemical Production | 0.2 | 0.1 | + | + | 0.1 | 0.1 | 0.1 |
| Ferroalloy Production | + | + | + | + | + | + | + |
| Silicon Carbide Production and Consumption | + | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | + | + | + | + | + | + | + |
| Incineration of Waste | + | + | + | + | + | + | + |
| International Bunker Fuels ^b | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| N₂O | 406.2 | 397.6 | 410.3 | 416.5 | 409.3 | 403.4 | 403.5 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Stationary Combustion | 11.9 | 20.2 | 22.2 | 21.3 | 21.4 | 22.9 | 23.4 |
| Manure Management | 14.0 | 16.5 | 17.2 | 17.4 | 17.5 | 17.5 | 17.5 |
| Mobile Combustion | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |

| | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Wastewater Treatment | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Composting | 0.3 | 1.7 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 |
| Incineration of Waste | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Semiconductor Manufacture | + | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| Field Burning of Agricultural Residues | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| <i>International Bunker Fuels^b</i> | <i>0.9</i> | <i>1.0</i> | <i>1.0</i> | <i>1.0</i> | <i>0.9</i> | <i>0.9</i> | <i>0.9</i> |
| HFCs | 46.6 | 119.9 | 149.4 | 154.3 | 155.9 | 158.9 | 166.7 |
| Substitution of Ozone Depleting Substances ^c | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacture | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Magnesium Production and Processing | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| PFCs | 24.3 | 6.7 | 4.5 | 7.0 | 6.0 | 5.8 | 5.6 |
| Semiconductor Manufacture | 2.8 | 3.2 | 2.7 | 3.5 | 3.1 | 2.9 | 3.0 |
| Aluminum Production | 21.5 | 3.4 | 1.9 | 3.5 | 2.9 | 3.0 | 2.5 |
| SF₆ | 31.1 | 14.0 | 9.5 | 10.0 | 7.6 | 7.2 | 7.3 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.6 | 1.5 | 1.0 |
| Semiconductor Manufacture | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.7 |
| NF₃ | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Semiconductor Manufacture | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| LULUCF Emissions^d | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 |
| LULUCF Total Net Flux^e | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| LULUCF Sector Total^f | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

Notes: Total emissions presented without LULUCF. Net emissions presented with LULUCF.

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

^b Emissions from International Bunker Fuels are not included in totals.

^c Small amounts of PFC emissions also result from this source.

^d LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Agricultural Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^e Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other*. Refer to Table ES-5 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

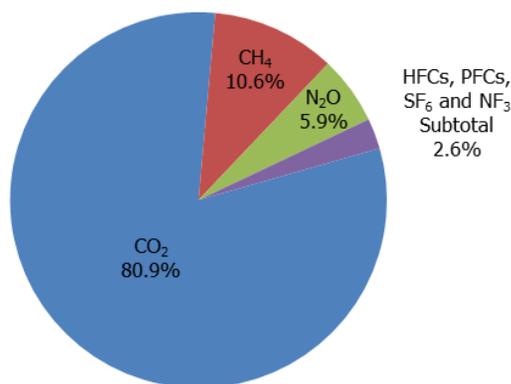
^f The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2014. Note, unless otherwise stated, all tables and figures provide total emissions without LULUCF. The primary greenhouse gas emitted by human activities in the United States was CO₂, representing approximately 80.9 percent of total greenhouse gas emissions. The largest source of CO₂, and of overall greenhouse gas emissions, was fossil fuel combustion. CH₄ emissions, which have decreased by 5.6 percent since 1990, resulted primarily from decomposition of wastes in landfills, enteric fermentation associated with domestic livestock, and natural gas systems. Agricultural soil management, manure management, mobile source fuel combustion and stationary fuel

combustion were the major sources of N₂O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate hydrofluorocarbon (HFC) emissions. Perfluorocarbon (PFC) emissions resulted as a byproduct of primary aluminum production and from semiconductor manufacturing, electrical transmission and distribution systems accounted for most sulfur hexafluoride (SF₆) emissions, and semiconductor manufacturing is the only source of nitrogen trifluoride (NF₃) emissions.

Figure ES-4: 2014 U.S. Greenhouse Gas Emissions by Gas (Percentages based on MMT CO₂ Eq.)



Overall, from 1990 to 2014, total emissions of CO₂ increased by 440.9 MMT CO₂ Eq. (8.6 percent), while total emissions of CH₄ decreased by 43.0 MMT CO₂ Eq. (5.6 percent), and N₂O decreased by 2.7 MMT CO₂ Eq. (0.7 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, SF₆ and NF₃ rose by 78.1 MMT CO₂ Eq. (76.6 percent). From 1990 to 2014, HFCs increased by 120.1 MMT CO₂ Eq. (257.9 percent), PFCs decreased by 18.7 MMT CO₂ Eq. (77.1 percent), SF₆ decreased by 23.7 MMT CO₂ Eq. (76.4 percent), and NF₃ increased by 0.4 MMT CO₂ Eq. (923.4 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, SF₆ and NF₃ are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF₆, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon (C) sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 11.5 percent of total emissions in 2014. The following sections describe each gas’s contribution to total U.S. greenhouse gas emissions in more detail.

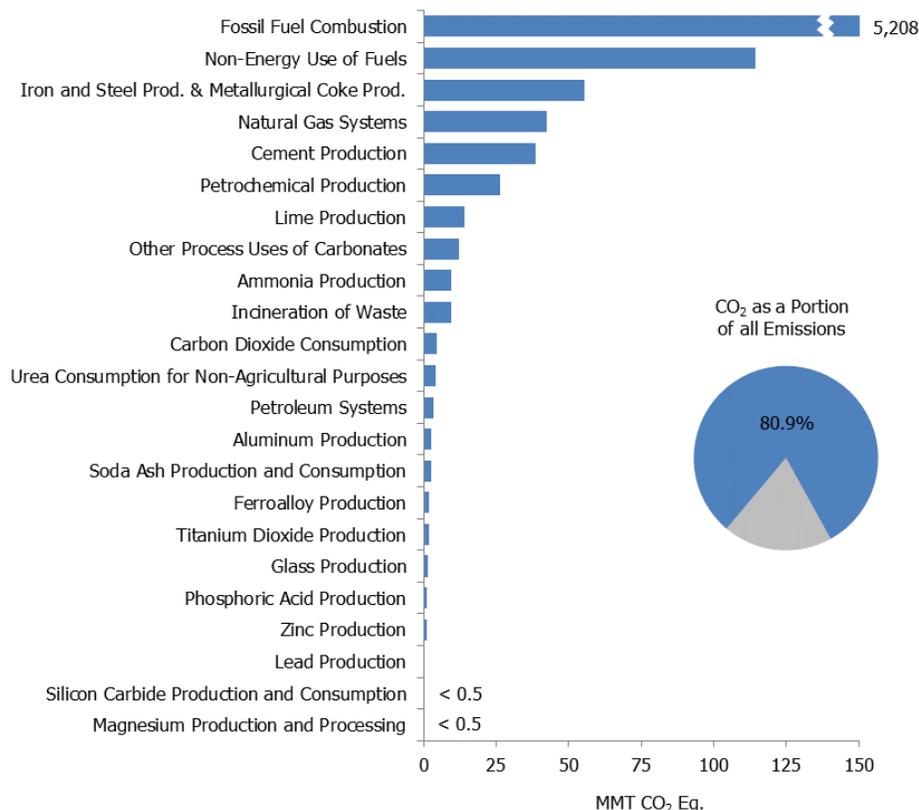
Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO₂ are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced.¹² Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO₂ have risen approximately 43 percent (IPCC 2013 and NOAA/ESRL 2016), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 93.7 percent of CO₂ emissions in 2014. Globally,

¹² The term “flux” is used to describe the net emissions of greenhouse gases accounting for both the emissions of CO₂ to and the removals of CO₂ from the atmosphere. Removal of CO₂ from the atmosphere is also referred to as “carbon sequestration.”

approximately 32,190 MMT of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2013, of which the United States accounted for approximately 16 percent.¹³ Changes in land use and forestry practices can also emit CO₂ (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO₂ (e.g., through net additions to forest biomass). Although fossil fuel combustion is the greatest source of CO₂ emissions, there are 22 additional sources of CO₂ emissions (Figure ES-5).

Figure ES-5: 2014 Sources of CO₂ Emissions (MMT CO₂ Eq.)



Note: Fossil Fuel Combustion includes electricity generation, which also includes emissions of less than 0.05 MMT CO₂ Eq. from geothermal-based generation.

As the largest source of U.S. greenhouse gas emissions, CO₂ from fossil fuel combustion has accounted for approximately 76 percent of GWP-weighted emissions since 1990, and is approximately 76 percent of total GWP-weighted emissions in 2014. Emissions of CO₂ from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2014. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 25 years, (2) an overall growth in emissions from electricity generation and transportation activities, and (3) a general decline in the carbon intensity of fuels combusted for energy in recent years by most sectors of the economy. Between 1990 and 2014, CO₂ emissions from fossil fuel combustion increased from 4,740.7 MMT CO₂ Eq. to 5,208.2 MMT CO₂ Eq., a 9.9 percent total increase over the twenty-five-year period. From 2013 to 2014, these emissions increased by 50.6 MMT CO₂ Eq. (1.0 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes,

¹³ Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *CO₂ Emissions from Fossil Fuels Combustion – Highlights* (2015). See <<https://www.iea.org/publications/freepublications/publication/CO2EmissionsFromFuelCombustionHighlights2015.pdf>>.

energy fuel choices, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2014 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO₂ Eq.)

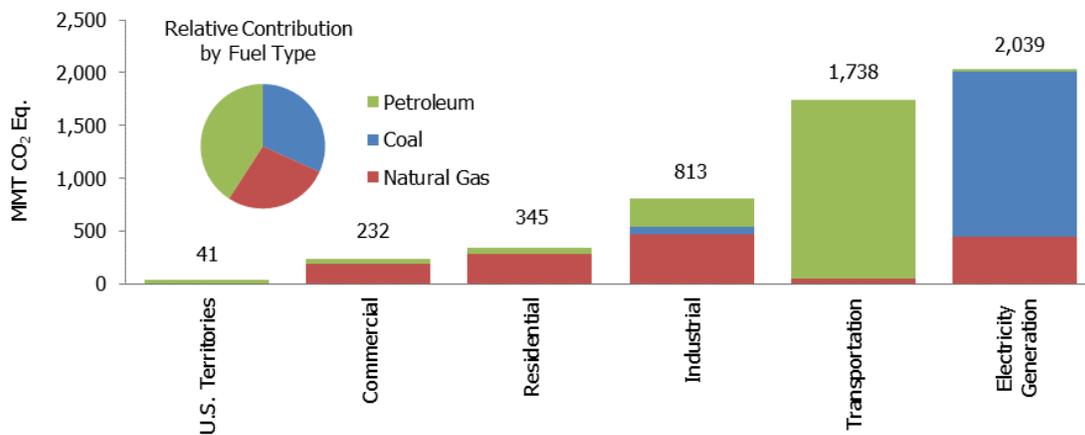
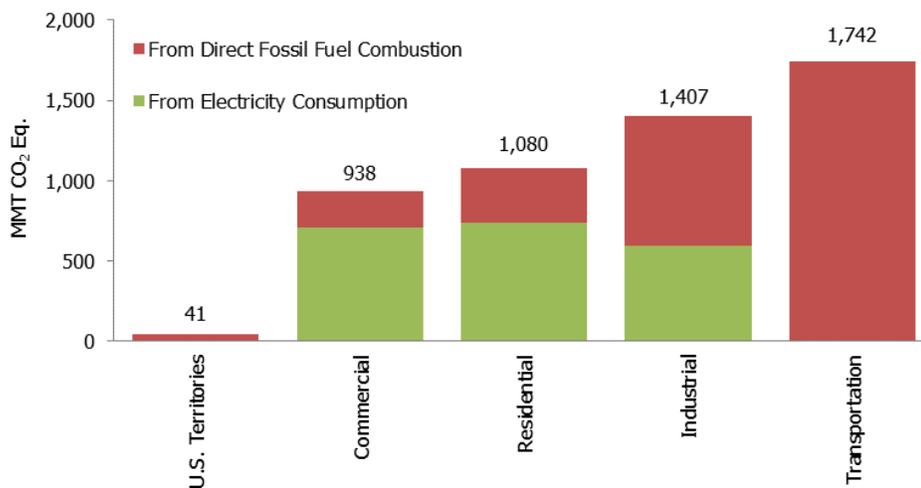


Figure ES-7: 2014 End-Use Sector Emissions of CO₂ from Fossil Fuel Combustion (MMT CO₂ Eq.)



The five major fuel consuming sectors contributing to CO₂ emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO₂ emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or “end-use”

sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. Territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors. Figure ES-6, Figure ES-7, and Table ES-3 summarize CO₂ emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO₂ Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Transportation | 1,496.8 | 1,891.8 | 1,732.7 | 1,711.9 | 1,700.6 | 1,717.0 | 1,741.7 |
| Combustion | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| Electricity | 3.0 | 4.7 | 4.5 | 4.3 | 3.9 | 4.0 | 4.1 |
| Industrial | 1,529.2 | 1,564.6 | 1,416.5 | 1,398.0 | 1,375.7 | 1,407.0 | 1,406.8 |
| Combustion | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| Electricity | 686.7 | 736.6 | 641.0 | 624.7 | 592.8 | 594.7 | 593.6 |
| Residential | 931.4 | 1,214.1 | 1,174.6 | 1,117.5 | 1,007.8 | 1,064.6 | 1,080.3 |
| Combustion | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| Electricity | 593.0 | 856.3 | 840.0 | 790.7 | 725.3 | 734.9 | 735.2 |
| Commercial | 755.4 | 1,026.8 | 993.0 | 958.8 | 897.0 | 925.5 | 938.4 |
| Combustion | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| Electricity | 538.0 | 803.3 | 772.9 | 738.0 | 700.3 | 704.5 | 706.5 |
| U.S. Territories^a | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Total | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| Electricity Generation | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |

^a Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Notes: Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector. Totals may not sum due to independent rounding.

Transportation End-Use Sector. When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 33.4 percent of U.S. CO₂ emissions from fossil fuel combustion in 2014. The largest sources of transportation CO₂ emissions in 2014 were passenger cars (42.4 percent), medium- and heavy-duty trucks (23.1 percent), light-duty trucks, which include sport utility vehicles, pickup trucks, and minivans (17.8 percent), commercial aircraft (6.6 percent), pipelines (2.7 percent), rail (2.6 percent), and ships and boats (1.6 percent). Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO₂, CH₄, N₂O, and HFCs.

In terms of the overall trend, from 1990 to 2014, total transportation CO₂ emissions rose by 16 percent due, in large part, to increased demand for travel as fleet wide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). The number of VMT by light-duty motor vehicles (i.e., passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices during the beginning of this period. Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder.

Industrial End-Use Sector. Industrial CO₂ emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 27 percent of CO₂ from fossil fuel combustion in 2014. Approximately 58 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other

end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 21 and 18 percent, respectively, of CO₂ emissions from fossil fuel combustion in 2014. Both sectors relied heavily on electricity for meeting energy demands, with 68 and 75 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from the residential and commercial end-use sectors have increased by 16 percent and 24 percent since 1990, respectively, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 34 percent of total U.S. energy uses from fossil fuels and emitted 39 percent of the CO₂ from fossil fuel combustion in 2014. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated through non-fossil fuel options such as nuclear, hydroelectric, or geothermal energy. Including all electricity generation modes, generators relied on coal for approximately 39 percent of their total energy requirements in 2014.¹⁴ In addition, the coal used by electricity generators accounted for 93 percent of all coal consumed for energy in the United States in 2014.¹⁵ Recently, a decrease in the carbon intensity of fuels consumed to generate electricity has occurred due to a decrease in coal consumption, and increased natural gas consumption and other generation sources. Including all electricity generation modes, electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014.¹⁶ Across the time series, changes in electricity demand and the carbon intensity of fuels used for electricity generation have a significant impact on CO₂ emissions.

Other significant CO₂ trends included the following:

- Carbon dioxide emissions from non-energy use of fossil fuels decreased by 3.8 MMT CO₂ Eq. (3.2 percent) from 1990 through 2014. Emissions from non-energy uses of fossil fuels were 114.3 MMT CO₂ Eq. in 2014, which constituted 2.1 percent of total national CO₂ emissions, approximately the same proportion as in 1990.
- Carbon dioxide emissions from iron and steel production and metallurgical coke production have declined by 44.3 MMT CO₂ Eq. (44.5 percent) from 1990 through 2014, due to restructuring of the industry, technological improvements, and increased scrap steel utilization.
- Carbon dioxide emissions from ammonia production (9.4 MMT CO₂ Eq. in 2014) decreased by 3.6 MMT CO₂ Eq. (27.7 percent) since 1990. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia.
- Total net flux from (i.e., net CO₂ removals) from Land Use, Land-Use Change, and Forestry increased by 34.1 MMT CO₂ Eq. (4.5 percent) from 1990 through 2014. This increase was primarily due to an increase in the rate of net C accumulation in forest and urban tree carbon stocks. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Box ES-2: Use of Ambient Measurements Systems for Validation of Emission Inventories

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.¹⁷ Several recent studies have measured emissions at the national or regional level (e.g., Petron 2012, Miller et al. 2013) with results that differ from EPA's estimate of emissions. A recent study reviewed technical literature on CH₄ emissions and estimated CH₄ emissions

¹⁴ See <http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states>.

¹⁵ See Table 6.2 Coal Consumption by Sector of EIA 2016.

¹⁶ See <http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states>.

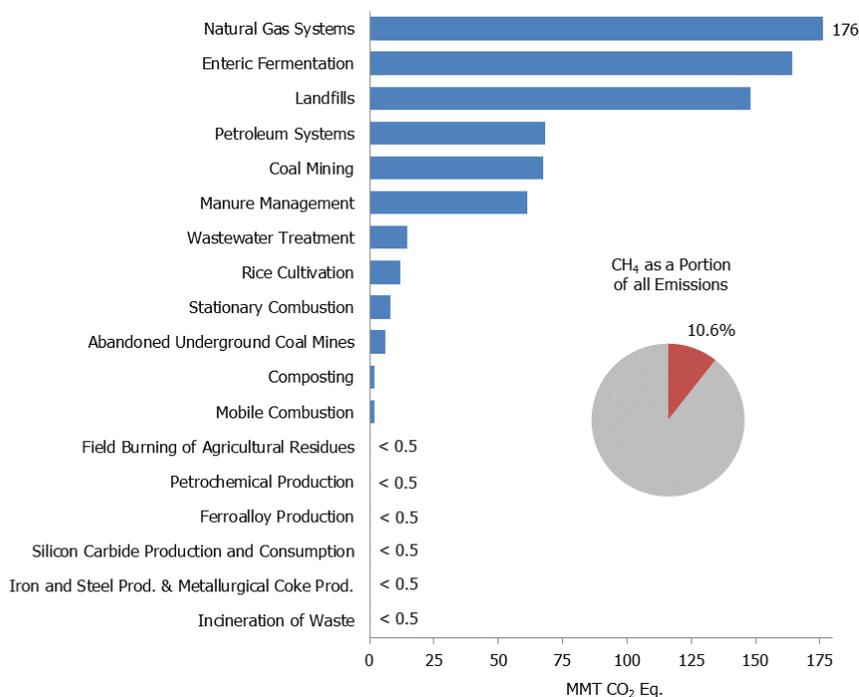
¹⁷ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

from all anthropogenic sources (e.g., livestock, oil and gas, waste emissions) to be greater than EPA’s estimate (Brandt et al. 2014). EPA has engaged with researchers on how remote sensing, ambient measurement, and inverse modeling techniques for greenhouse gas emissions could assist in improving the understanding of inventory estimates. An area of particular interest in EPA’s outreach efforts is how these data can be used in a manner consistent with this Inventory report’s transparency on its calculation methodologies, and the ability of these techniques to attribute emissions and removals from remote sensing to anthropogenic sources, as defined by the IPCC for this report, versus natural sources and sinks. In working with the research community on ambient measurement and remote sensing techniques to improve national greenhouse gas inventories, EPA relies upon guidance from the IPCC on the use of measurements and modeling to validate emission inventories.¹⁸

Methane Emissions

Methane (CH₄) is 25 times as effective as CO₂ at trapping heat in the atmosphere (IPCC 2007). Over the last two hundred and fifty years, the concentration of CH₄ in the atmosphere increased by 160 percent (IPCC 2013 and CDIAC 2015). Anthropogenic sources of CH₄ include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2014 Sources of CH₄ Emissions (MMT CO₂ Eq.)



Some significant trends in U.S. emissions of CH₄ include the following:

- Natural gas systems were the largest anthropogenic source category of CH₄ emissions in the United States in 2014 with 176.1 MMT CO₂ Eq. of CH₄ emitted into the atmosphere. Those emissions have decreased by 30.6 MMT CO₂ Eq. (14.8 percent) since 1990. The decrease in CH₄ emissions is largely due to the decrease in emissions from transmission, storage, and distribution. The decrease in transmission and storage

¹⁸ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1003_Uncertainty%20meeting_report.pdf>.

emissions is largely due to reduced compressor station emissions (including emissions from compressors and fugitives). The decrease in distribution emissions is largely attributed to increased use of plastic piping, which has lower emissions than other pipe materials, and station upgrades at metering and regulating (M&R) stations.

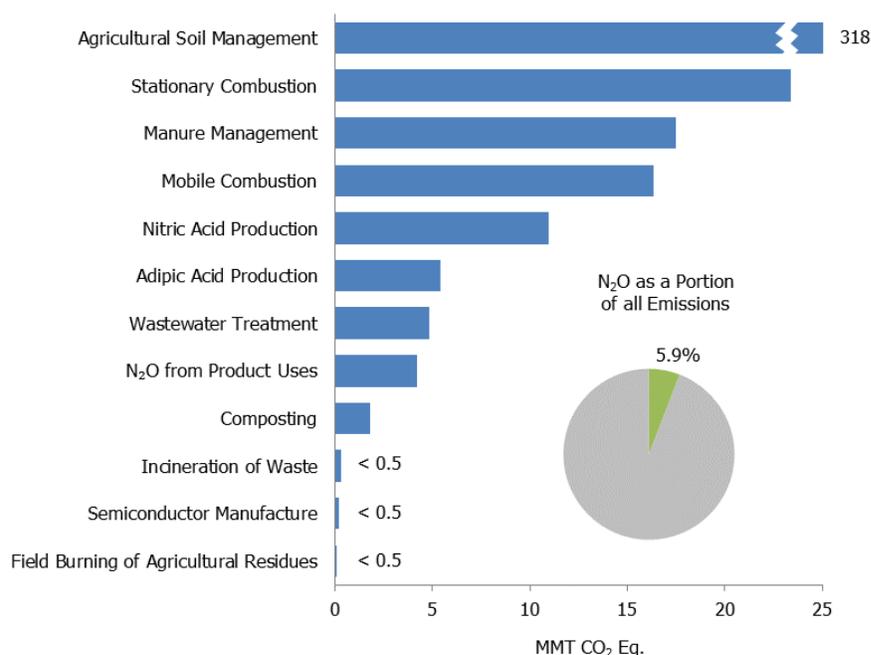
- Petroleum systems are the fourth anthropogenic source of CH₄ emissions in the United States (68.1 MMT CO₂ Eq.), accounting for 9.3 percent of total CH₄ emissions in 2014. From 1990 to 2014, CH₄ emissions from petroleum systems increased by 29.4 MMT CO₂ Eq. (or 76 percent). This increase is due primarily to increases in emissions from production equipment.
- Enteric fermentation is the second largest anthropogenic source of CH₄ emissions in the United States. In 2014, enteric fermentation CH₄ emissions were 164.3 MMT CO₂ Eq. (22.5 percent of total CH₄ emissions), which represents an increase of 0.1 MMT CO₂ Eq. (0.1 percent) since 1990. This increase in emissions from 1990 to 2014 generally follows the increasing trends in cattle populations. From 1990 to 1995 emissions increased and then generally decreased from 1996 to 2004, mainly due to fluctuations in beef cattle populations and increased digestibility of feed for feedlot cattle. Emissions increased from 2005 to 2007, as both dairy and beef populations underwent increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again from 2008 to 2014 as beef cattle populations again decreased.
- Landfills are the third largest anthropogenic source of CH₄ emissions in the United States (148.0 MMT CO₂ Eq.), accounting for 20.2 percent of total CH₄ emissions in 2014. From 1990 to 2014, CH₄ emissions from landfills decreased by 31.6 MMT CO₂ Eq. (17.6 percent), with small increases occurring in some interim years. This downward trend in emissions can be attributed to a 21 percent reduction in the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills over the time series (EPA 2015b) and an increase in the amount of landfill gas collected and combusted (i.e., used for energy or flared),¹⁹ which has more than offset the additional CH₄ emissions resulting from an increase in the amount of municipal solid waste landfilled.
- Methane emissions from manure management increased by 64.7 percent since 1990, from 37.2 MMT CO₂ Eq. in 1990 to 61.2 MMT CO₂ Eq. in 2014. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH₄ emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

Nitrous oxide (N₂O) is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N₂O emissions are much lower than CO₂ emissions, N₂O is approximately 300 times more powerful than CO₂ at trapping heat in the atmosphere (IPCC 2007). Since 1750, the global atmospheric concentration of N₂O has risen by approximately 21 percent (IPCC 2013 and CDIAC 2015). The main anthropogenic activities producing N₂O in the United States are agricultural soil management, stationary fuel combustion, fuel combustion in motor vehicles, manure management, and nitric acid production (see Figure ES-9).

¹⁹ Carbon dioxide emissions from landfills are not included specifically in summing waste sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

Figure ES-9: 2014 Sources of N₂O Emissions (MMT CO₂ Eq.)



Some significant trends in U.S. emissions of N₂O include the following:

- Agricultural soils accounted for approximately 78.9 percent of N₂O emissions and 4.6 percent of total emissions in the United States in 2014. Estimated emissions from this source in 2014 were 318.4 MMT CO₂ Eq. Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2014, although overall emissions were 5.0 percent higher in 2014 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production.
- Nitrous oxide emissions from stationary combustion increased 11.5 MMT CO₂ Eq. (96.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- In 2014, total N₂O emissions from manure management were estimated to be 17.5 MMT CO₂ Eq.; emissions were 14.0 MMT CO₂ Eq. in 1990. These values include both direct and indirect N₂O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N₂O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N₂O emissions showed a 24.9 percent increase from 1990 to 2014 and a 0.1 percent decrease from 2013 through 2014. Overall shifts toward liquid systems have driven down the emissions per unit of nitrogen excreted.
- Nitrous oxide emissions from mobile combustion decreased 24.9 MMT CO₂ Eq. (60.4 percent) from 1990 through 2014, primarily as a result of N₂O national emission control standards and emission control technologies for on-road vehicles.
- Nitrous oxide emissions from adipic acid production were 5.4 MMT CO₂ Eq. in 2014, and have decreased significantly since 1990 due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. Emissions from adipic acid production have decreased by 64.2 percent since 1990 and by 67.8 percent since a peak in 1995.

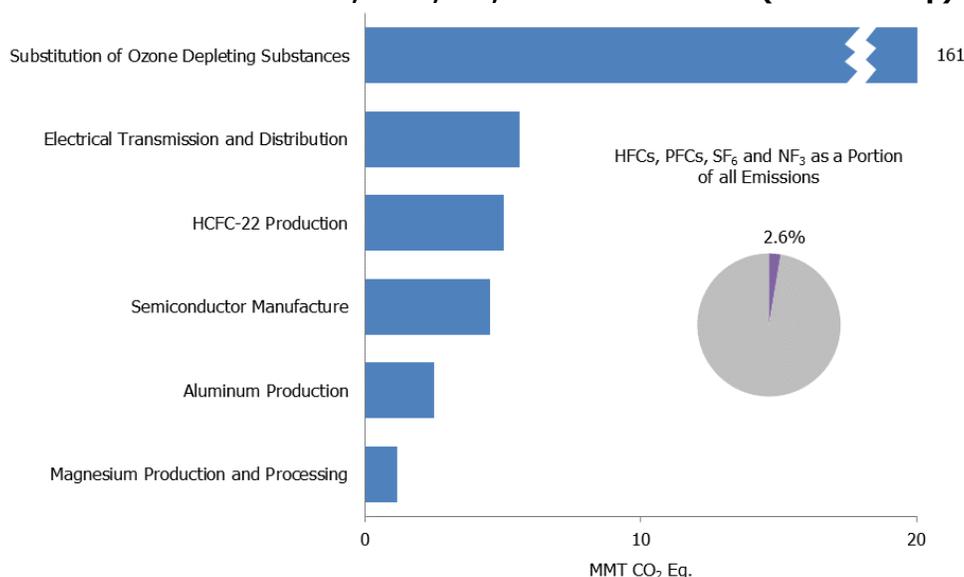
HFC, PFC, SF₆, and NF₃ Emissions

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are families of synthetic chemicals that are used as alternatives to ozone depleting substances (ODS), which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. Hydrofluorocarbons and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the *Montreal Protocol on Substances that Deplete the Ozone Layer*.

These compounds, however, along with SF₆ and NF₃, are potent greenhouse gases. In addition to having high global warming potentials, SF₆ and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 2013).

Other emissive sources of these gases include HCFC-22 production, electrical transmission and distribution systems, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2014 Sources of HFCs, PFCs, SF₆, and NF₃ Emissions (MMT CO₂ Eq.)



Some significant trends in U.S. HFC, PFC, SF₆, and NF₃ emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., chlorofluorocarbons [CFCs]) have been consistently increasing, from small amounts in 1990 to 161.2 MMT CO₂ Eq. in 2014. This increase was in large part the result of efforts to phase out CFCs and other ODS in the United States. In the short term, this trend is expected to continue, and will likely continue over the next decade as hydrochlorofluorocarbons (HCFCs), which are interim substitutes in many applications, are themselves phased out under the provisions of the *Copenhagen Amendments to the Montreal Protocol*.
- GWP-weighted PFC, HFC, SF₆, and NF₃ emissions from semiconductor manufacture have increased by 27.4 percent from 1990 to 2014, due to industrial growth and the adoption of emission reduction technologies. Within that time span, emissions peaked in 1999, the initial year of EPA's PFC Reduction/Climate Partnership for the Semiconductor Industry, but have since declined to 4.5 MMT CO₂ Eq. in 2014 (a 49.8 percent decrease relative to 1999).
- Sulfur hexafluoride emissions from electric power transmission and distribution systems decreased by 77.9 percent (19.8 MMT CO₂ Eq.) from 1990 to 2014. There are two potential causes for this decrease: (1) a sharp increase in the price of SF₆ during the 1990s and (2) a growing awareness of the environmental

impact of SF₆ emissions through programs such as EPA’s SF₆ Emission Reduction Partnership for Electric Power Systems.

- Perfluorocarbon emissions from aluminum production decreased by 88.2 percent (18.9 MMT CO₂ Eq.) from 1990 to 2014. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects.

ES.3. Overview of Sector Emissions and Trends

In accordance with the UNFCCC decision to set the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) as the standard for Annex I countries at the Nineteenth Conference of the Parties (UNFCCC 2014), Figure ES-11 and Table ES-4 aggregate emissions and sinks by the sectors defined by those guidelines. Over the twenty-five-year period of 1990 to 2014, total emissions in the Energy, Industrial Processes and Product Use, and Agriculture grew by 421.3 MMT CO₂ Eq. (7.9 percent), 38.3 MMT CO₂ Eq. (11.2 percent), and 41.6 MMT CO₂ Eq. (7.8 percent), respectively. Over the same period, total emissions in the Waste sector decreased by 27.9 MMT CO₂ Eq. (14.0 percent) and estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO₂ removals from all LULUCF source categories) decreased by 24.5 MMT CO₂ Eq. (3.3 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO₂ Eq.)

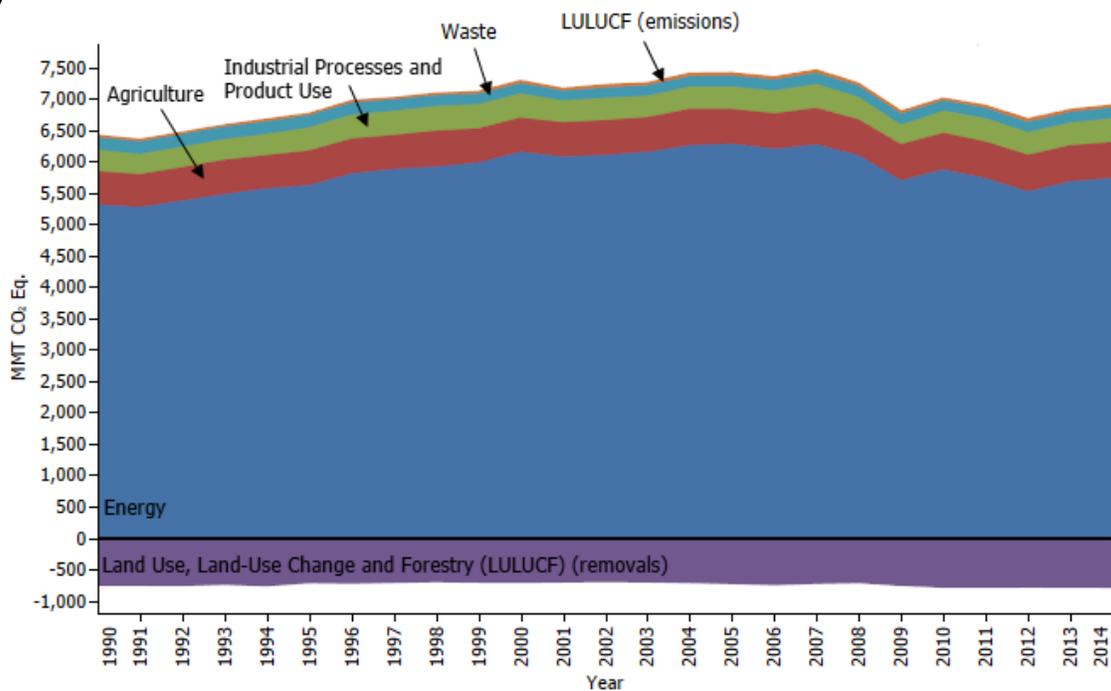


Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO₂ Eq.)

| Chapter/IPCC Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Energy | 5,324.9 | 6,294.5 | 5,884.6 | 5,744.0 | 5,533.9 | 5,693.5 | 5,746.2 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |

| | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Natural Gas Systems | 244.5 | 207.4 | 198.6 | 205.7 | 207.8 | 214.0 | 218.5 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Petroleum Systems | 42.3 | 52.8 | 58.2 | 60.5 | 62.2 | 68.4 | 71.7 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Stationary Combustion | 20.4 | 27.6 | 29.2 | 28.4 | 28.0 | 30.9 | 31.5 |
| Mobile Combustion | 46.9 | 37.1 | 25.9 | 24.7 | 22.2 | 20.3 | 18.4 |
| Incineration of Waste | 8.4 | 12.8 | 11.4 | 10.9 | 10.7 | 9.7 | 9.7 |
| Abandoned Underground Coal Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |
| Industrial Processes and Product Use | 340.9 | 354.3 | 353.0 | 370.5 | 360.1 | 363.5 | 379.2 |
| Substitution of Ozone Depleting Substances | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.6 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.8 | 27.5 | 27.3 | 26.4 | 26.5 | 26.5 | 26.6 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |
| Aluminum Production | 28.3 | 7.6 | 4.6 | 6.8 | 6.4 | 6.2 | 5.4 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacture | 3.6 | 4.7 | 4.0 | 5.1 | 4.5 | 4.2 | 4.7 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.7 | 1.5 | 1.2 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Agriculture | 532.0 | 552.2 | 582.3 | 583.1 | 583.3 | 575.3 | 573.6 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |
| Manure Management | 51.1 | 72.9 | 78.1 | 78.9 | 81.2 | 78.9 | 78.7 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Field Burning of Agricultural Residues | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Waste | 199.3 | 177.8 | 165.5 | 167.8 | 165.7 | 167.8 | 171.4 |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Wastewater Treatment | 19.0 | 20.2 | 19.9 | 19.9 | 19.8 | 19.6 | 19.5 |
| Composting | 0.7 | 3.5 | 3.5 | 3.5 | 3.7 | 3.9 | 3.9 |
| Total Emissions^a | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| Land Use, Land-Use Change, and Forestry | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Forest Land | (718.7) | (675.8) | (736.5) | (725.6) | (717.4) | (726.8) | (730.0) |
| Cropland | 38.5 | 25.9 | 34.0 | 17.1 | 21.1 | 21.1 | 22.3 |
| Grassland | 26.2 | 39.8 | 32.0 | 43.0 | 43.9 | 44.1 | 44.2 |

| | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Wetlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| Settlements | (59.0) | (78.2) | (83.8) | (84.8) | (85.8) | (87.1) | (88.2) |
| Other | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| Net Emissions (Sources and Sinks)^b | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

Notes: Total emissions presented without LULUCF. Net emissions presented with LULUCF.

^a Total emissions without LULUCF.

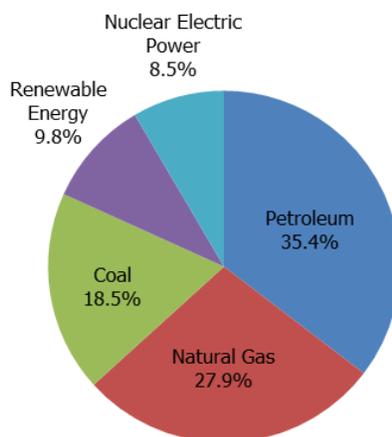
^b Total emissions with LULUCF.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO₂ emissions for the period of 1990 through 2014. In 2014, approximately 82 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 18 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH₄ and N₂O emissions (45 percent and 10 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 83.6 percent of total U.S. greenhouse gas emissions in 2014.

Figure ES-12: 2014 U.S. Energy Consumption by Energy Source (Percent)



Industrial Processes and Product Use

The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products.

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO₂, CH₄, and N₂O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production, urea consumption, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO₂ consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, zinc production, and N₂O from product uses. Industrial processes also release HFCs, PFCs, SF₆, and

NF₃. In addition to their use as ODS substitutes, HFCs, PFCs, SF₆, NF₃, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Overall, emission sources in the Industrial Process and Product Use chapter account for 5.5 percent of U.S. greenhouse gas emissions in 2014.

Agriculture

The Agriculture chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO₂ fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH₄ and N₂O were the primary greenhouse gases emitted by agricultural activities. CH₄ emissions from enteric fermentation and manure management represented 22.5 percent and 8.4 percent of total CH₄ emissions from anthropogenic activities, respectively, in 2014. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N₂O emissions in 2014, accounting for 78.9 percent. In 2014, emission sources accounted for in the Agricultural chapters were responsible for 8.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH₄ and N₂O, and emissions and removals of CO₂ from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net removal of CO₂ (C sequestration) in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 87 percent of total 2014 CO₂ removals, urban trees accounted for 11 percent, landfilled yard trimmings and food scraps accounted for 1.4 percent, and mineral and organic soil C stock changes from *Cropland Remaining Cropland* accounted for 1.0 percent of the total CO₂ removals in 2014. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of C stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

LULUCF activities in 2014 resulted in a net increase in C stocks (i.e., net CO₂ removals) of 787.0 MMT CO₂ Eq. (Table ES-5).²⁰ This represents an offset of 11.5 percent of total (i.e., gross) greenhouse gas emissions in 2014. Emissions from land use, land-use change, and forestry activities in 2014 are 24.6 MMT CO₂ Eq. and represent 0.4 percent of total greenhouse gas emissions.²¹ Between 1990 and 2014, total C sequestration in the LULUCF sector increased by 4.5 percent, primarily due to an increase in the rate of net C accumulation in forest and urban tree C stocks. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Carbon dioxide removals are presented in Table ES-5 along with CO₂, CH₄, and N₂O emissions for LULUCF source categories. Liming and urea fertilization in 2014 resulted in CO₂ emissions of 8.7 MMT CO₂ Eq. (8,653 kt). Lands

²⁰ Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.*

²¹ LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO₂ emissions of 0.8 MMT CO₂ Eq. (842 kt) and CH₄ and N₂O emissions of less than 0.05 MMT CO₂ Eq. each. The application of synthetic fertilizers to forest soils in 2014 resulted in N₂O emissions of 0.5 MMT CO₂ Eq. (2 kt). N₂O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, N₂O emissions from fertilizer application to settlement soils in 2014 accounted for 2.4 MMT CO₂ Eq. (8 kt). This represents an increase of 78 percent since 1990. Forest fires in 2014 resulted in CH₄ emissions of 7.3 MMT CO₂ Eq. (294 kt), and in N₂O emissions of 4.8 MMT CO₂ Eq. (16 kt).

Table ES-5: U.S. Greenhouse Gas Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry (MMT CO₂ Eq.)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Net CO₂ Flux^a | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| Forest Land Remaining Forest Land ^b | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Land Converted to Forest Land | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Cropland Remaining Cropland | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| Land Converted to Cropland | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Grassland Remaining Grassland | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Land Converted to Grassland | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Settlements Remaining Settlements | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| Other: Landfilled Yard Trimmings and Food Scraps | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| CO₂ | 8.1 | 9.0 | 9.6 | 8.9 | 11.0 | 9.0 | 9.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Urea Fertilization | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Liming | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| CH₄ | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.4 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.3 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| N₂O | 3.6 | 9.3 | 5.0 | 7.3 | 10.3 | 7.7 | 7.7 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 2.2 | 6.5 | 2.2 | 4.4 | 7.3 | 4.8 | 4.8 |
| Settlements Remaining Settlements: N ₂ O Fluxes from Settlement Soils ^c | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| Forest Land Remaining Forest Land: N ₂ O Fluxes from Forest Soils ^d | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| LULUCF Emissions^e | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 |
| LULUCF Total Net Flux^a | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| LULUCF Sector Total^f | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.*

^b Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^c Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^d Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

^e LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^f The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 86.3 percent of this chapter's emissions, and 20.2 percent of total U.S. CH₄ emissions.²² Additionally, wastewater treatment accounts for 11.4 percent of Waste emissions, 2.0 percent of U.S. CH₄ emissions, and 1.2 percent of U.S. N₂O emissions. Emissions of CH₄ and N₂O from composting are also accounted for in this chapter, generating emissions of 2.1 MMT CO₂ Eq. and 1.8 MMT CO₂ Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.5 percent of total U.S. greenhouse gas emissions in 2014.

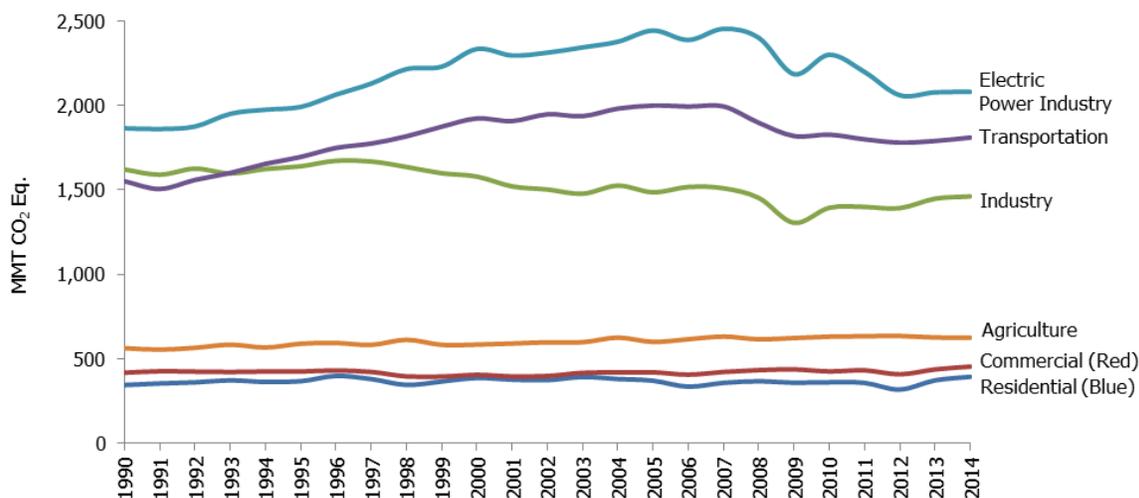
ES.4. Other Information

Emissions by Economic Sector

Throughout the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* report, emission estimates are grouped into five sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes and Product Use; Agriculture; LULUCF; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: residential, commercial, industry, transportation, electricity generation, agriculture, and U.S. Territories.

Table ES-6 summarizes emissions from each of these economic sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2014.

Figure ES-13: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO₂ Eq.)



²² Landfills also store carbon, due to incomplete degradation of organic materials such as harvest wood products, yard trimmings, and food scraps, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-6: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO₂ Eq.)

| Economic Sectors | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Electric Power Industry | 1,864.8 | 2,443.9 | 2,300.5 | 2,198.1 | 2,060.7 | 2,078.0 | 2,080.7 |
| Transportation | 1,551.3 | 1,999.6 | 1,827.4 | 1,799.6 | 1,780.4 | 1,789.9 | 1,810.3 |
| Industry ¹ | 1,620.9 | 1,486.2 | 1,394.5 | 1,399.0 | 1,392.1 | 1,448.2 | 1,461.7 |
| Agriculture | 563.4 | 600.2 | 631.1 | 633.7 | 635.4 | 626.3 | 625.4 |
| Commercial | 418.1 | 420.3 | 425.5 | 432.1 | 408.5 | 437.5 | 453.9 |
| Residential | 344.9 | 370.4 | 361.2 | 357.6 | 318.4 | 372.6 | 393.7 |
| U.S. Territories | 33.7 | 58.2 | 45.3 | 45.4 | 47.6 | 47.5 | 44.7 |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| LULUCF Sector Total^a | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

Note: Total emissions presented without LULUCF. Total net emissions presented with LULUCF.

^a The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Using this categorization, emissions from electricity generation accounted for the largest portion (30 percent) of U.S. greenhouse gas emissions in 2014. Transportation activities, in aggregate, accounted for the second largest portion (26 percent), while emissions from industry accounted for the third largest portion (21 percent) of U.S. greenhouse gas emissions in 2014. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 22 percent of U.S. greenhouse gas emissions were contributed by, in order of magnitude, the agriculture, commercial, and residential sectors, plus emissions from U.S. Territories. Activities related to agriculture accounted for 9 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N₂O emissions from agricultural soil management and CH₄ emissions from enteric fermentation. The commercial and residential sectors accounted for 7 percent and 6 percent of emissions, respectively, and U.S. Territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO₂ emissions from fossil fuel combustion. CO₂ was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-7 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.²³ These source categories include CO₂ from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO₂ and N₂O from incineration of waste, CH₄ and N₂O from stationary sources, and SF₆ from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities and transportation account for the largest shares of U.S. greenhouse gas emissions (29 percent and 26 percent, respectively) in 2014. The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2014. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances). In all sectors except agriculture, CO₂ accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Figure ES-14 shows the trend in these emissions by sector from 1990 to 2014.

²³ Emissions were not distributed to U.S. Territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

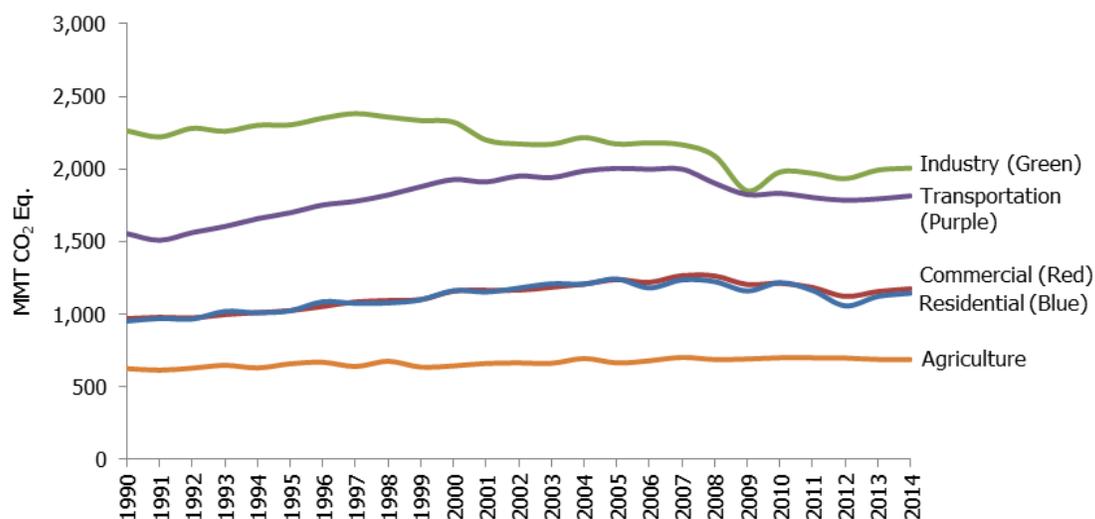
Table ES-7: U.S. Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (MMT CO₂ Eq.)

| Implied Sectors | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Industry | 2,262.9 | 2,171.9 | 1,979.1 | 1,970.0 | 1,934.0 | 1,992.5 | 2,005.7 |
| Transportation | 1,554.4 | 2,004.4 | 1,832.0 | 1,803.9 | 1,784.3 | 1,794.0 | 1,814.5 |
| Commercial | 969.1 | 1,238.0 | 1,212.8 | 1,183.9 | 1,122.1 | 1,155.8 | 1,174.7 |
| Residential | 952.2 | 1,242.1 | 1,216.9 | 1,163.1 | 1,057.5 | 1,121.9 | 1,143.8 |
| Agriculture | 624.8 | 664.2 | 699.5 | 699.1 | 697.5 | 688.3 | 687.0 |
| U.S. Territories | 33.7 | 58.2 | 45.3 | 45.4 | 47.6 | 47.5 | 44.7 |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| LULUCF Sector Total^a | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

^a The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector. Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Figure ES-14: U.S. Greenhouse Gas Emissions with Electricity-Related Emissions Distributed to Economic Sectors (MMT CO₂ Eq.)



Box ES-3: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2014; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-8 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.3 percent since 1990. Since 1990, this rate is slightly slower than that for total energy and for fossil fuel consumption, and

much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-8: Recent Trends in Various U.S. Data (Index 1990 = 100)

| Variable | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 | Avg. Annual Growth Rate |
|---------------------------------------|------|------|------|------|------|------|------|-------------------------|
| Greenhouse Gas Emissions ^a | 100 | 115 | 109 | 107 | 104 | 106 | 107 | 0.3% |
| Energy Consumption ^b | 100 | 118 | 116 | 115 | 112 | 116 | 117 | 0.7% |
| Fossil Fuel Consumption ^b | 100 | 119 | 112 | 110 | 107 | 110 | 111 | 0.5% |
| Electricity Consumption ^b | 100 | 134 | 137 | 137 | 135 | 136 | 138 | 1.4% |
| GDP ^c | 100 | 159 | 165 | 168 | 171 | 174 | 178 | 2.5% |
| Population ^d | 100 | 118 | 124 | 125 | 126 | 126 | 127 | 1.0% |

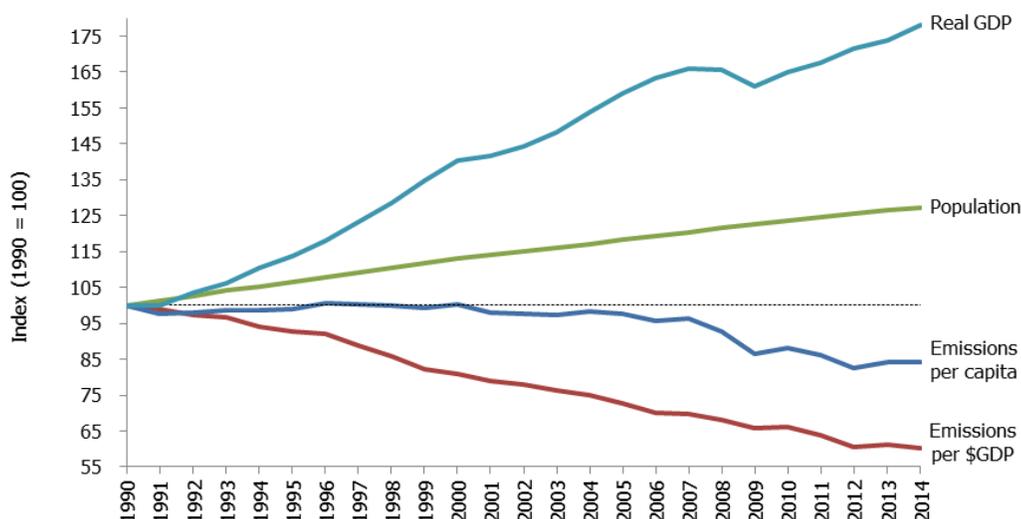
^a GWP-weighted values

^b Energy content-weighted values (EIA 2016)

^c Gross Domestic Product in chained 2009 dollars (BEA 2016)

^d U.S. Census Bureau (2015)

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product (GDP)



Source: BEA (2016), U.S. Census Bureau (2015), and emission estimates in this report.

Key Categories

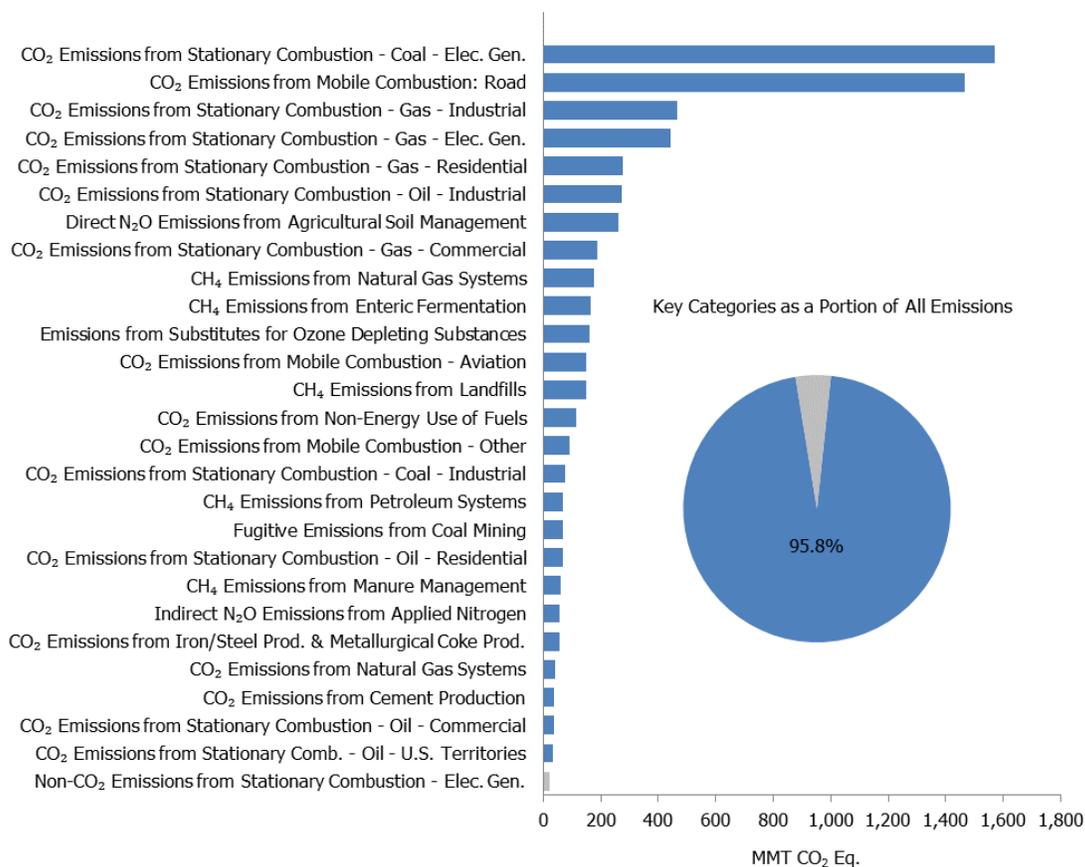
The 2006 IPCC Guidelines (IPCC 2006) defines a key category as a “[category] that is prioritized within the national inventory system because its estimate has a significant influence on a country’s total inventory of greenhouse gases in terms of the absolute level, the trend, or the uncertainty in emissions and removals.”²⁴ By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of

²⁴ See Chapter 4 “Methodological Choice and Identification of Key Categories” in IPCC (2006). See <<http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol1.html>>

individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2014 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the Inventory report. For more information regarding key categories, see Section 1.5 – Key Categories and Annex 1.

Figure ES-16: 2014 Key Categories (MMT CO₂ Eq.)



Note: For a complete discussion of the key category analysis, see Annex 1. Blue bars indicate either an Approach 1, or Approach 1 and Approach 2 level assessment key category. Gray bars indicate solely an Approach 2 level assessment key category.

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for Inventory development, the procedures followed for the current Inventory have been formalized in accordance with the *Quality Assurance/Quality Control and Uncertainty Management Plan (QA/QC Management Plan)* for the Inventory and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete inventory of greenhouse gas emissions and removals. Some of the current estimates, such as those for CO₂ emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the *2006 IPCC Guidelines* (IPCC 2006) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

Box ES-4: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the *2006 IPCC Guidelines* (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the Recalculations and Improvements chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent Inventory report, 1990 through 2013) has been recalculated to reflect the change, per the *2006 IPCC Guidelines* (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

1. Introduction

This report presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and sinks for the years 1990 through 2014. A summary of these estimates is provided in Table 2-1 and Table 2-2 by gas and source category in the Trends in Greenhouse Gas Emissions chapter. The emission estimates in these tables are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis¹ in order to show the relative contribution of each gas to global average radiative forcing. This report also discusses the methods and data used to calculate these emission estimates.

In 1992, the United States signed and ratified the United Nations Framework Convention on Climate Change (UNFCCC). As stated in Article 2 of the UNFCCC, “The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner.”^{2,3}

Parties to the Convention, by ratifying, “shall develop, periodically update, publish and make available... national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies...”⁴ The United States views this report as an opportunity to fulfill these commitments under the UNFCCC.

In 1988, preceding the creation of the UNFCCC, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) jointly established the Intergovernmental Panel on Climate Change (IPCC). The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation (IPCC 2003). Under Working Group 1 of the IPCC, nearly 140 scientists and national experts from more than thirty countries collaborated in the creation of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) to ensure that the emission inventories submitted to the UNFCCC are consistent and comparable between nations. The *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* and the *IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry* further expanded upon the methodologies in the *Revised 1996 IPCC Guidelines*. In 2006, the IPCC accepted the *2006 Guidelines for National Greenhouse Gas Inventories* at its Twenty-Fifth Session (Mauritius, April 2006). The *2006 IPCC Guidelines* built

¹ More information provided in “Global Warming Potentials” section of this chapter on the use of *IPCC Fourth Assessment Report* (AR4) GWP values.

² The term “anthropogenic,” in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC 2006).

³ Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <<http://unfccc.int>>. (UNEP/WMO 2000)

⁴ Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <<http://unfccc.int>>.

upon the previous bodies of work and include new sources and gases “...as well as updates to the previously published methods whenever scientific and technical knowledge have improved since the previous guidelines were issued. The UNFCCC adopted the *2006 IPCC Guidelines* as the standard methodological approach for Annex I countries at the Nineteenth Conference of the Parties (Warsaw, November 11-23, 2013). This report presents information in accordance with these guidelines.

Overall, this Inventory of anthropogenic greenhouse gas emissions and sinks provides a common and consistent mechanism through which Parties to the UNFCCC can estimate emissions and compare the relative contribution of individual sources, gases, and nations to climate change. The Inventory provides a national estimate of sources and sinks for the United States, including all states and U.S. Territories.⁵ The structure of this report is consistent with the current UNFCCC Guidelines on Annual Inventories (UNFCCC 2014).

Box 1-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the gross emissions total presented in this report for the United States excludes emissions and sinks from LULUCF. The net emissions total presented in this report for the United States includes emissions and sinks from LULUCF. All emissions and sinks are calculated using internationally-accepted methods provided by the IPCC.⁶ Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.⁷ The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. Emissions and sinks provided in this Inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the EPA’s GHGRP. 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons.⁸ Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections in this report’s chapters, EPA is analyzing the data for use, as applicable, to improve the national estimates presented in this Inventory.

⁵ U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

⁶ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

⁷ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>>.

⁸ See <<http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>> and <<http://ghgdata.epa.gov/ghgp/main.do>>.

1.1 Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, land-use changes, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our atmosphere (NOAA 2014). These gases in the atmosphere absorb some of the energy being radiated from the surface of the Earth and then re-radiate this energy with some returning to the Earth's surface, essentially acting like a blanket that makes the Earth's surface warmer than it would be otherwise.

Greenhouse gases are necessary to life as we know it. Without greenhouse gases in the atmosphere, the planet's surface would be about 60 degrees Fahrenheit cooler than present (EPA 2009). Carbon dioxide is also necessary for plant growth. With emissions from biological and geological sources, there is a natural level of greenhouse gases that is maintained in the atmosphere. But, as the concentrations of these gases continue to increase in from man-made sources, the Earth's temperature is climbing above past levels. The Earth's averaged land and ocean surface temperature has increased by about 1.2 to 1.9 degrees Fahrenheit since 1880. The last three decades have each been the warmest decade successively at the Earth's surface since 1850 (IPCC 2013). Most of the warming in recent decades is very likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

If greenhouse gases continue to increase, climate models predict that the average temperature at the Earth's surface is likely to increase from 0.5 to 8.6 degrees Fahrenheit above 1986 through 2005 levels by the end of this century, depending on future emissions (IPCC 2013). Scientists are certain that human activities are changing the composition of the atmosphere, and that increasing the concentration of greenhouse gases will change the planet's climate. However, they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.⁹

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2013). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the space and the earth system.¹⁰ A gauge of these changes is called radiative forcing, which is a measure of the influence a perturbation has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2013). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

Human activities are continuing to affect the Earth's energy budget by changing the emissions and resulting atmospheric concentrations of radiatively important gases and aerosols and by changing land surface properties (IPCC 2013).

Naturally occurring greenhouse gases include water vapor, CO₂, CH₄, N₂O, and ozone (O₃). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are

⁹ For more information see <<http://www.epa.gov/climatechange/science>>.

¹⁰ For more on the science of climate change, see NRC (2012).

covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in national greenhouse gas inventories.¹¹ Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), and nitrogen trifluoride (NF₃)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several other substances that influence the global radiation budget but are short-lived and therefore not well-mixed. These substances include carbon monoxide (CO), nitrogen dioxide (NO₂), sulfur dioxide (SO₂), and tropospheric (ground level) O₃. Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight).

Aerosols are extremely small particles or liquid droplets suspended in the Earth’s atmosphere that are often composed of sulfur compounds, carbonaceous combustion products (e.g., black carbon), crustal materials (e.g., dust) and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere (e.g., scattering incoming sunlight away from the Earth’s surface, or, in the case of black carbon, absorb sunlight) and can play a role in affecting cloud formation and lifetime affecting the radiative forcing of clouds and precipitation patterns. Comparatively, however, while the understanding of aerosols has increased in recent years, they still account for the largest contribution to uncertainty estimates in global energy budgets (IPCC 2013).

Carbon dioxide, CH₄, and N₂O are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes, except when directly or indirectly perturbed out of equilibrium by anthropogenic activities, generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 1-1.

Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime of Selected Greenhouse Gases

| Atmospheric Variable | CO ₂ | CH ₄ | N ₂ O | SF ₆ | CF ₄ |
|--|---------------------------|-------------------------|-------------------------|--------------------------|-------------------------|
| Pre-industrial atmospheric concentration | 280 ppm | 0.700 ppm | 0.270 ppm | 0 ppt | 40 ppt |
| Atmospheric concentration | 401 ppm ^a | 1.823 ppm ^b | 0.327 ppm ^b | 8.3 ppt ^b | 79 ppt ^c |
| Rate of concentration change | 2.3 ppm/yr | 5 ppb/yr ^{d,e} | 0.8 ppb/yr ^e | 0.27 ppt/yr ^e | 0.7 ppt/yr ^e |
| Atmospheric lifetime (years) | See footnote ^f | 12.4 ^g | 121 ^g | 3,200 | 50,000 |

^a The atmospheric CO₂ concentration is the 2015 annual average at the Mauna Loa, HI station (NOAA/ESRL 2016).

^b The values presented are global 2014 annual average mole fractions (CDIAC 2015).

^c The 2011 CF₄ global mean atmospheric concentration is from the Advanced Global Atmospheric Gases Experiment (IPCC 2013).

^d The growth rate for atmospheric CH₄ decreased from over 10 ppb/yr in the 1980s to nearly zero in the early 2000s; recently, the growth rate has been about 5 ppb/year.

^e The rate of concentration change is the average rate of change between 2005 and 2011 (IPCC 2013).

^f For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

^g This lifetime has been defined as an “adjustment time” that takes into account the indirect effect of the gas on its own residence time.

Source: Pre-industrial atmospheric concentrations, atmospheric lifetime, and rate of concentration changes for CH₄, N₂O, SF₆, and CF₄ are from IPCC (2013). The rate of concentration change for CO₂ is an average of the rates from 2011 through 2015 has fluctuated between 1.7 to 3.0 ppm per year over this period (NOAA/ESRL 2016).

¹¹ Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of GWPs, which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H₂O). Water vapor is the largest contributor to the natural greenhouse effect. Water vapor is fundamentally different from other greenhouse gases in that it can condense and rain out when it reaches high concentrations, and the total amount of water vapor in the atmosphere is in part a function of the Earth's temperature. While some human activities such as evaporation from irrigated crops or power plant cooling release water vapor into the air, this has been determined to have a negligible effect on climate (IPCC 2013). The lifetime of water vapor in the troposphere is on the order of 10 days. Water vapor can also contribute to cloud formation, and clouds can have both warming and cooling effects by either trapping or reflecting heat. Because of the relationship between water vapor levels and temperature, water vapor and clouds serve as a feedback to climate change, such that for any given increase in other greenhouse gases, the total warming is greater than would happen in the absence of water vapor. Aircraft contrails, which consist of water vapor and other substances, are aviation-induced clouds with the same radiative forcing effects as high-altitude cirrus clouds (IPCC 1999).

Carbon Dioxide (CO₂). In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO₂. Atmospheric CO₂ is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Carbon dioxide concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 401 ppmv in 2015, a 43 percent increase (IPCC 2013 and NOAA/ESRL 2016).^{12,13} The IPCC definitively states that “the increase of CO₂ ... is caused by anthropogenic emissions from the use of fossil fuel as a source of energy and from land use and land use changes, in particular agriculture” (IPCC 2013). The predominant source of anthropogenic CO₂ emissions is the combustion of fossil fuels. Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of CO₂. In its *Fifth Assessment Report*, the IPCC stated “it is extremely likely that more than half of the observed increase in global average surface temperature from 1951 to 2010 was caused by the anthropogenic increase in greenhouse gas concentrations and other anthropogenic forcings together,” of which CO₂ is the most important (IPCC 2013).

Methane (CH₄). Methane is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH₄, as does the decomposition of municipal solid wastes. Methane is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH₄ have increased by about 160 percent since 1750, from a pre-industrial value of about 700 ppb to 1,823 ppb in 2014,¹⁴ although the rate of increase decreased to near zero in the early 2000s, and has recently increased again to about 5 ppb/year. The IPCC has estimated that slightly more than half of the current CH₄ flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

Methane is primarily removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO₂. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH₄ reduce the concentration of OH, a feedback that increases the atmospheric lifetime of CH₄ (IPCC 2013). Methane's reactions in the atmosphere also lead to production of tropospheric ozone and stratospheric water vapor, both of which also contribute to climate change.

Nitrous Oxide (N₂O). Anthropogenic sources of N₂O emissions include agricultural soils, especially production of nitrogen-fixing crops and forages, the use of synthetic and manure fertilizers, and manure deposition by livestock; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater

¹² The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2013).

¹³ Carbon dioxide concentrations during the last 1,000 years of the pre-industrial period (i.e., 750 to 1750), a time of relative climate stability, fluctuated by about ±10 ppmv around 280 ppmv (IPCC 2013).

¹⁴ This value is the global 2014 annual average mole fraction (CDIAC 2015).

treatment and waste incineration; and biomass burning. The atmospheric concentration of N₂O has increased by 21 percent since 1750, from a pre-industrial value of about 270 ppb to 327 ppb in 2014,¹⁵ a concentration that has not been exceeded during the last thousand years. Nitrous oxide is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

Ozone (O₃). Ozone is present in both the upper stratosphere,¹⁶ where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,¹⁷ where it is the main component of anthropogenic photochemical “smog.” During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as CFCs, have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 2013). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover.

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the fourth largest increase in direct radiative forcing since the pre-industrial era, behind CO₂, black carbon, and CH₄. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds (including CH₄) mixing with NO_x in the presence of sunlight. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable (IPCC 2013).

Halocarbons, Perfluorocarbons, Sulfur Hexafluoride, and Nitrogen Trifluoride. Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine (CFCs, HCFCs, methyl chloroform, and carbon tetrachloride) and bromine (halons, methyl bromide, and hydrobromofluorocarbons) result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which itself is an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5¹⁸ countries beginning in 1996, and then followed by a complete phase-out by the year 2030. While ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC, they are reported in this inventory under Annex 6.2 of this report for informational purposes.

Hydrofluorocarbons, PFCs, SF₆, and NF₃ are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. Hydrofluorocarbons are primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process. Currently, they have a small aggregate radiative forcing impact, but it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2013). Perfluorocarbons, SF₆, and NF₃ are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium casting. Currently, the radiative forcing impact of PFCs, SF₆, and NF₃ is also small, but they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2013).

¹⁵ This value is the global 2014 annual average (CDIAC 2015).

¹⁶ The stratosphere is the layer from the troposphere up to roughly 50 kilometers. In the lower regions the temperature is nearly constant but in the upper layer the temperature increases rapidly because of sunlight absorption by the ozone layer. The ozone-layer is the part of the stratosphere from 19 kilometers up to 48 kilometers where the concentration of ozone reaches up to 10 parts per million.

¹⁷ The troposphere is the layer from the ground up to 11 kilometers near the poles and up to 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere where people live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for most weather processes, including most of the water vapor and clouds.

¹⁸ Article 5 of the Montreal Protocol covers several groups of countries, especially developing countries, with low consumption rates of ozone depleting substances. Developing countries with per capita consumption of less than 0.3 kg of certain ozone depleting substances (weighted by their ozone depleting potential) receive financial assistance and a grace period of ten additional years in the phase-out of ozone depleting substances.

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH₄ and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH₄ and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO₂. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides (NO_x). The primary climate change effects of nitrogen oxides (i.e., NO and NO₂) are indirect and result from their role in promoting the formation of ozone in the troposphere, are a precursor to nitrate particles (i.e., aerosols) and, to a lesser degree, lower stratosphere, where they have positive radiative forcing effects.¹⁹ Additionally, NO_x emissions are also likely to decrease CH₄ concentrations, thus having a negative radiative forcing effect (IPCC 2013). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning (both natural and anthropogenic fires) fuel combustion, and, in the stratosphere, from the photo-degradation of N₂O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Non-methane Volatile Organic Compounds (NMVOCs). Non-methane volatile organic compounds include substances such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere that are either directly emitted into or are created through chemical reactions in the Earth's atmosphere. Aerosols or their chemical precursors can be emitted by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, nitrates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous²⁰ aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning. Aerosols can be removed from the atmosphere relatively rapidly by precipitation or through more complex processes under dry conditions.

Aerosols affect radiative forcing differently than greenhouse gases. Their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation (and to a lesser extent scattering, absorption, and emission of terrestrial radiation); and indirectly by increasing cloud droplets and ice crystals that modify the formation, precipitation efficiency, and radiative properties of clouds (IPCC 2013). Despite advances in understanding of cloud-aerosol interactions, the contribution of aerosols to radiative forcing are difficult to quantify because aerosols generally have short atmospheric lifetimes, and have number concentrations, size distributions, and compositions that vary regionally, spatially, and temporally (IPCC 2013).

The net effect of aerosols on the Earth's radiative forcing is believed to be negative (i.e., net cooling effect on the climate). In fact, "despite the large uncertainty ranges on aerosol forcing, there is high confidence that aerosols have offset a substantial portion of GHG forcing" (IPCC 2013).²¹ Although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.²² Not all aerosols have a cooling effect. Current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing by heating the Earth's atmosphere and causing surface warming when deposited on ice and snow (IPCC 2013). Black carbon also influences cloud development, but the direction and magnitude of this forcing is an area of active research.

¹⁹ NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

²⁰ Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2013).

²¹ The IPCC (2013) defines high confidence as an indication of strong scientific evidence and agreement in this statement.

²² Volcanic activity can inject significant quantities of aerosol producing sulfur dioxide and other sulfur compounds into the stratosphere, which can result in a longer negative forcing effect (i.e., a few years) (IPCC 2013).

Global Warming Potentials

A global warming potential is a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas (see Table 1-2). It is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2007). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The reference gas used is CO₂, and therefore GWP-weighted emissions are measured in million metric tons of CO₂ equivalent (MMT CO₂ Eq.).²³ The relationship between kilotons (kt) of a gas and MMT CO₂ Eq. can be expressed as follows:

$$MMT\ CO_2\ Eq. = (kt\ of\ gas) \times (GWP) \times \left(\frac{MMT}{1,000\ kt} \right)$$

where,

MMT CO₂ Eq. = Million metric tons of CO₂ equivalent

kt = Kilotons (equivalent to a thousand metric tons)

GWP = Global warming potential

MMT = Million metric tons

GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ±35 percent. Parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon, although other time horizon values are available.

...the global warming potential values used by Parties included in Annex I to the Convention (Annex I Parties) to calculate the carbon dioxide equivalence of anthropogenic emissions by sources and removals by sinks of greenhouse gases shall be those listed in the column entitled “Global warming potential for given time horizon” in table 2.14 of the errata to the contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, based on the effects of greenhouse gases over a 100-year time horizon...²⁴

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO₂, CH₄, N₂O, HFCs, PFCs, SF₆, NF₃) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, ozone precursors (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO₂ products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. Parties to the UNFCCC have not agreed upon GWP values for these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report

| Gas | Atmospheric Lifetime | GWP ^c |
|------------------------------|----------------------|------------------|
| CO ₂ | ^b | 1 |
| CH ₄ ^a | 12 | 25 |
| N ₂ O | 114 | 298 |
| HFC-23 | 270 | 14,800 |
| HFC-32 | 4.9 | 675 |

²³ Carbon comprises 12/44^{ths} of carbon dioxide by weight.

²⁴ Framework Convention on Climate Change; Available online at: <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>; 31 January 2014; Report of the Conference of the Parties at its nineteenth session; held in Warsaw from 11 to 23 November 2013; Addendum; Part two: Action taken by the Conference of the Parties at its nineteenth session; Decision 24/CP.19; Revision of the UNFCCC reporting guidelines on annual inventories for Parties included in Annex I to the Convention; p. 2. (UNFCCC 2014).

| | | |
|--------------------------------|--------|--------|
| HFC-125 | 29 | 3,500 |
| HFC-134a | 14 | 1,430 |
| HFC-143a | 52 | 4,470 |
| HFC-152a | 1.4 | 124 |
| HFC-227ea | 34.2 | 3,220 |
| HFC-236fa | 240 | 9,810 |
| HFC-4310mee | 15.9 | 1,640 |
| CF ₄ | 50,000 | 7,390 |
| C ₂ F ₆ | 10,000 | 12,200 |
| C ₄ F ₁₀ | 2,600 | 8,860 |
| C ₆ F ₁₄ | 3,200 | 9,300 |
| SF ₆ | 3,200 | 22,800 |
| NF ₃ | 740 | 17,200 |

^a The GWP of CH₄ includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO₂ is not included.

^b For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

^c 100-year time horizon.

Source: (IPCC 2007)

Box 1-2: The IPCC Fifth Assessment Report and Global Warming Potentials

In 2014, the IPCC published its *Fifth Assessment Report* (AR5), which provided an updated and more comprehensive scientific assessment of climate change. Within the AR5 report, the GWP values of several gases were revised relative to previous IPCC reports, namely the *IPCC Second Assessment Report* (SAR) (IPCC 1996), the *IPCC Third Assessment Report* (TAR) (IPCC 2001), and the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). Although the AR4 GWP values are used throughout this report, consistent with UNFCCC reporting requirements, it is interesting to review the changes to the GWP values and the impact improved understanding has on the total GWP-weighted emissions of the United States. In the AR5, the IPCC has applied an improved calculation of CO₂ radiative forcing and an improved CO₂ response function in presenting updated GWP values. Additionally, the atmospheric lifetimes of some gases have been recalculated, and updated background concentrations were used. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, and the indirect effects of methane on ozone have been adjusted to match more recent science. Table 1-3 presents the new GWP values, relative to those presented in the AR4 and using the 100-year time horizon common to UNFCCC reporting.

Table 1-3: Comparison of 100-Year GWP values

| Gas | SAR | AR4 | AR5 ^a | AR5 with feedbacks ^b | Comparison to AR4 | | |
|------------------------------|--------|--------|------------------|---------------------------------|-------------------|---------|---------------------------------|
| | | | | | SAR | AR5 | AR5 with feedbacks ^b |
| CO ₂ | 1 | 1 | 1 | 1 | NC | NC | NC |
| CH ₄ ^c | 21 | 25 | 28 | 34 | (4) | 3 | 9 |
| N ₂ O | 310 | 298 | 265 | 298 | 12 | (33) | 0 |
| HFC-23 | 11,700 | 14,800 | 12,400 | 13,856 | (3,100) | (2,400) | (944) |
| HFC-32 | 650 | 675 | 677 | 817 | (25) | 2 | 142 |
| HFC-125 | 2,800 | 3,500 | 3,170 | 3,691 | (700) | (330) | 191 |
| HFC-134a | 1,300 | 1,430 | 1,300 | 1,549 | (130) | (130) | 119 |
| HFC-143a | 3,800 | 4,470 | 4,800 | 5,508 | (670) | 330 | 1,038 |
| HFC-152a | 140 | 124 | 138 | 167 | 16 | 14 | 43 |

| | | | | | | | |
|--------------------------------|--------|--------|--------|--------|---------|---------|-------|
| HFC-227ea | 2,900 | 3,220 | 3,350 | 3,860 | (320) | 130 | 640 |
| HFC-236fa | 6,300 | 9,810 | 8,060 | 8,998 | (3,510) | (1,750) | (812) |
| HFC-4310mee | 1,300 | 1,640 | 1,650 | 1,952 | (340) | 10 | 312 |
| CF ₄ | 6,500 | 7,390 | 6,630 | 7,349 | (890) | (760) | (41) |
| C ₂ F ₆ | 9,200 | 12,200 | 11,100 | 12,340 | (3,000) | (1,100) | 140 |
| C ₄ F ₁₀ | 7,000 | 8,860 | 9,200 | 10,213 | (1,860) | 340 | 1,353 |
| C ₆ F ₁₄ | 7,400 | 9,300 | 7,910 | 8,780 | (1,900) | (1,390) | (520) |
| SF ₆ | 23,900 | 22,800 | 23,500 | 26,087 | 1,100 | 700 | 3,287 |
| NF ₃ | NA | 17,200 | 16,100 | 17,885 | NA | (1,100) | 685 |

NC – No Change

NA – Not Applicable

^a The GWPs presented here are the ones most consistent with the methodology used in the AR4 report.

^b The GWP values presented here from the AR5 report include climate-carbon feedbacks for the non-CO₂ gases in order to be consistent with the approach used in calculating the CO₂ lifetime.

Additionally, the AR5 reported separate values for fossil versus biogenic methane in order to account for the CO₂ oxidation product.

^c The GWP of CH₄ includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO₂ is only included in the value from AR5 that includes climate-carbon feedbacks.

Note: Parentheses indicate negative values.

Source: (IPCC 2013, IPCC 2007, IPCC 2001, IPCC 1996).

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using AR4 GWP values, as required by the 2013 revision to the UNFCCC reporting guidelines for national inventories.²⁵ All estimates provided throughout this report are also presented in unweighted units. For informational purposes, emission estimates that use GWPs from other IPCC Assessment Reports are presented in detail in Annex 6.1 of this report.

1.2 National Inventory Arrangements

The U.S. Environmental Protection Agency (EPA), in cooperation with other U.S. government agencies, prepares the Inventory of U.S. Greenhouse Gas Emissions and Sinks. A wide range of agencies and individuals are involved in supplying data to, planning methodological approaches and improvements, reviewing, or preparing portions of the U.S. Inventory—including federal and state government authorities, research and academic institutions, industry associations, and private consultants.

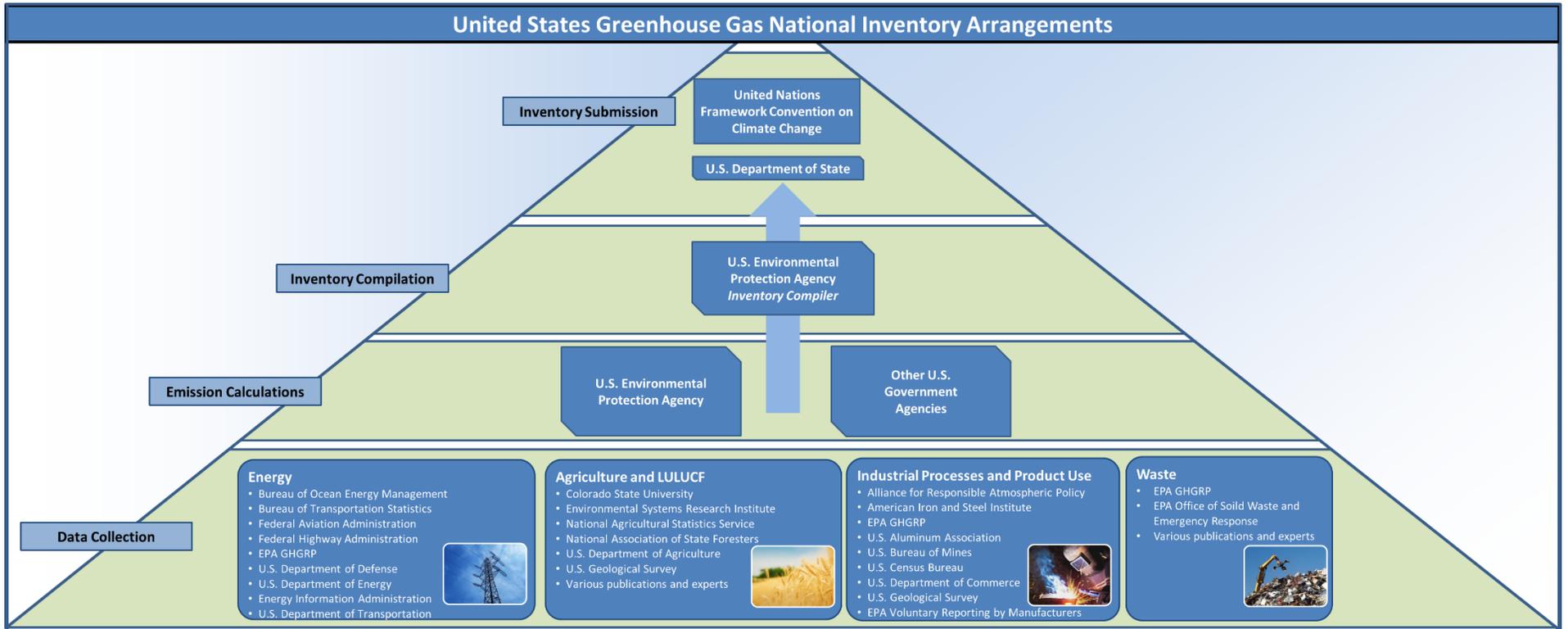
Within EPA, the Office of Atmospheric Programs (OAP) is the lead office responsible for the emission calculations provided in the Inventory, as well as the completion of the National Inventory Report and the Common Reporting Format tables. EPA's Office of Transportation and Air Quality (OTAQ) is also involved in calculating emissions for the Inventory. While the U.S. Department of State officially submits the annual Inventory to the UNFCCC, EPA's OAP serves as the Inventory focal point for technical questions and comments on the U.S. Inventory. The staff of OAP and OTAQ coordinates the annual methodological choice, activity data collection, and emission calculations at the individual source category level. Within OAP, an inventory coordinator compiles the entire Inventory into the proper reporting format for submission to the UNFCCC, and is responsible for the collection and consistency of cross-cutting issues in the Inventory.

Several other government agencies contribute to the collection and analysis of the underlying activity data used in the Inventory calculations. Formal relationships exist between EPA and other U.S. agencies that provide official data for use in the Inventory. The U.S. Department of Energy's Energy Information Administration provides

²⁵ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

national fuel consumption data and the U.S. Department of Defense provides military fuel consumption and bunker fuels. Informal relationships also exist with other U.S. agencies to provide activity data for use in EPA's emission calculations. These include: the U.S. Department of Agriculture, the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, and the Federal Aviation Administration. Academic and research centers also provide activity data and calculations to EPA, as well as individual companies participating in voluntary outreach efforts with EPA. Finally, the U.S. Department of State officially submits the Inventory to the UNFCCC each April. Figure 1-1 diagrams the National Inventory Arrangements.

Figure 1-1: National Inventory Arrangements Diagram



1.3 Inventory Process

EPA has a decentralized approach to preparing the annual U.S. Inventory, which consists of a National Inventory Report (NIR) and Common Reporting Format (CRF) tables. The inventory coordinator at EPA is responsible for compiling all emission estimates and ensuring consistency and quality throughout the NIR and CRF tables. Emission calculations for individual sources are the responsibility of individual source leads, who are most familiar with each source category and the unique characteristics of its emissions profile. The individual source leads determine the most appropriate methodology and collect the best activity data to use in the emission calculations, based upon their expertise in the source category, as well as coordinating with researchers and contractors familiar with the sources. A multi-stage process for collecting information from the individual source leads and producing the Inventory is undertaken annually to compile all information and data.

Methodology Development, Data Collection, and Emissions and Sink Estimation

Source leads at EPA collect input data and, as necessary, evaluate or develop the estimation methodology for the individual source categories. For most source categories, the methodology for the previous year is applied to the new “current” year of the Inventory, and inventory analysts collect any new data or update data that have changed from the previous year. If estimates for a new source category are being developed for the first time, or if the methodology is changing for an existing source category (e.g., the United States is implementing a higher Tiered approach for that source category), then the source category lead will develop a new methodology, gather the most appropriate activity data and emission factors (or in some cases direct emission measurements) for the entire time series, and conduct a special source-specific peer review process involving relevant experts from industry, government, and universities.

Once the methodology is in place and the data are collected, the individual source leads calculate emissions and sink estimates. The source leads then update or create the relevant text and accompanying annexes for the Inventory. Source leads are also responsible for completing the relevant sectoral background tables of the Common Reporting Format, conducting quality assurance and quality control (QA/QC) checks, and uncertainty analyses.

Summary Spreadsheet Compilation and Data Storage

The inventory coordinator at EPA collects the source categories’ descriptive text and Annexes, and also aggregates the emission estimates into a summary spreadsheet that links the individual source category spreadsheets together. This summary sheet contains all of the essential data in one central location, in formats commonly used in the Inventory document. In addition to the data from each source category, national trend and related data are also gathered in the summary sheet for use in the Executive Summary, Introduction, and Recent Trends sections of the Inventory report. Electronic copies of each year’s summary spreadsheet, which contains all the emission and sink estimates for the United States, are kept on a central server at EPA under the jurisdiction of the inventory coordinator.

National Inventory Report Preparation

The NIR is compiled from the sections developed by each individual source lead. In addition, the inventory coordinator prepares a brief overview of each chapter that summarizes the emissions from all sources discussed in the chapters. The inventory coordinator then carries out a key category analysis for the Inventory, consistent with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, and in accordance with the reporting requirements of the UNFCCC. Also at this time, the Introduction, Executive Summary, and Recent Trends sections are drafted, to reflect the trends for the most recent year of the current Inventory. The analysis of trends necessitates gathering supplemental data, including weather and temperature conditions, economic activity and gross domestic product, population, atmospheric conditions, and the annual consumption of electricity, energy, and fossil fuels.

Changes in these data are used to explain the trends observed in greenhouse gas emissions in the United States. Furthermore, specific factors that affect individual sectors are researched and discussed. Many of the factors that affect emissions are included in the Inventory document as separate analyses or side discussions in boxes within the text. Text boxes are also created to examine the data aggregated in different ways than in the remainder of the document, such as a focus on transportation activities or emissions from electricity generation. The document is prepared to match the specification of the UNFCCC reporting guidelines for National Inventory Reports.

Common Reporting Format Table Compilation

The CRF tables are compiled from individual tables completed by each individual source lead, which contain source emissions and activity data. The inventory coordinator integrates the source data into the UNFCCC's "CRF Reporter" for the United States, assuring consistency across all sectoral tables. The summary reports for emissions, methods, and emission factors used, the overview tables for completeness and quality of estimates, the recalculation tables, the notation key completion tables, and the emission trends tables are then completed by the inventory coordinator. Internal automated quality checks on the CRF Reporter, as well as reviews by the source leads, are completed for the entire time series of CRF tables before submission.

QA/QC and Uncertainty

QA/QC and uncertainty analyses are supervised by the QA/QC and Uncertainty coordinators, who have general oversight over the implementation of the QA/QC plan and the overall uncertainty analysis for the Inventory (see sections on QA/QC and Uncertainty, below). These coordinators work closely with the source leads to ensure that a consistent QA/QC plan and uncertainty analysis is implemented across all inventory sources. The inventory QA/QC plan, detailed in a following section, is consistent with the quality assurance procedures outlined by EPA and IPCC.

Expert and Public Review Periods

During the Expert Review period, a first draft of the document is sent to a select list of technical experts outside of EPA. The purpose of the Expert Review is to encourage feedback on the methodological and data sources used in the current Inventory, especially for sources which have experienced any changes since the previous Inventory.

Once comments are received and addressed, a second draft of the document is released for public review by publishing a notice in the U.S. Federal Register and posting the document on the EPA Web site. The Public Review period allows for a 30 day comment period and is open to the entire U.S. public.

Final Submittal to UNFCCC and Document Printing

After the final revisions to incorporate any comments from the Expert Review and Public Review periods, EPA prepares the final National Inventory Report and the accompanying Common Reporting Format Reporter database. The U.S. Department of State sends the official submission of the U.S. Inventory to the UNFCCC. The document is then formatted and posted online, available for the public.¹

1.4 Methodology and Data Sources

Emissions of greenhouse gases from various source and sink categories have been estimated using methodologies that are consistent with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). To the extent possible, the present report relies on published activity and emission factor data. Depending on the emission

¹ See <<http://epa.gov/climatechange/ghgemissions/usinventoryreport.html>>

source category, activity data can include fuel consumption or deliveries, vehicle-miles traveled, raw material processed, etc. Emission factors are factors that relate quantities of emissions to an activity.

The IPCC methodologies provided in the *2006 IPCC Guidelines* represent baseline methodologies for a variety of source categories, and many of these methodologies continue to be improved and refined as new research and data become available. This report uses the IPCC methodologies when applicable, and supplements them with other available country-specific methodologies and data where possible. Choices made regarding the methodologies and data sources used are provided in conjunction with the discussion of each source category in the main body of the report. Complete documentation is provided in the annexes on the detailed methodologies and data sources utilized in the calculation of each source category.

Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO₂ emissions from fossil fuel combustion in addition to their "bottom-up" sectoral methodology. This estimation method uses alternative methodologies and different data sources than those contained in that section of the Energy chapter. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys (see Annex 4 of this report). The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required.

1.5 Key Categories

The *2006 IPCC Guidelines* (IPCC 2006) defines a key category as a "[category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of greenhouse gases in terms of the absolute level, the trend, or the uncertainty in emissions and removals."² By definition, key categories include those categories that have the greatest contribution to the absolute level of national emissions. In addition, when an entire time series of emission and removal estimates is prepared, a thorough investigation of key categories must also account for the influence of trends and uncertainties of individual source and sink categories. This analysis culls out source and sink categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key categories is performed to capture any categories that were not identified in any of the quantitative analyses.

Approach 1, as defined in the *2006 IPCC Guidelines* (IPCC 2006), was implemented to identify the key categories for the United States. This analysis was performed twice; one analysis included sources and sinks from the Land Use, Land-Use Change, and Forestry (LULUCF) sector, the other analysis did not include the LULUCF categories. Following Approach 1, Approach 2, as defined in the *2006 IPCC Guidelines* (IPCC 2006), was then implemented to identify any additional key categories not already identified in Approach 1 assessment. This analysis, which includes each source category's uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Approach 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the *2006 IPCC Guidelines* (IPCC 2006), was conducted to capture any key categories that were not identified by either quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance

² See Chapter 4 "Methodological Choice and Identification of Key Categories" in IPCC (2006). See <<http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html>>.

with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to Approach 1. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, because it would qualify bunker fuels as a key category according to Approach 2. Table 1-4 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential (GWP)-weighted emissions in 2014. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Approach 1, Approach 2, and/or qualitative assessments). Annex 1 of this report provides additional information regarding the key categories in the United States and the methodologies used to identify them.

Table 1-4: Key Categories for the United States (1990-2014)

| IPCC Source Categories | Gas | Approach 1 | | | | Approach 2 | | | | Qual ^a | 2014 Emissions (MMT CO ₂ Eq.) |
|--|-----------------|----------------------|----------------------|-------------------|-------------------|----------------------|----------------------|-------------------|-------------------|-------------------|--|
| | | Level Without LULUCF | Trend Without LULUCF | Level With LULUCF | Trend With LULUCF | Level Without LULUCF | Trend Without LULUCF | Level With LULUCF | Trend With LULUCF | | |
| | | | | | | | | | | | |
| Energy | | | | | | | | | | | |
| CO ₂ Emissions from Stationary Combustion - Coal - Electricity Generation | CO ₂ | • | • | • | • | • | • | • | • | | 1,570.4 |
| CO ₂ Emissions from Mobile Combustion: Road | CO ₂ | • | • | • | • | • | • | • | • | | 1,467.5 |
| CO ₂ Emissions from Stationary Combustion - Gas - Industrial | CO ₂ | • | • | • | • | • | • | • | • | | 466.0 |
| CO ₂ Emissions from Stationary Combustion - Gas - Electricity Generation | CO ₂ | • | • | • | • | • | • | • | • | | 443.2 |
| CO ₂ Emissions from Stationary Combustion - Gas - Residential | CO ₂ | • | • | • | • | • | • | • | • | | 277.6 |
| CO ₂ Emissions from Stationary Combustion - Oil - Industrial | CO ₂ | • | • | • | • | • | • | • | • | | 271.9 |
| CO ₂ Emissions from Stationary Combustion - Gas - Commercial | CO ₂ | • | • | • | • | • | • | • | • | | 189.2 |
| CO ₂ Emissions from Mobile Combustion: Aviation | CO ₂ | • | • | • | • | • | • | • | • | | 150.1 |
| CO ₂ Emissions from Non-Energy Use of Fuels | CO ₂ | • | • | • | • | • | • | • | • | | 114.3 |
| CO ₂ Emissions from Mobile Combustion: Other | CO ₂ | • | • | • | • | • | • | • | • | | 92.0 |
| CO ₂ Emissions from Stationary Combustion - Coal - Industrial | CO ₂ | • | • | • | • | • | • | • | • | | 75.3 |
| CO ₂ Emissions from Stationary Combustion - Oil - Residential | CO ₂ | • | • | • | • | • | • | • | • | | 67.5 |
| CO ₂ Emissions from Natural Gas Systems | CO ₂ | • | • | • | • | • | • | • | • | | 42.4 |

| | | | | | | | | | | |
|---|------------------|---|---|---|---|---|---|---|---|-------|
| CO ₂ Emissions from Stationary Combustion - Oil - Commercial | CO ₂ | • | • | • | • | | | | | 38.2 |
| CO ₂ Emissions from Stationary Combustion - Oil - U.S. Territories | CO ₂ | • | | • | • | | | | | 34.6 |
| CO ₂ Emissions from Mobile Combustion: Marine | CO ₂ | • | • | • | • | | | | | 28.0 |
| CO ₂ Emissions from Stationary Combustion - Oil - Electricity Generation | CO ₂ | • | • | • | • | • | | • | | 25.3 |
| CO ₂ Emissions from Stationary Combustion - Coal - Commercial | CO ₂ | | • | | • | | | | | 4.5 |
| CO ₂ Emissions from Stationary Combustion - Gas - U.S. Territories | CO ₂ | | | | | • | | | | 3.0 |
| CO ₂ Emissions from Stationary Combustion - Coal - Residential | CO ₂ | | | | | • | | | | 0.0 |
| CH ₄ Emissions from Natural Gas Systems | CH ₄ | • | • | • | • | • | • | • | • | 176.1 |
| CH ₄ Emissions from Petroleum Systems | CH ₄ | • | • | • | • | • | • | • | • | 68.1 |
| Fugitive Emissions from Coal Mining | CH ₄ | • | • | • | • | • | • | • | • | 67.6 |
| Non-CO ₂ Emissions from Stationary Combustion - Residential | CH ₄ | | | | | • | | • | | 5.0 |
| Non-CO ₂ Emissions from Stationary Combustion - Electricity Generation | N ₂ O | | • | | • | • | • | • | • | 19.6 |
| N ₂ O Emissions from Mobile Combustion: Road | N ₂ O | • | • | • | • | • | • | | • | 12.5 |
| International Bunker Fuels ^b | Several | | | | | | | | • | 104.2 |

Industrial Processes and Product Use

| | | | | | | | | | | |
|--|------------------|---|---|---|---|---|---|---|---|-------|
| CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production | CO ₂ | • | • | • | • | • | • | • | • | 55.4 |
| CO ₂ Emissions from Cement Production | CO ₂ | • | | • | | | | | | 38.8 |
| CO ₂ Emissions from Other Process Uses of Carbonates | CO ₂ | | • | | • | | | | | 12.1 |
| N ₂ O Emissions from Adipic Acid Production | N ₂ O | | • | | • | | | | | 5.4 |
| Emissions from Substitutes for Ozone Depleting Substances | HiGWP | • | • | • | • | • | • | • | • | 161.2 |
| SF ₆ Emissions from Electrical Transmission and Distribution | HiGWP | | • | | • | | • | | • | 5.6 |
| HFC-23 Emissions from HCFC-22 Production | HiGWP | • | • | • | • | | • | | | 5.0 |
| PFC Emissions from Aluminum Production | HiGWP | | • | | • | | | | | 2.5 |

| Agriculture | | | | | | | | | | |
|--|------------------|---|---|---|---|---|---|---|---|----------------|
| CH ₄ Emissions from Enteric Fermentation | CH ₄ | • | • | • | • | • | • | • | | 164.3 |
| CH ₄ Emissions from Manure Management | CH ₄ | • | • | • | • | • | • | • | | 61.2 |
| Direct N ₂ O Emissions from Agricultural Soil Management | N ₂ O | • | | • | | • | | • | | 261.0 |
| Indirect N ₂ O Emissions from Applied Nitrogen | N ₂ O | • | | • | | • | • | • | • | 57.3 |
| Waste | | | | | | | | | | |
| CH ₄ Emissions from Landfills | CH ₄ | • | • | • | • | • | • | • | • | 148.0 |
| Land Use, Land-Use Change, and Forestry | | | | | | | | | | |
| CO ₂ Emissions from Land Converted to Grassland | CO ₂ | | | • | | | | | | 40.4 |
| CO ₂ Emissions from Land Converted to Cropland | CO ₂ | | | • | • | | | • | • | 22.1 |
| CO ₂ Emissions from Grassland Remaining Grassland | CO ₂ | | | | | | | • | • | 3.8 |
| CO ₂ Emissions from Cropland Remaining Cropland | CO ₂ | | | • | • | | | • | • | (8.4) |
| CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps | CO ₂ | | | | | | | • | • | (11.6) |
| CO ₂ Emissions from Urban Trees | CO ₂ | | | • | • | | | • | • | (90.6) |
| CO ₂ Emissions from Forest Land Remaining Forest Land | CO ₂ | | | • | • | | | • | • | (742.3) |
| CH ₄ Emissions from Forest Fires | CH ₄ | | | | | | | • | • | 7.3 |
| Subtotal Without LULUCF | | | | | | | | | | 6,687.8 |
| Total Emissions Without LULUCF | | | | | | | | | | 6,870.5 |
| Percent of Total Without LULUCF | | | | | | | | | | 97% |
| Subtotal With LULUCF | | | | | | | | | | 5,905.5 |
| Total Emissions With LULUCF | | | | | | | | | | 6,108.0 |
| Percent of Total With LULUCF | | | | | | | | | | 97% |

^a Qualitative criteria.

^b Emissions from this source not included in totals.

Note: Parentheses indicate negative values (or sequestration).

1.6 Quality Assurance and Quality Control (QA/QC)

As part of efforts to achieve its stated goals for inventory quality, transparency, and credibility, the United States has developed a quality assurance and quality control plan designed to check, document and improve the quality of its

inventory over time. QA/QC activities on the Inventory are undertaken within the framework of the U.S. *Quality Assurance/Quality Control and Uncertainty Management Plan* (QA/QC plan) for the U.S. Greenhouse Gas Inventory: Procedures Manual for QA/QC and Uncertainty Analysis.

Key attributes of the QA/QC plan are summarized in Figure 1-2. These attributes include:

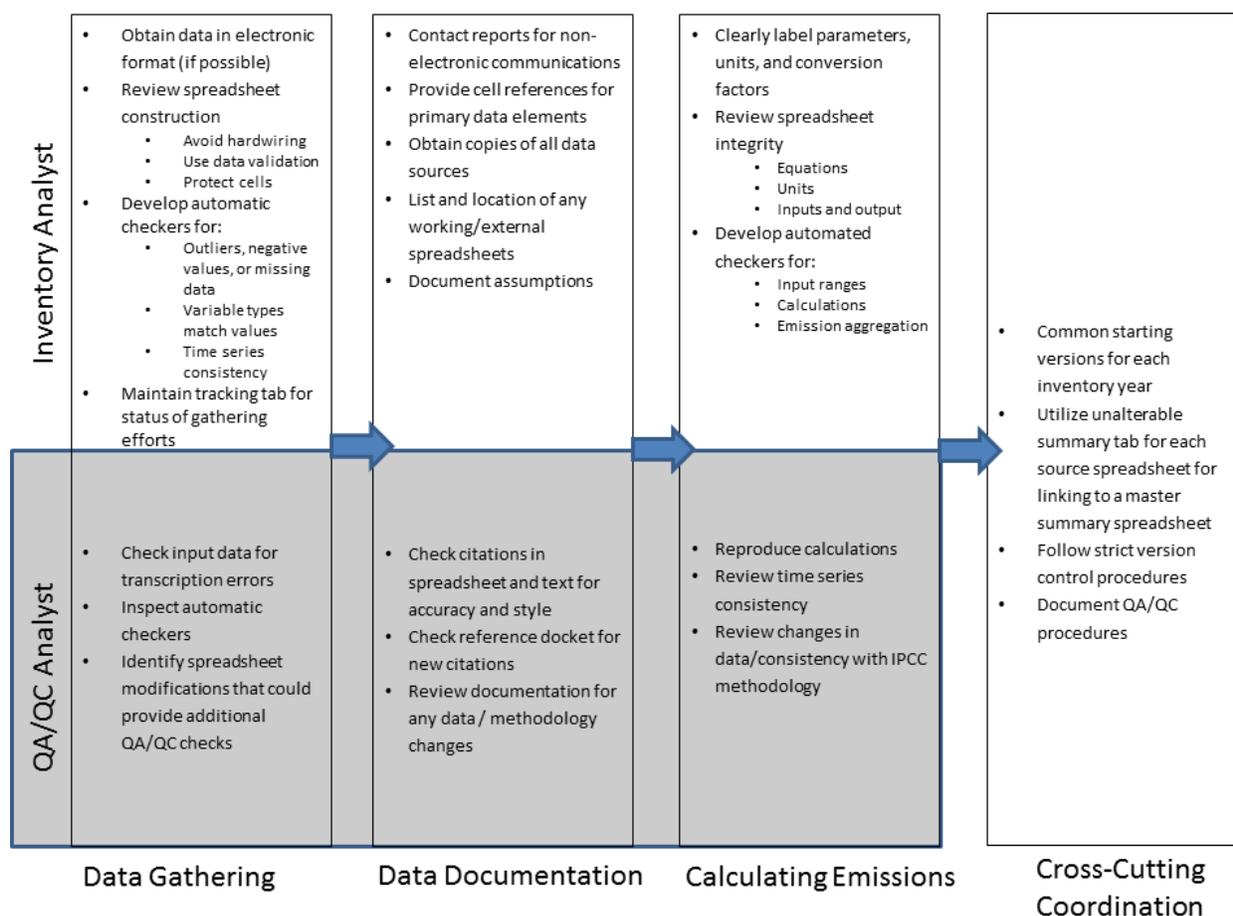
- *Procedures and Forms*: detailed and specific systems that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of uncertainty
- *Implementation of Procedures*: application of QA/QC procedures throughout the whole inventory development process from initial data collection, through preparation of the emission estimates, to publication of the Inventory
- *Quality Assurance*: expert and public reviews for both the inventory estimates and the inventory report (which is the primary vehicle for disseminating the results of the inventory development process)
- *Quality Control*: consideration of secondary data and source-specific checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates, which provides for more structured communication and integration with the suppliers of secondary information
- *Tier 1 (general) and Tier 2 (source-specific) Checks*: quality controls and checks, as recommended by *IPCC Good Practice Guidance*
- *Record Keeping*: provisions to track which procedures have been followed, the results of the QA/QC, uncertainty analysis, and feedback mechanisms for corrective action based on the results of the investigations which provide for continual data quality improvement and guided research efforts
- *Multi-Year Implementation*: a schedule for coordinating the application of QA/QC procedures across multiple years
- *Interaction and Coordination*: promoting communication within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the Inventory. The QA/QC Management Plan itself is intended to be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

The quality control activities described in the U.S. QA/QC plan occur throughout the inventory process; QA/QC is not separate from, but is an integral part of, preparing the Inventory. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

The QA/QC plan guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC procedures also include feedback loops and provide for corrective actions that are designed to improve the inventory estimates over time.

Figure 1-2: U.S. QA/QC Plan Summary



1.7 Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete and transparent emissions inventory. Uncertainty information is not intended to dispute the validity of the inventory estimates, but to help prioritize efforts to improve the accuracy of future inventories and guide future decisions on methodological choice. While the U.S. Inventory calculates its emission estimates with the highest possible accuracy, uncertainties are associated to a varying degree with the development of emission estimates for any inventory. Some of the current estimates, such as those for carbon dioxide (CO₂) emissions from energy-related activities, are considered to have minimal uncertainty associated with them. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty surrounding the estimates presented. The UNFCCC reporting guidelines follow the recommendation in the *2006 IPCC Guidelines* (IPCC 2006) and require that countries provide single point estimates for each gas and emission or removal source category. Within the discussion of each emission source, specific factors affecting the uncertainty associated with the estimates are discussed.

Additional research in the following areas could help reduce uncertainty in the U.S. Inventory:

- Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions are not available at this time. In particular, emissions from some land-use activities and industrial processes are not included in the inventory either because data are incomplete or

because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report.

- *Improving the accuracy of emission factors.* Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH₄ and N₂O emissions from stationary and mobile combustion is highly uncertain.
- *Collecting detailed activity data.* Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF₆ from electrical transmission and distribution is limited due to a lack of activity data regarding national SF₆ consumption or average equipment leak rates.

The overall uncertainty estimate for total U.S. greenhouse gas emissions was developed using the IPCC Approach 2 uncertainty estimation methodology. Estimates of quantitative uncertainty for the total U.S. greenhouse gas emissions are shown below, in Table 1-5.

The IPCC provides good practice guidance on two approaches—Approach 1 and Approach 2—to estimating uncertainty for individual source categories. Approach 2 uncertainty analysis, employing the Monte Carlo Stochastic Simulation technique, was applied wherever data and resources permitted; further explanation is provided within the respective source category text and in Annex 7. Consistent with the *2006 IPCC Guidelines* (IPCC 2006), over a multi-year timeframe, the United States expects to continue to improve the uncertainty estimates presented in this report.

Table 1-5: Estimated Overall Inventory Quantitative Uncertainty (MMT CO₂ Eq. and Percent)

| Gas | 2014 Emission Estimate ^a (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^b | | | | Mean ^c (MMT CO ₂ Eq.) | Standard Deviation ^c |
|--|--|--|----------------|---------------------------|------------|--|---------------------------------|
| | | Lower Bound ^d | | Upper Bound | | | |
| | | (MMT CO ₂ Eq.) | (%) | (MMT CO ₂ Eq.) | (%) | | |
| CO ₂ | 5,555.6 | 5,459.4 | 5,830.0 | -2% | 5% | 5,643.8 | 94.9 |
| CH ₄ ^e | 730.8 | 674.3 | 917.5 | -8% | 26% | 785.0 | 60.2 |
| N ₂ O ^e | 403.5 | 322.5 | 447.9 | -20% | 11% | 378.6 | 32.2 |
| PFC, HFC, SF ₆ , and NF ₃ ^e | 175.3 | 172.3 | 190.9 | -4% | 6% | 181.6 | 4.7 |
| Total | 6,865.2 | 6,765.4 | 7,223.9 | -2% | 5% | 6,989.0 | 117.5 |
| LULUCF Emissions^f | 24.6 | 12.8 | 38.9 | -48% | 58% | 23.0 | 6.8 |
| LULUCF Total Net Flux^g | (787.0) | (1,051.4) | (647.8) | -18% | 34% | (847.2) | 102.9 |
| LULUCF Sector Total^h | (762.5) | (1,029.8) | (622.5) | -18% | 35% | (824.2) | 103.0 |
| Net Emissions (Sources and Sinks) | 6,102.7 | 5,861.6 | 6,477.6 | -4% | 6% | 6,164.8 | 156.7 |

Notes: Total emissions (excluding emissions for which uncertainty was not quantified) is presented without LULUCF. Net emissions is presented with LULUCF.

^a Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 5.3 MMT CO₂ Eq. of emissions for which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.

^b The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

^c Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.

^d The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.

^e The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH₄, N₂O and high GWP gases used in the inventory emission calculations for 2014.

^f LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Agricultural Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^g Net CO₂ flux is the net C stock change from the following categories: Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.

^h The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions calculated for the U.S. Inventory reflect current best estimates; in some cases, however, estimates are based on approximate methodologies, assumptions, and incomplete data. As new information becomes available in the future, the United States will continue to improve and revise its emission estimates. See Annex 7 of this report for further details on the U.S. process for estimating uncertainty associated with the emission estimates and for a more detailed discussion of the limitations of the current analysis and plans for improvement. Annex 7 also includes details on the uncertainty analysis performed for selected source categories.

1.8 Completeness

This report, along with its accompanying CRF tables, serves as a thorough assessment of the anthropogenic sources and sinks of greenhouse gas emissions for the United States for the time series 1990 through 2014. Although this report is intended to be comprehensive, certain sources have been identified which were excluded from the estimates presented for various reasons. Generally speaking, sources not accounted for in this Inventory are excluded due to data limitations or a lack of thorough understanding of the emission process. The United States is continually working to improve upon the understanding of such sources and seeking to find the data required to estimate related emissions. As such improvements are implemented, new emission sources are quantified and included in the Inventory. For a complete list of sources not included, see Annex 5 of this report.

1.9 Organization of Report

In accordance with the revision of the UNFCCC reporting guidelines agreed to at the nineteenth Conference of the Parties (UNFCCC 2014), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into five sector-specific chapters, listed below in Table 1-6. In addition, chapters on Trends in Greenhouse Gas Emissions and Other information to be considered as part of the U.S. Inventory submission are included.

Table 1-6: IPCC Sector Descriptions

| Chapter/IPCC Sector | Activities Included |
|---|---|
| Energy | Emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions, and non-energy use of fossil fuels. |
| Industrial Processes and Product Use | Emissions resulting from industrial processes and product use of greenhouse gases. |
| Agriculture | Anthropogenic emissions from agricultural activities except fuel combustion, which is addressed under Energy. |
| Land Use, Land-Use Change, and Forestry | Emissions and removals of CO ₂ , CH ₄ , and N ₂ O from forest management, other land-use activities, and land-use change. |
| Waste | Emissions from waste management activities. |

Within each chapter, emissions are identified by the anthropogenic activity that is the source or sink of the greenhouse gas emissions being estimated (e.g., coal mining). Overall, the following organizational structure is consistently applied throughout this report:

Chapter/IPCC Sector: Overview of emission trends for each IPCC defined sector

Source category: Description of source pathway and emission trends.

Methodology: Description of analytical methods employed to produce emission estimates and identification of data references, primarily for activity data and emission factors.

Uncertainty and Timeseries Consistency: A discussion and quantification of the uncertainty in emission estimates and a discussion of time-series consistency.

QA/QC and Verification: A discussion on steps taken to QA/QC and verify the emission estimates, where beyond the overall U.S. QA/QC plan, and any key findings.

Recalculations: A discussion of any data or methodological changes that necessitate a recalculation of previous years' emission estimates, and the impact of the recalculation on the emission estimates, if applicable.

Planned Improvements: A discussion on any source-specific planned improvements, if applicable.

Special attention is given to CO₂ from fossil fuel combustion relative to other sources because of its share of emissions and its dominant influence on emission trends. For example, each energy consuming end-use sector (i.e., residential, commercial, industrial, and transportation), as well as the electricity generation sector, is described individually. Additional information for certain source categories and other topics is also provided in several Annexes listed in Table 1-7.

Table 1-7: List of Annexes

| | |
|---------|--|
| ANNEX 1 | Key Category Analysis |
| ANNEX 2 | Methodology and Data for Estimating CO ₂ Emissions from Fossil Fuel Combustion |
| 2.1. | Methodology for Estimating Emissions of CO ₂ from Fossil Fuel Combustion |
| 2.2. | Methodology for Estimating the Carbon Content of Fossil Fuels |
| 2.3. | Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels |
| ANNEX 3 | Methodological Descriptions for Additional Source or Sink Categories |
| 3.1. | Methodology for Estimating Emissions of CH ₄ , N ₂ O, and Indirect Greenhouse Gases from Stationary Combustion |
| 3.2. | Methodology for Estimating Emissions of CH ₄ , N ₂ O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions |
| 3.3. | Methodology for Estimating Emissions from Commercial Aircraft Jet Fuel Consumption |
| 3.4. | Methodology for Estimating CH ₄ Emissions from Coal Mining |
| 3.5. | Methodology for Estimating CH ₄ and CO ₂ Emissions from Petroleum Systems |
| 3.6. | Methodology for Estimating CH ₄ Emissions from Natural Gas Systems |
| 3.7. | Methodology for Estimating CO ₂ and N ₂ O Emissions from Incineration of Waste |
| 3.8. | Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military |
| 3.9. | Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances |
| 3.10. | Methodology for Estimating CH ₄ Emissions from Enteric Fermentation |
| 3.11. | Methodology for Estimating CH ₄ and N ₂ O Emissions from Manure Management |
| 3.12. | Methodology for Estimating N ₂ O Emissions, CH ₄ Emissions and Soil Organic C Stock Changes from Agricultural Lands (Cropland and Grassland) |
| 3.13. | Methodology for Estimating Net Carbon Stock Changes in Forest Land Remaining Forest Land and Land Converted to Forest Land |
| 3.14. | Methodology for Estimating CH ₄ Emissions from Landfills |
| ANNEX 4 | IPCC Reference Approach for Estimating CO ₂ Emissions from Fossil Fuel Combustion |
| ANNEX 5 | Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included |
| ANNEX 6 | Additional Information |
| 6.1. | Global Warming Potential Values |
| 6.2. | Ozone Depleting Substance Emissions |
| 6.3. | Sulfur Dioxide Emissions |
| 6.4. | Complete List of Source Categories |
| 6.5. | Constants, Units, and Conversions |

- 6.6. Abbreviations
- 6.7. Chemical Formulas
- ANNEX 7 Uncertainty
 - 7.1. Overview
 - 7.2. Methodology and Results
 - 7.3. Planned Improvements
- ANNEX 8 QA/QC Procedures
 - 8.1. Background
 - 8.2. Purpose
 - 8.3. Assessment Factors

2. Trends in Greenhouse Gas Emissions

2.1 Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2014, total U.S. greenhouse gas emissions were 6,870.5 MMT or million metric tons carbon dioxide (CO₂) Eq. Total U.S. emissions have increased by 7.4 percent from 1990 to 2014, and emissions increased from 2013 to 2014 by 1.0 percent (70.5 MMT CO₂ Eq.). The increase in CO₂ emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions. Since 1990, U.S. emissions have increased at an average annual rate of 0.3 percent. Figure 2-1 through Figure 2-3 illustrate the overall trend in total U.S. emissions by gas, annual changes, and absolute changes since 1990. Overall, net emissions in 2014 were 8.6 percent below 2005 levels as shown in Table 2-1.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO₂ Eq.)

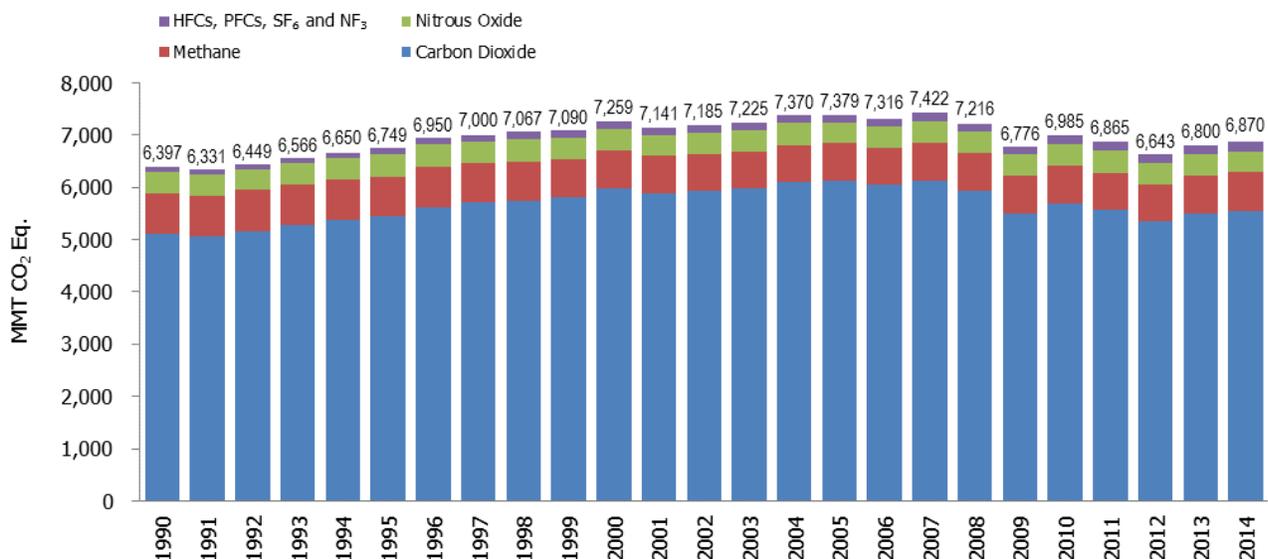


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions Relative to the Previous Year

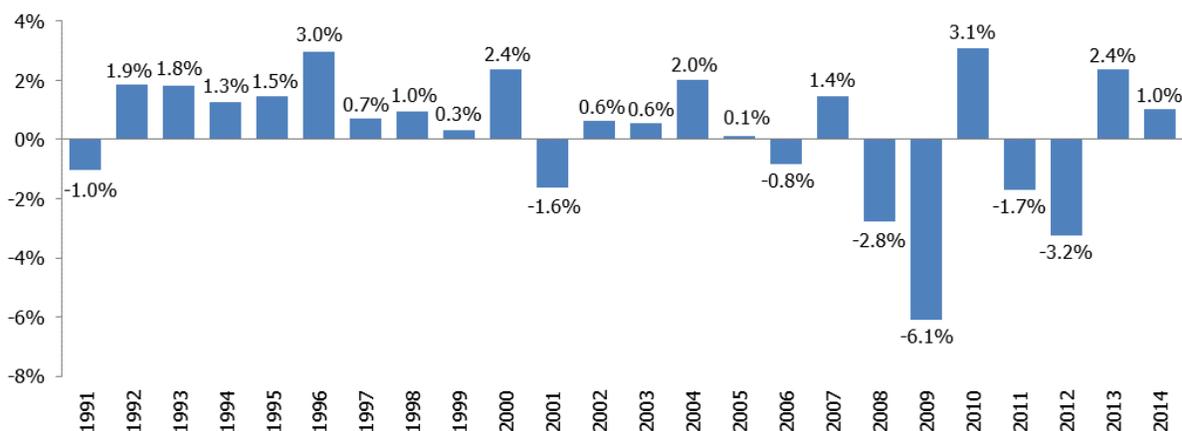
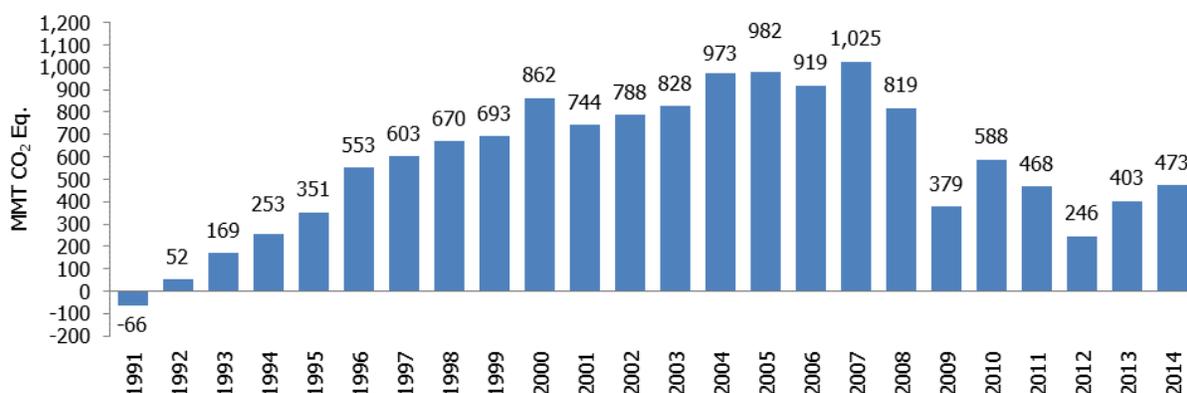


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990 (1990=0, MMT CO₂ Eq.)



Overall, from 1990 to 2014, total emissions of CO₂ increased by 440.9 MMT CO₂ Eq. (8.6 percent), while total emissions of methane (CH₄) decreased by 43.0 MMT CO₂ Eq. (5.6 percent), and total emissions of nitrous oxide (N₂O) decreased by 2.7 MMT CO₂ Eq. (0.7 percent). During the same period, aggregate weighted emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), and nitrogen trifluoride (NF₃) rose by 78.1 MMT CO₂ Eq. (76.6 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, SF₆, and NF₃ are significant because many of them have extremely high global warming potentials (GWPs), and, in the cases of PFCs, SF₆, and NF₃, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon (C) sequestration in managed forests, trees in urban areas, agricultural soils, and landfilled yard trimmings. These were estimated to offset 11.5 percent of total emissions in 2014.

As the largest contributor to U.S. greenhouse gas emissions, CO₂ from fossil fuel combustion has accounted for approximately 76 percent of GWP-weighted emissions for the entire time series since 1990, from 74 percent of total GWP-weighted emissions in 1990 to 76 percent in 2014. Emissions from this source category grew by 9.9 percent (467.5 MMT CO₂ Eq.) from 1990 to 2014 and were responsible for most of the increase in national emissions during this period. From 2013 to 2014, these emissions increased by 1.0 percent (50.6 MMT CO₂ Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, energy fuel choices,

and seasonal temperatures. On an annual basis, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than in a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

In the longer term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Energy-related CO₂ emissions also depend on the type of fuel or energy consumed and its C intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO₂ emissions because of the lower C content of natural gas.

A brief discussion of the year to year variability in fuel combustion emissions is provided below, beginning with 2010.

From 2010 to 2011, CO₂ emissions from fossil fuel combustion decreased by 2.4 percent. This decrease is a result of multiple factors including: (1) a decrease in the C intensity of fuels consumed to generate electricity due to a decrease in coal consumption, with increased natural gas consumption and a significant increase in hydropower used; (2) a decrease in transportation-related energy consumption due to higher fuel costs, improvements in fuel efficiency, and a reduction in miles traveled; and (3) relatively mild winter conditions resulting in an overall decrease in energy demand in most sectors. Changing fuel prices played a role in the decreasing emissions. A significant increase in the price of motor gasoline in the transportation sector was a major factor leading to a decrease in energy consumption by 1.2 percent. In addition, an increase in the price of coal and a concurrent decrease in natural gas prices led to a 5.7 percent decrease and a 2.5 percent increase in fuel consumption of these fuels by electric generators. This change in fuel prices also reduced the carbon intensity of fuels used to produce electricity in 2011, further contributing to the decrease in fossil fuel combustion emissions.

From 2011 to 2012, CO₂ emissions from fossil fuel combustion decreased by 3.9 percent, with emissions from fossil fuel combustion at their lowest level since 1994. This decrease from 2011 to 2012 is primarily a result of the decrease in the carbon intensity of fuels used to generate electricity due to a slight increase in the price of coal, and a significant decrease in the price of natural gas. The consumption of coal used to generate electricity decreased by 12.3 percent, while consumption of natural gas for electricity generation increased by 20.4 percent. Also, emissions declined in the transportation sector largely due to a small increase in fuel efficiency across different transportation modes and limited new demand for passenger transportation. In 2012, weather conditions remained fairly constant in the summer and were much warmer in the winter compared to 2011, as cooling degree days increased by 1.7 percent while heating degree days decreased 12.6 percent. This decrease in heating degree days resulted in a decreased demand for heating fuel in the residential and commercial sector, which had a decrease in natural gas consumption of 11.7 and 8.0 percent, respectively.

From 2012 to 2013, CO₂ emissions from fossil fuel combustion increased by 2.6 percent. This increase is primarily a result of the increased energy consumption in the residential and commercial sectors, as heating degree days increased 18.5 percent in 2013 as compared to 2012. The cooler weather led to an increase of 17.1 and 12.9 percent direct use of fuels in the residential and commercial sectors, respectively. In addition, there was an increase of 1.5 and 0.8 percent in electricity consumption in the residential and commercial sectors, respectively, due to regions that heat their homes with electricity. The consumption of natural gas used to generate electricity decreased by 9.8 percent due to an increase in the price of natural gas. Electric power plants shifted some consumption from natural gas to coal, and as a result increased coal consumption to generate electricity by 4.0 percent. Lastly, industrial production increased 1.9 percent from 2012 to 2013, resulting in an increase in the in CO₂ emissions from fossil fuel combustion from the industrial sector by 3.7 percent.

From 2013 to 2014, CO₂ emissions from fossil fuel combustion increased by 1.0 percent. This increase is primarily a result of the increased energy consumption in the transportation (around 50 percent of increase), residential (around 30 percent of increase), and commercial (around 20 percent of increase) sectors. In the transportation sector, VMT increased by 1.3 percent resulting in increased fuel consumption across on-road transportation modes. Heating

degree days increased 1.9 percent in 2014 as compared to 2013, resulting in an increased demand in heating fuels for the residential and commercial sectors. The cooler weather led to an increase of 4.5 and 5.0 percent in direct use of fuels in the residential and commercial sectors, respectively. In addition, there was an increase of 0.9 and 1.1 percent in electricity consumption in the residential and commercial sectors, respectively, due to regions that heat their homes with electricity. There was also an increase in transportation emissions resulting from an increase in VMT and fuel use across on-road transportation modes in 2014. Lastly, industrial production increased 3.7 percent from 2013 to 2014, resulting in a slight increase in CO₂ emissions from fossil fuel combustion from the industrial sector by 0.1 percent. From the perspective of how these sector trends contributed to the overall 1.0 percent increase from 2013 to 2014, the residential and commercial sectors were approximately 37 percent of the annual increase, the transportation sector was 35 percent of the annual increase, and the industrial sector was just over 1 percent of the 2013 to 2014 increase in overall U.S. emissions.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of MMT CO₂ Eq., while unweighted gas emissions and sinks in kilotons (kt) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 5,115.1 | 6,122.7 | 5,688.8 | 5,559.5 | 5,349.2 | 5,502.6 | 5,556.0 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| <i>Electricity Generation</i> | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| <i>Transportation</i> | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| <i>Industrial</i> | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| <i>Residential</i> | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| <i>Commercial</i> | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| <i>U.S. Territories</i> | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.5 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| Natural Gas Systems | 37.7 | 30.1 | 32.4 | 35.7 | 35.2 | 38.5 | 42.4 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.6 | 27.4 | 27.2 | 26.3 | 26.5 | 26.4 | 26.5 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Incineration of Waste | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Petroleum Systems | 3.6 | 3.9 | 4.2 | 4.2 | 3.9 | 3.7 | 3.6 |
| Aluminum Production | 6.8 | 4.1 | 2.7 | 3.3 | 3.4 | 3.3 | 2.8 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Magnesium Production and Processing | + | + | + | + | + | + | + |
| Wood Biomass and Ethanol Consumption ^a | 219.4 | 229.8 | 265.1 | 268.1 | 267.7 | 286.3 | 293.7 |
| International Bunker Fuels ^b | 103.5 | 113.1 | 117.0 | 111.7 | 105.8 | 99.8 | 103.2 |
| CH₄ | 773.9 | 717.4 | 722.4 | 717.4 | 714.4 | 721.5 | 730.8 |
| Natural Gas Systems | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |

| | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Petroleum Systems | 38.7 | 48.8 | 54.1 | 56.3 | 58.4 | 64.7 | 68.1 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Manure Management | 37.2 | 56.3 | 60.9 | 61.5 | 63.7 | 61.4 | 61.2 |
| Wastewater Treatment | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Stationary Combustion | 8.5 | 7.4 | 7.1 | 7.1 | 6.6 | 8.0 | 8.1 |
| Abandoned Underground Coal Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |
| Composting | 0.4 | 1.9 | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 |
| Mobile Combustion | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| Field Burning of Agricultural Residues | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Petrochemical Production | 0.2 | 0.1 | + | + | 0.1 | 0.1 | 0.1 |
| Ferroalloy Production | + | + | + | + | + | + | + |
| Silicon Carbide Production and Consumption | + | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | + | + | + | + | + | + | + |
| Incineration of Waste | + | + | + | + | + | + | + |
| <i>International Bunker Fuels^b</i> | <i>0.2</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> |
| N₂O | 406.2 | 397.6 | 410.3 | 416.5 | 409.3 | 403.4 | 403.5 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Stationary Combustion | 11.9 | 20.2 | 22.2 | 21.3 | 21.4 | 22.9 | 23.4 |
| Manure Management | 14.0 | 16.5 | 17.2 | 17.4 | 17.5 | 17.5 | 17.5 |
| Mobile Combustion | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |
| Wastewater Treatment | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Composting | 0.3 | 1.7 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 |
| Incineration of Waste | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Semiconductor Manufacture | + | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| Field Burning of Agricultural Residues | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| <i>International Bunker Fuels^b</i> | <i>0.9</i> | <i>1.0</i> | <i>1.0</i> | <i>1.0</i> | <i>0.9</i> | <i>0.9</i> | <i>0.9</i> |
| HFCs | 46.6 | 119.9 | 149.4 | 154.3 | 155.9 | 158.9 | 166.7 |
| Substitution of Ozone Depleting Substances ^c | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacture | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Magnesium Production and Processing | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| PFCs | 24.3 | 6.7 | 4.5 | 7.0 | 6.0 | 5.8 | 5.6 |
| Semiconductor Manufacture | 2.8 | 3.2 | 2.7 | 3.5 | 3.1 | 2.9 | 3.0 |
| Aluminum Production | 21.5 | 3.4 | 1.9 | 3.5 | 2.9 | 3.0 | 2.5 |
| SF₆ | 31.1 | 14.0 | 9.5 | 10.0 | 7.6 | 7.2 | 7.3 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.6 | 1.5 | 1.0 |
| Semiconductor Manufacture | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.7 |
| NF₃ | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Semiconductor Manufacture | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| LULUCF Emissions^d | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 |
| LULUCF Total Net Flux^e | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| LULUCF Sector Total^f | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

Notes: Total emissions presented without LULUCF. Net emissions presented with LULUCF.

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.

^b Emissions from International Bunker Fuels are not included in totals.

^c Small amounts of PFC emissions also result from this source.

^d LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Agricultural Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^e Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other*. Refer to Table 2-8 for a breakout of emissions and removals for LULUCF by gas and source category.

^f The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| CO₂ | 5,115,095 | 6,122,747 | 5,688,756 | 5,559,508 | 5,349,221 | 5,502,551 | 5,556,007 |
| Fossil Fuel Combustion | 4,740,671 | 5,747,142 | 5,358,292 | 5,227,690 | 5,024,685 | 5,157,583 | 5,208,207 |
| <i>Electricity Generation</i> | 1,820,818 | 2,400,874 | 2,258,399 | 2,157,688 | 2,022,181 | 2,038,122 | 2,039,321 |
| <i>Transportation</i> | 1,493,758 | 1,887,033 | 1,728,267 | 1,707,631 | 1,696,752 | 1,713,008 | 1,737,598 |
| <i>Industrial</i> | 842,473 | 827,999 | 775,535 | 773,312 | 782,929 | 812,221 | 813,274 |
| <i>Residential</i> | 338,347 | 357,834 | 334,587 | 326,808 | 282,540 | 329,674 | 345,105 |
| <i>Commercial</i> | 217,393 | 223,480 | 220,125 | 220,749 | 196,714 | 221,030 | 231,917 |
| <i>U.S. Territories</i> | 27,882 | 49,923 | 41,379 | 41,503 | 43,569 | 43,528 | 40,991 |
| Non-Energy Use of Fuels | 118,114 | 138,876 | 114,063 | 108,515 | 105,624 | 121,682 | 114,311 |
| Iron and Steel Production & Metallurgical Coke Production | 99,669 | 66,543 | 55,671 | 59,928 | 54,229 | 52,201 | 55,355 |
| Natural Gas Systems | 37,732 | 30,076 | 32,439 | 35,662 | 35,203 | 38,457 | 42,351 |
| Cement Production | 33,278 | 45,910 | 31,256 | 32,010 | 35,051 | 36,146 | 38,755 |
| Petrochemical Production | 21,609 | 27,380 | 27,246 | 26,326 | 26,464 | 26,437 | 26,509 |
| Lime Production | 11,700 | 14,552 | 13,381 | 13,981 | 13,715 | 14,045 | 14,125 |
| Other Process Uses of | | | | | | | |
| Carbonates | 4,907 | 6,339 | 9,560 | 9,335 | 8,022 | 10,414 | 12,077 |
| Ammonia Production | 13,047 | 9,196 | 9,188 | 9,292 | 9,377 | 9,962 | 9,436 |
| Incineration of Waste | 7,972 | 12,454 | 11,026 | 10,550 | 10,362 | 9,421 | 9,421 |
| Carbon Dioxide Consumption | 1,472 | 1,375 | 4,425 | 4,083 | 4,019 | 4,188 | 4,471 |
| Urea Consumption for Non-Agricultural Purposes | 3,784 | 3,653 | 4,730 | 4,029 | 4,449 | 4,179 | 4,007 |
| Petroleum Systems | 3,553 | 3,927 | 4,154 | 4,192 | 3,876 | 3,693 | 3,567 |
| Aluminum Production | 6,831 | 4,142 | 2,722 | 3,292 | 3,439 | 3,255 | 2,833 |
| Soda Ash Production and Consumption | 2,822 | 2,960 | 2,697 | 2,712 | 2,763 | 2,804 | 2,827 |
| Ferroalloy Production | 2,152 | 1,392 | 1,663 | 1,735 | 1,903 | 1,785 | 1,914 |
| Titanium Dioxide Production | 1,195 | 1,755 | 1,769 | 1,729 | 1,528 | 1,715 | 1,755 |
| Glass Production | 1,535 | 1,928 | 1,481 | 1,299 | 1,248 | 1,317 | 1,341 |
| Phosphoric Acid Production | 1,529 | 1,342 | 1,087 | 1,151 | 1,093 | 1,119 | 1,095 |
| Zinc Production | 632 | 1,030 | 1,182 | 1,286 | 1,486 | 1,429 | 956 |
| Lead Production | 516 | 553 | 542 | 538 | 527 | 546 | 518 |
| Silicon Carbide Production and Consumption | 375 | 219 | 181 | 170 | 158 | 169 | 173 |
| Magnesium Production and Processing | 1 | 3 | 1 | 3 | 2 | 2 | 2 |

| | | | | | | | |
|---|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| <i>Wood Biomass and Ethanol Consumption^a</i> | 219,413 | 229,844 | 265,110 | 268,064 | 267,730 | 286,323 | 293,729 |
| <i>International Bunker Fuels^b</i> | 103,463 | 113,139 | 116,992 | 111,660 | 105,805 | 99,763 | 103,201 |
| CH₄ | 30,954 | 28,694 | 28,896 | 28,697 | 28,576 | 28,859 | 29,233 |
| Natural Gas Systems | 8,270 | 7,093 | 6,647 | 6,803 | 6,906 | 7,023 | 7,045 |
| Enteric Fermentation | 6,566 | 6,755 | 6,853 | 6,757 | 6,670 | 6,619 | 6,572 |
| Landfills | 7,182 | 6,161 | 5,685 | 5,774 | 5,691 | 5,772 | 5,919 |
| Petroleum Systems | 1,550 | 1,953 | 2,163 | 2,251 | 2,335 | 2,588 | 2,726 |
| Coal Mining | 3,860 | 2,565 | 3,293 | 2,849 | 2,658 | 2,584 | 2,703 |
| Manure Management | 1,486 | 2,254 | 2,437 | 2,460 | 2,548 | 2,455 | 2,447 |
| Wastewater Treatment | 626 | 636 | 618 | 610 | 601 | 592 | 588 |
| Rice Cultivation | 525 | 521 | 474 | 474 | 476 | 477 | 476 |
| Stationary Combustion | 339 | 296 | 283 | 283 | 265 | 320 | 324 |
| Abandoned Underground Coal Mines | 288 | 264 | 263 | 257 | 249 | 249 | 253 |
| Composting | 15 | 75 | 73 | 75 | 77 | 81 | 82 |
| Mobile Combustion | 226 | 110 | 91 | 90 | 86 | 84 | 82 |
| Field Burning of Agricultural Residues | 10 | 8 | 11 | 11 | 11 | 11 | 11 |
| Petrochemical Production | 9 | 3 | 2 | 2 | 3 | 3 | 5 |
| Ferroalloy Production | 1 | + | + | + | 1 | + | 1 |
| Silicon Carbide Production and Consumption | 1 | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | 1 | 1 | + | + | + | + | + |
| Incineration of Waste | + | + | + | + | + | + | + |
| <i>International Bunker Fuels^b</i> | 7 | 5 | 6 | 5 | 4 | 3 | 3 |
| N₂O | 1,363 | 1,334 | 1,377 | 1,398 | 1,373 | 1,354 | 1,354 |
| Agricultural Soil Management | 1,018 | 997 | 1,076 | 1,084 | 1,084 | 1,069 | 1,068 |
| Stationary Combustion | 40 | 68 | 74 | 71 | 72 | 77 | 79 |
| Manure Management | 47 | 55 | 58 | 58 | 59 | 59 | 59 |
| Mobile Combustion | 138 | 115 | 79 | 75 | 67 | 61 | 55 |
| Nitric Acid Production | 41 | 38 | 39 | 37 | 35 | 36 | 37 |
| Adipic Acid Production | 51 | 24 | 14 | 34 | 19 | 13 | 18 |
| Wastewater Treatment | 11 | 15 | 15 | 16 | 16 | 16 | 16 |
| N ₂ O from Product Uses | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Composting | 1 | 6 | 5 | 6 | 6 | 6 | 6 |
| Incineration of Waste | 2 | 1 | 1 | 1 | 1 | 1 | 1 |
| Semiconductor Manufacture | + | + | + | 1 | 1 | 1 | 1 |
| Field Burning of Agricultural Residues | + | + | + | + | + | + | + |
| <i>International Bunker Fuels^b</i> | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| HFCs | M |
| Substitution of Ozone Depleting Substances ^c | M | M | M | M | M | M | M |
| HCFC-22 Production | 3 | 1 | 1 | 1 | + | + | + |
| Semiconductor Manufacture | + | + | + | + | + | + | + |
| Magnesium Production and Processing | 0 | 0 | + | + | + | + | + |
| PFCs | M |
| Semiconductor Manufacture | M | M | M | M | M | M | M |
| Aluminum Production | M | M | M | M | M | M | M |
| SF₆ | 1 | 1 | + | + | + | + | + |
| Electrical Transmission and Distribution | 1 | + | + | + | + | + | + |
| Magnesium Production and Processing | + | + | + | + | + | + | + |

| | | | | | | | |
|---------------------------|---|---|---|---|---|---|---|
| Semiconductor Manufacture | + | + | + | + | + | + | + |
| NF ₃ | + | + | + | + | + | + | + |
| Semiconductor Manufacture | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

M - Mixture of multiple gases

^a Emissions from Wood Biomass and Ethanol Consumption are not included in totals.

^b Emissions from International Bunker Fuels are not included in totals.

^c Small amounts of PFC emissions also result from this source.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Emissions of all gases can be summed from each source category into a set of five sectors defined by the Intergovernmental Panel on Climate Change (IPCC). Figure 2-4 and Table 2-3 illustrate that over the twenty five-year period of 1990 to 2014, total emissions in the Energy, Industrial Processes and Product Use, and Agriculture sectors grew by 421.3 MMT CO₂ Eq. (7.9 percent), 38.3 MMT CO₂ Eq. (11.2 percent), and 41.6 MMT CO₂ Eq. (7.8 percent), respectively. Emissions from the Waste sector decreased by 27.9 MMT CO₂ Eq. (14.0 percent). Over the same period, estimates of net C sequestration for the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO₂ removals from all LULUCF categories) increased by 24.5 MMT CO₂ Eq. (3.3 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO₂ Eq.)

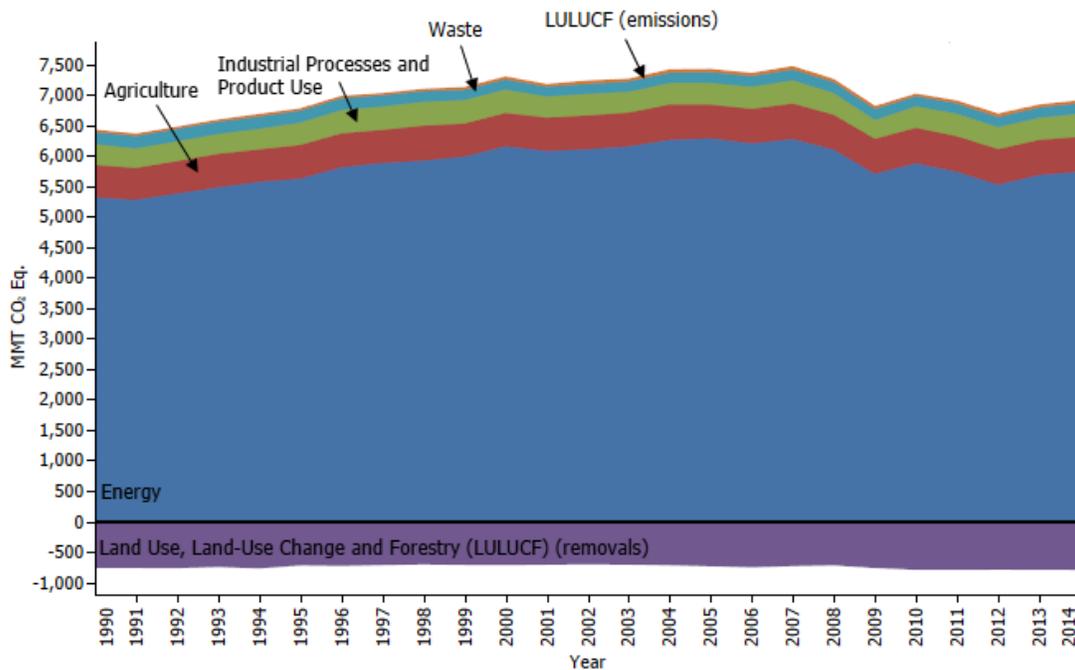


Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO₂ Eq.)

| Chapter/IPCC Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Energy | 5,324.9 | 6,294.5 | 5,884.6 | 5,744.0 | 5,533.9 | 5,693.5 | 5,746.2 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| Natural Gas Systems | 244.5 | 207.4 | 198.6 | 205.7 | 207.8 | 214.0 | 218.5 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Petroleum Systems | 42.3 | 52.8 | 58.2 | 60.5 | 62.2 | 68.4 | 71.7 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Stationary Combustion | 20.4 | 27.6 | 29.2 | 28.4 | 28.0 | 30.9 | 31.5 |
| Mobile Combustion | 46.9 | 37.1 | 25.9 | 24.7 | 22.2 | 20.3 | 18.4 |
| Incineration of Waste | 8.4 | 12.8 | 11.4 | 10.9 | 10.7 | 9.7 | 9.7 |
| Abandoned Underground Coal Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |

| | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Industrial Processes and Product Use | 340.9 | 354.3 | 353.0 | 370.5 | 360.1 | 363.5 | 379.2 |
| Substitution of Ozone Depleting Substances | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.6 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.8 | 27.5 | 27.3 | 26.4 | 26.5 | 26.5 | 26.6 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |
| Aluminum Production | 28.3 | 7.6 | 4.6 | 6.8 | 6.4 | 6.2 | 5.4 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacture | 3.6 | 4.7 | 4.0 | 5.1 | 4.5 | 4.2 | 4.7 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.7 | 1.5 | 1.2 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Agriculture | 532.0 | 552.2 | 582.3 | 583.1 | 583.3 | 575.3 | 573.6 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |
| Manure Management | 51.1 | 72.9 | 78.1 | 78.9 | 81.2 | 78.9 | 78.7 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Field Burning of Agricultural Residues | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Waste | 199.3 | 177.8 | 165.5 | 167.8 | 165.7 | 167.8 | 171.4 |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Wastewater Treatment | 19.0 | 20.2 | 19.9 | 19.9 | 19.8 | 19.6 | 19.5 |
| Composting | 0.7 | 3.5 | 3.5 | 3.5 | 3.7 | 3.9 | 3.9 |
| Total Emissions^a | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 |
| Land Use, Land-Use Change, and Forestry | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |
| Forest Land | (718.7) | (675.8) | (736.5) | (725.6) | (717.4) | (726.8) | (730.0) |
| Cropland | 38.5 | 25.9 | 34.0 | 17.1 | 21.1 | 21.1 | 22.3 |
| Grassland | 26.2 | 39.8 | 32.0 | 43.0 | 43.9 | 44.1 | 44.2 |
| Wetlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| Settlements | (59.0) | (78.2) | (83.8) | (84.8) | (85.8) | (87.1) | (88.2) |
| Other | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| Net Emissions (Sources and Sinks)^b | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 |

Notes: Total emissions presented without LULUCF. Net emissions presented with LULUCF.

^a Total emissions without LULUCF.

^b Net emissions with LULUCF.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO₂ emissions for the period of 1990 through 2014. In 2014, approximately 82 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 18 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure 2-5 and Figure 2-6). A discussion of specific trends related to CO₂ as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH₄ and N₂O emissions (45 percent and 10 percent of total U.S. emissions of each gas, respectively). Table 2-4 presents greenhouse gas emissions from the Energy chapter, by source and gas.

Figure 2-5: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)

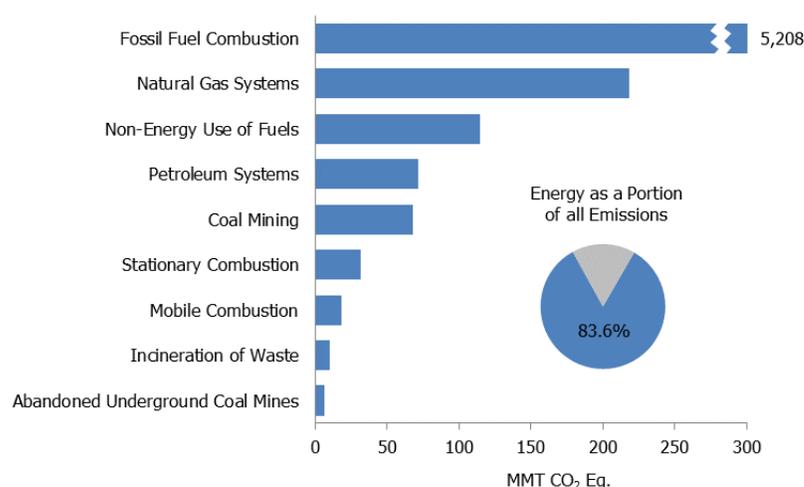


Figure 2-6: 2014 U.S. Fossil Carbon Flows (MMT CO₂ Eq.)

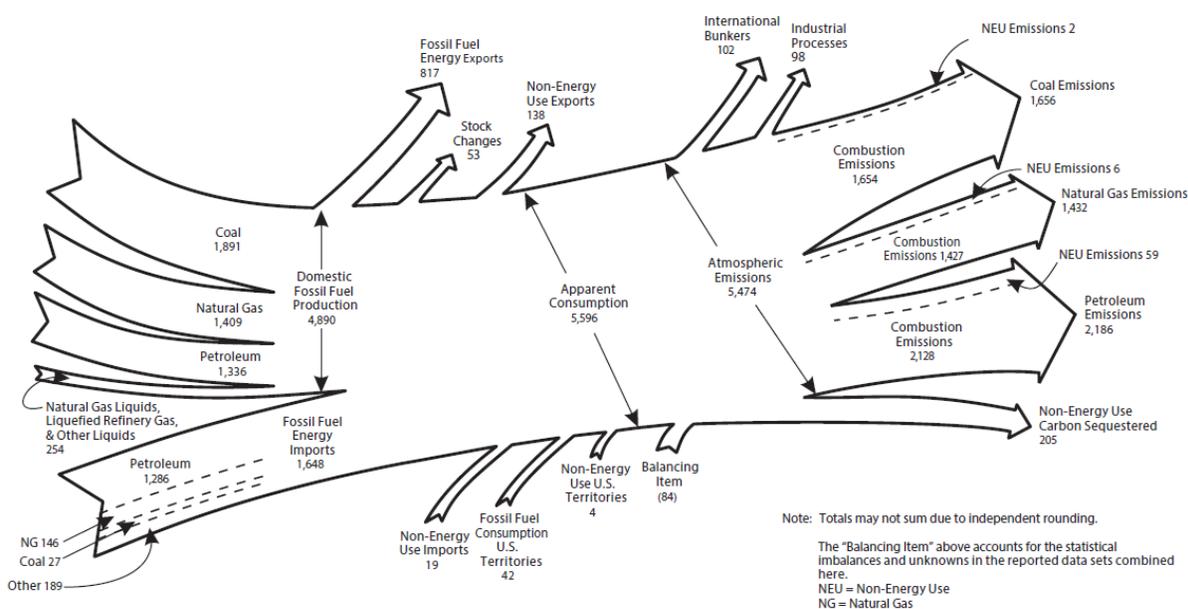


Table 2-4: Emissions from Energy (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 4,908.0 | 5,932.5 | 5,520.0 | 5,386.6 | 5,179.7 | 5,330.8 | 5,377.9 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| <i>Electricity Generation</i> | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| <i>Transportation</i> | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| <i>Industrial</i> | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| <i>Residential</i> | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| <i>Commercial</i> | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| <i>U.S. Territories</i> | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Natural Gas Systems | 37.7 | 30.1 | 32.4 | 35.7 | 35.2 | 38.5 | 42.4 |
| Incineration of Waste | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Petroleum Systems | 3.6 | 3.9 | 4.2 | 4.2 | 3.9 | 3.7 | 3.6 |
| <i>Biomass-Wood^a</i> | 215.2 | 206.9 | 192.5 | 195.2 | 194.9 | 211.6 | 217.7 |
| <i>International Bunker Fuels^b</i> | 103.5 | 113.1 | 117.0 | 111.7 | 105.8 | 99.8 | 103.2 |
| <i>Biomass-Ethanol^a</i> | 4.2 | 22.9 | 72.6 | 72.9 | 72.8 | 74.7 | 76.1 |
| CH₄ | 363.3 | 307.0 | 318.5 | 313.3 | 312.5 | 321.2 | 328.3 |
| Natural Gas Systems | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |
| Petroleum Systems | 38.7 | 48.8 | 54.1 | 56.3 | 58.4 | 64.7 | 68.1 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Stationary Combustion | 8.5 | 7.4 | 7.1 | 7.1 | 6.6 | 8.0 | 8.1 |
| Abandoned Underground Coal | | | | | | | |
| Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |
| Mobile Combustion | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| Incineration of Waste | + | + | + | + | + | + | + |
| <i>International Bunker Fuels^b</i> | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| N₂O | 53.6 | 55.0 | 46.1 | 44.0 | 41.7 | 41.4 | 40.0 |
| Stationary Combustion | 11.9 | 20.2 | 22.2 | 21.3 | 21.4 | 22.9 | 23.4 |
| Mobile Combustion | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |
| Incineration of Waste | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| <i>International Bunker Fuels^b</i> | 0.9 | 1.0 | 1.0 | 1.0 | 0.9 | 0.9 | 0.9 |
| Total | 5,324.9 | 6,294.5 | 5,884.6 | 5,744.0 | 5,533.9 | 5,693.5 | 5,746.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^aEmissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.

^bEmissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from fossil fuel combustion are presented in Table 2-5 based on the underlying U.S. energy consumer data collected by the U.S. Energy Information Administration (EIA). Estimates of CO₂ emissions from fossil fuel combustion are calculated from these EIA “end-use sectors” based on total consumption and appropriate fuel properties (any additional analysis and refinement of the EIA data is further explained in the Energy chapter of this report). EIA’s fuel consumption data for the electric power sector are comprised of electricity-only and combined-heat-and-power (CHP) plants within the North American Industry Classification System (NAICS) 22 category whose primary business is to sell electricity, or electricity and heat, to the public (nonutility power producers can be included in this sector as long as they meet they electric power sector definition). EIA statistics for the industrial sector include fossil fuel consumption that occurs in the fields of manufacturing, agriculture, mining, and construction. EIA’s fuel consumption data for the transportation sector consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another. EIA’s fuel consumption data for the industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (EIA includes generators that produce electricity and/or useful thermal output primarily to support on-site industrial activities in this sector). EIA’s fuel consumption data for the residential sector consist of living quarters for private households. EIA’s fuel consumption data for the commercial sector consist of service-providing facilities and equipment from private and public organizations and businesses (EIA includes generators that produce electricity and/or useful thermal output primarily to support the activities at commercial establishments in this sector). Table

2-5 and Figure 2-7 summarize CO₂ emissions from fossil fuel combustion by end-use sector. Figure 2-8 further describes the total emissions from fossil fuel combustion, separated by end-use sector, including CH₄ and N₂O in addition to CO₂.

Table 2-5: CO₂ Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Transportation | 1,496.8 | 1,891.8 | 1,732.7 | 1,711.9 | 1,700.6 | 1,717.0 | 1,741.7 |
| Combustion | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| Electricity | 3.0 | 4.7 | 4.5 | 4.3 | 3.9 | 4.0 | 4.1 |
| Industrial | 1,529.2 | 1,564.6 | 1,416.5 | 1,398.0 | 1,375.7 | 1,407.0 | 1,406.8 |
| Combustion | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| Electricity | 686.7 | 736.6 | 641.0 | 624.7 | 592.8 | 594.7 | 593.6 |
| Residential | 931.4 | 1,214.1 | 1,174.6 | 1,117.5 | 1,007.8 | 1,064.6 | 1,080.3 |
| Combustion | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| Electricity | 593.0 | 856.3 | 840.0 | 790.7 | 725.3 | 734.9 | 735.2 |
| Commercial | 755.4 | 1,026.8 | 993.0 | 958.8 | 897.0 | 925.5 | 938.4 |
| Combustion | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| Electricity | 538.0 | 803.3 | 772.9 | 738.0 | 700.3 | 704.5 | 706.5 |
| U.S. Territories^a | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Total | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| Electricity Generation | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |

^a Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Notes: Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector. Totals may not sum due to independent rounding.

Figure 2-7: 2014 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO₂ Eq.)

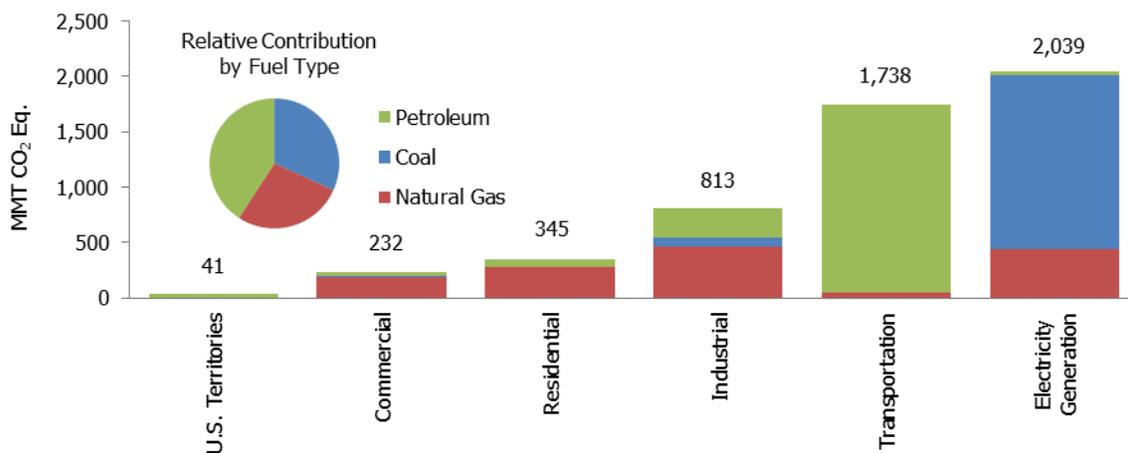
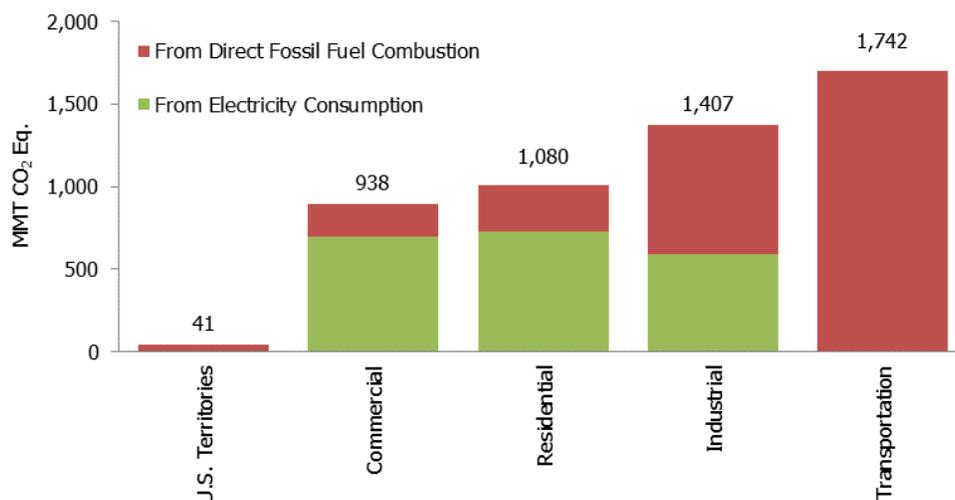


Figure 2-8: 2014 End-Use Sector Emissions of CO₂ from Fossil Fuel Combustion (MMT CO₂ Eq.)



The main driver of emissions in the Energy sector is CO₂ from fossil fuel combustion. Electricity generation is the largest emitter of CO₂, and electricity generators consumed 34 percent of U.S. energy from fossil fuels and emitted 39 percent of the CO₂ from fossil fuel combustion in 2014. Electricity generation emissions can also be allocated to the end-use sectors that are consuming that electricity, as presented in Table 2-5. The transportation end-use sector accounted for 1,741.7 MMT CO₂ Eq. in 2014 or approximately 33 percent of total CO₂ emissions from fossil fuel combustion. The industrial end-use sector accounted for 27 percent of CO₂ emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for 21 and 18 percent, respectively, of CO₂ emissions from fossil fuel combustion. Both of these end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 68 and 75 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty five-year period from 1990 through 2014 included the following:

- Total CO₂ emissions from fossil fuel combustion increased from 4,740.7 MMT CO₂ Eq. in 1990 to 5,208.2 MMT CO₂ Eq. in 2014 – a 9.9 percent total increase over the twenty five-year period. From 2013 to 2014, these emissions increased by 50.6 MMT CO₂ Eq. (1.0 percent).
- Methane emissions from natural gas systems and petroleum systems (combined here) decreased very slightly from 245.5 MMT CO₂ Eq. in 1990 to 244.3 MMT CO₂ Eq. (1.2 MMT CO₂ Eq. or less than 1 percent) from 1990 to 2014. Natural gas systems CH₄ emissions decreased by 30.6 MMT CO₂ Eq. (14.8 percent) since 1990, largely due to a decrease in emissions from transmission, storage, and distribution. The decrease in transmission and storage emissions is largely due to reduced compressor station emissions (including emissions from compressors and fugitives). The decrease in distribution emissions is largely attributed to increased use of plastic piping, which has lower emissions than other pipe materials, and station upgrades at metering and regulating (M&R) stations. Petroleum systems CH₄ emissions increased by 29.4 MMT CO₂ Eq. (or 76 percent) since 1990. This increase is due primarily to increases in emissions from production equipment.
- Carbon dioxide emissions from non-energy uses of fossil fuels decreased by 3.8 MMT CO₂ Eq. (3.2 percent) from 1990 through 2014. Emissions from non-energy uses of fossil fuels were 114.3 MMT CO₂ Eq. in 2014, which constituted 2.1 percent of total national CO₂ emissions, approximately the same proportion as in 1990.
- Nitrous oxide emissions from stationary combustion increased by 11.5 MMT CO₂ Eq. (96.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.

- Nitrous oxide emissions from mobile combustion decreased by 24.9 MMT CO₂ Eq. (60.4 percent) from 1990 through 2014, primarily as a result of N₂O national emission control standards and emission control technologies for on-road vehicles.
- Carbon dioxide emissions from incineration of waste (9.4 MMT CO₂ Eq. in 2014) increased by 1.4 MMT CO₂ Eq. (18.2 percent) from 1990 through 2014, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.

The increase in CO₂ emissions from fossil fuel combustion in 2014 was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014, which resulted in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in industrial production across multiple sectors, resulting in slight increases in industrial sector emissions;¹ and (3) an increase in transportation emissions resulting from an increase in VMT and fuel use across on-road transportation modes.

Industrial Processes and Product Use

The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products.

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO₂, CH₄, and N₂O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production, urea consumption, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO₂ consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, zinc production, and N₂O from product uses (see Figure 2-9). Industrial processes also release HFCs, PFCs, SF₆, and NF₃. In addition to their use as substitutes for ozone depleting substances (ODS), fluorinated compounds such as HFCs, PFCs, SF₆, NF₃, and others are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

¹ Further details on industrial sector combustion emissions are provided by EPA's GHGRP. See <<http://ghgdata.epa.gov/ghgp/main.do>>.

Figure 2-9: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)

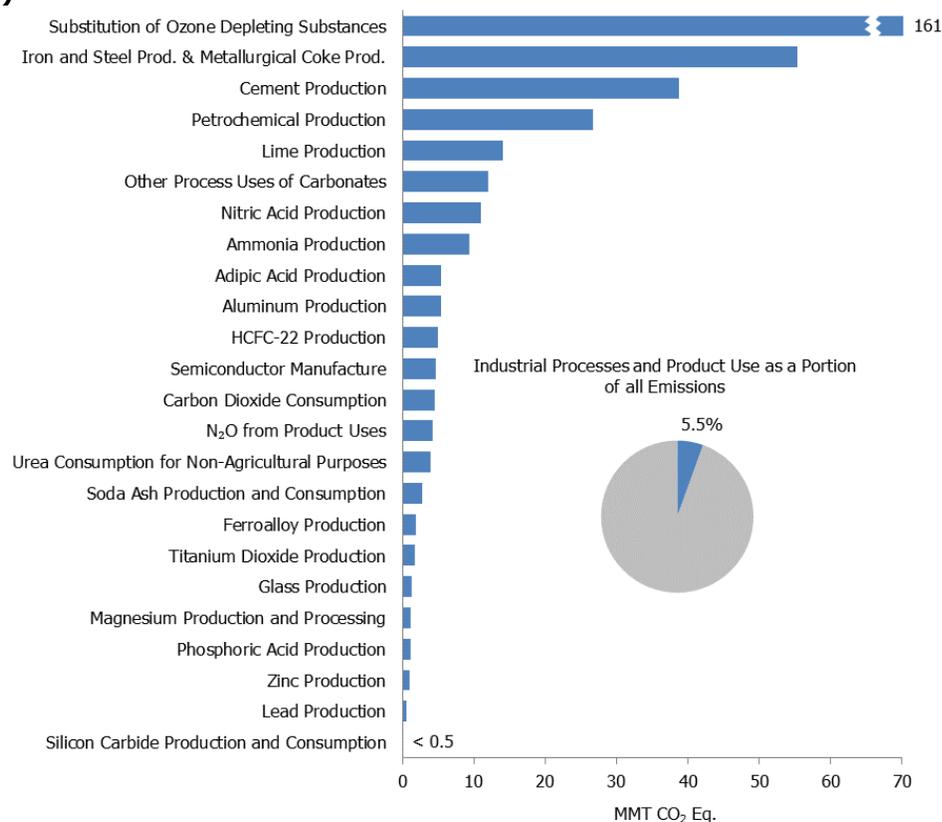


Table 2-6: Emissions from Industrial Processes and Product Use (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CO₂ | 207.1 | 190.3 | 168.8 | 172.9 | 169.5 | 171.7 | 178.1 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.5 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| <i>Iron and Steel Production</i> | 97.2 | 64.5 | 53.6 | 58.5 | 53.7 | 50.4 | 53.4 |
| <i>Metallurgical Coke Production</i> | 2.5 | 2.0 | 2.1 | 1.4 | 0.5 | 1.8 | 1.9 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.6 | 27.4 | 27.2 | 26.3 | 26.5 | 26.4 | 26.5 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Aluminum Production | 6.8 | 4.1 | 2.7 | 3.3 | 3.4 | 3.3 | 2.8 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Magnesium Production and Processing | + | + | + | + | + | + | + |

| | | | | | | | |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 |
| Petrochemical Production | 0.2 | 0.1 | + | + | 0.1 | 0.1 | 0.1 |
| Ferroalloy Production | + | + | + | + | + | + | + |
| Silicon Carbide Production and Consumption | + | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | + | + | + | + | + | + | + |
| <i>Iron and Steel Production</i> | + | + | + | + | + | + | + |
| <i>Metallurgical Coke Production</i> | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N₂O | 31.6 | 22.8 | 20.1 | 25.5 | 20.4 | 19.1 | 20.8 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Semiconductor Manufacturing | + | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| HFCs | 46.6 | 119.9 | 149.4 | 154.3 | 155.9 | 158.9 | 166.7 |
| Substitution of Ozone Depleting Substances ^a | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacturing | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Magnesium Production and Processing | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| PFCs | 24.3 | 6.7 | 4.5 | 7.0 | 6.0 | 5.8 | 5.6 |
| Semiconductor Manufacturing | 2.8 | 3.2 | 2.7 | 3.5 | 3.1 | 2.9 | 3.0 |
| Aluminum Production | 21.5 | 3.4 | 1.9 | 3.5 | 2.9 | 3.0 | 2.5 |
| SF₆ | 31.1 | 14.0 | 9.5 | 10.0 | 7.6 | 7.2 | 7.3 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.6 | 1.5 | 1.0 |
| Semiconductor Manufacturing | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.7 |
| NF₃ | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Semiconductor Manufacturing | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Total | 340.9 | 354.3 | 353.0 | 370.5 | 360.1 | 363.5 | 379.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from the IPPU sector increased by 11.2 percent from 1990 to 2014. Significant trends in emissions from IPPU source categories over the twenty five-year period from 1990 through 2014 included the following:

- Hydrofluorocarbon emissions from ODS substitutes have been increasing from small amounts in 1990 to 161.2 MMT CO₂ Eq. in 2014. This increase was in large part the result of efforts to phase out chlorofluorocarbons (CFCs) and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely continue over the next decade as hydrochlorofluorocarbons (HCFCs), which are interim substitutes in many applications, are themselves phased-out under the provisions of the *Copenhagen Amendments to the Montreal Protocol*.
- Combined CO₂ and CH₄ emissions from iron and steel production and metallurgical coke production increased by 6.0 percent to 55.4 MMT CO₂ Eq. from 2013 to 2014, and have declined overall by 44.3 MMT CO₂ Eq. (44.5 percent) from 1990 through 2014, due to restructuring of the industry, technological improvements, and increased scrap steel utilization.
- Carbon dioxide emissions from ammonia production (9.4 MMT CO₂ Eq. in 2014) decreased by 3.6 MMT CO₂ Eq. (27.7 percent) since 1990. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia.
- Urea consumption for non-agricultural purposes (4.0 MMT CO₂ Eq. in 2014) increased by 0.2 MMT CO₂ Eq. (5.9 percent) since 1990. From 1990 to 2007, emissions increased by 31 percent to a peak of 4.9 MMT CO₂ Eq., before decreasing by 19 percent to 2014 levels.

- In 2014, N₂O emissions from product uses constituted 1.0 percent of U.S. N₂O emissions. From 1990 to 2014, emissions from this source category decreased by 0.4 percent, though slight increases occurred in intermediate years.
- Nitrous oxide emissions from adipic acid production were 5.4 MMT CO₂ Eq. in 2014, and have decreased significantly since 1990 due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. Emissions from adipic acid production have decreased by 64.2 percent since 1990 and by 67.8 percent since a peak in 1995.
- PFC emissions from aluminum production decreased by 88.2 percent (18.9 MMT CO₂ Eq.) from 1990 to 2014, due to both industry emission reduction efforts and lower domestic aluminum production.

Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues.

In 2014, agricultural activities were responsible for emissions of 573.6 MMT CO₂ Eq., or 8.3 percent of total U.S. greenhouse gas emissions. Methane and nitrous oxide were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represented about 22.5 percent and 8.4 percent of total CH₄ emissions from anthropogenic activities, respectively, in 2014. Agricultural soil management activities, such as fertilizer use and other cropping practices, were the largest source of U.S. N₂O emissions in 2014, accounting for 78.9 percent. Figure 2-10 and Table 2-7 illustrate agricultural greenhouse gas emissions by source.

Figure 2-10: 2014 Agriculture Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)

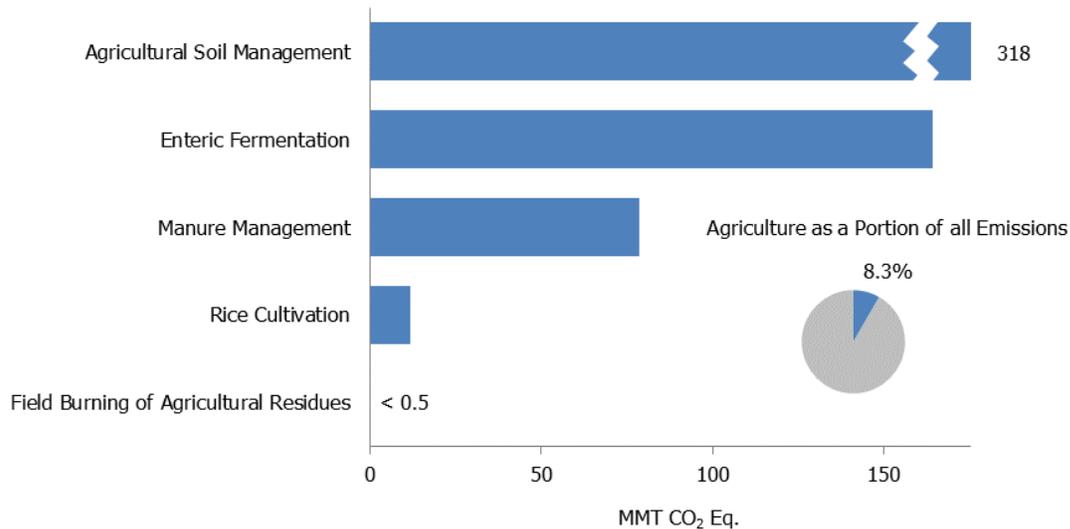


Table 2-7: Emissions from Agriculture (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 214.7 | 238.4 | 244.4 | 242.5 | 242.6 | 239.0 | 237.7 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |
| Manure Management | 37.2 | 56.3 | 60.9 | 61.5 | 63.7 | 61.4 | 61.2 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Field Burning of Agricultural Residues | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| N₂O | 317.4 | 313.8 | 338.0 | 340.6 | 340.7 | 336.2 | 336.0 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Manure Management | 14.0 | 16.5 | 17.2 | 17.4 | 17.5 | 17.5 | 17.5 |
| Field Burning of Agricultural Residues | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total | 532.0 | 552.2 | 582.3 | 583.1 | 583.3 | 575.3 | 573.6 |

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Agriculture source categories include the following:

- Agricultural soils produced approximately 78.9 percent of N₂O emissions in the United States in 2014. Estimated emissions from this source in 2014 were 318.4 MMT CO₂ Eq. Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2014, although overall emissions were 5.0 percent higher in 2014 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production.
- Enteric fermentation is the second largest anthropogenic source of CH₄ emissions in the United States. In 2014, enteric fermentation CH₄ emissions were 164.3 MMT CO₂ Eq. (22.5 percent of total CH₄ emissions), which represents an increase of 0.1 MMT CO₂ Eq. (0.1 percent) since 1990. This increase in emissions from 1990 to 2014 in enteric fermentation generally follows the increasing trends in cattle populations. From 1990 to 1995 emissions increased and then generally decreased from 1996 to 2004, mainly due to fluctuations in beef cattle populations and increased digestibility of feed for feedlot cattle. Emissions increased from 2005 to 2007, as both dairy and beef populations underwent increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again from 2008 to 2014 as beef cattle populations again decreased.
- Overall, emissions from manure management increased 53.8 percent between 1990 and 2014. This encompassed an increase of 64.7 percent for CH₄, from 37.2 MMT CO₂ Eq. in 1990 to 61.2 MMT CO₂ Eq. in 2014; and an increase of 24.9 percent for N₂O, from 14.0 MMT CO₂ Eq. in 1990 to 17.5 MMT CO₂ Eq. in 2014. The majority of the increase observed in CH₄ resulted from swine and dairy cow manure, where emissions increased 44 and 118 percent, respectively, from 1990 to 2014. From 2013 to 2014, there was a 0.3 percent decrease in total CH₄ emissions from manure management, mainly due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

Land Use, Land-Use Change, and Forestry

When humans alter the terrestrial biosphere through land use, changes in land use, and land management practices, they also alter the background C fluxes between biomass, soils, and the atmosphere. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps have resulted in a net removal of CO₂ (sequestration of C) in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 87 percent of total 2014 CO₂ removals, urban trees accounted for 11 percent, landfilled yard trimmings and food scraps accounted for 1.4 percent, and mineral and organic soil carbon stock changes from *Cropland Remaining Cropland* accounted for 1.0 percent of the total CO₂ removals in 2014. The net forest sequestration is a result of net forest growth, increasing forest area, and a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth and increased urban forest size. In agricultural soils, mineral and organic soils sequester approximately as much C as is emitted

from these soils through liming and urea fertilization. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming and food scraps carbon in landfills.

LULUCF activities in 2014 resulted in a net increase in C stocks (i.e., net CO₂ removals) of 787.0 MMT CO₂ Eq. (Table 2-3).² This represents an offset of approximately 11.5 percent of total (i.e., gross) greenhouse gas emissions in 2014. Emissions from LULUCF activities in 2014 are 24.6 MMT CO₂ Eq. and represent 0.4 percent of total greenhouse gas emissions.³ Between 1990 and 2014, total C sequestration in the LULUCF sector increased by 4.5 percent, primarily due to an increase in the rate of net C accumulation in forest and urban tree C stocks.

Carbon dioxide removals are presented in Table 2-8 along with CO₂, CH₄, and N₂O emissions for LULUCF source categories. Liming and urea fertilization resulted in CO₂ emissions of 8.7 MMT CO₂ Eq. in 2014, an increase of about 22.2 percent relative to 1990. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO₂ emissions of 0.8 MMT CO₂ Eq. and CH₄ and N₂O emissions of less than 0.05 MMT CO₂ Eq. each. Nitrous oxide emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 MMT CO₂ Eq. in 1990 to 0.5 MMT CO₂ Eq. in 2014. Settlement soils in 2014 resulted in N₂O emissions of 2.4 MMT CO₂ Eq., a 78.4 percent increase relative to 1990. Emissions from forest fires in 2014 resulted in CH₄ emissions of 7.3 MMT CO₂ and in N₂O emissions of 4.8 MMT CO₂ (see Table 2-8).

Table 2-8: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry (MMT CO₂ Eq.)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Net CO₂ Flux^a | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| Forest Land Remaining Forest Land ^b | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Land Converted to Forest Land | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Cropland Remaining Cropland | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| Land Converted to Cropland | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Grassland Remaining Grassland | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Land Converted to Grassland | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Settlements Remaining Settlements | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| Other: Landfilled Yard Trimmings and Food Scraps | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| CO₂ | 8.1 | 9.0 | 9.6 | 8.9 | 11.0 | 9.0 | 9.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Urea Fertilization | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Liming | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| CH₄ | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.4 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.3 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| N₂O | 3.6 | 9.3 | 5.0 | 7.3 | 10.3 | 7.7 | 7.7 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 2.2 | 6.5 | 2.2 | 4.4 | 7.3 | 4.8 | 4.8 |
| Settlements Remaining Settlements: N ₂ O Fluxes from Settlement Soils ^c | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| Forest Land Remaining Forest Land: N ₂ O Fluxes from Forest Soils ^d | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |

² Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land*, *Land Converted to Forest Land*, *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Other*.

³ LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

| | | | | | | | | |
|--|----------------|--|----------------|--|----------------|----------------|----------------|----------------|
| Wetlands Remaining Wetlands: | | | | | | | | |
| Peatlands Remaining Peatlands | + | | + | | + | + | + | + |
| LULUCF Emissions^e | 15.0 | | 28.2 | | 17.8 | 22.9 | 32.3 | 24.1 |
| LULUCF Total Net Flux^a | (753.0) | | (726.7) | | (784.3) | (784.9) | (782.0) | (783.7) |
| LULUCF Sector Total^f | (738.0) | | (698.5) | | (766.4) | (762.0) | (749.7) | (759.6) |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.*

^b Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^c Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^d Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

^e LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^f The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Other significant trends from 1990 to 2014 in emissions from LULUCF categories include:

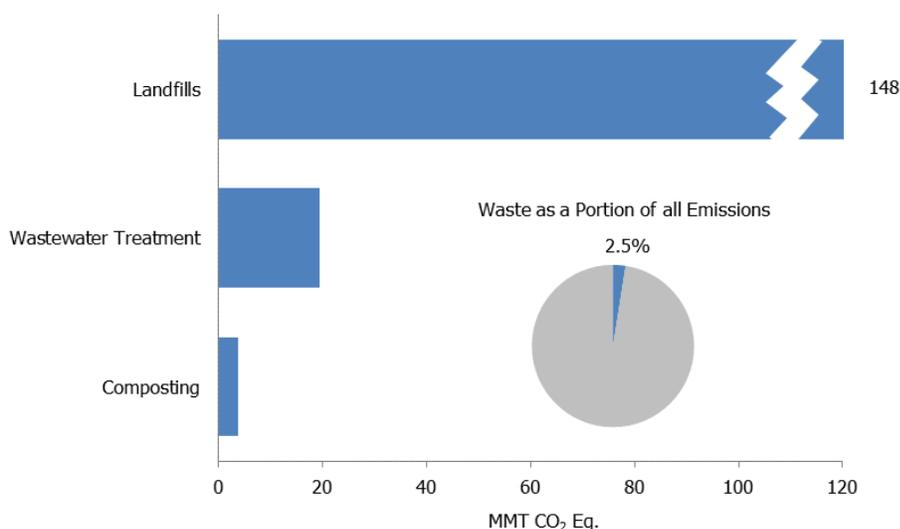
- Annual C sequestration by forest land (i.e., annual C stock accumulation in the five C pools for *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*) has increased by approximately 3 percent. This is primarily due to increased forest management and the effects of previous reforestation. The increase in intensive forest management resulted in higher growth rates and higher biomass density. The tree planting and conservation efforts of the 1970s and 1980s continue to have a significant impact on sequestration rates. Finally, the forested area in the United States increased over the past twenty five years, although only at an average rate of 0.1 percent per year.
- Annual C sequestration by urban trees has increased by 50.0 percent over the period from 1990 to 2014. This is primarily due to an increase in urbanized land area in the United States.
- Annual C sequestration in landfilled yard trimmings and food scraps has decreased by 55.4 percent since 1990. Food scrap generation has grown by 55 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 76 percent in 2014, the tonnage disposed in landfills has increased considerably (by 45 percent). Overall, the decrease in the landfill disposal rate of yard trimmings has more than compensated for the increase in food scrap disposal in landfills.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2014, landfills were the third-largest source of U.S. anthropogenic CH₄ emissions, accounting for 20.2 percent of total U.S. CH₄ emissions.⁴ Additionally, wastewater treatment accounts for 11.4 percent of Waste emissions, 2.0 percent of U.S. CH₄ emissions, and 1.2 percent of N₂O emissions. Emissions of CH₄ and N₂O from composting grew from 1990 to 2014, and resulted in emissions of 3.9 MMT CO₂ Eq. in 2014. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-9.

⁴ Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land Use, Land-Use Change, and Forestry chapter.

Figure 2-11: 2014 Waste Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



Overall, in 2014, waste activities generated emissions of 171.4 MMT CO₂ Eq., or 2.5 percent of total U.S. greenhouse gas emissions.

Table 2-9: Emissions from Waste (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 195.6 | 171.8 | 159.4 | 161.5 | 159.2 | 161.1 | 164.7 |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Wastewater Treatment | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 |
| Composting | 0.4 | 1.9 | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 |
| N₂O | 3.7 | 6.0 | 6.1 | 6.4 | 6.5 | 6.6 | 6.7 |
| Wastewater Treatment | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| Composting | 0.3 | 1.7 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 |
| Total | 199.3 | 177.8 | 165.5 | 167.8 | 165.7 | 167.8 | 171.4 |

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from waste source categories include the following:

- From 1990 to 2014, net CH₄ emissions from landfills decreased by 31.6 MMT CO₂ Eq. (17.6 percent), with small increases occurring in interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted as well as reductions in the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in municipal solid waste (MSW) landfills over the time series,⁵ which has more than offset the additional CH₄ emissions resulting from an increase in the amount of municipal solid waste landfilled.
- Combined CH₄ and N₂O emissions from composting have generally increased since 1990, from 0.7 MMT CO₂ Eq. to 3.9 MMT CO₂ Eq. in 2014, which represents slightly more than a five-fold increase over the time series. The growth in composting since the 1990s is attributable to primarily two factors: (1) steady growth in population and residential housing, and (2) the enactment of legislation by state and local governments that discouraged the disposal of yard trimmings in landfills.
- From 1990 to 2014, CH₄ and N₂O emissions from wastewater treatment decreased by 1.0 MMT CO₂ Eq. (6.1 percent) and increased by 1.5 MMT CO₂ Eq. (44.1 percent), respectively. Methane emissions from

⁵ The CO₂ produced from combusted landfill CH₄ at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

domestic wastewater treatment have decreased since 1999 due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. Nitrous oxide emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

2.2 Emissions by Economic Sector

Throughout this report, emission estimates are grouped into five sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes and Product Use; Agriculture; LULUCF; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following U.S. economic sectors: residential, commercial, industry, transportation, electricity generation, and agriculture, as well as U.S. Territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (30 percent) of U.S. greenhouse gas emissions in 2014. Transportation activities, in aggregate, accounted for the second largest portion (26 percent). Emissions from industry accounted for about 21 percent of U.S. greenhouse gas emissions in 2014. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements. The remaining 22 percent of U.S. greenhouse gas emissions were contributed by the residential, agriculture, and commercial sectors, plus emissions from U.S. Territories. The residential sector accounted for 6 percent, and primarily consisted of CO₂ emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 9 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N₂O emissions from agricultural soil management and CH₄ emissions from enteric fermentation, rather than CO₂ from fossil fuel combustion. The commercial sector accounted for roughly 7 percent of emissions, while U.S. Territories accounted for less than 1 percent. Carbon dioxide was also emitted and sequestered (in the form of C) by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Table 2-10 presents a detailed breakdown of emissions from each of these economic sectors by source category, as they are defined in this report. Figure 2-12 shows the trend in emissions by sector from 1990 to 2014.

Figure 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO₂ Eq.)

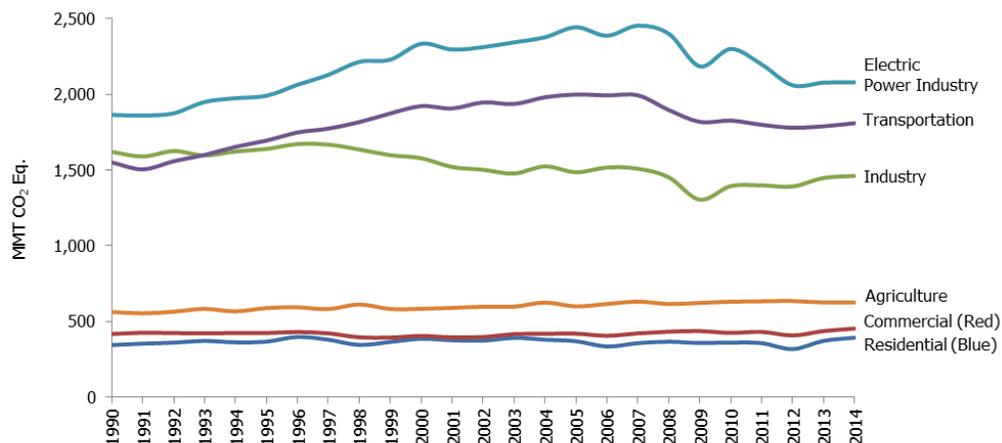


Table 2-10: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO₂ Eq. and Percent of Total in 2014)

| Sector/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent ^a |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------------|
| Electric Power Industry | 1,864.8 | 2,443.9 | 2,300.5 | 2,198.1 | 2,060.7 | 2,078.0 | 2,080.7 | 30.3% |
| CO ₂ from Fossil Fuel Combustion | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 | 29.7% |
| Stationary Combustion | 7.7 | 16.5 | 18.9 | 18.0 | 18.2 | 19.5 | 20.0 | 0.3% |
| Incineration of Waste | 8.4 | 12.8 | 11.4 | 10.9 | 10.7 | 9.7 | 9.7 | 0.1% |
| Other Process Uses of Carbonates | 2.5 | 3.2 | 4.8 | 4.7 | 4.0 | 5.2 | 6.0 | 0.1% |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 | 0.1% |
| Transportation | 1,551.3 | 1,999.6 | 1,827.4 | 1,799.6 | 1,780.4 | 1,789.9 | 1,810.3 | 26.3% |
| CO ₂ from Fossil Fuel Combustion | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 | 25.3% |
| Substitution of Ozone Depleting Substances | + | 67.1 | 65.6 | 60.2 | 55.1 | 49.8 | 47.2 | 0.7% |
| Mobile Combustion | 45.7 | 35.3 | 24.0 | 22.7 | 20.2 | 18.3 | 16.3 | 0.2% |
| Non-Energy Use of Fuels | 11.8 | 10.2 | 9.5 | 9.0 | 8.3 | 8.8 | 9.1 | 0.1% |
| Industry | 1,620.9 | 1,486.2 | 1,394.5 | 1,399.0 | 1,392.1 | 1,448.2 | 1,461.7 | 21.3% |
| CO ₂ from Fossil Fuel Combustion | 811.4 | 780.6 | 727.4 | 723.4 | 731.5 | 761.8 | 762.1 | 11.1% |
| Natural Gas Systems | 244.5 | 207.4 | 198.6 | 205.7 | 207.8 | 214.0 | 218.5 | 3.2% |
| Non-Energy Use of Fuels | 100.6 | 120.6 | 100.8 | 95.8 | 93.5 | 109.1 | 101.6 | 1.5% |
| Petroleum Systems | 42.3 | 52.8 | 58.2 | 60.5 | 62.2 | 68.4 | 71.7 | 1.0% |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 | 1.0% |
| Iron and Steel Production | 99.7 | 66.6 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 | 0.8% |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 | 0.6% |
| Petrochemical Production | 21.8 | 27.5 | 27.3 | 26.4 | 26.5 | 26.5 | 26.6 | 0.4% |
| Substitution of Ozone Depleting Substances | + | 7.3 | 15.3 | 17.0 | 18.7 | 20.4 | 22.2 | 0.3% |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 | 0.2% |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 | 0.2% |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 | 0.1% |
| Abandoned Underground Coal Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 | 0.1% |
| Other Process Uses of Carbonates | 2.5 | 3.2 | 4.8 | 4.7 | 4.0 | 5.2 | 6.0 | 0.1% |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 | 0.1% |
| Aluminum Production | 28.3 | 7.6 | 4.6 | 6.8 | 6.4 | 6.2 | 5.4 | 0.1% |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 | 0.1% |
| Semiconductor Manufacture | 3.6 | 4.7 | 4.0 | 5.1 | 4.5 | 4.2 | 4.7 | 0.1% |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 | 0.1% |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 0.1% |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 | 0.1% |
| Stationary Combustion | 4.9 | 4.6 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 0.1% |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | + |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 | + |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 | + |
| Mobile Combustion | 0.9 | 1.3 | 1.4 | 1.4 | 1.4 | 1.5 | 1.5 | + |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 | + |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.7 | 1.5 | 1.2 | + |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 | + |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 | + |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | + |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | + |
| Agriculture | 563.4 | 600.2 | 631.1 | 633.7 | 635.4 | 626.3 | 625.4 | 9.1% |
| N ₂ O from Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 | 4.6% |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 | 2.4% |
| Manure Management | 51.1 | 72.9 | 78.1 | 78.9 | 81.2 | 78.9 | 78.7 | 1.1% |
| CO ₂ from Fossil Fuel Combustion | 31.0 | 47.4 | 48.2 | 49.9 | 51.4 | 50.4 | 51.2 | 0.7% |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 | 0.2% |

| | | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Mobile Combustion | 0.3 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | + |
| Field Burning of Agricultural Residues | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | + |
| Stationary Combustion | + | + | + | + | + | + | + | + |
| Commercial | 418.1 | 420.3 | 425.5 | 432.1 | 408.5 | 437.5 | 453.9 | 6.6% |
| CO ₂ from Fossil Fuel Combustion | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 | 3.4% |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 | 2.2% |
| Substitution of Ozone Depleting Substances | + | 17.6 | 38.5 | 42.1 | 44.9 | 47.4 | 49.2 | 0.7% |
| Wastewater Treatment | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 | 0.2% |
| Human Sewage | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 | 0.1% |
| Composting | 0.7 | 3.5 | 3.5 | 3.5 | 3.7 | 3.9 | 3.9 | 0.1% |
| Stationary Combustion | 1.4 | 1.4 | 1.4 | 1.4 | 1.2 | 1.3 | 1.4 | + |
| Residential | 344.9 | 370.4 | 361.2 | 357.6 | 318.4 | 372.6 | 393.7 | 5.7% |
| CO ₂ from Fossil Fuel Combustion | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 | 5.0% |
| Substitution of Ozone Depleting Substances | 0.3 | 7.7 | 21.8 | 25.9 | 31.4 | 37.0 | 42.6 | 0.6% |
| Stationary Combustion | 6.3 | 4.9 | 4.8 | 4.9 | 4.5 | 5.9 | 6.0 | 0.1% |
| U.S. Territories | 33.7 | 58.2 | 45.3 | 45.4 | 47.6 | 47.5 | 44.7 | 0.7% |
| CO ₂ from Fossil Fuel Combustion | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 | 0.6% |
| Non-Energy Use of Fuels | 5.7 | 8.1 | 3.7 | 3.7 | 3.8 | 3.8 | 3.5 | 0.1% |
| Stationary Combustion | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | + |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 | 100.0% |
| LULUCF Sector Total^b | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) | (11.1%) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 | 88.9% |

Note: Total emissions presented without LULUCF. Total net emissions presented with LULUCF.

+ Does not exceed 0.05 MMT CO₂ Eq. or 0.05 percent.

^a Percent of total (gross) emissions excluding emissions from LULUCF for 2014.

^b The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Emissions with Electricity Distributed to Economic Sectors

It can also be useful to view greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). The generation, transmission, and distribution of electricity, which is the largest economic sector in the United States, accounted for 30 percent of total U.S. greenhouse gas emissions in 2014. Emissions increased by 12 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions increased from 2013 to 2014 by 0.1 percent, primarily due to increased CO₂ emissions from fossil fuel combustion. Electricity sales to the residential and commercial end-use sectors in 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased by approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased by 1.1 percent from the previous year. Despite this increase in generation, CO₂ emissions from the electric power sector increased by 0.1 percent as the consumption of petroleum for electricity generation increased by 15.8 percent in 2014 and the consumption of CO₂-intensive coal and natural gas for electricity generation decreased by 0.1 and 0.2 percent, respectively. Table 2-11 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-11: Electricity Generation-Related Greenhouse Gas Emissions (MMT CO₂ Eq.)

| Gas/Fuel Type or Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 1,831.2 | 2,416.5 | 2,274.2 | 2,172.9 | 2,036.6 | 2,052.8 | 2,054.8 |
| Fossil Fuel Combustion | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| Coal | 1,547.6 | 1,983.8 | 1,827.6 | 1,722.7 | 1,511.2 | 1,571.3 | 1,570.4 |
| Natural Gas | 175.3 | 318.8 | 399.0 | 408.8 | 492.2 | 444.0 | 443.2 |

| | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| <i>Petroleum</i> | 97.5 | 97.9 | 31.4 | 25.8 | 18.3 | 22.4 | 25.3 |
| <i>Geothermal</i> | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Incineration of Waste | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Other Process Uses of Carbonates | 2.5 | 3.2 | 4.8 | 4.7 | 4.0 | 5.2 | 6.0 |
| CH₄ | 0.3 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 |
| Stationary Sources (Elec Gen) | 0.3 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 |
| Incineration of Waste | + | + | + | + | + | + | + |
| N₂O | 7.8 | 16.4 | 18.8 | 17.9 | 18.1 | 19.4 | 19.9 |
| Stationary Sources (Elec Gen) | 7.4 | 16.0 | 18.5 | 17.6 | 17.8 | 19.1 | 19.6 |
| Incineration of Waste | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| SF₆ | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Total | 1,864.8 | 2,443.9 | 2,300.5 | 2,198.1 | 2,060.7 | 2,078.0 | 2,080.7 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Includes only stationary combustion emissions related to the generation of electricity.

Note: Totals may not sum due to independent rounding.

To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to each economic sector's share of retail sales of electricity consumption (EIA 2016 and Duffield 2006). These source categories include CO₂ from Fossil Fuel Combustion, CH₄ and N₂O from Stationary Combustion, Incineration of Waste, Other Process Uses of Carbonates, and SF₆ from Electrical Transmission and Distribution Systems. Note that only 50 percent of the Other Process Uses of Carbonates emissions were associated with electricity generation and distributed as described; the remainder of Other Process Uses of Carbonates emissions were attributed to the industrial processes economic end-use sector.⁶

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of total U.S. greenhouse gas emissions (29.2 percent), followed closely by emissions from transportation (26.4 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO₂ accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-12 presents a detailed breakdown of emissions from each of these economic sectors, with emissions from electricity generation distributed to them. Figure 2-13 shows the trend in these emissions by sector from 1990 to 2014.

⁶ Emissions were not distributed to U.S. Territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

Figure 2-13: U.S. Greenhouse Gas Emissions with Electricity-Related Emissions Distributed to Economic Sectors (MMT CO₂ Eq.)

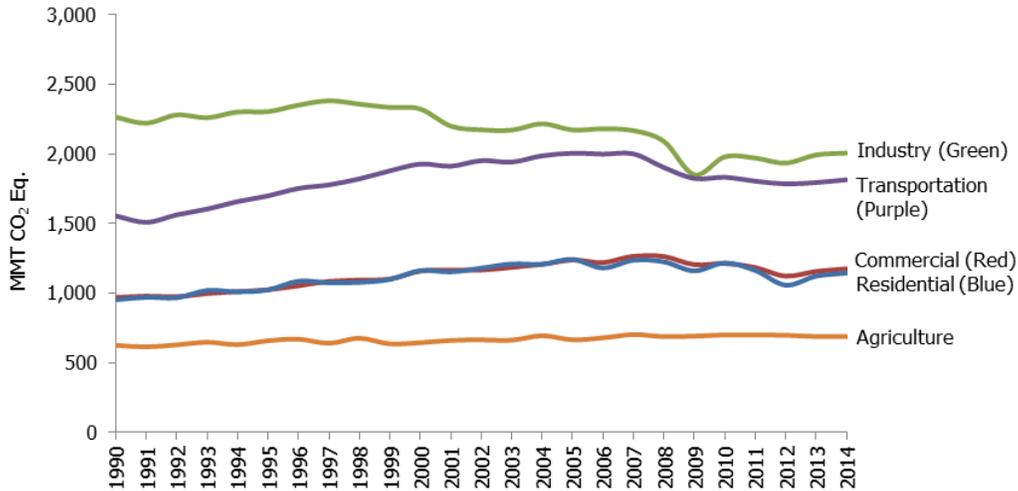


Table 2-12: U.S. Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (MMT CO₂ Eq.) and Percent of Total in 2014

| Sector/Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 | Percent ^a |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------------|
| Industry | 2,262.9 | 2,171.9 | 1,979.1 | 1,970.0 | 1,934.0 | 1,992.5 | 2,005.7 | 29.2% |
| Direct Emissions | 1,620.9 | 1,486.2 | 1,394.5 | 1,399.0 | 1,392.1 | 1,448.2 | 1,461.7 | 21.3% |
| CO ₂ | 1,157.9 | 1,122.3 | 1,028.8 | 1,027.2 | 1,029.5 | 1,079.6 | 1,081.7 | 15.7% |
| CH ₄ | 351.4 | 298.9 | 310.9 | 305.8 | 305.5 | 312.9 | 320.0 | 4.7% |
| N ₂ O | 35.4 | 26.7 | 23.7 | 29.1 | 24.0 | 22.7 | 24.5 | 0.4% |
| HFCs, PFCs, SF ₆ , and NF ₃ | 76.3 | 38.2 | 31.1 | 36.9 | 33.1 | 33.0 | 35.5 | 0.5% |
| Electricity-Related | 642.0 | 685.7 | 584.5 | 571.0 | 541.9 | 544.3 | 544.0 | 7.9% |
| CO ₂ | 630.4 | 678.0 | 577.9 | 564.4 | 535.6 | 537.7 | 537.2 | 7.8% |
| CH ₄ | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | + |
| N ₂ O | 2.7 | 4.6 | 4.8 | 4.7 | 4.8 | 5.1 | 5.2 | 0.1% |
| SF ₆ | 8.7 | 3.0 | 1.8 | 1.8 | 1.5 | 1.4 | 1.5 | + |
| Transportation | 1,554.4 | 2,004.4 | 1,832.0 | 1,803.9 | 1,784.3 | 1,794.0 | 1,814.5 | 26.4% |
| Direct Emissions | 1,551.3 | 1,999.6 | 1,827.4 | 1,799.6 | 1,780.4 | 1,789.9 | 1,810.3 | 26.3% |
| CO ₂ | 1,505.6 | 1,897.2 | 1,737.8 | 1,716.6 | 1,705.0 | 1,721.8 | 1,746.7 | 25.4% |
| CH ₄ | 5.4 | 2.4 | 1.9 | 1.8 | 1.8 | 1.7 | 1.6 | + |
| N ₂ O | 40.3 | 32.9 | 22.1 | 20.9 | 18.5 | 16.6 | 14.7 | 0.2% |
| HFCs ^b | + | 67.1 | 65.6 | 60.2 | 55.1 | 49.8 | 47.2 | 0.7% |
| Electricity-Related | 3.1 | 4.8 | 4.6 | 4.3 | 3.9 | 4.1 | 4.1 | 0.1% |
| CO ₂ | 3.1 | 4.8 | 4.5 | 4.3 | 3.9 | 4.0 | 4.1 | 0.1% |
| CH ₄ | + | + | + | + | + | + | + | + |
| N ₂ O | + | + | + | + | + | + | + | + |
| SF ₆ | + | + | + | + | + | + | + | + |
| Commercial | 969.1 | 1,238.0 | 1,212.8 | 1,183.9 | 1,122.1 | 1,155.8 | 1,174.7 | 17.1% |
| Direct Emissions | 418.1 | 420.3 | 425.5 | 432.1 | 408.5 | 437.5 | 453.9 | 6.6% |
| CO ₂ | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 | 3.4% |
| CH ₄ | 196.6 | 172.8 | 160.5 | 162.5 | 160.1 | 162.2 | 165.8 | 2.4% |
| N ₂ O | 4.1 | 6.4 | 6.4 | 6.7 | 6.7 | 6.9 | 7.0 | 0.1% |
| HFCs | + | 17.6 | 38.5 | 42.1 | 44.9 | 47.4 | 49.2 | 0.7% |
| Electricity-Related | 551.0 | 817.7 | 787.3 | 751.9 | 713.6 | 718.3 | 720.8 | 10.5% |
| CO ₂ | 541.1 | 808.5 | 778.3 | 743.3 | 705.2 | 709.5 | 711.8 | 10.4% |
| CH ₄ | 0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.2 | 0.2 | + |
| N ₂ O | 2.3 | 5.5 | 6.4 | 6.1 | 6.3 | 6.7 | 6.9 | 0.1% |

| | | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| SF ₆ | 7.5 | 3.5 | 2.4 | 2.3 | 1.9 | 1.9 | 1.9 | + |
| Residential | 952.2 | 1,242.1 | 1,216.9 | 1,163.1 | 1,057.5 | 1,121.9 | 1,143.8 | 16.6% |
| Direct Emissions | 344.9 | 370.4 | 361.2 | 357.6 | 318.4 | 372.6 | 393.7 | 5.7% |
| CO ₂ | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 | 5.0% |
| CH ₄ | 5.2 | 4.1 | 4.0 | 4.0 | 3.7 | 5.0 | 5.0 | 0.1% |
| N ₂ O | 1.0 | 0.9 | 0.8 | 0.8 | 0.7 | 1.0 | 1.0 | + |
| HFCs | 0.3 | 7.7 | 21.8 | 25.9 | 31.4 | 37.0 | 42.6 | 0.6% |
| Electricity-Related | 607.3 | 871.7 | 855.7 | 805.5 | 739.1 | 749.3 | 750.2 | 10.9% |
| CO ₂ | 596.4 | 861.9 | 845.9 | 796.3 | 730.4 | 740.2 | 740.8 | 10.8% |
| CH ₄ | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | + |
| N ₂ O | 2.5 | 5.8 | 7.0 | 6.6 | 6.5 | 7.0 | 7.2 | 0.1% |
| SF ₆ | 8.3 | 3.8 | 2.6 | 2.5 | 2.0 | 1.9 | 2.0 | + |
| Agriculture | 624.8 | 664.2 | 699.5 | 699.1 | 697.5 | 688.3 | 687.0 | 10.0% |
| Direct Emissions | 563.4 | 600.2 | 631.1 | 633.7 | 635.4 | 626.3 | 625.4 | 9.1% |
| CO ₂ | 31.0 | 47.4 | 48.2 | 49.9 | 51.4 | 50.4 | 51.2 | 0.7% |
| CH ₄ | 214.8 | 238.6 | 244.6 | 242.7 | 242.8 | 239.2 | 237.9 | 3.5% |
| N ₂ O | 317.6 | 314.1 | 338.3 | 341.0 | 341.1 | 336.6 | 336.4 | 4.9% |
| Electricity-Related | 61.3 | 64.1 | 68.4 | 65.4 | 62.1 | 62.1 | 61.6 | 0.9% |
| CO ₂ | 60.2 | 63.4 | 67.6 | 64.7 | 61.4 | 61.3 | 60.8 | 0.9% |
| CH ₄ | + | + | + | + | + | + | + | + |
| N ₂ O | 0.3 | 0.4 | 0.6 | 0.5 | 0.5 | 0.6 | 0.6 | + |
| SF ₆ | 0.8 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | + |
| U.S. Territories | 33.7 | 58.2 | 45.3 | 45.4 | 47.6 | 47.5 | 44.7 | 0.7% |
| Total Emissions | 6,397.1 | 7,378.8 | 6,985.5 | 6,865.4 | 6,643.0 | 6,800.0 | 6,870.5 | 100.0% |
| LULUCF Sector Total^c | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) | (11.1%) |
| Net Emissions (Sources and Sinks) | 5,659.2 | 6,680.3 | 6,219.0 | 6,103.4 | 5,893.3 | 6,040.4 | 6,108.0 | 88.9% |

Note: Total emissions presented without LULUCF. Net emissions presented with LULUCF.

+ Does not exceed 0.05 MMT CO₂ Eq. or 0.05 percent.

^a Percent of total gross emissions excluding emissions from LULUCF for year 2014.

^b Includes primarily HFC-134a.

^c The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector. Totals may not sum due to independent rounding.

Industry

The industry end-use sector includes CO₂ emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This end-use sector also includes emissions that are produced as a byproduct of the non-energy-related industrial process activities. The variety of activities producing these non-energy-related emissions includes methane emissions from petroleum and natural gas systems, fugitive CH₄ emissions from coal mining, by-product CO₂ emissions from cement manufacture, and HFC, PFC, SF₆, and NF₃ byproduct emissions from semiconductor manufacture, to name a few. Since 1990, industrial sector emissions have declined. The decline has occurred both in direct emissions and indirect emissions associated with electricity use. In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions. In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

Transportation

When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 26 percent of U.S. greenhouse gas emissions in 2014. The largest sources of transportation greenhouse gases in 2014 were passenger cars (42.0 percent), freight trucks (22.5 percent), light-duty trucks, which include sport utility vehicles, pickup trucks, and minivans (18.6 percent), commercial aircraft (6.4 percent), rail (2.6 percent), pipelines

(2.6 percent), and ships and boats (1.6 percent). These figures include direct CO₂, CH₄, and N₂O emissions from fossil fuel combustion used in transportation and emissions from non-energy use (i.e., lubricants) used in transportation, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types.

In terms of the overall trend, from 1990 to 2014, total transportation emissions rose by 17 percent due, in large part, to increased demand for travel as fleet wide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices. The decline in new light-duty vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in Model Year (MY) 2014 (EPA 2015a). Between 2013 and 2014, VMT increased by only 1.3 percent. Table 2-13 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

From 2008 to 2009, CO₂ emissions from the transportation end-use sector declined 4.2 percent. The decrease in emissions could largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. After reaching a decadal low in 2012, CO₂ emissions from the transportation end-use sector stabilized and grew slowly in 2013 and 2014 as the economic recovery gained strength.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to 2014. This rise in CO₂ emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 47.2 MMT CO₂ Eq. in 2014, led to an increase in overall emissions from transportation activities of 17 percent.

Table 2-13: Transportation-Related Greenhouse Gas Emissions (MMT CO₂ Eq.)

| Gas/Vehicle | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Passenger Cars | 656.6 | 708.9 | 783.6 | 774.3 | 767.9 | 763.2 | 762.5 |
| CO ₂ | 629.3 | 660.1 | 742.0 | 736.9 | 735.5 | 735.5 | 737.6 |
| CH ₄ | 3.2 | 1.2 | 1.2 | 1.2 | 1.1 | 1.0 | 1.0 |
| N ₂ O | 24.1 | 15.9 | 12.9 | 12.3 | 10.7 | 9.4 | 8.0 |
| HFCs | + | 31.7 | 27.5 | 23.9 | 20.6 | 17.3 | 16.0 |
| Light-Duty Trucks | 335.6 | 551.5 | 348.9 | 332.0 | 326.0 | 323.4 | 338.1 |
| CO ₂ | 321.1 | 504.3 | 308.8 | 294.8 | 291.9 | 292.5 | 309.2 |
| CH ₄ | 1.7 | 0.8 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 |
| N ₂ O | 12.8 | 13.2 | 5.5 | 5.0 | 4.4 | 3.9 | 3.6 |
| HFCs | + | 33.3 | 34.2 | 31.7 | 29.3 | 26.7 | 25.0 |
| Medium- and Heavy-Duty Trucks | 231.1 | 398.2 | 389.7 | 388.4 | 388.7 | 395.7 | 407.4 |
| CO ₂ | 230.1 | 395.4 | 385.6 | 383.9 | 383.7 | 390.3 | 402.0 |
| CH ₄ | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| N ₂ O | 0.7 | 1.1 | 1.1 | 1.0 | 0.9 | 0.9 | 0.9 |
| HFCs | + | 1.5 | 2.9 | 3.4 | 3.9 | 4.4 | 4.4 |
| Buses | 8.4 | 12.1 | 15.8 | 16.8 | 17.8 | 18.0 | 19.1 |
| CO ₂ | 8.4 | 11.8 | 15.3 | 16.2 | 17.3 | 17.5 | 18.6 |
| CH ₄ | + | + | + | + | + | + | + |
| N ₂ O | + | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| HFCs | + | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Motorcycles | 1.8 | 1.7 | 3.7 | 3.6 | 4.2 | 4.0 | 3.9 |
| CO ₂ | 1.7 | 1.6 | 3.6 | 3.6 | 4.1 | 3.9 | 3.8 |

| | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CH ₄ | + | + | + | + | + | + | + |
| N ₂ O | + | + | + | + | + | + | + |
| Commercial Aircraft^a | 110.9 | 134.0 | 114.4 | 115.7 | 114.3 | 115.4 | 116.3 |
| CO ₂ | 109.9 | 132.7 | 113.3 | 114.6 | 113.3 | 114.3 | 115.2 |
| CH ₄ | + | + | + | + | + | + | + |
| N ₂ O | 1.0 | 1.2 | 1.0 | 1.1 | 1.0 | 1.1 | 1.1 |
| Other Aircraft^b | 78.3 | 59.7 | 40.4 | 34.2 | 32.1 | 34.7 | 35.2 |
| CO ₂ | 77.5 | 59.1 | 40.1 | 33.9 | 31.8 | 34.4 | 34.9 |
| CH ₄ | 0.1 | 0.1 | + | + | + | + | + |
| N ₂ O | 0.7 | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 |
| Ships and Boats^c | 44.9 | 44.9 | 44.7 | 46.4 | 40.1 | 39.4 | 28.6 |
| CO ₂ | 44.3 | 44.3 | 44.0 | 45.5 | 39.3 | 38.7 | 28.0 |
| CH ₄ | + | + | + | + | + | + | + |
| N ₂ O | 0.6 | 0.6 | 0.8 | 0.8 | 0.7 | 0.7 | 0.5 |
| HFCs | + | + | + | + | + | + | + |
| Rail | 39.0 | 51.1 | 44.2 | 45.9 | 44.6 | 45.5 | 47.6 |
| CO ₂ | 38.5 | 50.3 | 43.1 | 44.7 | 43.4 | 44.2 | 45.7 |
| CH ₄ | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| N ₂ O | 0.3 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 |
| HFCs | + | 0.3 | 0.6 | 0.7 | 0.8 | 0.9 | 1.4 |
| Other Emissions from Electricity Generation ^d | 0.1 | 0.1 | + | + | + | + | + |
| Pipelines^e | 36.0 | 32.2 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 |
| CO ₂ | 36.0 | 32.2 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 |
| Lubricants | 11.8 | 10.2 | 9.5 | 9.0 | 8.3 | 8.8 | 9.1 |
| CO ₂ | 11.8 | 10.2 | 9.5 | 9.0 | 8.3 | 8.8 | 9.1 |
| Total Transportation | 1,554.4 | 2,004.4 | 1,832.0 | 1,803.9 | 1,784.3 | 1,794.0 | 1,814.5 |
| <i>International Bunker</i> | <i>104.5</i> | <i>114.2</i> | <i>118.1</i> | <i>112.8</i> | <i>106.8</i> | <i>100.7</i> | <i>104.2</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).

^b Consists of emissions from jet fuel and aviation gasoline consumption by general aviation and military aircraft.

^c Fluctuations in emission estimates are associated with fluctuations in reported fuel consumption, and may reflect issues with data sources.

^d Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in “trash-to-steam” electricity generation plants), electrical transmission and distribution, and a portion of Other Process Uses of Carbonates (from pollution control equipment installed in electricity generation plants).

^e CO₂ estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH₄ and N₂O, these emissions are not directly attributed to pipelines in the U.S. Inventory.

^f Emissions from International Bunker Fuels include emissions from both civilian and military activities; these emissions are not included in the transportation totals.

Notes: Passenger cars and light-duty trucks include vehicles typically used for personal travel and less than 8,500 lbs; medium- and heavy-duty trucks include vehicles larger than 8,500 lbs. HFC emissions primarily reflect HFC-134a. Totals may not sum due to independent rounding.

Commercial

The commercial sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Energy-related emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. Landfills and wastewater treatment are included in this sector, with landfill emissions decreasing since 1990 and wastewater treatment emissions decreasing slightly.

Residential

The residential sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Emissions from the residential sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, this sector is also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Agriculture

The agriculture end-use sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2014, agricultural soil management was the largest source of N₂O emissions, and enteric fermentation was the second largest source of CH₄ emissions in the United States. This sector also includes small amounts of CO₂ emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector is less reliant on electricity than the other sectors.

Box 2-1: Methodology for Aggregating Emissions by Economic Sector

In presenting the Economic Sectors in the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, the Inventory expands upon the standard IPCC sectors common for UNFCCC reporting. Discussing greenhouse gas emissions relevant to U.S.-specific sectors improves communication of the report's findings.

In the Electricity Generation economic sector, CO₂ emissions from the combustion of fossil fuels included in the EIA electric utility fuel consuming sector are apportioned to this economic sector. Stationary combustion emissions of CH₄ and N₂O are also based on the EIA electric utility sector. Additional sources include CO₂, CH₄, and N₂O from waste incineration, as the majority of municipal solid waste is combusted in “trash-to-steam” electricity generation plants. The Electricity Generation economic sector also includes SF₆ from Electrical Transmission and Distribution, and a portion of CO₂ from Other Process Uses of Carbonates (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO₂ emissions from the combustion of fossil fuels included in the EIA transportation fuel consuming sector are apportioned to this economic sector (additional analyses and refinement of the EIA data is further explained in the Energy chapter of this report). Emissions of CH₄ and N₂O from Mobile Combustion are also apportioned to this economic sector based on the EIA transportation fuel consuming sector. Substitution of Ozone Depleting Substances emissions are apportioned based on their specific end-uses within the source category, with emissions from transportation refrigeration/air-conditioning systems to this economic sector. Finally, CO₂ emissions from Non-Energy Uses of Fossil Fuels identified as lubricants for transportation vehicles are included in the Transportation economic sector.

For the Industry economic sector, the CO₂ emissions from the combustion of fossil fuels included in the EIA industrial fuel consuming sector, minus the agricultural use of fuel explained below, are apportioned to this economic sector. The CH₄ and N₂O emissions from stationary and mobile combustion are also apportioned to this economic sector based on the EIA industrial fuel consuming sector, minus emissions apportioned to the Agriculture economic sector described below. Substitution of Ozone Depleting Substance emissions are apportioned based on their specific end-uses within the source category, with most emissions falling within the Industry economic sector. Additionally, all process-related emissions from sources with methods considered within the IPCC IPPU sector have been apportioned to this economic sector. This includes the process-related emissions (i.e., emissions from the actual process to make the material, not from fuels to power the plant) from such activities as Cement Production, Iron and Steel Production and Metallurgical Coke Production, and Ammonia Production. Additionally, fugitive emissions from energy production sources, such as Natural Gas Systems, Coal Mining, and Petroleum Systems are included in the Industry economic sector. A portion of CO₂ from Other Process Uses of Carbonates (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally,

all remaining CO₂ emissions from Non-Energy Uses of Fossil Fuels are assumed to be industrial in nature (besides the lubricants for transportation vehicles specified above), and are attributed to the Industry economic sector.

As agriculture equipment is included in EIA’s industrial fuel consuming sector surveys, additional data is used to extract the fuel used by agricultural equipment, to allow for accurate reporting in the Agriculture economic sector from all sources of emissions, such as motorized farming equipment. Energy consumption estimates are obtained from Department of Agriculture survey data, in combination with separate EIA fuel sales reports. This supplementary data is used to apportion some of the CO₂ emissions from fossil fuel combustion, and CH₄ and N₂O emissions from stationary and mobile combustion, to the Agriculture economic sector. The other emission sources included in this economic sector are intuitive for the agriculture sectors, such as N₂O emissions from Agricultural Soils, CH₄ from Enteric Fermentation, CH₄ and N₂O from Manure Management, CH₄ from Rice Cultivation, CO₂ emissions from Liming and Urea Application, and CH₄ and N₂O from Forest Fires. N₂O emissions from the Application of Fertilizers to tree plantations (termed “forest land” by the IPCC) are also included in the Agriculture economic sector.

The Residential economic sector includes the CO₂ emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH₄ and N₂O are also based on the EIA residential fuel consuming sector. Substitution of Ozone Depleting Substances are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N₂O emissions from the Application of Fertilizers to developed land (termed “settlements” by the IPCC) are also included in the Residential economic sector.

The Commercial economic sector includes the CO₂ emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Emissions of CH₄ and N₂O from Mobile Combustion are also apportioned to this economic sector based on the EIA transportation fuel consuming sector. Substitution of Ozone Depleting Substances emissions are apportioned based on their specific end-uses within the source category, with emissions from commercial refrigeration/air-conditioning systems apportioned to this economic sector. Public works sources including direct CH₄ from Landfills and CH₄ and N₂O from Wastewater Treatment and Composting are also included in this economic sector.

Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2014; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-14 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.3 percent since 1990. Since 1990, this rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Table 2-14 and Figure 2-14).

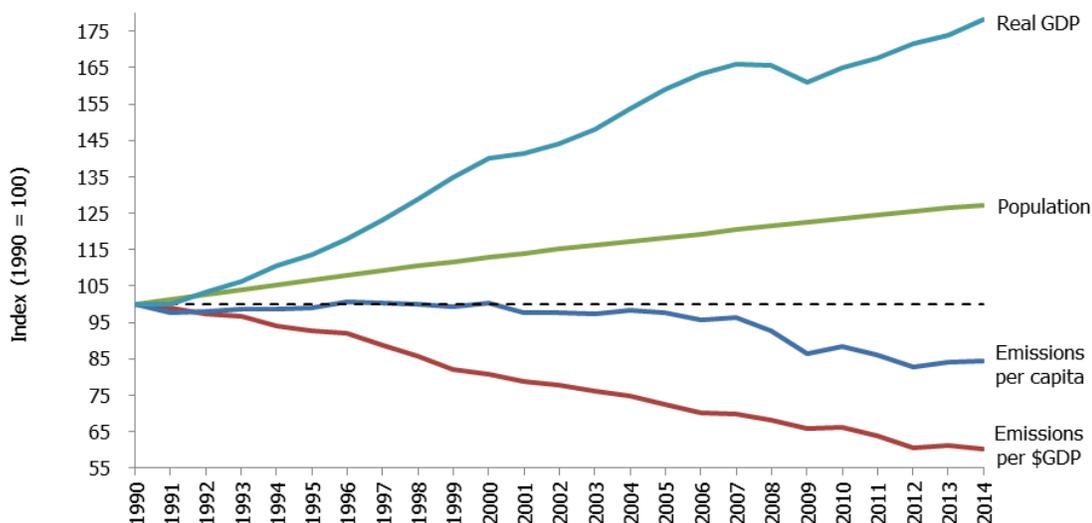
Table 2-14: Recent Trends in Various U.S. Data (Index 1990 = 100)

| Chapter/IPCC Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 | Growth ^a |
|---------------------------------------|------|------|------|------|------|------|------|---------------------|
| Greenhouse Gas Emissions ^b | 100 | 115 | 109 | 107 | 104 | 106 | 107 | 0.3% |
| Energy Consumption ^c | 100 | 118 | 116 | 115 | 112 | 116 | 117 | 0.7% |
| Fossil Fuel Consumption ^c | 100 | 119 | 112 | 110 | 107 | 110 | 111 | 0.5% |
| Electricity Consumption ^c | 100 | 134 | 137 | 137 | 135 | 136 | 138 | 1.4% |
| GDP ^d | 100 | 159 | 165 | 168 | 171 | 174 | 178 | 2.5% |
| Population ^e | 100 | 118 | 124 | 125 | 126 | 126 | 127 | 1.0% |

^a Average annual growth rate

- ^b GWP-weighted values
- ^c Energy-content-weighted values (EIA 2016)
- ^d Gross Domestic Product in chained 2009 dollars (BEA 2016)
- ^e U.S. Census Bureau (2015)

Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product



Source: BEA (2016), U.S. Census Bureau (2015), and emission estimates in this report.

2.3 Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO₂)

The reporting requirements of the UNFCCC⁷ request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO₂. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO₂, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Carbon monoxide is produced when carbon-containing fuels are combusted incompletely. Nitrogen oxides (i.e., NO and NO₂) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N₂O. Non-methane volatile organic compounds—which include hundreds of organic compounds that participate in atmospheric chemical reactions (i.e., propane, butane, xylene, toluene, ethane, and many others)—are emitted primarily from transportation, industrial processes, and non-industrial consumption of organic solvents. In the United States, SO₂ is primarily emitted from coal combustion for electric power generation and the metals industry. Sulfur-containing compounds emitted into the atmosphere tend to exert a negative radiative forcing (i.e., cooling) and therefore are discussed separately.

⁷ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>>.

One important indirect climate change effect of NMVOCs and NO_x is their role as precursors for tropospheric ozone formation. They can also alter the atmospheric lifetimes of other greenhouse gases. Another example of indirect greenhouse gas formation into greenhouse gases is CO's interaction with the hydroxyl radical—the major atmospheric sink for CH₄ emissions—to form CO₂. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH₄.

Since 1970, the United States has published estimates of emissions of CO, NO_x, NMVOCs, and SO₂ (EPA 2015),⁸ which are regulated under the Clean Air Act. Table 2-15 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table 2-15: Emissions of NO_x, CO, NMVOCs, and SO₂ (kt)

| Gas/Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------------|----------------|---------------|---------------|---------------|---------------|---------------|---------------|
| NO_x | 21,783 | 17,421 | 12,565 | 12,416 | 11,778 | 11,195 | 10,633 |
| Mobile Fossil Fuel Combustion | 10,862 | 10,295 | 7,290 | 7,294 | 6,788 | 6,283 | 5,777 |
| Stationary Fossil Fuel Combustion | 10,023 | 5,858 | 4,092 | 3,807 | 3,567 | 3,579 | 3,522 |
| Oil and Gas Activities | 139 | 321 | 545 | 622 | 622 | 622 | 622 |
| Industrial Processes and Product Use | 592 | 572 | 472 | 452 | 452 | 452 | 452 |
| Forest Fires | 78 | 239 | 80 | 159 | 266 | 177 | 177 |
| Waste Combustion | 82 | 128 | 77 | 73 | 73 | 73 | 73 |
| Agricultural Burning | 6 | 6 | 7 | 8 | 8 | 8 | 8 |
| Waste | + | 2 | 1 | 1 | 1 | 1 | 1 |
| CO | 132,764 | 75,240 | 49,507 | 51,238 | 53,240 | 48,229 | 46,413 |
| Mobile Fossil Fuel Combustion | 119,360 | 58,615 | 39,475 | 38,305 | 36,491 | 34,676 | 32,861 |
| Forest Fires | 2,792 | 8,515 | 2,845 | 5,683 | 9,499 | 6,298 | 6,298 |
| Stationary Fossil Fuel Combustion | 5,000 | 4,648 | 4,103 | 4,170 | 4,170 | 4,170 | 4,169 |
| Industrial Processes and Product Use | 4,129 | 1,557 | 1,280 | 1,229 | 1,229 | 1,229 | 1,229 |
| Waste Combustion | 978 | 1,403 | 1,084 | 1,003 | 1,003 | 1,003 | 1,003 |
| Oil and Gas Activities | 302 | 318 | 487 | 610 | 610 | 610 | 610 |
| Agricultural Burning | 202 | 177 | 229 | 233 | 234 | 238 | 238 |
| Waste | 1 | 7 | 5 | 5 | 5 | 5 | 5 |
| NMVOCs | 20,930 | 13,154 | 11,641 | 11,726 | 11,416 | 11,107 | 10,796 |
| Industrial Processes and Product Use | 7,638 | 5,849 | 4,133 | 3,929 | 3,929 | 3,929 | 3,928 |
| Mobile Fossil Fuel Combustion | 10,932 | 5,724 | 4,591 | 4,562 | 4,252 | 3,942 | 3,632 |
| Oil and Gas Activities | 554 | 510 | 2,205 | 2,517 | 2,517 | 2,517 | 2,517 |
| Stationary Fossil Fuel Combustion | 912 | 716 | 576 | 599 | 599 | 599 | 599 |
| Waste Combustion | 222 | 241 | 92 | 81 | 81 | 81 | 81 |
| Waste | 673 | 114 | 44 | 38 | 38 | 38 | 39 |
| Agricultural Burning | NA | NA | NA | NA | NA | NA | NA |
| SO₂ | 20,935 | 13,196 | 7,014 | 5,877 | 4,711 | 4,625 | 4,528 |
| Stationary Fossil Fuel Combustion | 18,407 | 11,541 | 6,120 | 5,008 | 3,859 | 3,790 | 3,710 |
| Industrial Processes and Product Use | 1,307 | 831 | 617 | 604 | 604 | 604 | 604 |
| Mobile Fossil Fuel Combustion | 390 | 180 | 117 | 108 | 108 | 108 | 108 |
| Oil and Gas Activities | 793 | 619 | 144 | 142 | 125 | 108 | 90 |
| Waste Combustion | 38 | 25 | 16 | 15 | 15 | 15 | 15 |
| Waste | + | 1 | + | + | + | + | + |
| Agricultural Burning | NA | NA | NA | NA | NA | NA | NA |

+ Does not exceed 0.5 kt.

NA - Not Available

Note: Totals may not sum due to independent rounding.

Source: (EPA 2015) except for estimates from Field Burning of Agricultural Residues.

⁸ NO_x and CO emission estimates from Field Burning of Agricultural Residues were estimated separately, and therefore not taken from EPA (2015).

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO₂) emitted into the atmosphere through natural and anthropogenic processes affects the earth's radiative budget through its photochemical transformation into sulfate aerosols that can (1) scatter radiation from the sun back to space, thereby reducing the radiation reaching the earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., by providing surfaces for heterogeneous chemical reactions). The indirect effect of sulfur-derived aerosols on radiative forcing can be considered in two parts. The first indirect effect is the aerosols' tendency to decrease water droplet size and increase water droplet concentration in the atmosphere. The second indirect effect is the tendency of the reduction in cloud droplet size to affect precipitation by increasing cloud lifetime and thickness. Although still highly uncertain, the radiative forcing estimates from both the first and the second indirect effect are believed to be negative, as is the combined radiative forcing of the two (IPCC 2001). However, because SO₂ is short-lived and unevenly distributed in the atmosphere, its radiative forcing impacts are highly uncertain.

Sulfur dioxide is also a major contributor to the formation of regional haze, which can cause significant increases in acute and chronic respiratory diseases. Once SO₂ is emitted, it is chemically transformed in the atmosphere and returns to the earth as the primary source of acid rain. Because of these harmful effects, the United States has regulated SO₂ emissions in the Clean Air Act.

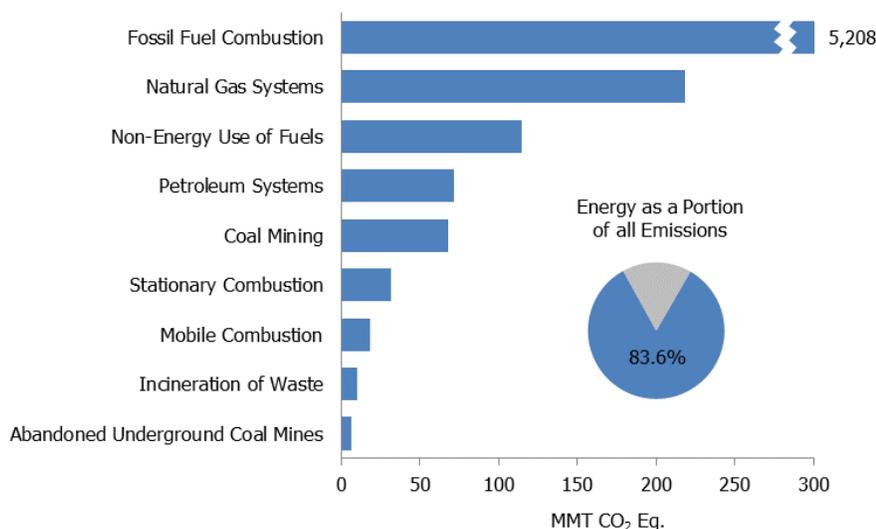
Electricity generation is the largest anthropogenic source of SO₂ emissions in the United States, accounting for 64.0 percent in 2014. Coal combustion contributes nearly all of those emissions (approximately 92 percent). Sulfur dioxide emissions have decreased in recent years, primarily as a result of electric power generators switching from high-sulfur to low-sulfur coal and installing flue gas desulfurization equipment.

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 83.6 percent of total greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis in 2014.¹ This included 97, 45, and 10 percent of the nation's CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively. Energy-related CO₂ emissions alone constituted 78.3 percent of national emissions from all sources on a CO₂ equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total national emissions (5.4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1). Globally, approximately 32,190 million metric tons (MMT) of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2013, of which the United States accounted for approximately 16 percent.² Due to their relative importance, fossil fuel combustion-related CO₂ emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH₄ and N₂O. Stationary combustion of fossil fuels was the second-largest source of N₂O emissions in the United States and mobile fossil fuel combustion was the fourth-largest source.

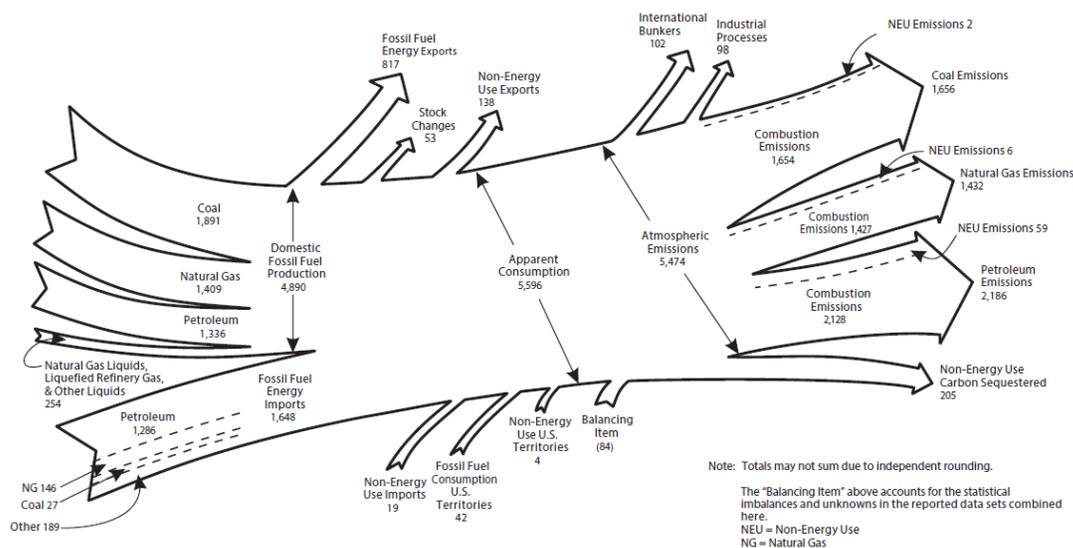
Figure 3-1: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



¹ Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

² Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *CO₂ Emissions from Fossil Fuels Combustion – Highlights* <<https://www.iea.org/publications/freepublications/publication/CO2EmissionsFromFuelCombustionHighlights2015.pdf>> IEA (2015).

Figure 3-2: 2014 U.S. Fossil Carbon Flows (MMT CO₂ Eq.)



Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH₄ from natural gas systems, petroleum systems, and coal mining. Table 3-1 summarizes emissions from the Energy sector in units of MMT CO₂ Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,746.2 MMT CO₂ Eq. in 2014,³ an increase of 7.9 percent since 1990.

Table 3-1: CO₂, CH₄, and N₂O Emissions from Energy (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 4,908.8 | 5,932.5 | 5,520.0 | 5,386.6 | 5,179.7 | 5,330.8 | 5,377.9 |
| Fossil Fuel Combustion | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| Electricity Generation | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| Transportation | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| Industrial | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| Residential | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| Commercial | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| U.S. Territories | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |
| Non-Energy Use of Fuels | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |
| Natural Gas Systems | 37.7 | 30.1 | 32.4 | 35.7 | 35.2 | 38.5 | 42.4 |
| Incineration of Waste | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Petroleum Systems | 3.6 | 3.9 | 4.2 | 4.2 | 3.9 | 3.7 | 3.6 |
| Biomass-Wood ^a | 215.2 | 206.9 | 192.5 | 195.2 | 194.9 | 211.6 | 217.7 |
| International Bunker Fuels ^a | 103.5 | 113.1 | 117.0 | 111.7 | 105.8 | 99.8 | 103.2 |
| Biomass-Ethanol ^a | 4.2 | 22.9 | 72.6 | 72.9 | 72.8 | 74.7 | 76.1 |
| CH₄ | 363.3 | 307.0 | 318.5 | 313.3 | 312.5 | 321.2 | 328.3 |
| Natural Gas Systems | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |
| Petroleum Systems | 38.7 | 48.8 | 54.1 | 56.3 | 58.4 | 64.7 | 68.1 |
| Coal Mining | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |
| Stationary Combustion | 8.5 | 7.4 | 7.1 | 7.1 | 6.6 | 8.0 | 8.1 |
| Abandoned Underground Coal | | | | | | | |
| Mines | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |
| Mobile Combustion | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| Incineration of Waste | + | + | + | + | + | + | + |
| International Bunker Fuels ^a | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |

³ Following the revised reporting requirements under the UNFCCC, this Inventory report presents CO₂ equivalent values based on the IPCC Fourth Assessment Report (AR4) GWP values. See the Introduction chapter for more information.

| | | | | | | | |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| N₂O | 53.6 | 55.0 | 46.1 | 44.0 | 41.7 | 41.4 | 40.0 |
| Stationary Combustion | 11.9 | 20.2 | 22.2 | 21.3 | 21.4 | 22.9 | 23.4 |
| Mobile Combustion | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |
| Incineration of Waste | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| <i>International Bunker Fuels^a</i> | <i>0.9</i> | <i>1.0</i> | <i>1.0</i> | <i>1.0</i> | <i>0.9</i> | <i>0.9</i> | <i>0.9</i> |
| Total | 5,324.9 | 6,294.5 | 5,884.6 | 5,744.0 | 5,533.9 | 5,693.5 | 5,746.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO₂, CH₄, and N₂O Emissions from Energy (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| CO₂ | 4,908,041 | 5,932,474 | 5,519,975 | 5,386,609 | 5,179,749 | 5,330,837 | 5,377,857 |
| Fossil Fuel Combustion | 4,740,671 | 5,747,142 | 5,358,292 | 5,227,690 | 5,024,685 | 5,157,583 | 5,208,207 |
| Non-Energy Use of Fuels | 118,114 | 138,876 | 114,063 | 108,515 | 105,624 | 121,682 | 114,311 |
| Natural Gas Systems | 37,732 | 30,076 | 32,439 | 35,662 | 35,203 | 38,457 | 42,351 |
| Incineration of Waste | 7,972 | 12,454 | 11,026 | 10,550 | 10,362 | 9,421 | 9,421 |
| Petroleum Systems | 3,553 | 3,927 | 4,154 | 4,192 | 3,876 | 3,693 | 3,567 |
| <i>Biomass – Wood^a</i> | <i>215,186</i> | <i>206,901</i> | <i>192,462</i> | <i>195,182</i> | <i>194,903</i> | <i>211,581</i> | <i>217,654</i> |
| <i>International Bunker Fuels^a</i> | <i>103,463</i> | <i>113,139</i> | <i>116,992</i> | <i>111,660</i> | <i>105,805</i> | <i>99,763</i> | <i>103,201</i> |
| <i>Biomass – Ethanol^a</i> | <i>4,227</i> | <i>22,943</i> | <i>72,647</i> | <i>72,881</i> | <i>72,827</i> | <i>74,743</i> | <i>76,075</i> |
| CH₄ | 14,532 | 12,281 | 12,741 | 12,533 | 12,498 | 12,848 | 13,132 |
| Natural Gas Systems | 8,270 | 7,093 | 6,647 | 6,803 | 6,906 | 7,023 | 7,045 |
| Petroleum Systems | 1,550 | 1,953 | 2,163 | 2,251 | 2,335 | 2,588 | 2,726 |
| Coal Mining | 3,860 | 2,565 | 3,293 | 2,849 | 2,658 | 2,584 | 2,703 |
| Stationary Combustion | 339 | 296 | 283 | 283 | 265 | 320 | 324 |
| Abandoned Underground | | | | | | | |
| Coal Mines | 288 | 264 | 263 | 257 | 249 | 249 | 253 |
| Mobile Combustion | 226 | 110 | 91 | 90 | 86 | 84 | 82 |
| Incineration of Waste | + | + | + | + | + | + | + |
| <i>International Bunker Fuels^a</i> | <i>7</i> | <i>5</i> | <i>6</i> | <i>5</i> | <i>4</i> | <i>3</i> | <i>3</i> |
| N₂O | 180 | 185 | 155 | 148 | 140 | 139 | 134 |
| Stationary Combustion | 40 | 68 | 74 | 71 | 72 | 77 | 79 |
| Mobile Combustion | 138 | 115 | 79 | 75 | 67 | 61 | 55 |
| Incineration of Waste | 2 | 1 | 1 | 1 | 1 | 1 | 1 |
| <i>International Bunker Fuels^a</i> | <i>3</i> |

+ Does not exceed 0.5 kt

^a These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the United Nations Framework Convention on Climate Change (UNFCCC) requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC). Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement. The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations, but rather, this Inventory presents emissions and sinks in a common format consistent with how countries are to report Inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

Box 3-2: Energy Data from the Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. 40 CFR part 98 requires reporting by 41 industrial categories. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility. In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year.

The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections for source categories in this chapter, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this Inventory (see, also, Box 3-4). Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions and provisions for reporting fuel types in EPA's GHGRP may differ from those used in the Inventory in meeting the UNFCCC reporting guidelines. In line with the UNFCCC reporting guidelines, the inventory report is a comprehensive accounting of all emissions from fuel types identified in the IPCC guidelines and provides a separate reporting of emissions from biomass. Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the GHGRP website.

EPA presents the data collected by its GHGRP through a data publication tool that allows data to be viewed in several formats including maps, tables, charts and graphs for individual facilities or groups of facilities.

3.1 Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO₂ from fossil fuel combustion also differ from the estimation of CH₄ and N₂O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (MMT CO₂ Eq.)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO ₂ | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |
| CH ₄ | 14.1 | 10.2 | 9.3 | 9.3 | 8.8 | 10.1 | 10.1 |
| N ₂ O | 53.1 | 54.7 | 45.8 | 43.8 | 41.5 | 41.2 | 39.8 |
| Total | 4,807.9 | 5,812.0 | 5,413.4 | 5,280.8 | 5,074.9 | 5,208.8 | 5,258.1 |

Note: Totals may not sum due to independent rounding

Table 3-4: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (kt)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|
| CO ₂ | 4,740,671 | 5,747,142 | 5,358,292 | 5,227,690 | 5,024,685 | 5,157,583 | 5,208,207 |
| CH ₄ | 565 | 406 | 372 | 374 | 352 | 404 | 405 |
| N ₂ O | 178 | 183 | 154 | 147 | 139 | 138 | 133 |

CO₂ from Fossil Fuel Combustion

Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO₂ emissions from fossil fuel combustion are presented in Table 3-5. In 2014, CO₂ emissions from fossil fuel combustion increased by 1.0 percent relative to the previous year. The increase in CO₂ emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions.⁴ In 2014, CO₂ emissions from fossil fuel combustion were 5,208.2 MMT CO₂ Eq., or 9.9 percent above emissions in 1990 (see Table 3-5).⁵

Table 3-5: CO₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq.)

| Fuel/Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Coal | 1,718.4 | 2,112.3 | 1,927.7 | 1,813.9 | 1,592.8 | 1,654.4 | 1,653.7 |
| Residential | 3.0 | 0.8 | NO | NO | NO | NO | NO |
| Commercial | 12.0 | 9.3 | 6.6 | 5.8 | 4.1 | 3.9 | 4.5 |
| Industrial | 155.3 | 115.3 | 90.1 | 82.0 | 74.1 | 75.7 | 75.3 |
| Transportation | NE |
| Electricity Generation | 1,547.6 | 1,983.8 | 1,827.6 | 1,722.7 | 1,511.2 | 1,571.3 | 1,570.4 |
| U.S. Territories | 0.6 | 3.0 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| Natural Gas | 1,000.3 | 1,166.7 | 1,272.1 | 1,291.5 | 1,352.6 | 1,391.2 | 1,426.6 |
| Residential | 238.0 | 262.2 | 258.6 | 254.7 | 224.8 | 266.2 | 277.6 |
| Commercial | 142.1 | 162.9 | 167.7 | 170.5 | 156.9 | 179.1 | 189.2 |
| Industrial | 408.9 | 388.5 | 407.2 | 417.3 | 434.8 | 451.9 | 466.0 |
| Transportation | 36.0 | 33.1 | 38.1 | 38.9 | 41.3 | 47.0 | 47.6 |
| Electricity Generation | 175.3 | 318.8 | 399.0 | 408.8 | 492.2 | 444.0 | 443.2 |
| U.S. Territories | NO | 1.3 | 1.5 | 1.4 | 2.6 | 3.0 | 3.0 |
| Petroleum | 2,021.5 | 2,467.8 | 2,158.2 | 2,121.9 | 2,078.9 | 2,111.6 | 2,127.5 |
| Residential | 97.4 | 94.9 | 76.0 | 72.2 | 57.7 | 63.4 | 67.5 |
| Commercial | 63.3 | 51.3 | 45.8 | 44.5 | 35.7 | 38.0 | 38.2 |
| Industrial | 278.3 | 324.2 | 278.2 | 274.0 | 274.1 | 284.6 | 271.9 |
| Transportation | 1,457.7 | 1,854.0 | 1,690.2 | 1,668.8 | 1,655.4 | 1,666.0 | 1,690.0 |
| Electricity Generation | 97.5 | 97.9 | 31.4 | 25.8 | 18.3 | 22.4 | 25.3 |
| U.S. Territories | 27.2 | 45.6 | 36.5 | 36.7 | 37.6 | 37.1 | 34.6 |
| Geothermal^a | 0.4 |
| Total | 4,740.7 | 5,747.1 | 5,358.3 | 5,227.7 | 5,024.7 | 5,157.6 | 5,208.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

NE (Not estimated)

⁴ Further details on industrial sector combustion emissions are provided by EPA's GHGRP <<http://ghgdata.epa.gov/ghgp/main.do>>.

⁵ An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

NO (Not occurring)

^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

Trends in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

Carbon dioxide emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.⁶ Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO₂ Emissions and Total 2014 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO₂ Eq. and Percent)

| Sector | Fuel Type | 2010 to 2011 | | 2011 to 2012 | | 2012 to 2013 | | 2013 to 2014 | | Total 2014 |
|--------------------------------|------------------------------|---------------|--------------|---------------|--------------|--------------|-------------|--------------|-------------|----------------|
| Electricity Generation | Coal | -104.9 | -5.7% | -211.5 | -12.3% | 60.1 | 4.0% | -0.9 | -0.1% | 1,570.4 |
| Electricity Generation | Natural Gas | 9.8 | 2.5% | 83.5 | 20.4% | -48.3 | -9.8% | -0.8 | -0.2% | 443.2 |
| Electricity Generation | Petroleum | -5.6 | -17.8% | -7.5 | -29.0% | 4.1 | 22.3% | 2.9 | 12.8% | 25.3 |
| Transportation ^a | Petroleum | -21.4 | -1.3% | -13.3 | -0.8% | 10.6 | 0.6% | 24.0 | 1.4% | 1,690.0 |
| Residential | Natural Gas | -3.9 | -1.5% | -29.8 | -11.7% | 41.4 | 18.4% | 11.4 | 4.3% | 277.6 |
| Commercial | Natural Gas | 2.7 | 1.6% | -13.6 | -8.0% | 22.3 | 14.2% | 10.0 | 5.6% | 189.2 |
| Industrial | Coal | -8.1 | -9.0% | -7.9 | -9.7% | 1.7 | 2.3% | -0.4 | -0.6% | 75.3 |
| Industrial | Natural Gas | 10.1 | 2.5% | 17.5 | 4.2% | 17.1 | 3.9% | 14.2 | 3.1% | 466.0 |
| All Sectors^b | All Fuels^b | -130.6 | -2.4% | -203.0 | -3.9% | 132.9 | 2.6% | 50.6 | 1.0% | 5,208.2 |

^a Excludes emissions from International Bunker Fuels.

^b Includes fuels and sectors not shown in table.

Note: Totals may not sum due to independent rounding.

In the United States, 82 percent of the energy consumed in 2014 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (10 percent), primarily hydroelectric power, wind energy and biofuels (EIA 2016).⁷ Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 35 percent of total U.S. energy consumption in 2014. Natural gas and coal followed in order of energy demand importance, accounting for approximately 28 percent and 19 percent of total U.S. energy consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2016).

⁶ Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

⁷ Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

Figure 3-3: 2014 U.S. Energy Consumption by Energy Source (Percent)

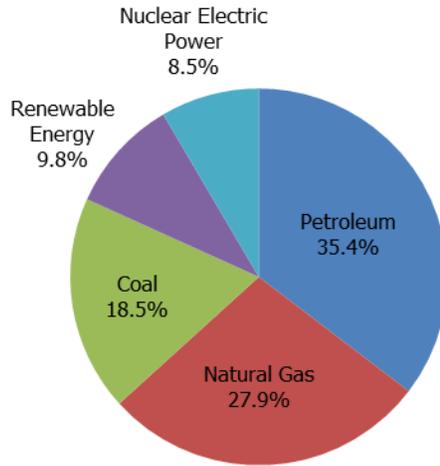


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

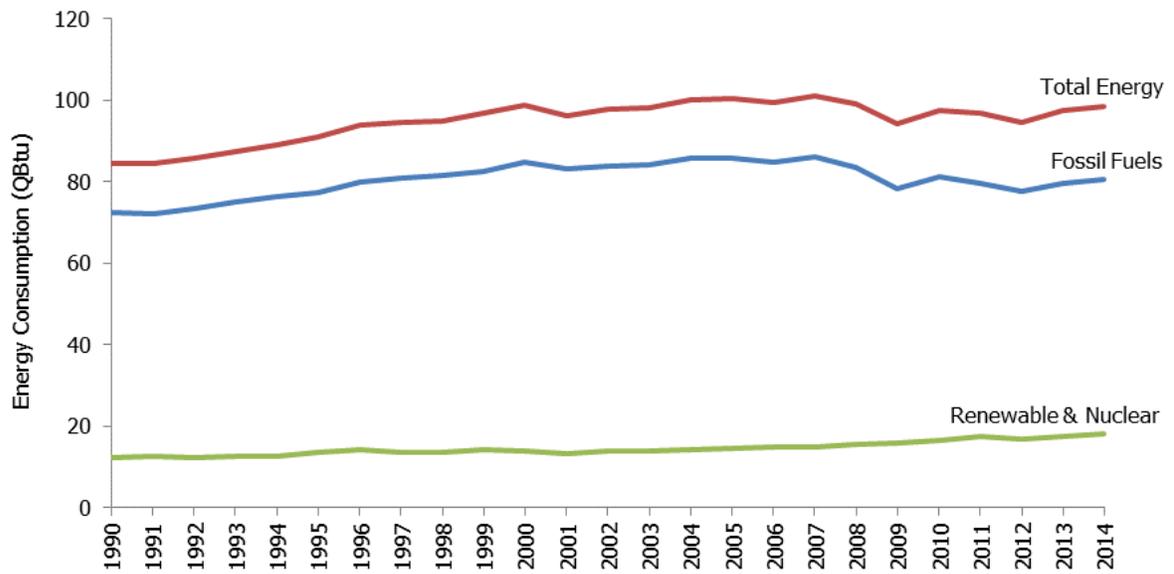
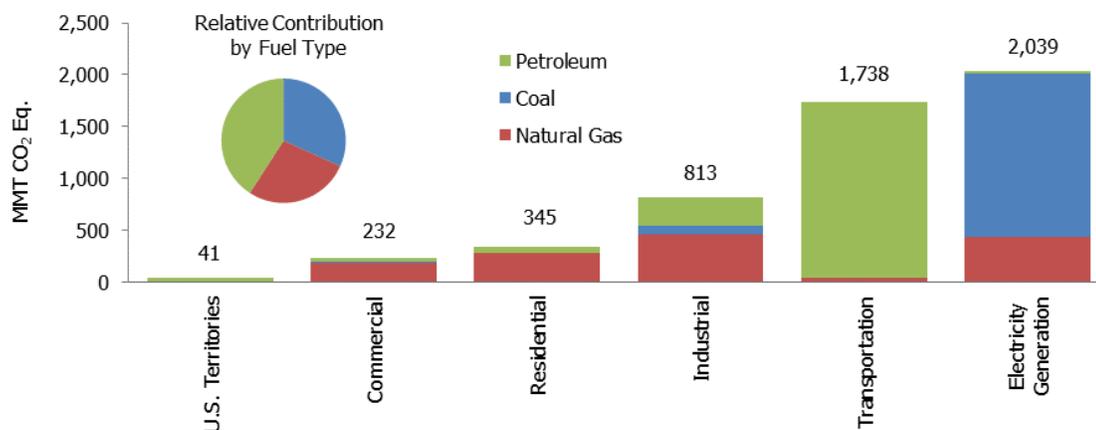


Figure 3-5: 2014 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO₂ Eq.)



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO₂ and smaller amounts of other gases, including CH₄, CO, and NMVOCs.⁸ These other C containing non-CO₂ gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO₂ in the atmosphere. Therefore, it is assumed all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO₂.

Box 3-3: Weather and Non-Fossil Energy Effects on CO₂ from Fossil Fuel Combustion Trends

In 2014, weather conditions, and a very cold first quarter of the year in particular, caused a significant increase in energy demand for heating fuels and is reflected in the increased residential emissions during the early part of the year (EIA 2016). The United States in 2014 also experienced a cooler winter overall compared to 2013, as heating degree days increased (1.9 percent). Cooling degree days decreased by 0.6 percent and despite this decrease in cooling degree days, electricity demand to cool homes still increased slightly. Colder winter conditions compared to 2013 resulted in a significant increase in the amount of energy required for heating, and heating degree days in the United States were 0.6 percent above normal for the first time since 2003 (see Figure 3-6). Summer conditions were slightly cooler in 2014 compared to 2013, and summer temperatures were warmer than normal, with cooling degree days 6.7 percent above normal (see Figure 3-7) (EIA 2016).⁹

⁸ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ gas emissions from fossil fuel combustion.

⁹ Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. Heating degree days have a considerably greater effect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2014, Index Normal = 100)

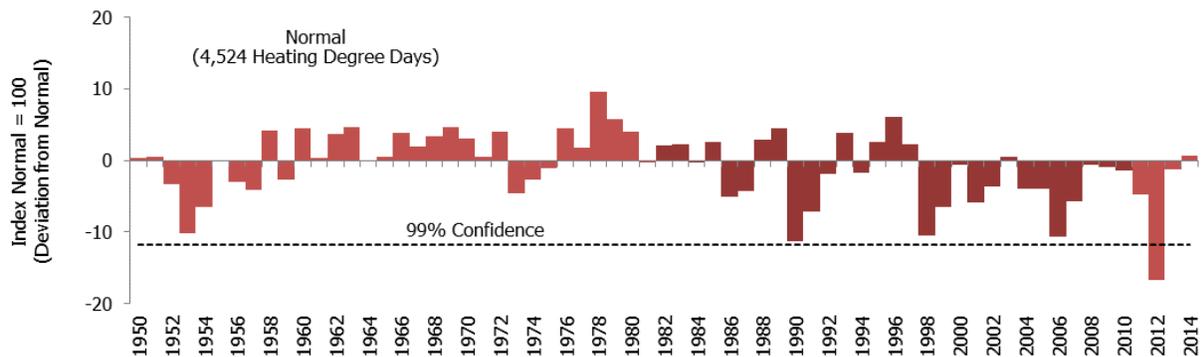
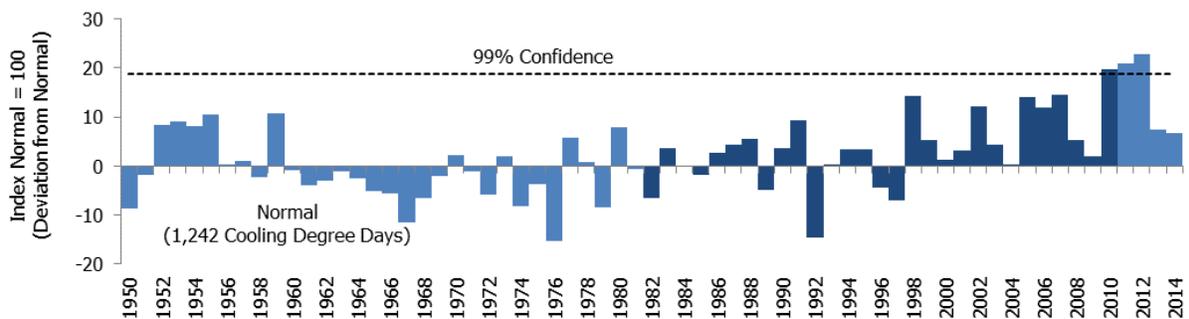


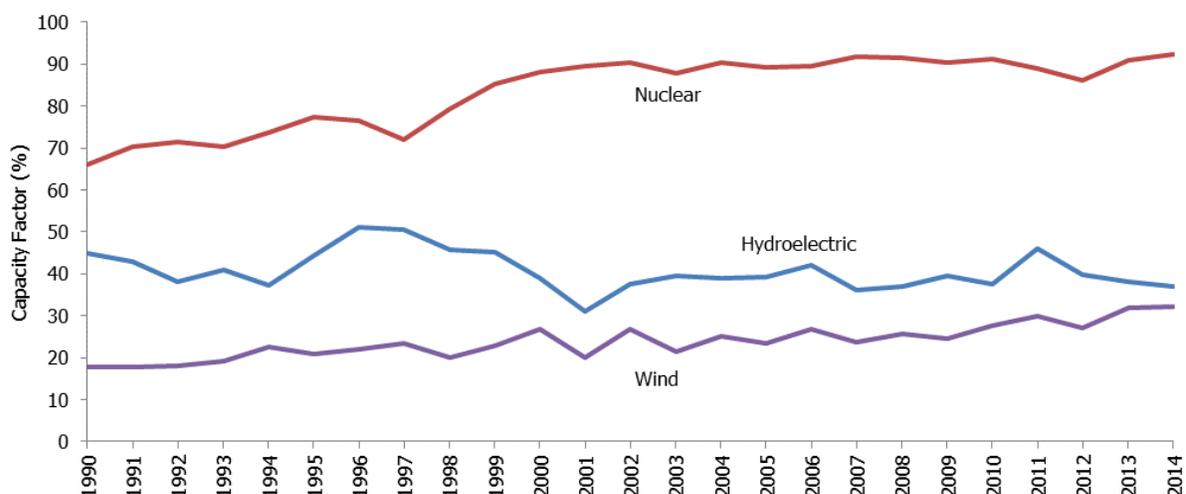
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2014, Index Normal = 100)



Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors)¹⁰ of existing plants in 2014 remained high at 92 percent. Electricity output by hydroelectric power plants decreased in 2014 by approximately 3 percent. In recent years, the wind power sector has been showing strong growth, such that, on the margin, it is becoming a relatively important electricity source. Electricity generated by nuclear plants in 2014 provided more than 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2016). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

¹⁰ The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2016).

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2014, Percent)



Fossil Fuel Combustion Emissions by Sector

In addition to the CO₂ emitted from fossil fuel combustion, CH₄ and N₂O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO₂, CH₄, and N₂O emissions from fossil fuel combustion by sector.

Table 3-7: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by Sector (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Electricity Generation | 1,828.5 | 2,417.4 | 2,277.4 | 2,175.8 | 2,040.5 | 2,057.7 | 2,059.4 |
| CO ₂ | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| CH ₄ | 0.3 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 |
| N ₂ O | 7.4 | 16.0 | 18.5 | 17.6 | 17.8 | 19.1 | 19.6 |
| Transportation | 1,540.6 | 1,924.1 | 1,754.2 | 1,732.3 | 1,718.9 | 1,733.3 | 1,756.0 |
| CO ₂ | 1,493.8 | 1,887.0 | 1,728.3 | 1,707.6 | 1,696.8 | 1,713.0 | 1,737.6 |
| CH ₄ | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| N ₂ O | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |
| Industrial | 847.4 | 832.7 | 779.3 | 777.3 | 786.9 | 816.2 | 817.2 |
| CO ₂ | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| CH ₄ | 1.8 | 1.7 | 1.4 | 1.5 | 1.5 | 1.5 | 1.5 |
| N ₂ O | 3.1 | 2.9 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| Residential | 344.6 | 362.8 | 339.4 | 331.7 | 287.0 | 335.6 | 351.1 |
| CO ₂ | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| CH ₄ | 5.2 | 4.1 | 4.0 | 4.0 | 3.7 | 5.0 | 5.0 |
| N ₂ O | 1.0 | 0.9 | 0.8 | 0.8 | 0.7 | 1.0 | 1.0 |
| Commercial | 218.8 | 224.9 | 221.5 | 222.1 | 197.9 | 222.4 | 233.3 |
| CO ₂ | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| CH ₄ | 1.0 | 1.1 | 1.1 | 1.0 | 0.9 | 1.0 | 1.1 |
| N ₂ O | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |

| | | | | | | | |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| U.S. Territories^a | 28.0 | 50.1 | 41.6 | 41.7 | 43.7 | 43.7 | 41.2 |
| Total | 4,807.9 | 5,812.0 | 5,413.4 | 5,280.8 | 5,074.9 | 5,208.8 | 5,258.1 |

^a U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Notes: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O and the indirect greenhouse gases NO_x, CO, and NMVOCs.¹¹ Methane and N₂O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO₂, including CH₄, N₂O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N₂O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N₂O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH₄ content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH₄ and N₂O from transportation.¹² Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data. This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity consumption in that sector. The results of this alternative method are presented in Table 3-8.

Table 3-8: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Transportation | 1,543.7 | 1,928.9 | 1,758.7 | 1,736.6 | 1,722.8 | 1,737.4 | 1,760.1 |
| CO ₂ | 1,496.8 | 1,891.8 | 1,732.7 | 1,711.9 | 1,700.6 | 1,717.0 | 1,741.7 |
| CH ₄ | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| N ₂ O | 41.2 | 34.4 | 23.7 | 22.5 | 20.1 | 18.2 | 16.4 |
| Industrial | 1,537.0 | 1,574.3 | 1,425.7 | 1,407.2 | 1,385.0 | 1,416.6 | 1,416.6 |
| CO ₂ | 1,529.2 | 1,564.6 | 1,416.5 | 1,398.0 | 1,375.7 | 1,407.0 | 1,406.8 |
| CH ₄ | 2.0 | 1.9 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| N ₂ O | 5.9 | 7.8 | 7.6 | 7.6 | 7.7 | 8.0 | 8.2 |
| Residential | 940.2 | 1,224.9 | 1,186.5 | 1,129.0 | 1,018.8 | 1,077.6 | 1,093.6 |
| CO ₂ | 931.4 | 1,214.1 | 1,174.6 | 1,117.5 | 1,007.8 | 1,064.6 | 1,080.3 |
| CH ₄ | 5.4 | 4.2 | 4.2 | 4.2 | 3.9 | 5.1 | 5.2 |
| N ₂ O | 3.4 | 6.6 | 7.7 | 7.3 | 7.1 | 7.9 | 8.1 |

¹¹ Sulfur dioxide (SO₂) emissions from stationary combustion are addressed in Annex 6.3.

¹² Separate calculations were performed for transportation-related CH₄ and N₂O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

| | | | | | | | |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Commercial | 759.1 | 1,033.7 | 1,000.9 | 966.3 | 904.5 | 933.6 | 946.7 |
| CO ₂ | 755.4 | 1,026.8 | 993.0 | 958.8 | 897.0 | 925.5 | 938.4 |
| CH ₄ | 1.1 | 1.2 | 1.2 | 1.2 | 1.1 | 1.2 | 1.2 |
| N ₂ O | 2.5 | 5.7 | 6.6 | 6.3 | 6.4 | 6.9 | 7.1 |
| U.S. Territories^a | 28.0 | 50.1 | 41.6 | 41.7 | 43.7 | 43.7 | 41.2 |
| Total | 4,807.9 | 5,812.0 | 5,413.4 | 5,280.8 | 5,074.9 | 5,208.8 | 5,258.1 |

^a U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Notes: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO₂ emissions from fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section of CO₂ from Fossil Fuel Combustion). Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O. Table 3-10 and Table 3-11 present CH₄ and N₂O emissions from the combustion of fuels in stationary sources.¹³ Methane and N₂O emissions from stationary combustion sources depend upon fuel characteristics, combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency. The CH₄ and N₂O emission estimation methodology was revised in 2010 to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (see Methodology section for CH₄ and N₂O from stationary combustion). Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO₂ Eq.)

| Sector/Fuel Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Electricity Generation | 1,820.8 | 2,400.9 | 2,258.4 | 2,157.7 | 2,022.2 | 2,038.1 | 2,039.3 |
| Coal | 1,547.6 | 1,983.8 | 1,827.6 | 1,722.7 | 1,511.2 | 1,571.3 | 1,570.4 |
| Natural Gas | 175.3 | 318.8 | 399.0 | 408.8 | 492.2 | 444.0 | 443.2 |
| Fuel Oil | 97.5 | 97.9 | 31.4 | 25.8 | 18.3 | 22.4 | 25.3 |
| Geothermal | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Industrial | 842.5 | 828.0 | 775.5 | 773.3 | 782.9 | 812.2 | 813.3 |
| Coal | 155.3 | 115.3 | 90.1 | 82.0 | 74.1 | 75.7 | 75.3 |
| Natural Gas | 408.9 | 388.5 | 407.2 | 417.3 | 434.8 | 451.9 | 466.0 |
| Fuel Oil | 278.3 | 324.2 | 278.2 | 274.0 | 274.1 | 284.6 | 271.9 |
| Commercial | 217.4 | 223.5 | 220.1 | 220.7 | 196.7 | 221.0 | 231.9 |
| Coal | 12.0 | 9.3 | 6.6 | 5.8 | 4.1 | 3.9 | 4.5 |
| Natural Gas | 142.1 | 162.9 | 167.7 | 170.5 | 156.9 | 179.1 | 189.2 |
| Fuel Oil | 63.3 | 51.3 | 45.8 | 44.5 | 35.7 | 38.0 | 38.2 |
| Residential | 338.3 | 357.8 | 334.6 | 326.8 | 282.5 | 329.7 | 345.1 |
| Coal | 3.0 | 0.8 | NO | NO | NO | NO | NO |
| Natural Gas | 238.0 | 262.2 | 258.6 | 254.7 | 224.8 | 266.2 | 277.6 |
| Fuel Oil | 97.4 | 94.9 | 76.0 | 72.2 | 57.7 | 63.4 | 67.5 |
| U.S. Territories | 27.9 | 49.9 | 41.4 | 41.5 | 43.6 | 43.5 | 41.0 |

¹³ Since emission estimates for U.S. Territories cannot be disaggregated by gas in Table 3-10 and Table 3-11, the values for CH₄ and N₂O exclude U.S. territory emissions.

| | | | | | | | | | |
|--------------|----------------|--|----------------|--|----------------|----------------|----------------|----------------|----------------|
| Coal | 0.6 | | 3.0 | | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| Natural Gas | NO | | 1.3 | | 1.5 | 1.4 | 2.6 | 3.0 | 3.0 |
| Fuel Oil | 27.2 | | 45.6 | | 36.5 | 36.7 | 37.6 | 37.1 | 34.6 |
| Total | 3,246.9 | | 3,860.1 | | 3,630.0 | 3,520.1 | 3,327.9 | 3,444.6 | 3,470.6 |

+ Does not exceed 0.05 MMT CO₂ Eq.

NO - Not occurring

Note: Totals may not sum due to independent rounding.

Table 3-10: CH₄ Emissions from Stationary Combustion (MMT CO₂ Eq.)

| Sector/Fuel Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|------------|------------|------------|------------|------------|------------|------------|
| Electric Power | 0.3 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 |
| Coal | 0.3 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 |
| Fuel Oil | + | + | + | + | + | + | + |
| Natural gas | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Wood | + | + | + | + | + | + | + |
| Industrial | 1.8 | 1.7 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Coal | 0.4 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Fuel Oil | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.2 | 0.1 |
| Natural gas | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Wood | 1.0 | 1.0 | 0.9 | 0.9 | 1.0 | 0.9 | 0.9 |
| Commercial | 1.0 | 1.1 | 1.1 | 1.0 | 0.9 | 1.0 | 1.1 |
| Coal | + | + | + | + | + | + | + |
| Fuel Oil | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 |
| Natural gas | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Wood | 0.5 | 0.5 | 0.5 | 0.5 | 0.4 | 0.5 | 0.5 |
| Residential | 5.2 | 4.1 | 4.0 | 4.0 | 3.7 | 5.0 | 5.0 |
| Coal | 0.2 | 0.1 | NO | NO | NO | NO | NO |
| Fuel Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 |
| Natural Gas | 0.5 | 0.6 | 0.6 | 0.6 | 0.5 | 0.6 | 0.6 |
| Wood | 4.1 | 3.1 | 3.1 | 3.2 | 3.0 | 4.1 | 4.1 |
| U.S. Territories | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Coal | + | + | + | + | + | + | + |
| Fuel Oil | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Natural Gas | NO | + | + | + | + | + | + |
| Wood | NO |
| Total | 8.5 | 7.4 | 7.1 | 7.1 | 6.6 | 8.0 | 8.1 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N₂O Emissions from Stationary Combustion (MMT CO₂ Eq.)

| Sector/Fuel Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Electricity Generation | 7.4 | 16.0 | 18.5 | 17.6 | 17.8 | 19.1 | 19.6 |
| Coal | 6.3 | 11.6 | 12.5 | 11.5 | 10.2 | 12.1 | 12.4 |
| Fuel Oil | 0.1 | 0.1 | + | + | + | + | + |
| Natural Gas | 1.0 | 4.3 | 5.9 | 6.1 | 7.5 | 7.0 | 7.2 |
| Wood | + | + | + | + | + | + | + |
| Industrial | 3.1 | 2.9 | 2.5 | 2.4 | 2.4 | 2.4 | 2.4 |
| Coal | 0.7 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Fuel Oil | 0.5 | 0.5 | 0.4 | 0.4 | 0.3 | 0.4 | 0.3 |
| Natural Gas | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Wood | 1.6 | 1.6 | 1.4 | 1.5 | 1.5 | 1.5 | 1.5 |
| Commercial | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Coal | 0.1 | + | + | + | + | + | + |
| Fuel Oil | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |

| | | | | | | | | |
|-------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|------------|
| Natural Gas | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Wood | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Residential | 1.0 | 0.9 | 0.8 | 0.8 | 0.7 | 1.0 | 1.0 | |
| Coal | + | + | NO | NO | NO | NO | NO | NO |
| Fuel Oil | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Natural Gas | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Wood | 0.7 | 0.5 | 0.5 | 0.5 | 0.5 | 0.7 | 0.7 | 0.7 |
| U.S. Territories | 0.1 | 0.1 |
| Coal | + | + | + | + | + | + | + | + |
| Fuel Oil | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Natural Gas | NO | + | + | + | + | + | + | + |
| Wood | NO | NO |
| Total | 11.9 | 20.2 | 22.2 | 21.3 | 21.4 | 22.9 | 23.4 | |

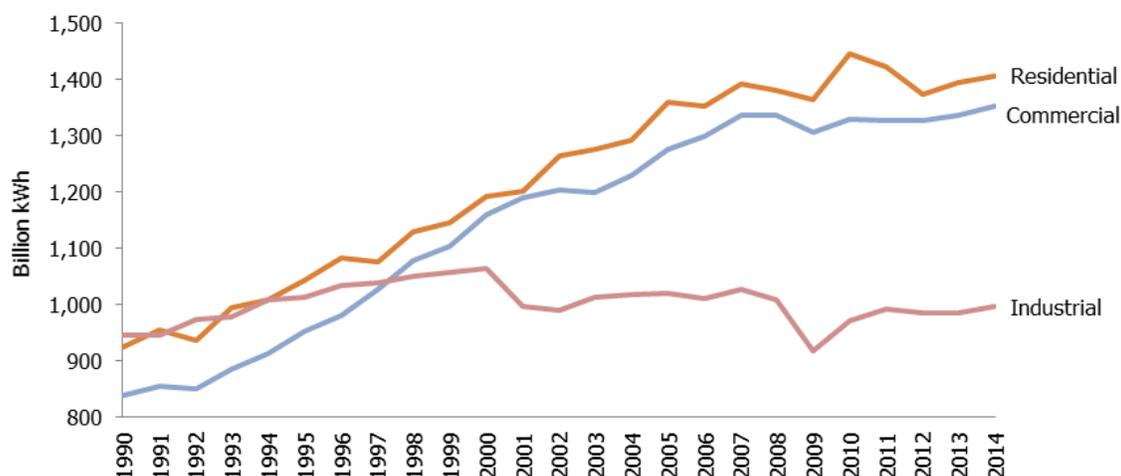
+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO₂ emissions in the United States, representing 37 percent of total CO₂ emissions from all CO₂ emissions sources across the United States. Methane and N₂O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 1.0 percent, respectively. Electricity generation also accounted for the largest share of CO₂ emissions from fossil fuel combustion, approximately 39.2 percent in 2014. Methane and N₂O from electricity generation represented 4.4 and 49.3 percent of total methane and N₂O emissions from fossil fuel combustion in 2014, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9). Electricity generators, including those using low-CO₂ emitting technologies, relied on coal for approximately 39 percent of their total energy requirements in 2014. Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources. Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014 (EIA 2015a).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector (Billion kWh)



The electric power industry includes all power producers, consisting of both regulated utilities and non-utilities (e.g. independent power producers, qualifying co-generators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production

of electricity, while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.¹⁴

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder, more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased approximately 1.1 percent relative to the previous year, while CO₂ emissions from the electric power sector increased by 0.1 percent. The increase in CO₂ emissions, despite the relatively larger increase in electricity generation was a result of a slight decrease in the consumption of coal and natural gas for electricity generation by 0.1 percent and 0.2 percent, respectively, in 2014, and an increase in the consumption of petroleum for electricity generation by 15.8 percent.

Industrial Sector

Industrial sector CO₂, CH₄, and N₂O, emissions accounted for 16, 15, and 6 percent of CO₂, CH₄, and N₂O, emissions from fossil fuel combustion, respectively. Carbon dioxide, CH₄, and N₂O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2016 and EIA 2009b).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.¹⁵ In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

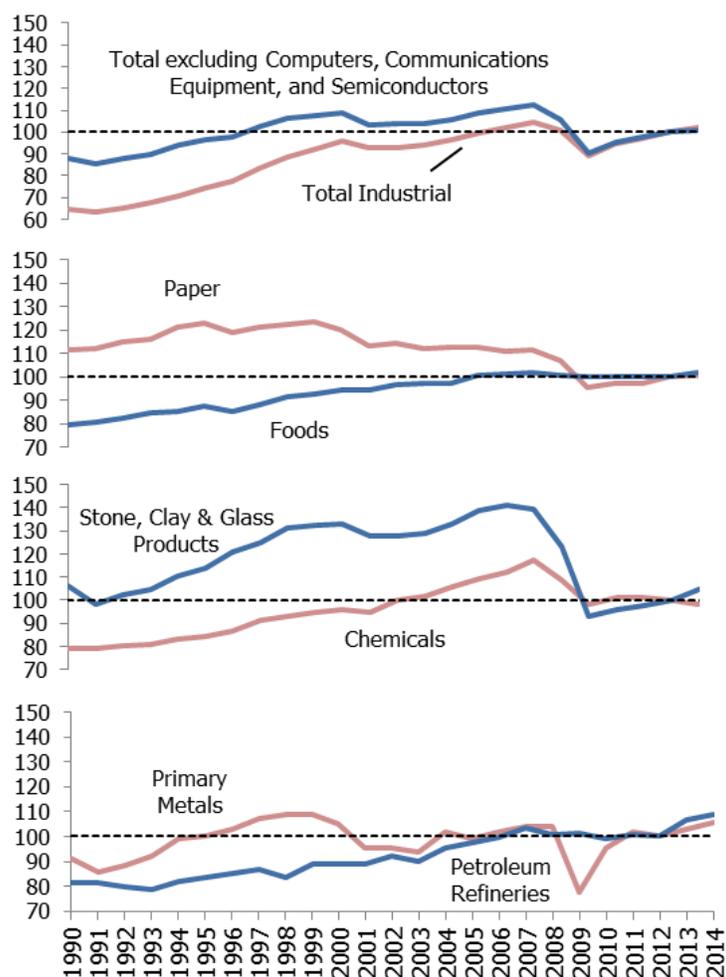
From 2013 to 2014, total industrial production and manufacturing output increased by 3.7 percent (FRB 2015). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, Primary Metals, and Nonmetallic Mineral Products, and decreased slightly for Paper (see Figure 3-10). Through EPA's Greenhouse Gas Reporting Program (GHGRP), industrial trends can be discerned from the overall EIA industrial fuel consumption data used for these calculations. For example, from 2013 to 2014 the underlying EIA data showed increased consumption of natural gas and a decrease in petroleum fuels in the industrial sector. EPA's GHGRP data highlights that chemical manufacturing and nonmetallic mineral products were contributors to these trends.¹⁶

¹⁴ Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

¹⁵ Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

¹⁶ Further details on industrial sector combustion emissions are provided by EPA's GHGRP. See <<http://ghgdata.epa.gov/ghgp/main.do>>.

Figure 3-10: Industrial Production Indices (Index 2007=100)



Despite the growth in industrial output (64 percent) and the overall U.S. economy (78 percent) from 1990 to 2014, CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 3.5 percent over the same time series. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,416.6 MMT CO₂ Eq., or approximately equal to 2013 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO₂ emissions accounted for 7 and 4 percent of CO₂ emissions from fossil fuel combustion, CH₄ emissions accounted for 49 and 11 percent of CH₄ emissions from fossil fuel combustion, and N₂O emissions accounted for 2 and 1 percent of N₂O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,093.6 MMT CO₂ Eq. and 946.7 MMT CO₂ Eq., respectively. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 1.5 and 1.4 percent from 2013 to 2014, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

In 2014, combustion emissions from natural gas consumption represent 80 and 82 percent of the direct fossil fuel CO₂ emissions from the residential and commercial sectors, respectively. Natural gas combustion CO₂ emissions from the residential and commercial sectors in 2014 increased by 4.3 percent and 5.6 percent from 2013 levels, respectively.

U.S. Territories

Emissions from U.S. Territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section for CO₂ from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO₂, CH₄, and N₂O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector and Mobile Combustion

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

Transportation End-Use Sector

The transportation end-use sector accounted for 1,760.1 MMT CO₂ Eq. in 2014, which represented 33 percent of CO₂ emissions, 20 percent of CH₄ emissions, and 41 percent of N₂O emissions from fossil fuel combustion, respectively.¹⁷ Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 104.2 MMT CO₂ Eq. in 2014; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

From 1990 to 2014, transportation emissions from fossil fuel combustion rose by 14 percent due, in large part, to increased demand for travel with limited gains in fuel efficiency for much of this time period. The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

From 2013 to 2014, CO₂ emissions from the transportation end-use sector increased by 1.4 percent.¹⁸ The increase in emissions can largely be attributed to small increases in VMT and fuel use across many on-road transportation modes. Commercial aircraft emissions have decreased 18 percent since 2007.¹⁹ Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to

¹⁷ Note that these totals include CO₂, CH₄ and N₂O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH₄ and N₂O emissions from transportation rail electricity.

¹⁸ Note that this value does not include lubricants.

¹⁹ Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

2014. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO₂, N₂O, CH₄, and HFCs.

Transportation Fossil Fuel Combustion CO₂ Emissions

Domestic transportation CO₂ emissions increased by 16 percent (244.8 MMT CO₂) between 1990 and 2014, an annualized increase of 0.7 percent. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 60 percent of CO₂ emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 24 percent, commercial aircraft 7 percent, and other sources 9 percent. See Table 3-12 for a detailed breakdown of transportation CO₂ emissions by mode and fuel type.

Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol and biodiesel for transportation purposes, along with the emissions associated with the agricultural and industrial processes involved in the production of biofuel, are captured in other Inventory sectors.²⁰ Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.9 billion gallons in 2014, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.4 billion gallons in 2014. For further information, see the section on biofuel consumption at the end of this chapter and Table A-93 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,046.9 MMT CO₂ in 2014, an increase of 10 percent (96.4 MMT CO₂) from 1990 due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,181.1 MMT CO₂ in 2004, and since then have declined about 11 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-11) reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in model year 2014 (EPA 2015a).

Medium- and heavy-duty truck CO₂ emissions increased by 75 percent from 1990 to 2014. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 94 percent between 1990 and 2014.²¹ Carbon dioxide from the domestic operation of commercial aircraft increased by 5 percent (5.3 MMT CO₂) from 1990 to 2014.²² Across all categories of aviation, excluding international bunkers, CO₂ emissions decreased by 20 percent (37.3 MMT CO₂) between 1990 and 2014.²³ This includes a 56 percent (19.6 MMT CO₂) decrease in CO₂ emissions from domestic military operations.

Transportation sources also produce CH₄ and N₂O; these emissions are included in Table 3-13 and Table 3-14 and in the “Mobile Combustion” Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO₂, CH₄, N₂O, and HFCs.

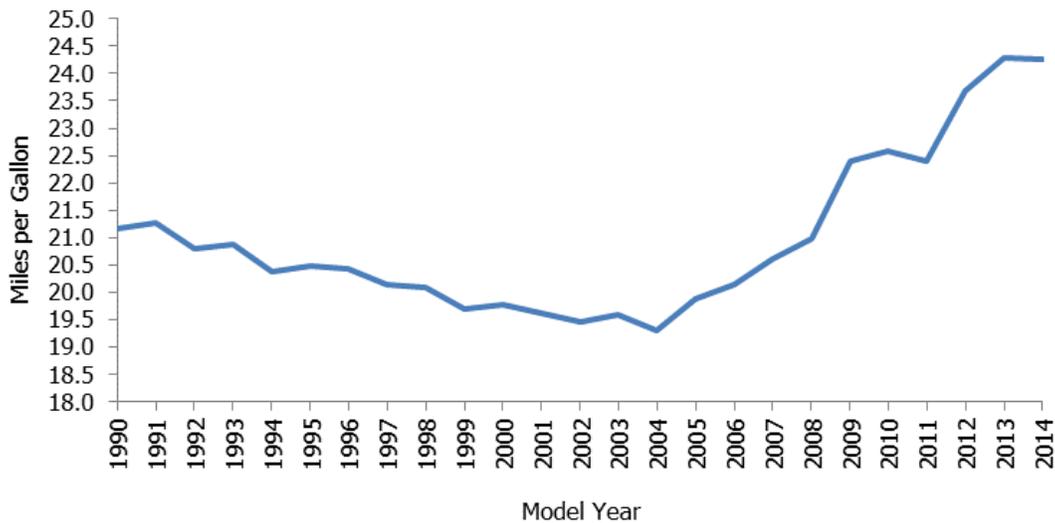
²⁰ Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 6). More information and additional analyses on biofuels are available at EPA’s “Renewable Fuels: Regulations & Standards;” See <<http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm>>.

²¹ While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2014 time period, part of the growth reflects a method change for estimating VMT starting in 2007. This change in methodology in FHWA’s VM-1 table resulted in large changes in VMT by vehicle class, thus leading to a shift in VMT and emissions among on-road vehicle classes in the 2007 to 2014 time period. During the time period prior to the method change (1990-2006), VMT for medium- and heavy-duty trucks increased by 51 percent.

²² Commercial aircraft, as modeled in FAA’s AEDT, consists of passenger aircraft, cargo, and other chartered flights.

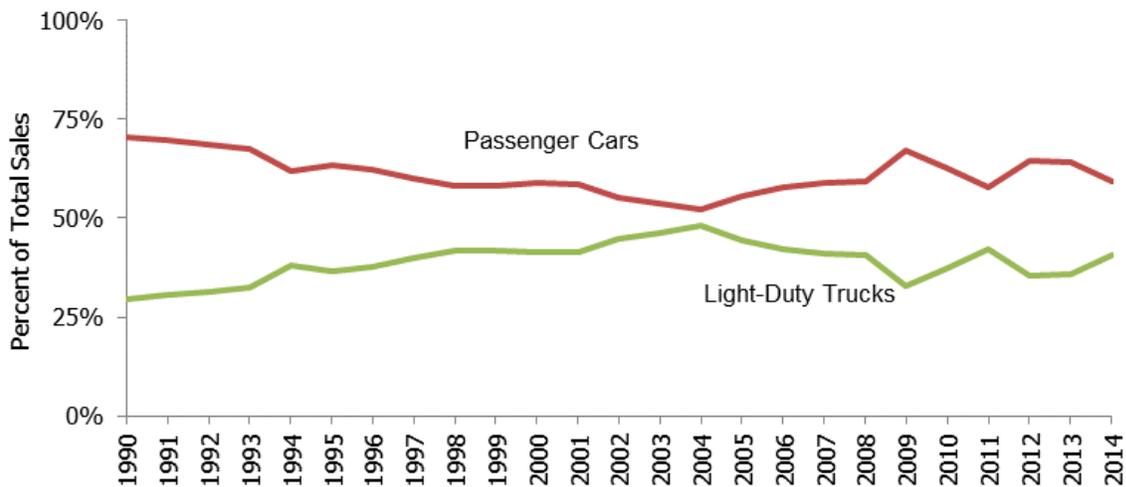
²³ Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2014 (miles/gallon)



Source: EPA (2015)

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2014 (Percent)



Source: EPA (2015)

Table 3-12: CO₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMT CO₂ Eq.)

| Fuel/Vehicle Type | 1990 | 2005 | 2010 ^a | 2011 | 2012 | 2013 | 2014 |
|-----------------------------|--------------|----------------|-------------------|----------------|----------------|----------------|----------------|
| Gasoline^b | 983.5 | 1,183.7 | 1,092.5 | 1,068.8 | 1,064.7 | 1,065.6 | 1,083.8 |
| Passenger Cars | 621.4 | 655.9 | 738.2 | 732.8 | 731.4 | 731.4 | 733.5 |
| Light-Duty Trucks | 309.1 | 477.2 | 295.0 | 280.4 | 277.4 | 277.7 | 293.5 |

| | | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Medium- and Heavy-Duty Trucks ^c | 38.7 | 34.8 | 42.3 | 38.9 | 38.7 | 39.5 | 40.0 |
| Buses | 0.3 | 0.4 | 0.7 | 0.7 | 0.8 | 0.8 | 0.9 |
| Motorcycles | 1.7 | 1.6 | 3.6 | 3.6 | 4.1 | 3.9 | 3.8 |
| Recreational Boats ^d | 12.2 | 13.9 | 12.6 | 12.4 | 12.3 | 12.3 | 12.2 |
| Distillate Fuel Oil (Diesel)^{b,e} | 262.9 | 457.5 | 422.0 | 430.0 | 427.5 | 433.9 | 447.6 |
| Passenger Cars | 7.9 | 4.2 | 3.7 | 4.1 | 4.1 | 4.1 | 4.1 |
| Light-Duty Trucks | 11.5 | 25.8 | 12.5 | 13.0 | 12.9 | 12.9 | 13.9 |
| Medium- and Heavy-Duty Trucks ^c | 190.5 | 360.2 | 342.7 | 344.4 | 344.4 | 350.0 | 361.3 |
| Buses | 8.0 | 10.6 | 13.5 | 14.4 | 15.4 | 15.5 | 16.6 |
| Rail | 35.5 | 45.5 | 38.6 | 40.4 | 39.5 | 40.1 | 41.7 |
| Recreational Boats | 2.0 | 3.2 | 3.6 | 3.6 | 3.7 | 3.7 | 3.8 |
| Ships and Other Boats ^f | 7.5 | 8.0 | 7.4 | 10.1 | 7.5 | 7.5 | 6.2 |
| <i>International Bunker Fuels^g</i> | <i>11.7</i> | <i>9.4</i> | <i>9.5</i> | <i>7.9</i> | <i>6.8</i> | <i>5.6</i> | <i>6.1</i> |
| Jet Fuel | 184.2 | 189.3 | 151.5 | 146.6 | 143.4 | 147.1 | 148.6 |
| Commercial Aircraft ^h | 109.9 | 132.7 | 113.3 | 114.6 | 113.3 | 114.3 | 115.2 |
| Military Aircraft | 35.0 | 19.4 | 13.6 | 11.6 | 12.1 | 11.0 | 15.4 |
| General Aviation Aircraft | 39.4 | 37.3 | 24.6 | 20.4 | 18.0 | 21.8 | 18.0 |
| <i>International Bunker Fuels^g</i> | <i>38.0</i> | <i>60.1</i> | <i>61.0</i> | <i>64.8</i> | <i>64.5</i> | <i>65.7</i> | <i>69.4</i> |
| <i>International Bunker Fuels from Commercial Aviation</i> | <i>30.0</i> | <i>55.6</i> | <i>57.4</i> | <i>61.7</i> | <i>61.4</i> | <i>62.8</i> | <i>66.3</i> |
| Aviation Gasoline | 3.1 | 2.4 | 1.9 | 1.9 | 1.7 | 1.5 | 1.5 |
| General Aviation Aircraft | 3.1 | 2.4 | 1.9 | 1.9 | 1.7 | 1.5 | 1.5 |
| Residual Fuel Oil | 22.6 | 19.3 | 20.4 | 19.4 | 15.8 | 15.1 | 5.8 |
| Ships and Other Boats ^f | 22.6 | 19.3 | 20.4 | 19.4 | 15.8 | 15.1 | 5.8 |
| <i>International Bunker Fuels^g</i> | <i>53.7</i> | <i>43.6</i> | <i>46.5</i> | <i>38.9</i> | <i>34.5</i> | <i>28.5</i> | <i>27.7</i> |
| Natural Gas | 36.0 | 33.1 | 38.1 | 38.9 | 41.3 | 47.0 | 47.6 |
| Passenger Cars | + | + | + | + | + | + | + |
| Light-Duty Trucks | + | + | + | + | + | + | + |
| Buses | + | 0.8 | 1.1 | 1.1 | 1.0 | 1.1 | 1.1 |
| Pipeline ⁱ | 36.0 | 32.2 | 37.1 | 37.8 | 40.3 | 45.9 | 46.5 |
| LPG | 1.4 | 1.7 | 1.8 | 2.1 | 2.3 | 2.7 | 2.7 |
| Light-Duty Trucks | 0.6 | 1.3 | 1.3 | 1.5 | 1.6 | 1.9 | 1.9 |
| Medium- and Heavy-Duty Trucks ^c | 0.8 | 0.4 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 |
| Buses | + | + | + | + | + | + | + |
| Electricity | 3.0 | 4.7 | 4.5 | 4.3 | 3.9 | 4.0 | 4.1 |
| Rail | 3.0 | 4.7 | 4.5 | 4.3 | 3.9 | 4.0 | 4.1 |
| Ethanol^j | 4.1 | 22.4 | 71.3 | 71.5 | 71.5 | 73.4 | 74.8 |
| Total | 1,496.8 | 1,891.8 | 1,732.7 | 1,711.9 | 1,700.6 | 1,717.0 | 1,741.7 |
| Total (Including Bunkers)^g | 1,600.3 | 2,004.9 | 1,849.7 | 1,823.6 | 1,806.4 | 1,816.8 | 1,844.9 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

^b Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c Includes medium- and heavy-duty trucks over 8,500 lbs.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Updates to the distillate fuel oil heat content data from EIA for years 1993 through 2014 resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^f Note that large year over year fluctuations in emission estimates partially reflect nature of data collection for these sources.

^g Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

^h Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

ⁱ Pipelines reflect CO₂ emissions from natural gas powered pipelines transporting natural gas.

^j Ethanol estimates are presented for informational purposes only. See Section 3.10 of this chapter and the estimates in Land Use, Land-Use Change, and Forestry (see Chapter 6), in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

Notes: This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation. In addition, this table does not include CO₂ emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory. Totals may not sum due to independent rounding.

Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions

Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the U.S.

Inventory with the exception of pipelines and electric locomotives;²⁴ mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.).²⁵ Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide mobile fossil fuel CH₄ and N₂O emission estimates in MMT CO₂ Eq.²⁶

Mobile combustion was responsible for a small portion of national CH₄ emissions (0.3 percent) but was the fourth largest source of U.S. N₂O emissions (4.0 percent). From 1990 to 2014, mobile source CH₄ emissions declined by 64 percent, to 2.0 MMT CO₂ Eq. (82 kt CH₄), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH₄ emissions. Mobile source emissions of N₂O decreased by 60 percent, to 16.3 MMT CO₂ Eq. (55 kt N₂O). Earlier generation control technologies initially resulted in higher N₂O emissions, causing a 28 percent increase in N₂O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N₂O output, resulting in a 69 percent decrease in mobile source N₂O emissions from 1997 to 2014 (Figure 3-13). Overall, CH₄ and N₂O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

²⁴ Emissions of CH₄ from natural gas systems are reported separately. More information on the methodology used to calculate these emissions are included in this chapter and Annex 3.4.

²⁵ See the methodology sub-sections of the CO₂ from Fossil Fuel Combustion and CH₄ and N₂O from Mobile Combustion sections of this chapter. Note that N₂O and CH₄ emissions are reported using different categories than CO₂. CO₂ emissions are reported by end-use sector (Transportation, Industrial, Commercial, Residential, U.S. Territories), and generally adhere to a top-down approach to estimating emissions. CO₂ emissions from non-transportation sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO₂ emissions are included in the Commercial end-use sector instead of the Transportation end-use sector). CH₄ and N₂O emissions are reported using the "Mobile Combustion" category, which includes non-transportation mobile sources. CH₄ and N₂O emissions estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO₂ emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

²⁶ See Annex 3.2 for a complete time series of emission estimates for 1990 through 2014.

Figure 3-13: Mobile Source CH₄ and N₂O Emissions (MMT CO₂ Eq.)

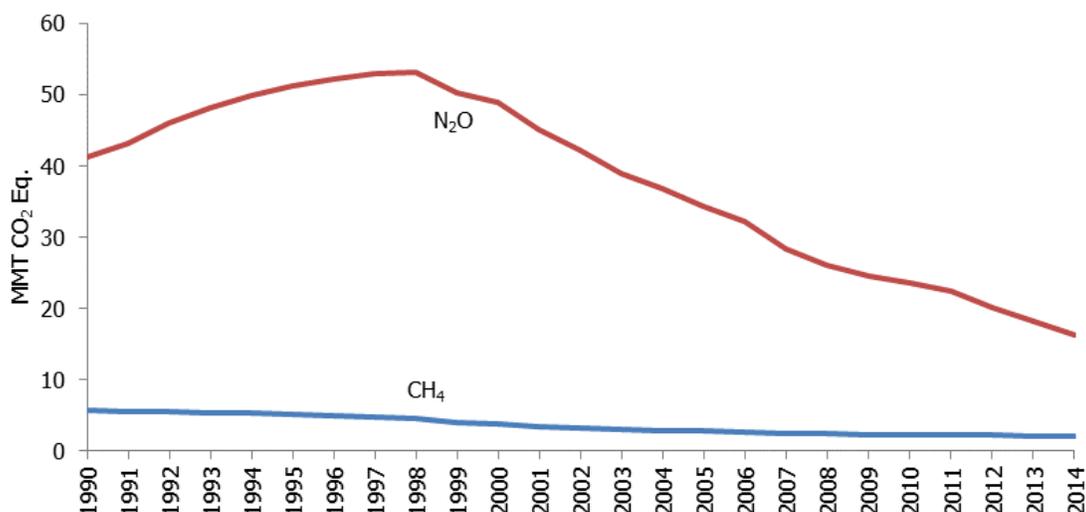


Table 3-13: CH₄ Emissions from Mobile Combustion (MMT CO₂ Eq.)

| Fuel Type/Vehicle Type ^a | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------|------------|------------|------------|------------|------------|------------|
| Gasoline On-Road^b | 5.2 | 2.2 | 1.7 | 1.6 | 1.5 | 1.5 | 1.4 |
| Passenger Cars | 3.2 | 1.2 | 1.2 | 1.2 | 1.1 | 1.0 | 1.0 |
| Light-Duty Trucks | 1.7 | 0.8 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 |
| Medium- and Heavy-Duty Trucks and Buses | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Motorcycles | + | + | + | + | + | + | + |
| Diesel On-Road^b | + |
| Passenger Cars | + | + | + | + | + | + | + |
| Light-Duty Trucks | + | + | + | + | + | + | + |
| Medium- and Heavy-Duty Trucks and Buses | + | + | + | + | + | + | + |
| Alternative Fuel On-Road^c | + |
| Non-Road^d | 0.4 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 |
| Ships and Boats | + | + | + | + | + | + | + |
| Rail ^e | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Aircraft | 0.1 | 0.1 | + | + | + | + | + |
| Agricultural Equipment ^f | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Construction/Mining Equipment ^g | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Other ^h | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total | 5.6 | 2.7 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^dIn 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than 2 percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^eRail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^fIncludes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^gIncludes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h“Other” includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

Table 3-14: N₂O Emissions from Mobile Combustion (MMT CO₂ Eq.)

| Fuel Type/Vehicle Type ^a | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Gasoline On-Road^b | 37.5 | 29.9 | 19.2 | 18.0 | 15.7 | 13.8 | 12.1 |
| Passenger Cars | 24.1 | 15.9 | 12.9 | 12.3 | 10.7 | 9.3 | 7.9 |
| Light-Duty Trucks | 12.8 | 13.2 | 5.5 | 5.0 | 4.4 | 3.9 | 3.6 |
| Medium- and Heavy-Duty Trucks and Buses | 0.5 | 0.8 | 0.8 | 0.7 | 0.6 | 0.6 | 0.5 |
| Motorcycles | + | + | + | + | + | + | + |
| Diesel On-Road^b | 0.2 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Passenger Cars | + | + | + | + | + | + | + |
| Light-Duty Trucks | + | + | + | + | + | + | + |
| Medium- and Heavy-Duty Trucks and Buses | 0.2 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Alternative Fuel On-Road^c | + | + | + | 0.1 | 0.1 | 0.1 | 0.1 |
| Non-Road^d | 3.5 | 4.1 | 4.0 | 4.0 | 3.9 | 3.9 | 3.8 |
| Ships and Boats | 0.6 | 0.6 | 0.8 | 0.8 | 0.7 | 0.7 | 0.5 |
| Rail ^e | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Aircraft | 1.7 | 1.8 | 1.4 | 1.4 | 1.3 | 1.4 | 1.4 |
| Agricultural Equipment ^f | 0.2 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Construction/Mining Equipment ^g | 0.3 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Other ^h | 0.4 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Total | 41.2 | 34.4 | 23.6 | 22.4 | 20.0 | 18.2 | 16.3 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE’s TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current Inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^f Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^g Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

CO₂ from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).²⁷ The use of the most recently published calculation methodologies by the IPCC, as contained in the *2006 IPCC Guidelines*, is considered to improve the rigor and accuracy of this Inventory and is fully in line with IPCC Good Practice Guidance. A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the EIA of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2016). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).²⁸

For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this Inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every four years). These consumption data sets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total.²⁹

²⁷ The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft.

²⁸ Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed total emissions of 41.2 MMT CO₂ Eq. in 2014.

²⁹ See IPCC Reference Approach for estimating CO₂ emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

Also, note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).³⁰

2. *Subtract uses accounted for in the Industrial Processes and Product Use chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the Industrial Processes and Product Use chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2013), Coffeyville (2014), U.S. Census Bureau (2011), EIA (2016), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009), USGS (2010), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2012a) and USGS (2012b).³¹
3. *Adjust for conversion of fuels and exports of CO₂.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO₂.³² Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.³³ Since October 2000, the Dakota Gasification Plant has been exporting CO₂ to Canada by pipeline. Since this CO₂ is not emitted to the atmosphere in the United States, energy used to produce this CO₂ is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2015), data for synthetic natural gas were collected from EIA (2014), and data for CO₂ exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2008) and DOE (2012).
4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2015), Benson (2002 through 2004), DOE (1993 through 2015), EIA (2007), EIA (1991 through 2015), EPA (2015c), and FHWA (1996 through 2015).³⁴

³⁰ A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

³¹ See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes and Product Use chapter.

³² Energy statistics from EIA (2015) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

³³ These adjustments are explained in greater detail in Annex 2.1.

³⁴ The source of highway vehicle VMT and fuel consumption is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 to 2010 Inventory and apply to the 2007 to 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2016).
6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).³⁵ The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2015) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2016); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2014) for 1990 through 2001 and 2007 through 2014, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail in the International Bunker Fuels section of this chapter.
7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO₂. The C content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 2008* (EIA 2009a), and an EPA analysis of C content coefficients used in the GHGRP (EPA 2010). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
8. *Estimate CO₂ Emissions.* Total CO₂ emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).
9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2016) and USAF (1998).³⁶
 - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2014); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2013).
 - For non-road vehicles, activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (2016), Benson (2002 through 2004), DOE (1993 through 2015), DLA Energy (2015), DOC (1991 through 2015), DOT (1991 through 2015), EIA (2009a), EIA (2016), EIA (2013), EIA (1991 through 2015), EPA (2015c), and Gaffney (2007).

³⁵ See International Bunker Fuels section in this chapter for a more detailed discussion.

³⁶ For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8.

- For jet fuel used by aircraft, CO₂ emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC (2006) (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

Box 3-4: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from Industrial Sector Fossil Fuel Combustion

As described in the calculation methodology, total fossil fuel consumption for each year is based on aggregated end-use sector consumption published by the EIA. The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) has provided an opportunity to better characterize the industrial sector's energy consumption and emissions in the United States, through a disaggregation of EIA's industrial sector fuel consumption data from select industries.

For EPA's GHGRP 2010, 2011, 2012, 2013, and 2014 reporting years, facility-level fossil fuel combustion emissions reported through the GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the Inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.³⁷

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.³⁸ For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future Inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, this year's analysis expanded this effort through the full time series presented in the CRF tables. Analyses were conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data in order to disaggregate the full 1990 through 2014 time series in the CRF tables. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

Additionally, to assist in the disaggregation of industrial fuel consumption, EIA will now synthesize energy consumption data using the same procedure as is used for the last historical (benchmark) year of the Annual Energy Outlook (AEO). This procedure reorganizes the most recent data from the Manufacturing Energy Consumption Survey (MECS) (conducted every four years) into the nominal data submission year using the same energy-economy integrated model used to produce the AEO projections, the National Energy Modeling System (NEMS). EIA believes this "nowcasting" technique provides an appropriate estimate of energy consumption for the CRF.

To address gaps in the time series, EIA performs a NEMS model projection, using the MECS baseline sub-sector energy consumption. The NEMS model accounts for changes in factors that influence industrial sector energy consumption, and has access to data which may be more recent than MECS, such as industrial sub-sector macro industrial output (i.e., shipments) and fuel prices. By evaluating the impact of these factors on industrial subsector

³⁷ See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

³⁸ See <<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>>.

energy consumption, NEMS can anticipate changes to the energy shares occurring post-MECS and can provide a way to appropriately disaggregate the energy-related emissions data into the CRF.

While the fuel consumption values for the various manufacturing sub-sectors are not directly surveyed for all years, they represent EIA's best estimate of historical consumption values for non-MECS years. Moreover, as an integral part of each AEO publication, this synthetic data series is likely to be maintained consistent with all available EIA and non-EIA data sources even as the underlying data sources evolve for both manufacturing and non-manufacturing industries alike.

Other sectors' fuel consumption (commercial, residential, transportation) will be benchmarked with the latest aggregate values from the Monthly Energy Review.³⁹ EIA will work with EPA to back cast these values to 1990.

Box 3-5: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO₂ is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO₂ emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 MMT CO₂ Eq./QBTu for natural gas to upwards of 95 MMT CO₂ Eq./QBTu for coal and petroleum coke.⁴⁰ In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For the purposes of following reporting guidelines and maintaining the focus of this section, renewable energy and nuclear electricity and consumption are not included in the totals shown in Table 3-15 in order to focus attention on fossil fuel combustion as detailed in this chapter. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO₂ Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO₂ Eq./QBTu)

| Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Residential ^a | 57.4 | 56.6 | 55.8 | 55.7 | 55.5 | 55.3 | 55.4 |
| Commercial ^a | 59.1 | 57.5 | 56.8 | 56.6 | 56.1 | 55.8 | 55.8 |
| Industrial ^a | 64.3 | 64.3 | 62.9 | 62.4 | 62.0 | 61.8 | 61.5 |
| Transportation ^a | 71.1 | 71.4 | 71.5 | 71.5 | 71.5 | 71.4 | 71.4 |
| Electricity Generation ^b | 87.3 | 85.8 | 83.5 | 82.9 | 79.9 | 81.3 | 81.3 |
| U.S. Territories ^c | 73.0 | 73.4 | 73.1 | 73.1 | 72.4 | 72.1 | 71.6 |
| All Sectors^c | 73.0 | 73.5 | 72.4 | 72.0 | 70.9 | 70.9 | 70.7 |

^a Does not include electricity or renewable energy consumption.

³⁹ See <<http://www.eia.gov/totalenergy/data/monthly/>>.

⁴⁰ One exajoule (EJ) is equal to 10¹⁸ joules or 0.9478 QBTu.

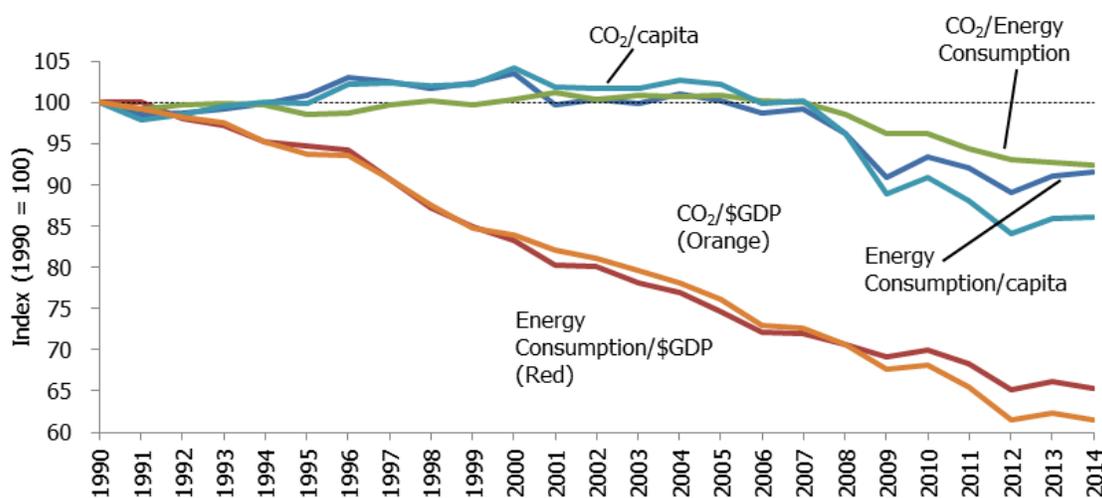
^b Does not include electricity produced using nuclear or renewable energy.

^c Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-five-year period of 1990 through 2014, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2014 was approximately 8.5 percent below levels in 1990 (see Figure 3-14). To differentiate these estimates from those of Table 3-15, the C intensity trend shown in Figure 3-14 and described below includes nuclear and renewable energy EIA data to provide a comprehensive economy-wide picture of energy consumption. Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO₂ emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2016).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP



C intensity estimates were developed using nuclear and renewable energy data from EIA (2016), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty and Time-Series Consistency

For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO₂ emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO₂ emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the

more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO₂ emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO₂ emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO₂ estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. Territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO₂ emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂ from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO₂ from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.⁴¹ Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.⁴²

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).⁴³ For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO₂ emissions in 2014 were estimated to be between 5,102.4 and 5,457.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2014 emission estimate of 5,208.2 MMT CO₂ Eq.

⁴¹ SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

⁴² In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

⁴³ Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Table 3-16: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq. and Percent)

| Fuel/Sector | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|---|---|--|----------------|-------------|-------------|
| | | (MMT CO ₂ Eq.) | | (%) | |
| | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Coal^b | 1,653.7 | 1,596.3 | 1,809.1 | -3% | 9% |
| Residential | NE | NE | NE | NE | NE |
| Commercial | 4.5 | 4.3 | 5.2 | -5% | 15% |
| Industrial | 75.3 | 71.8 | 87.2 | -5% | 16% |
| Transportation | NE | NE | NE | NE | NE |
| Electricity Generation | 1,570.4 | 1,509.0 | 1,721.0 | -4% | 10% |
| U.S. Territories | 3.4 | 3.0 | 4.0 | -13% | 19% |
| Natural Gas^b | 1,426.6 | 1,411.4 | 1,492.7 | -1% | 5% |
| Residential | 277.6 | 269.7 | 297.1 | -3% | 7% |
| Commercial | 189.2 | 183.8 | 202.4 | -3% | 7% |
| Industrial | 466.0 | 452.1 | 499.6 | -3% | 7% |
| Transportation | 47.6 | 46.3 | 51.0 | -3% | 7% |
| Electricity Generation | 443.2 | 430.4 | 465.6 | -3% | 5% |
| U.S. Territories | 3.0 | 2.6 | 3.5 | -12% | 17% |
| Petroleum^b | 2,127.5 | 1,997.0 | 2,251.9 | -6% | 6% |
| Residential | 67.5 | 63.8 | 71.0 | -5% | 5% |
| Commercial | 38.2 | 36.3 | 40.0 | -5% | 5% |
| Industrial | 271.9 | 219.1 | 321.2 | -19% | 18% |
| Transportation | 1,690.0 | 1,577.3 | 1,800.7 | -7% | 7% |
| Electric Utilities | 25.3 | 24.1 | 27.3 | -5% | 8% |
| U.S. Territories | 34.6 | 31.9 | 38.5 | -8% | 11% |
| Total (excluding Geothermal)^b | 5,207.8 | 5,102.0 | 5,457.0 | -2% | 5% |
| Geothermal | 0.4 | NE | NE | NE | NE |
| Total (including Geothermal)^{b,c} | 5,208.2 | 5,102.4 | 5,457.4 | -2% | 5% |

NE (Not Estimated)

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

^b The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.

^c Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO₂ emissions from geothermal production.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO₂ from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO₂ emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2016) updated energy consumption statistics across the time series relative to the previous Inventory. One such revision is the historical coal and petroleum product consumption in the industrial sector for the entire time series. In addition, EIA revised 2013 natural gas consumption in the

transportation sector and 2013 kerosene and Liquefied Petroleum Gas (LPG) consumption in the residential and commercial sectors.

Kerosene consumption increased in the residential sector by 9 percent in 2013 and decreased by 14 and 25 percent in the commercial and industrial sectors in 2013, respectively. Transportation sector distillate fuel consumption decreased by 0.4 percent across the entire time series.

In early 2015, EIA revised the heat content used to calculate the energy of distillate fuel oil consumption. Previously, a single constant factor (5.825 MMBtu/barrel) from EIA's Monthly Energy Review (MER) Table A1 was applied to the volumetric data. For the January 2015 release, this single constant factor in Table A1 was replaced with heat content factors for distillate fuel oil by sulfur content. Instead of using the factor(s) listed in Table A1, EIA began to use an annually variable quantity-weighted factor (5.774 MMBtu/barrel for 2013) that was added to Table A3. EIA notes that quantity-weighted averages of the sulfur-content categories of distillate fuel oil are calculated by using heat content values shown in Table A1, and that these values exclude renewable diesel fuel (including biodiesel) blended into distillate fuel oil.

Overall, these changes resulted in an average annual decrease of 1.1 MMT CO₂ Eq. (less than 0.1 percent) in CO₂ emissions from fossil fuel combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

To reduce uncertainty of CO₂ from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. Territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO₂ from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁴⁴ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from fossil fuel combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. Additional work will commence to ensure CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will continue to be relied upon.⁴⁵

Another planned improvement is to develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated.

An additional potential improvement is to include CO₂ emissions from natural gas (LNG and CNG) use in medium- and heavy-duty trucks, light trucks and passenger cars. Currently data from the Transportation Energy Data book is

⁴⁴ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁴⁵ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

used to allocate CO₂ emissions to vehicle categories. However, this data source only estimates natural gas use in buses. We are currently investigating the use of alternative data sources from the EIA that would allow some of the CO₂ from natural gas consumption to be allocated to these other vehicle categories.

In addition, we are investigating an approach to account for CO₂ emissions from the use of urea-based additives in catalytic converters for on-road vehicles between 2010 and 2014. The approach would utilize the MOVES model to estimate fuel use by diesel vehicles with urea-based catalysts. The *2006 IPCC Guidelines* estimates urea use between one and three percent of diesel fuel used.

CH₄ and N₂O from Stationary Combustion

Methodology

Methane and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). Beginning with the current Inventory report, the electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used are described in the following subsections.

Industrial, Residential, Commercial, and U.S. Territories

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. Territories. For the CH₄ and N₂O estimates, wood consumption data for the United States was obtained from EIA's Monthly Energy Review (EIA 2016). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2016). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).⁴⁶ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.⁴⁷ Construction and agricultural fuel use was obtained from EPA (2014). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA. Tier 1 default emission factors for these three end-use sectors were provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). U.S. Territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

Electric Power Sector

The electric power sector now uses a Tier 2 emission estimation methodology as fuel consumption for the electricity generation sector by control-technology type was obtained from EPA's Acid Rain Program Dataset (EPA 2015a). This combustion technology- and fuel-use data was available by facility from 1996 to 2014. The Tier 2 emission factors used were taken from IPCC (2006), which in turn are based on emission factors published by EPA.

Since there was a difference between the EPA (2015a) and EIA (2016) total energy consumption estimates, the remaining energy consumption from EIA (2016) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2014.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2015a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2016) and the ratio of combustion technology and fuel types from EPA (2015a). The consumption estimates from 1990 to 1995 were estimated by

⁴⁶ U.S. Territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

⁴⁷ Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995. Emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2015a) and EIA (2016) datasets. The higher wood biomass consumption from EIA (2016) in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2016).

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH₄ and N₂O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH₄ and N₂O stationary source inventory estimation models with the model for CO₂ from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO₂ emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N₂O emission factors, based on the SAIC/EIA (2001) report.⁴⁸ For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).⁴⁹ However, the CH₄ emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH₄ emissions in 2014 (*including* biomass) were estimated to be between 4.8 and 20.6 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 41 percent below to 155 percent above the 2014 emission estimate of 8.1 MMT CO₂ Eq.⁵⁰ Stationary combustion N₂O emissions in 2014 (*including* biomass) were estimated to be between 17.9 and 34.2 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 46 percent above the 2014 emissions estimate of 23.4 MMT CO₂ Eq.

⁴⁸ SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

⁴⁹ In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

⁵⁰ The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|-----------------------|------------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Stationary Combustion | CH ₄ | 8.1 | 4.8 | 20.6 | -41% | +155% |
| Stationary Combustion | N ₂ O | 23.4 | 17.9 | 34.2 | -24% | +46% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH₄ and N₂O are greater than those associated with estimates of CO₂ from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH₄ and N₂O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH₄, N₂O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Methane and N₂O emissions from stationary sources (excluding CO₂) across the entire time series were revised due to revised data from EIA (2016) and EPA (2015a) relative to the previous Inventory. The CH₄ emission estimates were also revised due to a corrected emission factor for Natural Gas Combined Cycle gas turbines that was corrected from 1 g/GJ to 4 g/GJ, per IPCC (2006). The historical data changes resulted in an average annual increase of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in CH₄ emissions, and an average annual decrease of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in N₂O emissions from stationary combustion for the period 1990 through 2013.

Planned Improvements

Several items are being evaluated to improve the CH₄ and N₂O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. Territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Future improvements to the CH₄ and N₂O from Stationary Combustion category involve research into the availability of CH₄ and N₂O from stationary combustion data, and analyzing data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for CH₄ and N₂O from Stationary Combustion category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this Inventory. In

implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁵¹

CH₄ and N₂O from Mobile Combustion

Methodology

Estimates of CH₄ and N₂O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH₄ and N₂O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH₄ and N₂O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and emission factors by vehicle and fuel type.⁵²

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO₂, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.⁵³

Emission factors for AFVs were first developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2014 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2015).⁵⁴ VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories

⁵¹ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

⁵² Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

⁵³ Additional information regarding the model can be found online at <<http://www.epa.gov/OMS/m6.htm>>.

⁵⁴ The source of VMT is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through

using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2015) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2015). VMT for AFVs were estimated based on Browning (2015). The age distributions of the U.S. vehicle fleet were obtained from EPA (2015b, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2015b).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999a) and IPCC (2006).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N₂O and CH₄ per kilogram of fuel consumed).⁵⁵ Activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DHS (2008), DLA Energy (2015), DOC (1991 through 2015), DOE (1993 through 2015), DOT (1991 through 2015), EIA (2002, 2007, 2015a), EIA (2007 through 2015), EIA (1991 through 2015), EPA (2015b), Esser (2003 through 2004), FAA (2016), FHWA (1996 through 2015), Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2014 estimates of CH₄ and N₂O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see Section 1.7 Uncertainty Analysis of Emission Estimates. However, a much higher level of uncertainty is associated with CH₄ and N₂O emission factors due to limited emission test data, and because, unlike CO₂ emissions, the emission pathways of CH₄ and N₂O are highly complex.

Mobile combustion CH₄ emissions from all mobile sources in 2014 were estimated to be between 1.8 and 2.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 12 percent below to 18 percent above the corresponding 2014 emission estimate of 2.0 MMT CO₂ Eq. Also at a 95 percent confidence level, mobile combustion N₂O emissions from mobile sources in 2014 were estimated to be between 15.7 and 20.7 MMT CO₂ Eq., indicating a range of 4 percent below to 27 percent above the corresponding 2014 emission estimate of 16.3 MMT CO₂ Eq.

2014 time period. This resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

⁵⁵ The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Mobile Sources (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate ^a (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|----------------|------------------|--|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Mobile Sources | CH ₄ | 2.0 | 1.8 | 2.4 | -12% | +18% |
| Mobile Sources | N ₂ O | 16.3 | 15.7 | 20.7 | -4% | +27% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Approach 2 uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH₄ and N₂O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

Decreases to CH₄ and N₂O emissions from mobile combustion are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES 2014a) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. These changes are due to the updated MOVES age distributions for years 1999 through 2013 in this year's Inventory. These changes in the age distribution increased the percentage of vehicles and VMT for some vehicle types in newer model years that have better emissions control technology. For aircrafts, a weighted jet fuel heat content was applied to the jet fuel N₂O emissions calculation. The weighted factor accounts for the different heat contents of jet fuels used in commercial aviation, general aviation and the military. This resulted in a 0.4 percent increase in the heat content and a similar increase in N₂O emissions.

Estimates of alternative fuel vehicle mileage were also revised to reflect updates made to Energy Information Administration (EIA) data on alternative fuel use and vehicle counts. The energy economy ratios (EERs) in the alternative fuel vehicle analysis were also updated in this Inventory. EERs are the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles. These were taken from the Argonne National Laboratory's GREET model (ANL 2015). Most of the energy economy ratios were within 10 percent of their previous values. More significant changes occurred with Neighborhood Electric Vehicles (NEVs) (-26 percent), Electric Vehicles (EVs) (17 percent), Hydrogen Fuel Cell Vehicles (-15 percent), Neat Methanol Internal Combustion Engines (ICEs) (12 percent), Neat Ethanol ICEs (25 percent), LPG ICEs (11 percent) and LPG Bi-fuel (11 percent). Increases in EERs increase miles per gallon, estimated VMT, and emissions.

Overall, these changes resulted in an average annual decrease of 0.1 MMT CO₂ Eq. (4 percent) in CH₄ emissions and an average annual decrease of 1.4 MMT CO₂ Eq. (3 percent) in N₂O emissions from mobile combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

While the data used for this report represent the most accurate information available, several areas have been identified that could potentially be improved in the near term given available resources.

- Develop improved estimates of domestic waterborne fuel consumption. The Inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated. Additionally, the feasibility of including data from a broader range of domestic and international sources for domestic bunker fuels, including data from studies such as the *Third IMO GHG Study 2014*, is being considered.
- Continue to examine the use of EPA's MOVES model in the development of the Inventory estimates, including use for uncertainty analysis. Although the Inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. The use of MOVES will be further explored.

3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO₂ emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 60 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 40 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this Inventory. For example, some of the NEU products release CO₂ at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO₂ emissions accounted for in the Industrial Processes and Product Use chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations adjust for the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2014 from the non-energy uses of fossil fuels were 114.3 MMT CO₂ Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2014, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,761.2 TBtu, an increase of 6.3 percent since 1990 (see Table 3-20). About 55.9 MMT (205.1 MMT CO₂ Eq.) of the C in these fuels was stored, while the remaining 31.2 MMT C (114.3 MMT CO₂ Eq.) was emitted.

Table 3-19: CO₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO₂ Eq. and percent)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Potential Emissions | 312.1 | 377.5 | 325.1 | 316.6 | 311.9 | 327.1 | 319.5 |
| C Stored | 194.0 | 238.6 | 211.0 | 208.1 | 206.2 | 205.4 | 205.1 |
| Emissions as a % of Potential | 38% | 37% | 35% | 34% | 34% | 37% | 36% |
| Emissions | 118.1 | 138.9 | 114.1 | 108.5 | 105.6 | 121.7 | 114.3 |

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2013, 2015b) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.^{56,57} Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel’s non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in the Energy sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC (2006), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBTu)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Industry | 4,215.8 | 5,110.9 | 4,572.7 | 4,470.2 | 4,377.4 | 4,621.4 | 4,571.6 |
| Industrial Coking Coal | + | 80.4 | 64.8 | 60.8 | 132.5 | 119.6 | 23.0 |
| Industrial Other Coal | 8.2 | 11.9 | 10.3 | 10.3 | 10.3 | 10.3 | 10.3 |
| Natural Gas to Chemical Plants | 281.6 | 260.9 | 298.7 | 297.1 | 292.7 | 297.0 | 305.1 |

⁵⁶ These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

⁵⁷ Some degree of double counting may occur between these estimates of non-energy use of fuels and process emissions from petrochemical production presented in the Industrial Processes and Product Use sector. Data integration is not feasible at this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g., petrochemical production) as currently collected through EPA’s GHGRP and used for the petrochemical production category.

| | | | | | | | |
|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Asphalt & Road Oil | 1,170.2 | 1,323.2 | 877.8 | 859.5 | 826.7 | 783.3 | 792.6 |
| LPG | 1,120.5 | 1,610.1 | 1,834.0 | 1,865.7 | 1,887.3 | 2,062.9 | 2,109.4 |
| Lubricants | 186.3 | 160.2 | 149.5 | 141.8 | 130.5 | 138.1 | 144.0 |
| Pentanes Plus | 117.6 | 95.5 | 75.3 | 26.4 | 40.3 | 45.4 | 43.5 |
| Naphtha (<401 °F) | 326.3 | 679.6 | 474.5 | 469.4 | 432.2 | 498.8 | 435.2 |
| Other Oil (>401 °F) | 662.1 | 499.5 | 433.2 | 368.2 | 267.4 | 209.1 | 236.2 |
| Still Gas | 36.7 | 67.7 | 147.8 | 163.6 | 160.6 | 166.7 | 164.6 |
| Petroleum Coke | 27.2 | 105.2 | + | + | + | + | + |
| Special Naphtha | 100.9 | 60.9 | 25.3 | 21.8 | 14.1 | 96.6 | 104.4 |
| Distillate Fuel Oil | 7.0 | 11.7 | 5.8 | 5.8 | 5.8 | 5.8 | 5.8 |
| Waxes | 33.3 | 31.4 | 17.1 | 15.1 | 15.3 | 16.5 | 14.8 |
| Miscellaneous Products | 137.8 | 112.8 | 158.7 | 164.7 | 161.6 | 171.2 | 182.7 |
| Transportation | 176.0 | 151.3 | 141.2 | 133.9 | 123.2 | 130.4 | 136.0 |
| Lubricants | 176.0 | 151.3 | 141.2 | 133.9 | 123.2 | 130.4 | 136.0 |
| U.S. Territories | 86.7 | 121.9 | 56.4 | 56.7 | 58.1 | 57.4 | 53.6 |
| Lubricants | 0.7 | 4.6 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Other Petroleum (Misc. Prod.) | 86.0 | 117.3 | 55.4 | 55.7 | 57.1 | 56.4 | 52.6 |
| Total | 4,478.5 | 5,384.1 | 4,770.3 | 4,660.9 | 4,558.7 | 4,809.2 | 4,761.2 |

+ Does not exceed 0.05 TBtu

NA - Not Applicable

Note: Totals may not sum due to independent rounding.

Table 3-21: 2014 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

| Sector/Fuel Type | Adjusted Non-Energy Use ^a (TBtu) | Carbon Content Coefficient (MMT C/QBtu) | Potential Carbon (MMT C) | Storage Factor | Carbon Stored (MMT C) | Carbon Emissions (MMT C) | Carbon Emissions (MMT CO ₂ Eq.) |
|-------------------------------|--|---|--------------------------------|-------------------|-----------------------------|--------------------------------|---|
| Industry | 4,571.6 | NA | 83.3 | NA | 55.6 | 27.7 | 101.6 |
| Industrial Coking Coal | 23.0 | 31.00 | 0.7 | 0.04 | 0.1 | 0.6 | 2.4 |
| Industrial Other Coal | 10.3 | 25.82 | 0.3 | 0.65 | 0.2 | 0.1 | 0.3 |
| Natural Gas to | | | | | | | |
| Chemical Plants | 305.1 | 14.46 | 4.4 | 0.65 | 2.9 | 1.5 | 5.6 |
| Asphalt & Road Oil | 792.6 | 20.55 | 16.3 | 1.00 | 16.2 | 0.1 | 0.3 |
| LPG | 2,109.4 | 17.06 | 36.0 | 0.65 | 23.6 | 12.4 | 45.6 |
| Lubricants | 144.0 | 20.20 | 2.9 | 0.09 | 0.3 | 2.6 | 9.7 |
| Pentanes Plus | 43.5 | 19.10 | 0.8 | 0.65 | 0.5 | 0.3 | 1.1 |
| Naphtha (<401° F) | 435.2 | 18.55 | 8.1 | 0.65 | 5.3 | 2.8 | 10.2 |
| Other Oil (>401° F) | 236.2 | 20.17 | 4.8 | 0.65 | 3.1 | 1.6 | 6.0 |
| Still Gas | 164.6 | 17.51 | 2.9 | 0.65 | 1.9 | 1.0 | 3.6 |
| Petroleum Coke | + | 27.85 | + | 0.04 | + | + | + |
| Special Naphtha | 104.4 | 19.74 | 2.1 | 0.65 | 1.3 | 0.7 | 2.6 |
| Distillate Fuel Oil | 5.8 | 20.17 | 0.1 | 0.04 | 0.1 | 0.1 | 0.2 |
| Waxes | 14.8 | 19.80 | 0.3 | 0.58 | 0.2 | 0.1 | 0.5 |
| Miscellaneous Products | 182.7 | 20.31 | 3.7 | 0.04 | 0.0 | 3.7 | 13.6 |
| Transportation | 136.0 | NA | 2.7 | NA | 0.3 | 2.5 | 9.1 |
| Lubricants | 136.0 | 20.20 | 2.7 | 0.09 | 0.3 | 2.5 | 9.1 |
| U.S. Territories | 53.6 | NA | 1.1 | NA | 0.1 | 1.0 | 3.5 |
| Lubricants | 1.0 | 20.20 | + | 0.09 | + | + | 0.1 |
| Other Petroleum (Misc. Prod.) | 52.6 | 20.00 | 1.1 | 0.04 | 0.1 | 0.9 | 3.5 |
| Total | 4,761.2 | | 87.1 | | 55.9 | 31.2 | 114.3 |

+ Does not exceed 0.05 TBtu

NA - Not Applicable

^aTo avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2015a), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011), and the Chemical Data Access Tool (EPA 2012); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013b, 2015b); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2012, 2013, 2014); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990-2015); Gosselin, Smith, and Hodge (1984); EPA's Municipal Solid Waste (MSW) Facts and Figures (EPA 2013a; 2014a); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001-2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003-2011, 2012, 2013, 2014a, 2014b, 2015); and the *Guide to the Business of Chemistry* (ACC 2015b). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Approach 2 methodology (Monte Carlo Stochastic Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-20 and Table 3-21), the storage factors were taken directly from IPCC (2006), where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2014 was estimated to be between 86.2 and 162.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 42 percent above the 2014 emission estimate of 114.3 MMT CO₂ Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Non-Energy Uses of Fossil Fuels (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|--------------|-----------------------|---|--|--------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Feedstocks | CO ₂ | 75.1 | 49.6 | 125.3 | -34% | 67% |
| Asphalt | CO ₂ | 0.3 | 0.1 | 0.6 | -57% | 117% |
| Lubricants | CO ₂ | 18.9 | 15.5 | 21.9 | -18% | 16% |
| Waxes | CO ₂ | 0.5 | 0.3 | 0.7 | -28% | 63% |
| Other | CO ₂ | 19.6 | 14.1 | 21.7 | -28% | 11% |
| Total | CO₂ | 114.3 | 86.2 | 162.9 | -25% | 42% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Totals may not sum due to independent rounding.

Table 3-23: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

| Source | Gas | 2014 Storage Factor (%) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|------------|-----------------|----------------------------|--|-------------|--------------|-------------|
| | | | (%) | | (% Relative) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Feedstocks | CO ₂ | 65% | 52% | 72% | -20% | 10% |
| Asphalt | CO ₂ | 99.6% | 99.1% | 99.8% | -0.5% | 0.25% |
| Lubricants | CO ₂ | 9% | 4% | 17% | -57% | 88% |
| Waxes | CO ₂ | 58% | 49% | 70% | -15% | 22% |
| Other | CO ₂ | 4% | 4% | 24% | -3% | 479% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses

involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2013 as well as their trends across the time series.

Petrochemical input data reported by EIA will continue to be investigated in an attempt to address an input/output discrepancy in the NEU model. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. Starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. A portion of this discrepancy has been reduced and two strategies have been developed to address the remaining portion (see Planned Improvements, below).

Recalculations Discussion

A number of updates to historical production values were included in the most recent Monthly Energy Review; these have been populated throughout this document.

Planned Improvements

There are several improvements planned for the future:

- Analyzing the fuel and feedstock data from EPA's GHGRP to better disaggregate CO₂ emissions in NEU model and CO₂ process emissions from petrochemical production.
- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, reconsider the use of top-down C input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.
- Response to potential changes in NEU input data. In 2013 EIA initiated implementation of new data reporting definitions for Natural Gas Liquids (NGL) and Liquefied Petroleum Gases (LPG); the new definitions may affect the characterization of the input data that EIA provides for the NEU model and may therefore result in the need for changes to the NEU methodology. EIA also obtains and applies proprietary data for LPG inputs that are not directly applied as NEU input data because the data are proprietary. The potential use of the proprietary data (in an aggregated, non-proprietary form) as inputs to the NEU model will be investigated with EIA.
- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses. For example, "miscellaneous

products” category includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the “miscellaneous products” category; however, EIA has indicated that recovered sulfur from petroleum and natural gas processing, and potentially also C black feedstock could be reported in this category. Recovered sulfur would not be reported in the NEU calculation or elsewhere in the Inventory.

- Updating the average C content of solvents was researched, since the entire time series depends on one year’s worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive C in solvents. Additional sources of solvents data will be identified in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

Box 3-6: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in Energy Sector

IPCC (2006) provides methodological guidance to estimate emissions from the first use of fossil fuels as a product for primary purposes other than combustion for energy purposes (including lubricants, paraffin waxes, bitumen/asphalt, and solvents) under the Industrial Processes and Product Use (IPPU) sector.⁵⁸ In this Inventory, C storage and C emissions from product use of lubricants, waxes, and asphalt and road oil are reported under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category (IPCC Source Category 1A).⁵⁹

The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category’s unique country-specific data sources and methodology. The country-specific methodology used for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., C inputs-outputs) calculation of the aggregate amount of fossil fuels used for non-energy uses, including inputs of lubricants, waxes, asphalt and road oil (see Section 3.2, Table 3-21). For those inputs, U.S. country-specific data on C stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the C stored by the fossil fuel non-energy products to the total C content of the fuel consumed, taking into account losses in the production process and during product use.⁶⁰ The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of

⁵⁸ See Volume 3: Industrial Processes and Product Use, Chapter 5: Non-Energy Products from Fuels and Solvent Use of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

⁵⁹ Non-methane volatile organic compound (NMVOC) emissions from solvent use are reported separately in the IPPU sector, following Chapter 5 of the *2006 IPCC Guidelines*.

⁶⁰ Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3: Methodology and Data for Estimating CO₂ Emissions from Fossil Fuel Combustion.

lubricants, waxes, and asphalt and road oil. Due to U.S. national circumstances, reporting these C emissions separately under IPPU would involve making artificial adjustments to both the C inputs and C outputs of the non-energy use C balance. These artificial adjustments would also result in the C emissions for lubricants, waxes, and asphalt and road oil being reported under IPPU, while the C storage for lubricants, waxes, and asphalt and road oil would be reported under Energy. To avoid presenting an incomplete C balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of C storage and C emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the C storage and C emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

3.3 Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000; Goldstein and Madtes 2001; Kaufman et al. 2004; Simmons et al. 2006; van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as scrap tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. Incineration of waste results in conversion of the organic inputs to CO₂. According to IPCC guidelines, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black in scrap tires—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, scrap tires (which contain synthetic rubber and carbon black) are also considered a “non-hazardous” waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the C mass balance for non-energy uses of fossil fuels.

Approximately 29.6 million metric tons of MSW were incinerated in the United States in 2013 (EPA 2015). Data for the amount of MSW incinerated in 2014 were not available, so data for 2014 was assumed to be equal to data for 2013. CO₂ emissions from incineration of waste rose 18 percent since 1990, to an estimated 9.4 MMT CO₂ Eq. (9,421 kt) in 2014, as the volume of scrap tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of CH₄ and N₂O emissions (De Soete 1993; IPCC 2006). Methane emissions from the incineration of waste were estimated to be less than 0.05 MMT CO₂ Eq. (less than 0.5 kt CH₄) in 2014, and have not changed significantly since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.3 MMT CO₂ Eq. (1 kt N₂O) in 2014, and have not changed significantly since 1990.

Table 3-24: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (MMT CO₂ Eq.)

| Gas/Waste Product | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 ^a |
|---------------------------|------|------|------|------|------|------|-------------------|
| CO ₂ | 8.0 | 12.5 | 11.0 | 10.5 | 10.4 | 9.4 | 9.4 |
| Plastics | 5.6 | 6.9 | 6.0 | 5.8 | 5.7 | 4.9 | 4.9 |
| Synthetic Rubber in Tires | 0.3 | 1.6 | 1.5 | 1.4 | 1.3 | 1.2 | 1.2 |

| | | | | | | | |
|-------------------------|------------|-------------|-------------|-------------|-------------|------------|------------|
| Carbon Black in Tires | 0.4 | 2.0 | 1.8 | 1.7 | 1.5 | 1.4 | 1.4 |
| Synthetic Rubber in MSW | 0.9 | 0.8 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Synthetic Fibers | 0.8 | 1.2 | 1.1 | 1.1 | 1.1 | 1.3 | 1.3 |
| CH₄ | + | + | + | + | + | + | + |
| N₂O | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Total | 8.4 | 12.8 | 11.4 | 10.9 | 10.7 | 9.7 | 9.7 |

^a Set equal to 2013 value.

Table 3-25: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (kt)

| Gas/Waste Product | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 ^a |
|---------------------------|--------------|---------------|---------------|---------------|---------------|--------------|-------------------|
| CO₂ | 7,972 | 12,454 | 11,026 | 10,550 | 10,362 | 9,421 | 9,421 |
| Plastics | 5,588 | 6,919 | 5,969 | 5,757 | 5,709 | 4,857 | 4,857 |
| Synthetic Rubber in Tires | 308 | 1,599 | 1,461 | 1,363 | 1,262 | 1,158 | 1,158 |
| Carbon Black in Tires | 385 | 1,958 | 1,783 | 1,663 | 1,537 | 1,412 | 1,412 |
| Synthetic Rubber in MSW | 854 | 765 | 701 | 712 | 705 | 729 | 729 |
| Synthetic Fibers | 838 | 1,212 | 1,112 | 1,056 | 1,149 | 1,265 | 1,265 |
| CH₄ | + | + | + | + | + | + | + |
| N₂O | 2 | 1 | 1 | 1 | 1 | 1 | 1 |

^a Set equal to 2013 value.

Methodology

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO₂ were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.7.

For each of the methods used to calculate CO₂ emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers in MSW, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2014, the amount of MSW incinerated was assumed to be equal to that in 2013, due to the lack of available data. The proportion of total waste discarded that is incinerated was derived from Shin (2014). Data on total waste incinerated was not available for 2012 through 2014, so these values were assumed to equal to the 2011 value. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2013 data (RMA 2014). Average C contents for the “Other” plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through 2001 is the average of 1998 and 2002 values; and C content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers’ Association internet site (RMA 2012a).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO₂ emissions) was reported in EPA’s life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of CH₄ and N₂O. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, CH₄ and N₂O emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in *BioCycle* (van Haaren et al. 2010). Data for 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the *BioCycle* data set for 2012 through 2014, so these values were assumed to equal the 2011 *BioCycle* data set value.

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. The emission factors of N₂O and CH₄ emissions per quantity of municipal solid waste combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from IPCC (2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted (BioCycle data set)

| Year | Waste Discarded | Waste Incinerated | Incinerated (% of Discards) |
|------|--------------------------|-------------------|-----------------------------|
| 1990 | 235,733,657 | 30,632,057 | 13.0% |
| 2005 | 259,559,787 | 25,973,520 | 10.0% |
| 2010 | 271,592,991 | 22,714,122 | 8.0% |
| 2011 | 273,116,704 | 20,756,870 | 7.6% |
| 2012 | 273,116,704 ^a | 20,756,870 | 7.6% |
| 2013 | 273,116,704 ^a | 20,756,870 | 7.6% |
| 2014 | 273,116,704 ^a | 20,756,870 | 7.6% |

^a Assumed equal to 2011 value.

Source: van Haaren et al. (2010)

Uncertainty and Time-Series Consistency

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low emissions for CH₄, no uncertainty estimate was derived). IPCC Approach 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N₂O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO₂ emissions in 2014 were estimated to be between 8.5 and 11.5 MMT CO₂ Eq. at a 95 percent confidence level.

This indicates a range of 10 percent below to 14 percent above the 2014 emission estimate of 9.4 MMT CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2014 were estimated to be between 0.1 and 0.8 MMT CO₂ Eq. This indicates a range of 53 percent below to 163 percent above the 2014 emission estimate of 0.3 MMT CO₂ Eq.

Table 3-27: Approach 2 Quantitative Uncertainty Estimates for CO₂ and N₂O from the Incineration of Waste (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------------|------------------|---|--|----------------|----------------|----------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Incineration of Waste | CO ₂ | 9.4 | 8.5 | 11.5 | -10% | +14% |
| Incineration of Waste | N ₂ O | 0.3 | 0.1 | 0.8 | -53% | +163% |

^a Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

For the current Inventory, emission estimates for 2013 have been updated based on *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015).

The data which calculates the percent incineration was updated in the current Inventory. *Biocycle* has not released a new State of Garbage in America Report since 2010 (with 2008 data), which used to be a semi-annual publication which publishes the results of the nation-wide MSW survey. The results of the survey have been published in Shin 2014. This provided updated incineration data for 2011, so the generation and incineration data for 2012 through 2014 are assumed equivalent to the 2011 values. The data for 2009 and 2010 were based on interpolations between 2008 and 2011.

Planned Improvements

The availability of facility-level waste incineration data through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize waste incineration operations in the United States. This characterization could include future improvements as to the operations involved in waste incineration for energy, whether in the power generation sector or the industrial sector. Additional examinations will be necessary as, unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,⁶¹ some facility-level waste incineration emissions reported under EPA's GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, emissions for waste incineration with energy recovery are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In

⁶¹ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

examining data from EPA’s GHGRP that would be useful to improve the emission estimates for the waste incineration category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA’s GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on ensuring CO₂ emissions from the biomass component of waste are separated in the facility-level reported data, and on maintaining consistency with national waste generation and fate statistics currently used to estimate total, national U.S. greenhouse gas emissions. In implementing improvements and integration of data from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁶² GHGRP data is available for MSW combustors, which contains information on the CO₂, CH₄, and N₂O emissions from MSW combustion, plus the fraction of the emissions that are biogenic. To calculate biogenic versus total CO₂ emissions, a default biogenic fraction of 0.6 is used. The biogenic fraction will be calculated using the current input data and assumptions to verify the current MSW emission estimates.

If GHGRP data would not provide a more accurate estimate of the amount of solid waste combusted, new data sources for the total MSW generated will be explored given that the data previously published semi-annually in Biocycle (van Haaren et al. 2010) has ceased to be published, according to the authors. Equivalent data was derived from Shin (2014) for 2011. A new methodology would be developed based on the available data within the annual update of EPA’s *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015). In developing the new methodology, appropriate assumptions would need to be made to ensure that the MSW figures included all waste. Additionally, the carbon content of the synthetic fiber will be updated based on each year’s production mix.

Additional improvements will be conducted to improve the transparency in the current reporting of waste incineration. Currently, hazardous industrial waste incineration is included within the overall calculations for the Carbon Emitted from Non-Energy Uses of Fossil Fuels category. Waste incineration activities that do not include energy recovery will be examined. Synthetic fibers within scrap tires are not included in this analysis and will be explored for future inventories. The carbon content of fibers within scrap tires would be used to calculate the associated incineration emissions. Updated fiber content data from the Fiber Economics Bureau will also be explored.

3.4 Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining–related activities release CH₄ to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of CH₄ emissions (see Table 3-29 and Table 3-30) due to the higher CH₄ content of coal in the deeper underground coal seams. In 2014, 345 underground coal mines and 613 surface mines were operating in the United States. In recent years the total number of active coal mines in the United States has declined. In 2014, the United States was the second largest coal producer in the world (906 MMT), after China (3,650 MMT) and followed by India (668 MMT) (IEA 2015).

Table 3-28: Coal Production (kt)

| Year | Underground | | Surface | | Total | |
|------|-----------------|------------|-----------------|------------|-----------------|------------|
| | Number of Mines | Production | Number of Mines | Production | Number of Mines | Production |
| 1990 | 1,683 | 384,244 | 1,656 | 546,808 | 3,339 | 931,052 |
| 2005 | 586 | 334,398 | 789 | 691,448 | 1,398 | 1,025,846 |
| 2010 | 497 | 305,862 | 760 | 676,177 | 1,257 | 982,039 |
| 2011 | 508 | 313,529 | 788 | 684,807 | 1,296 | 998,337 |
| 2012 | 488 | 310,608 | 719 | 610,307 | 1,207 | 920,915 |
| 2013 | 395 | 309,546 | 637 | 581,270 | 1,032 | 890,815 |
| 2014 | 345 | 321,783 | 613 | 583,974 | 958 | 905,757 |

⁶² See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Underground mines liberate CH₄ from ventilation systems and from degasification systems. Ventilation systems pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust significant amounts of CH₄ to the atmosphere in low concentrations. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large, often highly concentrated volumes of CH₄ before, during, or after mining. Some mines recover and use CH₄ generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH₄ as the overburden is removed and the coal is exposed to the atmosphere. CH₄ emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their level of emissions is much lower than from underground mines.

In addition, CH₄ is released during post-mining activities, as the coal is processed, transported, and stored for use.

Total CH₄ emissions in 2014 were estimated to be 2,703 kt (67.6 MMT CO₂ eq.), a decline of 30 percent since 1990 (see Table 3-29 and Table 3-30). Of this amount, underground mines accounted for approximately 73 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 13 percent.

Table 3-29: CH₄ Emissions from Coal Mining (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Underground (UG) Mining | 74.2 | 42.0 | 61.6 | 50.2 | 47.3 | 46.2 | 49.1 |
| Liberated | 80.8 | 59.7 | 85.2 | 71.0 | 65.8 | 65.8 | 65.7 |
| Recovered & Used | (6.6) | (17.7) | (23.6) | (20.8) | (18.5) | (19.6) | (16.6) |
| Surface Mining | 10.8 | 11.9 | 11.5 | 11.6 | 10.3 | 9.7 | 9.6 |
| Post-Mining (UG) | 9.2 | 7.6 | 6.8 | 6.9 | 6.7 | 6.6 | 6.7 |
| Post-Mining (Surface) | 2.3 | 2.6 | 2.5 | 2.5 | 2.2 | 2.1 | 2.1 |
| Total | 96.5 | 64.1 | 82.3 | 71.2 | 66.5 | 64.6 | 67.6 |

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-30: CH₄ Emissions from Coal Mining (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| UG Mining | 2,968 | 1,682 | 2,463 | 2,008 | 1,891 | 1,849 | 1,964 |
| Liberated | 3,234 | 2,390 | 3,406 | 2,839 | 2,631 | 2,633 | 2,627 |
| Recovered & Used | (266) | (708) | (943) | (831) | (740) | (784) | (662) |
| Surface Mining | 430 | 475 | 461 | 465 | 410 | 388 | 386 |
| Post-Mining (UG) | 368 | 306 | 270 | 276 | 268 | 263 | 270 |
| Post-Mining (Surface) | 93 | 103 | 100 | 101 | 89 | 84 | 84 |
| Total | 3,860 | 2,565 | 3,293 | 2,849 | 2,658 | 2,584 | 2,703 |

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH₄ emissions from coal mining consists of two steps:

- Estimate emissions from underground mines. These emissions have two sources: ventilation systems and degasification systems. They are estimated on a mine-by-mine basis, then summed to determine total CH₄ liberated. The CH₄ recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- Estimate CH₄ emissions from surface mines and post-mining activities. Unlike the methodology for underground mines, which uses mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

Step 1: Estimate CH₄ Liberated and CH₄ Emitted from Underground Mines

Underground mines generate CH₄ from ventilation systems and from degasification systems. Some mines recover and use the generated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted from underground mines equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from degasification systems, minus the CH₄ recovered and used.

Step 1.1: Estimate CH₄ Liberated from Ventilation Systems

To estimate CH₄ liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP) (subpart FF, “Underground Coal Mines”), data provided by the U.S. Mine Safety and Health Administration (MSHA), and occasionally data collected from other sources on a site-specific level (e.g., state data). Since 2011, the nation’s “gassiest” underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH₄ per year (about 14,700 MT CO₂ eq.)—have been required to report to EPA’s GHGRP (EPA 2015).⁶³ Mines that report to the GHGRP must report quarterly measurements of CH₄ emissions from ventilation systems to EPA; they have the option of recording their own measurements, or using the measurements taken by MSHA as part of that agency’s quarterly safety inspections of all mines in the United States with detectable CH₄ concentrations.⁶⁴

Since 2013, ventilation emission estimates have been calculated based on both GHGRP data submitted by underground mines that recorded their own measurements, and on quarterly measurement data obtained directly from MSHA for the remaining mines (not MSHA data reported by the mines to the GHGRP).⁶⁵ The quarterly measurements are used to determine the average daily emissions rate for the reporting year quarter.

Step 1.2: Estimate CH₄ Liberated from Degasification Systems

Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH₄ before, during, or after mining. This CH₄ can then be collected for use or vented to the atmosphere. Twenty-five mines used degasification systems in 2014, and the CH₄ removed through these systems was reported to EPA’s GHGRP (EPA 2015). Based on the weekly measurements reported to EPA’s GHGRP, degasification data summaries for each mine were added together to estimate the CH₄ liberated from degasification systems. Sixteen of the 25 mines with degasification systems had operational CH₄ recovery and use projects (see step 1.3 below), and GHGRP reports show the remaining nine mines vented CH₄ from degasification systems to the atmosphere.⁶⁶

Degasification volumes for the life of any pre-mining wells are attributed to the mine as emissions in the year in which the well is mined through.⁶⁷ EPA’s GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under subpart FF. Most pre-mining wells drilled from the surface are considered coalbed methane wells and are reported under another subpart of the program (subpart W, “Petroleum and Natural Gas Systems”). As a result, for the 10 mines with degasification systems that include pre-mining wells, GHGRP information was supplemented with historical data from state gas well production databases (GSA 2016, WVGES 2015), as well as with mine-specific information regarding the dates on which the pre-mining wells are mined through (JWR 2010, El Paso 2009).

Degasification information reported to EPA’s GHGRP by underground coal mines was the primary source of data used to develop estimates of CH₄ liberated from degasification systems. Data reported to EPA’s GHGRP were used to estimate CH₄ liberated from degasification systems at 20 of the 25 mines that employed degasification systems in 2014. For the other five mines (all with pre-mining wells from which CH₄ was recovered), GHGRP data—along with supplemental information from state gas production databases (GSA 2016, WVGES 2015)—were used to

⁶³ Underground coal mines report to EPA under Subpart FF of the GHGRP. In 2014, 128 underground coal mines reported to the program.

⁶⁴ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

⁶⁵ EPA has determined that certain mines are having difficulty interpreting the MSHA data so that they report them correctly to the GHGRP. EPA is working with these mines to correct their GHGRP reports, and in the meantime is relying on data obtained directly from MSHA for purposes of the national inventory.

⁶⁶ Several of the mines venting CH₄ from degasification systems use a small portion the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH₄ use is not considered to be a formal recovery and use project.

⁶⁷ A well is “mined through” when coal mining development or the working face intersects the borehole or well.

estimate CH₄ liberated from degasification systems. For one mine, due to a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the CH₄ liberated was based on both the reported GHGRP data (for the vented portion of CH₄ recovered) and an estimate from historical mine-provided CH₄ recovery and use rates based on gas sales records (JWR 2010, El Paso 2009).

Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Sixteen mines had CH₄ recovery and use projects in place in 2014. Fourteen of these mines sold the recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. In addition, one mine used recovered CH₄ for electrical power generation, and one used recovered CH₄ to heat mine ventilation air.

Ten of the 16 mines deployed degasification systems in 2014; for those mines, estimates of CH₄ recovered from the systems were exclusively based on GHGRP data. Based on weekly measurements, the GHGRP degasification destruction data summaries for each mine were added together to estimate the CH₄ recovered and used from degasification systems.

All 10 mines with degasification systems used pre-mining wells as part of those systems, but only four of them intersected pre-mining wells in 2014. GHGRP and supplemental data were used to estimate CH₄ recovered and used at two of these four mines; supplemental data alone (GSA 2016) were used for the other two mines, which reported to EPA's GHGRP as a single entity. Supplemental information was used for these four mines because estimating CH₄ recovery and use from pre-mining wells requires additional data (not reported under subpart FF of EPA's GHGRP, see discussion in step 1.2 above) to account for the emissions avoided. The supplemental data came from state gas production databases, as well as mine-specific information on the timing of mined-through pre-mining wells.

GHGRP information was not used to estimate CH₄ recovered and used at two mines. At one of these mines, a portion (16 percent) of reported CH₄ vented was applied to an ongoing mine air heating project. Because of a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the 2014 CH₄ recovered and used at the other mine was based on an estimate from historical mine-provided CH₄ recovery and use rates (including emissions avoided from pre-mining wells).

In 2014, one mine destroyed a portion of its CH₄ emissions from ventilation systems using thermal oxidation technology. The amount of CH₄ recovered and destroyed by the project was determined through publicly-available emission reduction project information (CAR 2015).

Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH₄ emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's Annual Coal Report (EIA 2015) was multiplied by basin-specific CH₄ contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH₄ from over- and under-burden) to estimate CH₄ emissions (see King 1994, Saghafi 2013). For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a mid-range 32.5 percent emission factor for CH₄ desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data were compiled from AAPG (1984) and USBM (1986).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from EPA's GHGRP or from MSHA, uncertainty is relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not continuous but rather quarterly instantaneous readings that were used to determine the average daily emissions rate for the quarter. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH₄ emissions (Mutmansky & Wang 2000). GHGRP data were used for a significant number of the mines that reported their own measurements to the program beginning in 2013; however, the equipment uncertainty is applied to both GHGRP and MSHA data.

Estimates of CH₄ recovered by degasification systems are relatively certain for utilized CH₄ because of the availability of GHGRP data and gas sales information. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated.

EPA's GHGRP requires weekly CH₄ monitoring of mines that report degasification systems, and continuous CH₄ monitoring is required for utilized CH₄ on- or off-site. Since 2012, GHGRP data have been used to estimate CH₄ emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used for this subsource. Beginning in 2013, GHGRP data were also used for determining CH₄ recovery and use at mines without publicly available gas usage or sales records, which has reduced the uncertainty from previous estimation methods that were based on information from coal industry contacts.

Surface mining and post-mining emissions are associated with considerably more uncertainty than underground mines, because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions constitute the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH₄ emissions in 2014 were estimated to be between 59.9 and 77.4 MMT CO₂ eq. at a 95 percent confidence level. This indicates a range of 11.9 percent below to 15.3 percent above the 2014 emission estimate of 67.6 MMT CO₂ eq.

Table 3-31: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Coal Mining (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|-------------|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Coal mining | CH ₄ | 67.6 | 59.9 | 77.4 | -11.9% | +15.3% |

^a Range of emission estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.
Note: Emissions values are presented in CO₂ equivalent mass units using IPCC AR4 GWP values.

Methodological recalculations were applied to the entire time-series to ensure consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the methodology section.

Recalculations Discussion

For the current Inventory, no recalculations were performed on prior inventory years.

Planned Improvements

Future improvements to the coal mining category will include continued analysis and integration into the national inventory of the degasification quantities and ventilation emissions data reported by underground coal mines to EPA's GHGRP. A higher reliance on EPA's GHGRP will provide greater consistency and accuracy in future inventories. MSHA data will serve as a quality assurance tool for validating GHGRP data. Reconciliation of the GHGRP and Inventory data sets is still in progress. In implementing improvements and integrating data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied on (IPCC 2011).

3.5 Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of coal mine methane (CMM) emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH₄ after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH₄ that may find its way to surface structures through overburden fractures. As work stops within the mines, CH₄ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH₄ at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH₄ migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH₄ flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Annual gross abandoned mine CH₄ emissions ranged from 7.2 to 10.8 MMT CO₂ Eq. from 1990 through 2014, varying, in general, by less than 1 percent to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (10.8 MMT CO₂ Eq.) due to the large number of gassy mine⁶⁸ closures from 1994 to 1996 (72 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. Since 2002, there have been fewer than twelve gassy mine closures each year. There were seven gassy mine closures in 2014. In 2014, gross abandoned mine emissions decreased slightly to 8.7 MMT CO₂ Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH₄ recovered and used at 37 mines, resulting in net emissions in 2014 of 6.3 MMT CO₂ Eq.

Table 3-32: CH₄ Emissions from Abandoned Coal Mines (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------|------------|------------|------------|------------|------------|------------|------------|
| Abandoned Underground Mines | 7.2 | 8.4 | 9.7 | 9.3 | 8.9 | 8.8 | 8.7 |
| Recovered & Used | + | 1.8 | 3.2 | 2.9 | 2.7 | 2.6 | 2.4 |
| Total | 7.2 | 6.6 | 6.6 | 6.4 | 6.2 | 6.2 | 6.3 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

⁶⁸ A mine is considered a “gassy” mine if it emits more than 100 thousand cubic feet of CH₄ per day (100 mcf/d).

Table 3-33: CH₄ Emissions from Abandoned Coal Mines (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------|------------|------------|------------|------------|------------|------------|------------|
| Abandoned Underground Mines | 288 | 334 | 389 | 373 | 358 | 353 | 350 |
| Recovered & Used | + | 70 | 126 | 116 | 109 | 104 | 97 |
| Total | 288 | 264 | 263 | 257 | 249 | 249 | 253 |

+ Does not exceed 0.5 kt

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH₄ emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH₄ from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH₄ emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH₄ emissions over time for a given abandoned mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH₄ leaves the system, the reservoir pressure (Pr) declines as described by the isotherm's characteristics. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at the pressures of interest (atmospheric to 30 psia). The CH₄ flow rate is determined by the laws of gas flow through porous media, such as Darcy's Law. A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i (1 + bD_i t)^{-1/b}$$

where,

- q = Gas flow rate at time t in million cubic feet per day (mmcf/d)
- q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t₀ (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2004).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emissions after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore will no longer have any measurable CH₄ emissions. Based on this assumption, an average decline rate for flooded mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2004).

$$q = q_i e^{-Dt}$$

where,

- q = Gas flow rate at time t in mmcf/d
- q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- D = Decline rate, 1/yr
- t = Elapsed time from t₀ (years)

Seals have an inhibiting effect on the rate of flow of CH₄ into the atmosphere compared to the flow rate that would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A computational fluid dynamics simulator was used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - [\text{initial emissions from sealed mine} / \text{emission rate at abandonment prior to sealing}])$. Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (mcf/d) account for 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned mines. It was determined that the 500 abandoned mines closed after 1972 produced emissions greater than 100 mcf/d when active. Further, the status of 291 of the 500 mines (or 58 percent) is known to be either: 1) vented to the atmosphere; 2) sealed to some degree (either earthen or concrete seals); or, 3) flooded (enough to inhibit CH₄ flow to the atmosphere). The remaining 42 percent of the mines whose status is unknown were placed in one of these three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2004).

Table 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins in 2014, grouped by Class according to Post-Abandonment State

| Basin | Sealed | Vented | Flooded | Total Known | Unknown | Total Mines |
|----------------|------------|-----------|-----------|-------------|------------|-------------|
| Central Appl. | 37 | 25 | 51 | 113 | 137 | 250 |
| Illinois | 32 | 3 | 14 | 49 | 27 | 76 |
| Northern Appl. | 43 | 22 | 16 | 81 | 36 | 117 |
| Warrior Basin | 0 | 0 | 16 | 16 | 0 | 16 |
| Western Basins | 27 | 3 | 2 | 32 | 9 | 41 |
| Total | 139 | 53 | 99 | 291 | 209 | 500 |

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1971; however, such data are largely unknown for mines closed before 1972. Information that is readily available, such as coal production by state and county, is helpful but does not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned before 1972. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1971 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH₄ emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to the 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH₄ emissions rates during the 1970s (EPA 2004).

Abandoned mine emission estimates are based on all closed mines known to have active mine CH₄ ventilation emission rates greater than 100 mcf/d at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database (MSHA 2015). Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH₄ degasification amounts were added to the quantity of CH₄ vented to determine the total CH₄ liberation rate for all mines that closed between 1992 and 2014. Since the sample of gassy mines is assumed to

account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2014, emission totals were downwardly adjusted to reflect abandoned mine CH₄ emissions avoided from those mines. The Inventory totals were not adjusted for abandoned mine reductions from 1990 through 1992 because no data was reported for abandoned coal mining CH₄ recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH₄ flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but rather values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-35. Annual abandoned coal mine CH₄ emissions in 2014 were estimated to be between 5.2 and 7.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 18 percent below to 24 percent above the 2014 emission estimate of 6.3 MMT CO₂ Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH₄ liberation rates exist.

Table 3-35: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Abandoned Underground Coal Mines (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|----------------------------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Abandoned Underground Coal Mines | CH ₄ | 6.3 | 5.2 | 7.9 | -18% | +24% |

^a Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.6 Petroleum Systems (IPCC Source Category 1B2a)

Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During these activities, CH₄ is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO₂ emissions from petroleum systems are primarily associated with crude oil production and refining

operations but are negligible in transportation operations. Total CH₄ emissions from petroleum systems in 2014 were 68.1 MMT CO₂ Eq. (2,726 kt).

Production Field Operations. Production field operations account for approximately 99 percent of total CH₄ emissions from petroleum systems. Vented CH₄ from field operations account for approximately 92 percent of the net emissions from the production sector, fugitive emissions are approximately 5 percent, uncombusted CH₄ emissions (i.e., unburned fuel) account for approximately 4 percent, and process upset emissions are 0.1 percent. The most dominant sources of emissions from production field operations are pneumatic controllers, oil tanks, chemical injection pumps, offshore oil platforms, hydraulic fractured oil well completions, gas engines, and oil wellheads. These sources alone emit over 95 percent of the production field operations emissions. The remaining 5 percent of the emissions are distributed among around 20 additional activities.

Since 1990, CH₄ emissions from production field operations have increased by nearly 80 percent. Total methane emissions (from all segments) have increased by around 5 percent from 2013 levels.

Vented CO₂ associated with production field operations account for approximately 99 percent of the total CO₂ emissions from production field operations, while fugitive and process upsets together account for approximately 1 percent of the emissions. The most dominant sources of CO₂ emissions are oil tanks, pneumatic controllers, chemical injection pumps, and offshore oil platforms. These five sources together account for slightly over 97 percent of the non-combustion CO₂ emissions from production field operations, while the remaining 3 percent of the emissions is distributed among around 20 additional activities. Note that CO₂ from associated gas flaring is accounted in natural gas systems production emissions. Total CO₂ emissions from flaring for both natural gas and oil were 20.8 MMT CO₂ Eq. in 2014.

Crude Oil Transportation. Crude oil transportation activities account for approximately 0.3 percent of total CH₄ emissions from the oil industry. Venting from tanks, truck loading, rail loading, and marine vessel loading operations account for 84 percent of CH₄ emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for approximately 12 percent of CH₄ emissions from crude oil transportation. The remaining 4 percent is distributed between two additional sources within the vented emissions category (i.e., pump station maintenance and pipeline pigging), and fugitive emissions from pump stations.

Since 1990, CH₄ emissions from transportation have increased by almost 24 percent. However, because emissions from crude oil transportation account for such a small percentage of the total emissions from the petroleum industry, this has had little impact on the overall emissions. Methane emissions from transportation have increased by approximately 13 percent from 2013 levels.

Crude Oil Refining. Crude oil refining processes and systems account for approximately 1 percent of total CH₄ emissions from the oil industry because most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH₄ in all refined products. Within refineries, combustion emissions account for slightly over 50 percent of the CH₄ emissions, while vented and fugitive emissions account for approximately 31 and 19 percent, respectively. Flare emissions are the primary combustion emissions contributor, accounting for approximately 79 percent of combustion CH₄ emissions. Refinery system blowdowns for maintenance and process vents are the primary venting contributors (96 percent). Most of the fugitive CH₄ emissions from refineries are from equipment leaks and storage tanks (89 percent).

Methane emissions from refining of crude oil have decreased by approximately 1.4 percent since 1990; however, similar to the transportation subcategory, this decrease has had little effect on the overall emissions of CH₄. Since 1990, CH₄ emissions from crude oil refining have fluctuated between 23 and 28 kt.

Flare emissions from crude oil refining accounts for slightly more than 94 percent of the total CO₂ emissions in petroleum systems. Refinery CO₂ emissions decreased by slightly more than 7 percent from 1990 to 2014.

Table 3-36: CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Production Field Operations | | | | | | | |
| (Potential) | 38.0 | 48.9 | 54.8 | 56.6 | 58.7 | 64.7 | 68.1 |
| Pneumatic controller venting ^a | 19.0 | 30.2 | 33.2 | 33.7 | 33.3 | 37.7 | 39.2 |
| Tank venting | 6.3 | 4.7 | 5.3 | 5.5 | 7.0 | 8.2 | 9.9 |
| Combustion & process upsets | 2.9 | 2.3 | 2.5 | 2.5 | 2.7 | 2.9 | 3.1 |
| Misc. venting & fugitives | 8.4 | 10.5 | 12.5 | 13.5 | 14.3 | 14.3 | 14.5 |

| | | | | | | | |
|--|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Wellhead fugitives | 1.5 | 1.2 | 1.4 | 1.4 | 1.5 | 1.5 | 1.5 |
| Production Voluntary Reductions | (0.0) | (0.9) | (1.5) | (1.1) | (1.1) | (0.8) | (0.8) |
| Production Field Operations (Net) | 38.0 | 48.0 | 53.3 | 55.4 | 57.5 | 63.9 | 67.4 |
| Crude Oil Transportation | 0.2 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 |
| Refining | 0.6 | 0.7 | 0.6 | 0.7 | 0.7 | 0.6 | 0.6 |
| Total | 38.7 | 48.8 | 54.1 | 56.3 | 58.4 | 64.7 | 68.1 |

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-37: CH₄ Emissions from Petroleum Systems (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Production Field Operations (Potential) | 1,519 | 1,957 | 2,193 | 2,263 | 2,347 | 2,586 | 2,725 |
| Pneumatic controller venting ^a | 761 | 1,209 | 1,328 | 1,346 | 1,332 | 1,509 | 1,567 |
| Tank venting | 250 | 188 | 210 | 220 | 278 | 330 | 396 |
| Combustion & process upsets | 115 | 91 | 98 | 101 | 108 | 114 | 122 |
| Misc. venting & fugitives | 334 | 421 | 502 | 540 | 570 | 573 | 578 |
| Wellhead fugitives | 59 | 48 | 54 | 56 | 59 | 60 | 62 |
| Production Voluntary Reductions | (0) | (36) | (60) | (45) | (45) | (31) | (31) |
| Production Field Operations (Net) | 1,519 | 1,921 | 2,133 | 2,218 | 2,302 | 2,556 | 2,694 |
| Crude Oil Transportation | 7 | 5 | 5 | 5 | 6 | 7 | 8 |
| Refining | 24 | 27 | 26 | 28 | 27 | 26 | 23 |
| Total | 1,550 | 1,953 | 2,163 | 2,251 | 2,335 | 2,588 | 2,726 |

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-38: CO₂ Emissions from Petroleum Systems (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------------|------------|------------|------------|------------|------------|------------|------------|
| Production Field Operations | 0.4 | 0.3 | 0.4 | 0.4 | 0.5 | 0.6 | 0.6 |
| Pneumatic controller venting | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Tank venting | 0.3 | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 |
| Misc. venting & fugitives | + | + | + | + | + | + | + |
| Wellhead fugitives | + | + | + | + | + | + | + |
| Process upsets | + | + | + | + | + | + | + |
| Crude Refining | 3.2 | 3.6 | 3.8 | 3.8 | 3.4 | 3.1 | 2.9 |
| Total | 3.6 | 3.9 | 4.2 | 4.2 | 3.9 | 3.7 | 3.6 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-39: CO₂ Emissions from Petroleum Systems (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Production Field Operations | 391 | 338 | 379 | 395 | 473 | 550 | 640 |
| Pneumatic controller venting | 42 | 67 | 74 | 75 | 74 | 84 | 87 |
| Tank venting | 328 | 246 | 276 | 288 | 365 | 432 | 519 |
| Misc. venting & fugitives | 17 | 21 | 26 | 28 | 30 | 30 | 30 |
| Wellhead fugitives | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Process upsets | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Crude Refining | 3,162 | 3,589 | 3,775 | 3,797 | 3,404 | 3,143 | 2,927 |
| Total | 3,553 | 3,927 | 4,154 | 4,192 | 3,876 | 3,693 | 3,567 |

Note: Totals may not sum due to independent rounding.

Methodology

The estimates of CH₄ emissions from petroleum systems are largely based on GRI/EPA 1996, EPA 1999, and EPA's GHGRP data (EPA 2015a). Petroleum Systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil production field operations, crude oil transportation activities, and refining operations. Annex 3.5 provides detail on the emission estimates for these activities. The estimates of CH₄ emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per activity) by the corresponding activity data (e.g., equipment count or frequency of activity).

References for emission factors include DrillingInfo (2015), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), and the GHGRP (2010 through 2014).

Emission factors from EPA 1999 are used for all activities except those related to pneumatic controllers, chemical injection pumps, hydraulic fractured oil well completions, offshore oil production, field storage tanks, and refineries. The emission factors for pneumatic controllers venting and chemical injection pumps were developed using EPA's GHGRP data for reporting year 2014. Emission factors for hydraulically fractured (HF) oil well completions (controlled and uncontrolled) were developed using data analyzed for the 2015 NSPS OOOOa proposal (EPA 2015b). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2011). For offshore oil production, two emission factors were calculated using data collected for all federal offshore platforms (EPA 2015c, BOEM 2014), one for oil platforms in shallow water, and one for oil platforms in deep water. For all sources, emission factors are held constant for the period 1990 through 2014.

References for activity data include DrillingInfo (2015), the Energy Information Administration annual and monthly reports (EIA 1990 through 2015), (EIA 1995 through 2015a, 2015b), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2015), the Interstate Oil and Gas Compact Commission (IOGCC 2012), the United States Army Corps of Engineers, (1995 through 2015), and the GHGRP (2010 through 2014).

For many sources, complete activity data were not available for all years of the time series. In such cases, one of three approaches was employed. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA 1996, and/or GHGRP data. In other cases, the activity data were held constant from 1990 through 2014 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. For offshore production, the number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,c).

For petroleum refining activities, 2010 to 2014 emissions were directly obtained from EPA's GHGRP. All refineries have been required to report CH₄ and CO₂ emissions for all major activities since 2010. The national totals of these emissions for each activity were used for the 2010 to 2014 emissions. The national emission totals for each activity were divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors, which were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for each year (EPA 2015d).

The Inventory estimate for Petroleum Systems takes into account Natural Gas STAR reductions. Voluntary reductions included in the Petroleum Systems calculations were those reported to Natural Gas STAR for the following activities: artificial lift - gas lift; artificial lift - use compression; artificial lift - use pumping unit; consolidate crude oil production and water storage tanks; lower heater-treater temperature; re-inject gas for enhanced oil recovery; re-inject gas into crude; and route casinghead gas to vapor recovery unit or compressor.

The methodology for estimating CO₂ emissions from petroleum systems includes calculation of vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and three activities from petroleum refining. Generally, emissions are estimated for each activity by multiplying CO₂ emission factors by their corresponding activity data. The emission factors for CO₂ are generally estimated by multiplying the CH₄ emission factors by a conversion factor, which is the ratio of CO₂ content and CH₄ content in produced associated gas. One exception to this methodology is the set of emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factors for offshore oil production (shallow and deep water), which were derived using data from BOEM (EPA 2015c, BOEM 2014). Other exceptions to this methodology are the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO₂ emissions data for 2010 to 2014 were directly obtained from the GHGRP. The 2010 to 2013 CO₂ emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CO₂ emission factors (i.e., sum of activity emissions/sum of refinery feed) which were then applied to the annual refinery feed to estimate CO₂ emissions for 1990 to 2009.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. It is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent). Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emission estimates using the 7 highest-emitting sources ("top 7 sources") for the year 2010. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for the 1990 through 2014 Inventory years; instead, EPA has applied the uncertainty percentage ranges calculated previously to 2014 emission estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. However, as discussed in the Methodology and Recalculations Discussion sections, EPA has revised the methodology and data for many emission sources. Given these revisions, the 2009 uncertainty ranges applied may not reflect the uncertainty associated with the recently revised emission factors and activity data sources.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH₄ emissions in 2014 were estimated to be between 51.8 and 101.5 MMT CO₂ Eq., while CO₂ emissions were estimated to be between 2.7 and 5.4 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. This indicates a range of 24 percent below to 149 percent above the 2014 emission estimates of 68.1 and 3.6 MMT CO₂ Eq. for CH₄ and CO₂, respectively.

Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) ^b | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-------------------|-----------------|--|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Petroleum Systems | CH ₄ | 68.1 | 51.8 | 101.5 | -24% | 149% |
| Petroleum Systems | CO ₂ | 3.6 | 2.7 | 5.4 | -24% | 149% |

^a Range of 2014 relative uncertainty predicted by Monte Carlo Stochastic Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

^b All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

EPA compared the quantitative uncertainty estimate for CH₄ emissions from petroleum systems to those reported in the recently published study by Lyon et al., (2015) (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁶⁹ Lyon et al., (2015) used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates developed by that study for the Barnett Shale. The uncertainty range in the study differ from those of EPA. However, it is difficult to extrapolate an uncertainty range from this study that can be applied to the Inventory estimate because the coverage of the Lyon et al. (2015) study is limited to the 25-county Barnett Shale area, the reported estimate encompasses natural gas in addition to petroleum system emissions, and the two estimates use different methodologies and data sources.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The petroleum system emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through the annual expert and public review period. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made revisions to the production segment methodology for the 2016 (current) Inventory including revised equipment activity data, revised pneumatic controller activity and emissions data, and included a separate estimate for hydraulically fractured oil well completions, which previously were not estimated as a distinct subcategory of oil well completions.

In February 2016, the EPA released a draft memorandum, “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” that discussed the changes under consideration and requested stakeholder

⁶⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

feedback on those changes. Please see <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The combined impact of revisions to 2013 petroleum production segment emissions, compared to the 1990-2013 Inventory, is an increase in CH₄ emissions from 24.2 to 63.9 MMT CO₂ Eq. (40 MMT CO₂ Eq., or 164 percent).

The recalculations resulted in an average increase in emission estimates across the 1990 to 2013 time series, compared to the previous (2015) Inventory, of 21 MMT CO₂ Eq., or an 85 percent. The largest increases in the estimate occurred in later years of the time series.

Production

This section references the final 2016 (current) Inventory memorandum, “Revisions to Natural Gas and Petroleum Production Emissions” (EPA 2016b).⁷⁰ “Revisions to Natural Gas and Petroleum Production Emissions” contains further details and documentation of recalculations (EPA 2016b).

Updated activity factors for fugitives, pumps and controllers

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per oil well) for separators, headers, heater-treaters, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for year 2011-on in the 2016 (current) Inventory petroleum production segment, while retaining the previous activity factors for 1990 through 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of calculated national equipment counts in 1992 (based on GRI/EPA) and calculated national equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts observed in the 1996 study and the counts observed in the recent GHGRP data.

For the year 2013, the CH₄ emissions increase due to use of revised activity factors for major equipment and pneumatic pumps is approximately 4.2 MMT CO₂ Eq.

Table 3-41: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

| Type | Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|-----------------|---------------------------------|------------|------------|------------|------------|------|
| Venting | Chemical Injection Pumps | 1.2 | 3.4 | 4.3 | 4.7 | 4.8 |
| | <i>Previous-Chemical</i> | | | | | |
| <i>Venting</i> | <i>Injection Pumps</i> | <i>1.4</i> | <i>1.2</i> | <i>1.3</i> | <i>1.4</i> | |
| Fugitive | Oil Wellheads | 1.5 | 1.2 | 1.4 | 1.5 | 1.5 |
| <i>Fugitive</i> | <i>Previous-Oil Wellheads</i> | <i>1.5</i> | <i>1.2</i> | <i>1.3</i> | <i>1.5</i> | |
| Fugitive | Separators | 0.3 | 0.6 | 0.8 | 0.8 | 0.9 |
| <i>Fugitive</i> | <i>Previous-Separators</i> | <i>0.3</i> | <i>0.2</i> | <i>0.2</i> | <i>0.3</i> | |
| Fugitive | Heater/Treaters | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 |
| <i>Fugitive</i> | <i>Previous-Heater/Treaters</i> | <i>0.3</i> | <i>0.2</i> | <i>0.3</i> | <i>0.3</i> | |
| Fugitive | Headers | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| <i>Fugitive</i> | <i>Previous-Headers</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> | <i>0.1</i> | |
| Fugitive | Compressors | 0.1 | + | + | 0.1 | 0.1 |
| <i>Fugitive</i> | <i>Previous-Compressors</i> | <i>0.1</i> | + | + | + | |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA has also developed technology-specific activity data and emission factors for pneumatic controllers. Data reported under EPA’s GHGRP allow for development of emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and separation of activity data into these categories. EPA used this separation of pneumatic controller counts by bleed types and emission factors developed from reported GHGRP data. Comparing the updated 2013 estimate to the previous Inventory 2013

⁷⁰ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data is an increase of approximately 26 MMT CO₂ Eq. Over the 1990 through 2013 time series, the average increase due to the recalculation is 16 MMT CO₂ Eq.

Table 3-42: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|----------------------------|-------------|-------------|-------------|-------------|-------------|
| All | 19.0 | 30.2 | 33.2 | 37.7 | 39.2 |
| High bleed | 17.8 | 17.5 | 12.6 | 5.5 | 4.7 |
| Low bleed | 1.2 | 1.8 | 2.0 | 1.4 | 1.2 |
| Intermittent bleed | + | 10.9 | 18.6 | 30.9 | 33.3 |
| <i>Previous-All</i> | <i>12.2</i> | <i>10.1</i> | <i>10.8</i> | <i>11.9</i> | <i>NA</i> |
| <i>Previous-High bleed</i> | <i>9.5</i> | <i>7.8</i> | <i>8.4</i> | <i>9.2</i> | <i>NA</i> |
| <i>Previous-Low bleed</i> | <i>2.8</i> | <i>2.3</i> | <i>2.4</i> | <i>2.7</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach to revising the Inventory methodology by incorporating technology-specific GHGRP data for pneumatic controllers resulted in net emissions being directly calculated for these sources in each time series year. This methodology revision obviates the need to apply Gas STAR reductions data for pneumatic controllers as had been done in previous Inventories. EPA removed the pneumatic controller Gas STAR reductions from its calculations.

Oil Well Completions

The Inventory previously did not distinguish between oil well completions and workovers with hydraulic fracturing (HF) and oil well completions and workovers without hydraulic fracturing. The Inventory emission factors for all oil well completions and workovers were developed using an assumption that all oil well workovers and completions are flared. In the current Inventory, an estimate for the subcategories of oil well completions with hydraulic fracturing with and without controls was included. This estimate was developed using an uncontrolled emission factor developed as part of the analysis supporting the OOOOa NSPS proposal (7.5 tons CH₄/completion)⁷¹, and a controlled emission factor that assumes 95 percent control efficiency (0.4 tons CH₄/completion). For the OOOOa proposal analysis, EPA extracted gas production data from oil well records in DrillingInfo, and developed average daily gas production rates (over the first month of production) for wells that were determined to have been completed with hydraulic fracturing in 2012. The average value for these wells was 255.47 Mcf/day. This was then multiplied by a 3 day completion duration, and a methane content value of 47 percent to develop the uncontrolled factor. Total annual national HF oil well completion data were developed from DrillingInfo data (DrillingInfo 2015). The Inventory uses the NSPS OOOOa proposal information for the percentage of oil well completions that are controlled due to state regulations, 7 percent and applies that value beginning in 2008. It is assumed in the inventory estimate that prior to 2008, all oil well completions with HF are uncontrolled. The inventory continues to use one estimate for workover emissions for completions of all types (i.e. both hydraulically fractured and non-hydraulically fractured). This recalculation results in a 3 MMT CO₂ Eq. increase from the previous 2013 estimate for completions and workovers, and an average increase of 1 MMT CO₂ Eq. over the 1990 through 2013 time series.

Table 3-43: CH₄ Emissions from Oil Well Completions and Workovers (C&W) (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|
| HF Completions | 0.6 | 0.9 | 1.7 | 3.0 | 3.0 |
| NonHF Completions | + | + | + | + | + |
| Workovers (HF and nonHF) | + | + | + | + | + |
| Total C&W | 0.6 | 0.9 | 1.7 | 3.0 | 3.0 |

⁷¹ The value presented in the NSPS proposal, 9.72 short tons was the average emissions calculated for the subset of HF oil well completions with GOR >300 scf/bbl. The inventory averaged emissions from the same base data set, without the GOR <300 scf/bbl exclusion, so that for the inventory, the emission factor can be applied to all HF oil well completions in the U.S., including those with lower GOR.

Previous Total C&W + ■ + ■ + ■ + *NA*

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Planned Improvements

In response to the public review draft and earlier released memorandum outlining potential revisions to the production segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. EPA will continue to assess GHGRP data for additional updates to the inventory. While comments received supported the update to include hydraulically fractured oil well completions as a distinct subcategory category, commenters differed on the recommended data for the update (DI Desktop approach versus GHGRP data). EPA will review the first year of reported GHGRP data on hydraulically fractured oil well completions and workovers and will consider how it may be used to update the inventory. Additionally, EPA received comments suggesting that EPA use associated gas venting and flaring data from GHGRP and apply it to the population of associated gas wells in the Inventory, to address the concern that casinghead gas emissions occur at a wider set of associated gas wells, not only at stripper wells. EPA will investigate the appropriateness of using associated gas venting and flaring data from the GHGRP to replace or supplement current estimates of casinghead gas venting from stripper wells in the 2017 Inventory.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 [current] Inventory). EPA will evaluate available data studies on this emission source.

EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active oil wells across the time series.

EPA will continue to consider methods to refine the time series. For many sources with, the time series calculations rely on linear interpolation between 1990's data points and 2011 data points.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions to the methodology and data for the 2016 (current) Inventory. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. It is difficult to project whether the uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent) given these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty

Estimates” (EPA 2016a).⁷² As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” for more information on planned improvements regarding uncertainty (EPA 2016a).

Box 3-7: Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO₂ is produced from both naturally-occurring CO₂ reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions from naturally-produced CO₂ are estimated based on the specific application.

In the Inventory, CO₂ that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO₂ used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO₂ emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO₂ is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO₂ captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO₂ emissions estimates for geologic storage.

In the United States, facilities that produce CO₂ for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO₂, exporters of CO₂, facilities that conduct geologic sequestration of CO₂, and facilities that inject CO₂ underground (including facilities conducting EOR), are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO₂ are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO₂ sequestered using a mass balance approach.

Available GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO₂ captured and extracted for EOR applications for 2010 to 2014. In the current Inventory, the previous estimates for 2010 to 2013 were replaced with GHGRP data for 2010 to 2013, and estimates for 2014 were directly taken from the reported GHGRP data for 2014. For the year 2013, this update has resulted in an increase of approximately 28 percent over the previous estimate. Using the GHGRP data has resulted in an average annual increase of approximately 11 MMT CO₂ Eq., or by approximately 25 percent, over the time series 2010 through 2013.

EPA will continue to evaluate the availability of additional GHGRP data and other opportunities for improving the emission estimates.

These estimates indicate that the amount of CO₂ captured and extracted from industrial and natural sites for EOR applications in 2014 is 59.3 MMT CO₂ Eq. (59,318 kt) (see Table 3-44 and Table 3-45). Site-specific monitoring and reporting data for CO₂ injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO₂ is emitted.

Table 3-44: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (MMT CO₂ Eq.)

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Capture Facilities | 4.8 | 6.5 | 9.9 | 9.9 | 9.3 | 12.2 | 13.1 |
| Extraction Facilities | 20.8 | 28.3 | 44.8 | 48.4 | 48.9 | 47.0 | 46.2 |
| Total | 25.6 | 34.7 | 54.7 | 58.2 | 58.1 | 59.2 | 59.3 |

⁷² See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

Table 3-45: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (kt)

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Capture Facilities | 4,832 | 6,475 | 9,900 | 9,877 | 9,267 | 12,205 | 13,093 |
| Extraction Facilities | 20,811 | 28,267 | 44,759 | 48,370 | 48,869 | 46,984 | 46,225 |
| Total | 25,643 | 34,742 | 54,659 | 58,247 | 58,136 | 59,189 | 59,318 |

3.7 Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 176.1 MMT CO₂ Eq. (7,045 kt) of CH₄ in 2014, a 15 percent decrease compared to 1990 emissions, and a slight (i.e., less than 1 percent) increase compared to 2013 emissions (see Table 3-46, Table 3-47, and Table 3-48) and 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions.

The 1990 to 2014 trend is not consistent across segments. Overall, the 1990 to 2014 decrease in CH₄ emissions is due primarily to the decrease in emissions from in the transmission/storage and distribution segments. Over the same time period, the production and processing segments saw increased methane emissions, of 31 and 13 percent, respectively. Natural gas systems also emitted 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions, and a 10 percent increase from 2013 emissions (see Table 3-49 and Table 3-50). Both the 1990 to 2014 and the 2013 to 2014 increases in CO₂ are due primarily to flaring; the volume of gas flared increased 93 percent from 1990 and 12 percent from 2013.

CH₄ and non-combustion CO₂ emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include: natural gas engine and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic controllers, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH₄ and non-combustion CO₂ emissions are discussed.

Production (including gathering and boosting). In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and well-site gas treatment facilities such as dehydrators and separators. Gathering and boosting emission sources are not reported under a unique segment, but are included within the production sector. The gathering and boosting segment of natural gas systems comprises gathering and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment). Emissions from production (including gathering and boosting) account for 62 percent of CH₄ emissions and 44 percent of non-combustion CO₂ emissions from natural gas systems in 2014. Emissions from gathering stations, pneumatic controllers, kimray pumps, liquids unloading, condensate tanks, gathering pipeline leaks, and offshore platforms account for the majority of CH₄ emissions in 2014. Flaring emissions account for the majority of the non-combustion CO₂ emissions. CH₄ emissions from production increased by 31 percent from 1990 to 2014, due primarily to increases in emissions from gathering and boosting stations (due to an increase in the number of stations), increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers), and condensate tanks (due to an increase in condensate produced). CO₂ emissions from production increased 88 percent from 1990 to 2014 due primarily to increases in flaring.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Fugitive CH₄ emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO₂ emissions come from acid gas removal (AGR) units, which are designed to remove CO₂ from natural gas. Processing plants account for 14 percent of CH₄ emissions and 56 percent of non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from processing increased by 13 percent from 1990 to 2014 as emissions from compressors increased along with the quantity of gas produced. CO₂ emissions from processing decreased by 15 percent from 1990 to 2014, as a result of a decrease in acid gas removal emissions.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the U.S. transmission system. Fugitive CH₄ emissions from these compressor stations, and venting from pneumatic controllers account for the majority of the emissions from this stage. Uncombusted engine exhaust and pipeline venting are also sources of CH₄ emissions from transmission. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from storage. CH₄ emissions from the transmission and storage sector account for approximately 18 percent of emissions from natural gas systems, while CO₂ emissions from transmission and storage account for less than 1 percent of the non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from this source decreased by 45 percent from 1990 to 2014 due to reduced compressor station emissions (including emissions from compressors and fugitives). CO₂ emissions from transmission and storage have decreased by 37 percent from 1990 to 2014, also due to reduced compressor station emissions.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were 1,264,340 miles of distribution mains in 2014, an increase of over 320,000 miles since 1990 (PHMSA 2015). Distribution system emissions, which account for 6 percent of CH₄ emissions from natural gas systems and less than 1 percent of non-combustion CO₂ emissions, result mainly from fugitive emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH₄ and CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH₄ emissions in 2014 were 74 percent lower than 1990 levels (changed from 43.5 MMT CO₂ Eq. to 11.1 MMT CO₂ Eq.), while distribution CO₂ emissions in 2014 were 72 percent lower than 1990 levels (CO₂ emission from this segment are less than 0.1 MMT CO₂ Eq. across the time series).

Total CH₄ emissions for the four major stages of natural gas systems are shown in MMT CO₂ Eq. (Table 3-46) and kt (Table 3-47). Table 3-48 provides additional information on how the estimates in Table 3-46 were calculated. Table 3-48 shows the calculated CH₄ release (i.e., potential emissions before any controls are applied) from each stage, and the amount of CH₄ that is estimated to have been flared, captured, or otherwise controlled, and therefore not emitted to the atmosphere. Subtracting the value for CH₄ that is controlled, from the value for calculated potential release of CH₄, results in the total emissions values. More disaggregated information on potential emissions and emissions is available in Annex 3.6. See Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems.

Table 3-46: CH₄ Emissions from Natural Gas Systems (MMT CO₂ Eq.)^a

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Field Production | 83.4 | 108.1 | 108.3 | 108.8 | 111.1 | 110.7 | 109.0 |
| Processing | 21.3 | 16.4 | 17.9 | 21.3 | 22.3 | 22.6 | 24.0 |
| Transmission and Storage | 58.6 | 30.7 | 27.5 | 28.8 | 27.9 | 30.8 | 32.1 |
| Distribution | 43.5 | 22.1 | 12.5 | 11.2 | 11.4 | 11.5 | 11.1 |
| Total | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-47: CH₄ Emissions from Natural Gas Systems (kt)^a

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Field Production | 3,335 | 4,326 | 4,330 | 4,352 | 4,442 | 4,429 | 4,359 |
| Processing | 852 | 655 | 717 | 851 | 890 | 904 | 960 |
| Transmission and Storage | 2,343 | 1,230 | 1,100 | 1,152 | 1,116 | 1,232 | 1,282 |
| Distribution | 1,741 | 884 | 500 | 449 | 457 | 458 | 444 |
| Total | 8,270 | 7,093 | 6,647 | 6,803 | 6,906 | 7,023 | 7,045 |

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-48: Calculated Potential CH₄ and Captured/Combusted CH₄ from Natural Gas Systems (MMT CO₂ Eq.)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Calculated Potential^a | 206.9 | 202.7 | 196.3 | 196.5 | 199.6 | 202.3 | 203.8 |
| Field Production | 83.5 | 115.7 | 120.5 | 121.3 | 123.6 | 124.2 | 123.3 |
| Processing | 21.3 | 20.6 | 23.6 | 25.2 | 26.2 | 26.5 | 27.9 |
| Transmission and Storage | 58.6 | 43.1 | 38.3 | 37.3 | 37.3 | 39.1 | 40.4 |
| Distribution | 43.5 | 23.3 | 13.9 | 12.7 | 12.5 | 12.5 | 12.1 |
| Captured/Combusted^b | 0.1 | 25.4 | 30.1 | 26.4 | 27.0 | 26.7 | 27.7 |
| Field Production | 0.1 | 7.6 | 12.2 | 12.5 | 12.5 | 13.5 | 14.4 |
| Processing | + | 4.2 | 5.7 | 3.9 | 3.9 | 3.9 | 4.0 |
| Transmission and Storage | + | 12.4 | 10.8 | 8.5 | 9.4 | 8.3 | 8.4 |
| Distribution | + | 1.2 | 1.4 | 1.5 | 1.1 | 1.0 | 1.0 |
| Net Emissions | 206.8 | 177.3 | 166.2 | 170.1 | 172.6 | 175.6 | 176.1 |
| Field Production | 83.4 | 108.1 | 108.3 | 108.8 | 111.1 | 110.7 | 109.0 |
| Processing | 21.3 | 16.4 | 17.9 | 21.3 | 22.3 | 22.6 | 24.0 |
| Transmission and Storage | 58.6 | 30.7 | 27.5 | 28.8 | 27.9 | 30.8 | 32.1 |
| Distribution | 43.5 | 22.1 | 12.5 | 11.2 | 11.4 | 11.5 | 11.1 |

+ Does not exceed 0.1 MMT CO₂ Eq.

^a In this context, “potential” means the total emissions calculated before voluntary reductions and regulatory controls are applied.

^b In 2014, over half of the capture and combustion accounted here is in the production segment, while 14 percent is from processing, 30 percent from transmission and storage, and 4 percent from distribution. For additional information, please see Annex 3.6.

Note: Totals may not sum due to independent rounding.

Table 3-49: Non-combustion CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq.)

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Field Production | 9.9 | 8.3 | 11.0 | 14.1 | 13.7 | 16.6 | 18.6 |
| Processing | 27.8 | 21.7 | 21.3 | 21.5 | 21.5 | 21.8 | 23.7 |
| Transmission and Storage | 0.1 | + | + | + | + | + | + |
| Distribution | 0.1 | + | + | + | + | + | + |
| Total | 37.7 | 30.1 | 32.4 | 35.7 | 35.2 | 38.5 | 42.4 |

+ Does not exceed 0.1 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-50: Non-combustion CO₂ Emissions from Natural Gas Systems (kt)

| Stage | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|--------|--------|--------|--------|--------|--------|--------|
| Field Production | 9,857 | 8,260 | 11,041 | 14,146 | 13,684 | 16,649 | 18,585 |
| Processing | 27,763 | 21,746 | 21,346 | 21,466 | 21,469 | 21,756 | 23,713 |

| | | | | | | | |
|--------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Transmission and Storage | 62 | 43 | 37 | 36 | 35 | 37 | 39 |
| Distribution | 50 | 27 | 16 | 15 | 14 | 14 | 14 |
| Total | 37,732 | 30,076 | 32,439 | 35,662 | 35,203 | 38,457 | 42,351 |

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for natural gas emissions estimates presented in this Inventory involves the calculation of CH₄ and CO₂ emissions for over 100 emissions sources, and then the summation of emissions for each natural gas segment.

The approach for calculating emissions for natural gas systems generally involves the application of emission factors to activity data. For some sources, the approach uses what are considered “potential methane factors,” and reduction data to calculate net emissions; for other sources, the approach uses technology-specific emission factors or emission factors that vary over time to take into account changes to technologies and practices, and these calculate net emissions directly.

The approach of calculating potential CH₄ and then applying reductions data to calculate net emissions was used to ensure a time series that reflects real emission trends. As noted below, key data on emissions from many sources are from 1996 GRI/EPA report containing data collected in 1992. Since the time of this study, practices and technologies have changed. While this study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would, in many cases, overestimate emissions. As updated emission factors reflecting changing practices are not available for some sources, the 1992 emission factors continue to be used for some sources for all years of the Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time. For the Inventory, the calculated potential emissions are adjusted using data on reductions reported to the Natural Gas STAR program, and data on regulations that result in CH₄ reductions. The revisions in the current inventory (see Recalculations Discussion below) result in net emission approaches being used for many sources in the inventory.

The calculation of emissions from natural gas systems is outlined below:

Step 1. Calculate Potential Methane (or Net Methane) – Collect activity data on production and equipment in use and apply emission factors (i.e., scf gas per unit or activity)

Step 2. Compile Reductions Data – Calculate the amount of the methane that is not emitted, using data on voluntary action and regulations

Step 3. Calculate Net Emissions – Deduct methane that is not emitted from the total methane potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

Step 1. Calculate Potential Methane (or Net Methane)—Collect activity data on production and equipment in use and apply emission factors

In the first step, potential CH₄ is calculated by multiplying activity data (such as miles of pipeline or number of wells) by factors that relate that activity data to potential CH₄. Potential CH₄ is the amount of CH₄ that would be emitted in the absence of any control technology or mitigation activity. It is important to note that potential CH₄ factors in most cases do not represent emitted CH₄, and must be adjusted for any emissions-reducing technologies, or practices, as appropriate. For more information, please see the Annex.

Potential Methane Factors and Net Emission Factors

A primary basis for estimates of CH₄ and non-combustion-related CO₂ emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute (GRI) and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH₄ emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The EPA/GRI study was based on a combination of process engineering studies, collection of activity data, and measurements at representative gas facilities conducted in the early 1990s. Methane compositions from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas

Composition Databases (GTI 2001) are adjusted year to year using gross production for oil and gas supply National Energy Modeling System (NEMS) regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the CH₄ composition for each NEMS oil and gas supply module region. The emission factors used to estimate CH₄ were also used to calculate non-combustion CO₂ emissions. Data from GTI 2001 were used to adapt the CH₄ emission factors into non-combustion related CO₂ emission factors. Additional information about CO₂ content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO₂ emission factors.

Although the Inventory primarily uses EPA/GRI emission factors (especially for early years of the time series), EPA has made revisions to the potential factor methodology in the emissions estimates for several sources in recent Inventories. For gas well completions and workovers (refracturing) with hydraulic fracturing, EPA uses its Greenhouse Gas Reporting Program (GHGRP) Subpart W data to stratify the emission sources into four different categories and developed CH₄ emission factors for each category. For liquids unloading, EPA calculates national emissions through the use of region-specific emission factors developed from well data collected in a survey conducted by API/ANGA (API/ANGA 2012). In the current Inventory, EPA has used data generated by studies and the GHGRP to develop emission factors that are control category-specific (e.g., bleed rate-specific emission factors for pneumatic controllers in the production and transmission and storage segments) and to reflect current practices for activities (e.g., distribution M&R station emission factors for recent years). For these sources, the emission factors are not potential factors, but are instead factors for net emissions.

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH₄ and non-combustion CO₂ emissions from natural gas systems.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2015); American Gas Association (AGA 1991 through 1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2015a, 2015b, 2015c); the Natural Gas STAR Program annual emissions savings (EPA 2013c); Oil and Gas Journal (OGJ 1997 through 2015); Pipeline and Hazardous Materials Safety Administration (PHMSA 2015a, 2015b); Federal Energy Regulatory Commission (FERC 2015); Greenhouse Gas Reporting Program (EPA 2015); other Energy Information Administration data and publications (EIA 2001, 2004, 2012, 2013, 2014); (EPA 1999); Conservation Commission (Wyoming 2015); and the Alabama State Oil and Gas Board (Alabama 2015).

For a few sources, recent direct activity data are not available. For these sources, either 2013 data was used as a proxy for 2014 data, or a set of industry activity data drivers was developed and used to calculate activity data over the time series. Drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations. More information on activity data and drivers is available in Annex 3.6.

Step 2. Compile Reductions Data—Calculate the amount of the CH₄ that is not emitted, using data on voluntary action and regulations

The emissions calculated in Step 1 above for many sources represent potential emissions from an activity, and do not take into account use of technologies and practices that reduce emissions. To take into account use of such technologies, data, where available, are collected on both regulatory and voluntary reductions. Regulatory actions taken into account using this method include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR. For more information on these reductions, please see Annex 3.6. The emission estimates presented in Table 3-46 and Table 3-47 are the CH₄ that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

The Inventory also includes the impacts of the New Source Performance Standards (NSPS) Subpart OOOO, which came into effect in October 2012. By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific CH₄ emission factors for each category, EPA is implicitly accounting for Subpart OOOO reductions from hydraulically fractured gas wells. The method for calculating emissions from pneumatic controllers (by bleed rate category) also implicitly accounts for NSPS reductions in the high bleed pneumatic controller category.

The use of data from the EPA's GHGRP and recent studies to revise certain emission factors as discussed above obviated the need to apply Gas STAR or other reductions data for those sources (i.e., the calculated emissions were already net emissions, instead of potential emissions). More information is in the Recalculations Discussion below.

Step 3. Calculate Net Emissions—Deduct CH₄ that is not emitted from the total CH₄ potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

In the final step, emission reductions from voluntary and regulatory actions are deducted from the total calculated potential emissions to estimate the net emissions that are presented in Table 3-46, and included in the Inventory totals. As discussed above, for a number of categories (e.g., liquids unloading, condensate tanks, gas well completions and workovers with hydraulic fracturing, gathering stations, centrifugal compressors, pneumatic controllers, transmission and storage station fugitives, M&R stations, and pipeline leaks) emissions are calculated directly using emission factors that vary by technology or over time and account for any control measures in place that reduce CH₄ emissions.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory report that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies (e.g., Lamb, et al. 2015; Lyon, et al. 2015; Marchese, et al. 2015; Zimmerle, et al. 2015) and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. At this time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emissions estimates using the 12 highest-emitting sources ("top 12 sources") for the year 2009. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for this inventory; instead, EPA has applied the uncertainty percentage ranges calculated previously for 2009 to the 2014 emissions estimates. As discussed in the Recalculations Discussion section, EPA has used findings from multiple recently published studies along with GHGRP Subpart W data to revise the emission factors and activity data for many emission sources. Given these substantive revisions, it is unlikely that the 2009 uncertainty ranges applied will reflect the uncertainty associated with the recently revised emission factors and activity data sources. Details on an updated uncertainty analysis to reflect recent recalculations are described in the Planned Improvements section.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-51. Natural gas systems CH₄ emissions in 2014 were estimated to be between 142.7 and 229.0 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. Natural gas systems non-energy CO₂ emissions in 2014 were estimated to be between 34.3 and 55.1 MMT CO₂ Eq. at a 95 percent confidence level.

Table 3-51: Approach 2 Quantitative Uncertainty Estimates for CH₄ and Non-energy CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) ^b | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|----------------------------------|-----------------|--|---|--------------------------|--------------------------|--------------------------|
| | | | Lower Bound ^b | Upper Bound ^b | Lower Bound ^b | Upper Bound ^b |
| Natural Gas Systems | CH ₄ | 176.1 | 142.7 | 229.0 | -19% | +30% |
| Natural Gas Systems ^c | CO ₂ | 42.4 | 34.3 | 55.1 | -19% | +30% |

^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2009.

^b All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in Table 3-46 and Table 3-47.

^c An uncertainty analysis for the non-energy CO₂ emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH₄ uncertainty analysis was applied to the point estimate of non-energy CO₂ emissions

EPA compared the quantitative uncertainty estimates for CH₄ emissions in recent years from natural gas systems to those reported in recently published studies (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁷³ All studies reviewed for uncertainty information used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates reported which is in line with the IPCC recommended Approach 2 methodology. The uncertainty ranges in the reported studies differ from those of EPA. However, it is difficult to extrapolate uncertainty ranges from these studies to apply to the Inventory estimates because the Inventory source category level uncertainty analysis is not directly comparable to source- or segment-specific uncertainty analyses in these studies. Further, the methodologies and data sources used in estimating CH₄ emissions in these studies differ significantly from the studies underlying previous Inventory methodologies.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The natural gas emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through annual expert and public review periods. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made several updates, including revisions to production segment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility emissions, transmission and storage station activity and emissions data, distribution segment emissions data for pipelines, distribution segment M&R station activity and emissions data, and distribution segment customer meter emissions data.

⁷³ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

From December 2015 through February 2016, the EPA released four draft memoranda that discussed the changes under consideration and requested stakeholder feedback on those changes. See “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” “Revisions under Consideration for Gathering and Boosting Emissions,” “Revisions under Consideration for Transmission and Storage Emissions,” and “Revisions under Consideration for Distribution Emissions,” available at <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The impact of all revisions to natural gas systems is an increase of 18 MMT CO₂ Eq., or 12 percent, comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change is an increase of 13 MMT CO₂ Eq., or 7 percent.

Recalculations for the production segment (including gathering and boosting facilities) resulted in a large increase in the 2013 CH₄ emission estimate, from 47.0 MMT CO₂ Eq. in the previous (2015) Inventory, to 110.7 MMT CO₂ Eq. in the current (2016) Inventory, or 136 percent. Over the time series, the average change is an increase of 35 MMT CO₂ Eq., or 57 percent.

Although there were no methodological updates to the processing segment, recalculations due to updated data (specifically data on national dry gas production in 2013, which were revised slightly downwards) impacted emissions estimates, resulting in a decrease of 0.1 MMT CO₂ Eq., or less than 1 percent comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change was less than 1 percent.

Recalculations for the transmission and storage segment resulted in a large decrease in the 2013 CH₄ emission estimate, from 54.4 MMT CO₂ Eq. in the previous (2015) Inventory, to 30.8 MMT CO₂ Eq. in the current (2016) Inventory, or 43 percent. Over the time series, the average change is a decrease of 13 MMT CO₂ Eq., or 25 percent.

Recalculations for the distribution segment also resulted in a large decrease in the 2013 CH₄ emission estimate, from 33.3 MMT CO₂ Eq. in the previous (2015) Inventory, to 11.5 MMT CO₂ Eq. in the current (2016) Inventory, or 65 percent. Over the time series, the average change is a decrease of 9 MMT CO₂ Eq., or 27 percent.

Production

This section references the final 2016 (current) Inventory production segment supporting memoranda: “Revisions to Natural Gas and Petroleum Production Emissions” and “Revisions to Natural Gas Gathering and Boosting Emissions” (EPA 2016b and EPA 2016c).⁷⁴ These memoranda contain further details and documentation of recalculations.

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per gas well) for in-line heaters, separators, dehydrators, compressors, meters/piping, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for the years from 2011 to 2014 in the 2016 (current) Inventory natural gas production segment, while retaining the previous activity factors for 1990 to 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of per well equipment counts in 1992 (based on GRI/EPA) and per well equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts per well observed in the 1996 study and the counts observed in the recent GHGRP data.

The production segment activity data revisions not only reflect more current information on activity, but also tailor these emission sources to specifically reflect activity occurring at well pad facilities and not at gathering/centralized facilities. As discussed below and in the two supporting memoranda for the production segment, EPA has also implemented revisions to the gathering and boosting sub-segment so that equipment leaks from both types of facilities are fully, but separately, represented. In the public review draft, EPA noted potential issues with ensuring that vented emissions from certain equipment (e.g., pneumatic controllers, chemical injection pumps, dehydrator vents, and Kimray pumps) are not double-counted or inadvertently excluded due to these methodological revisions.

⁷⁴ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

The 2016 (current) Inventory methodology for these sources generally addresses this concern. Please refer to “Revisions to Natural Gas and Petroleum Production Emissions” for more information (EPA 2015b).

The impact of using activity factors developed from GHGRP data is an increase in emissions. This increase is shown in Table 3-52. For the year 2013, compared to the previous Inventory, the calculated CH₄ emissions increase due to use of revised activity factors for heaters, separators, dehydrators, compressors, and meters/piping is approximately 0.4 MMT CO₂ Eq. In addition, as dehydrator counts are an input to the calculation of emissions from the dehydrator vent and Kimray pump source, the revision to activity data impacted those estimates as well, resulting in a decrease of 2 MMT CO₂ Eq. for dehydrator vents, and 7 MMT CO₂ Eq. for Kimray pumps (comparing updated 2013 estimate to previous 2013 estimate). For chemical injection pumps, in addition to updating the activity data, emission factors were also recalculated using GHGRP data. This recalculation resulted in an increase in calculated emissions from chemical pumps for 2013 of 1.7 MMT CO₂ Eq., compared with the previous inventory estimate for 2013.

Table 3-52: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

| Type | Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|-----------------|-------------------------------|------------|------------|------------|------------|-----------|
| Venting | Chemical Injection Pumps | 0.7 | 2.4 | 3.3 | 3.2 | 3.2 |
| | <i>Previous-Chemical</i> | | | | | |
| <i>Venting</i> | <i>Injection Pumps</i> | <i>0.7</i> | <i>1.4</i> | <i>1.6</i> | <i>1.5</i> | <i>NA</i> |
| Fugitive | Dehydrators | 0.4 | 0.3 | 0.2 | 0.2 | 0.2 |
| <i>Fugitive</i> | <i>Previous-Dehydrators</i> | <i>0.4</i> | <i>0.7</i> | <i>0.8</i> | <i>0.8</i> | <i>NA</i> |
| Fugitive | Separators | 1.1 | 2.4 | 3.0 | 3.0 | 3.0 |
| <i>Fugitive</i> | <i>Previous-Separators</i> | <i>1.1</i> | <i>2.1</i> | <i>2.6</i> | <i>2.6</i> | <i>NA</i> |
| Fugitive | Heaters | 0.3 | 0.5 | 0.6 | 0.6 | 0.6 |
| <i>Fugitive</i> | <i>Previous- Heaters</i> | <i>0.3</i> | <i>0.7</i> | <i>0.8</i> | <i>0.8</i> | <i>NA</i> |
| Fugitive | Meters/Piping | 1.2 | 2.3 | 2.7 | 2.7 | 2.7 |
| <i>Fugitive</i> | <i>Previous-Meters/Piping</i> | <i>1.3</i> | <i>2.2</i> | <i>2.7</i> | <i>2.6</i> | <i>NA</i> |
| Fugitive | Compressors | 0.8 | 1.9 | 2.4 | 2.4 | 2.4 |
| <i>Fugitive</i> | <i>Previous-Compressors</i> | <i>0.9</i> | <i>1.5</i> | <i>1.8</i> | <i>1.7</i> | <i>NA</i> |

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA also developed technology-specific activity data and emission factors for pneumatic controllers. Reported data under the GHGRP allow for the development of pneumatic controller emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and the associated break-out of activity data into these categories. These revised emission factors and bleed type-specific activity data reflect net emissions. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data on pneumatic controller emissions is an increase of approximately 18.0 MMT CO₂ Eq., as shown in Table 3-53.

Table 3-53: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|---------------------|-------------|-------------|-------------|-------------|-------------|
| All | 13.9 | 27.0 | 31.2 | 31.5 | 27.6 |
| High bleed | + | 12.1 | 10.9 | 4.8 | 3.3 |
| Low bleed | 8.4 | 0.6 | 1.1 | 0.6 | 1.0 |
| Intermittent bleed | 5.5 | 14.3 | 19.2 | 26.0 | 23.3 |
| <i>Previous-All</i> | <i>13.4</i> | <i>20.2</i> | <i>16.2</i> | <i>13.5</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The 2015 Marchese et al. study assessed CH₄ emissions from an expanded universe of gathering stations compared with what was previously included in the Inventory. The Marchese et al. study analyzed emissions from five different types of gathering stations: compression only; compression and dehydration; compression, dehydration, and acid gas removal; dehydration only; and dehydration and acid gas removal. Previous Inventories estimated emissions from only gathering compression stations. In this Inventory, the EPA has applied a station-level emission factor and national activity estimates developed from the Marchese et al. data. See “Revisions to Natural Gas

Gathering and Boosting Emissions” for more information (EPA 2016c).⁷⁵ The impact of using revised activity data and emission factors for gathering stations cannot be straightforwardly determined based on the structure of previous Inventories (e.g., dehydrator emissions in previous inventories are not differentiated between well pad and gathering facility locations); however, due to the activity data revision alone, production segment emissions greatly increase compared to previous estimates. The station-level emission factor was applied to all years of the time series, and current activity data estimates were replaced with station counts based on the Marchese et al. estimate (scaled for earlier years based on national natural gas marketed production). Methane emissions from gathering and boosting are shown in Table 3-54.

Table 3-54: CH₄ Emissions from Gathering and Boosting (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|---------------------------------|------|------|------|------|------|
| Gathering and Boosting Stations | 23.9 | 27.7 | 35.8 | 43.3 | 46.6 |

The EPA’s approach for revising the Inventory methodology to incorporate GHGRP data and Marchese et al. data obviates the need to apply Gas STAR reductions data for certain sources in the production segment. EPA carried forward reported reductions for sources that are not being revised to use a net emission factor approach. There are also significant Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 18 MMT CO₂ Eq. of CH₄ in year 2014). To address potential double-counting of reductions, a scaling factor was applied to the “other voluntary reductions” to reduce this reported amount based on an estimate of the fraction of those reductions that occur in the sources that are now calculated using net emissions approaches. This fraction was developed by dividing the net emissions from sources with net emissions approaches, by the total production segment emissions (without deducting the Gas STAR reductions). The result for 2014, is that approximately 50 percent of the reductions were estimated to occur in sources for which net emissions are now calculated, which yields an adjusted “other voluntary reduction” number of 9 MMT CO₂ Eq.

Transmission and Storage

This section references the final 2016 (current) Inventory Transmission and Storage supporting memorandum: “Revisions to Natural Gas Transmission and Storage Emissions” (EPA 2016d).⁷⁶ This memorandum contains further details and documentation of recalculations.

For transmission and storage non-compressor fugitive emissions in the 2016 (current) Inventory, EPA used Zimmerle et al. data to develop the activity data for transmission stations (“Alternative” approach) and EIA data on active storage fields, along with the Zimmerle estimate of storage stations per storage field to develop storage station counts. The EPA then applied emission factors from Zimmerle et al. to calculate emissions for fugitives from these sources.

Interpolation was used to create time series consistency between earlier years’ emission factors (1990-1992) that generally rely on data from GRI/EPA 1996 and the Zimmerle et al. emission factors for recent years. However, the station fugitive emission factors in previous Inventories included station fugitives but not compressor fugitives, and separate emission factors were applied for compressor emissions (including compressor fugitive and vented sources). Because Zimmerle et al. grouped compressor fugitives with station fugitives, the two sets of emission factors (GRI/EPA and Zimmerle et al.) cannot be directly compared. Therefore in the 2016 (current) Inventory, the EPA calculated total station-level emission factors for transmission and storage stations that include station and compressor fugitive sources as well as compressor vented sources.

In the 2016 (current) Inventory, the EPA incorporated Zimmerle et al. national population estimates of reciprocating and centrifugal compressor activity data, along with the GHGRP break out between centrifugal compressor seal types (wet versus dry seals), and Zimmerle et al. emission factor data, in development of emission estimates for compressors in transmission and storage.

⁷⁵ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

⁷⁶ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

In order to create time series consistency between earlier years' compressor count estimates (1990 to 1992) and the most recent years' compressor count estimates (2012 to 2014) that were calculated from Zimmerle et al. and GHGRP data, compressor counts for the years 1993 through 2011 were calculated using linear interpolation between the data endpoints of 1992 and 2012.

The overall impact of using revised emissions data and activity data from Zimmerle et al. and GHGRP is a decrease in emissions for station fugitives and compressors. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station fugitives and compressor venting is approximately 18.4 MMT CO₂ Eq. Methane emissions from transmission stations are shown in Table 3-55, while methane emissions from storage stations are shown in Table 3-56.

Table 3-55: CH₄ Emissions from Transmission Stations (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|--|--------------------|--------------------|--------------------|--------------------|------------------|
| Station Total Emissions | 27.5 | 16.7 | 13.0 | 13.4 | 14.3 |
| Station + Compressor | | | | | |
| Fugitive Emissions | NA | NA | NA | 2.7 | 2.9 |
| Reciprocating Compressor | NA | NA | NA | 7.9 | 8.5 |
| Centrifugal Compressor (wet seals) | NA | NA | NA | 1.4 | 1.5 |
| Centrifugal Compressor (dry seals) | NA | NA | NA | 1.3 | 1.4 |
| <i>Previous-Station Total</i> | <i>27.5</i> | <i>28.1</i> | <i>28.5</i> | <i>28.3</i> | <i>NA</i> |
| <i>Previous-Station Fugitives^a</i> | <i>2.7</i> | <i>2.8</i> | <i>2.8</i> | <i>2.8</i> | <i>NA</i> |
| <i>Previous-Reciprocating Compressor^a</i> | <i>18.6</i> | <i>19.2</i> | <i>19.4</i> | <i>19.3</i> | <i>NA</i> |
| <i>Previous-Centrifugal Compressor (wet seals)^a</i> | <i>6.2</i> | <i>5.9</i> | <i>5.9</i> | <i>5.8</i> | <i>NA</i> |
| <i>Previous-Centrifugal Compressor (dry seals)^a</i> | <i>+</i> | <i>0.3</i> | <i>0.4</i> | <i>0.4</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

*These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

Table 3-56: CH₄ Emissions from Storage Stations (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|--|-------------------|-------------------|-------------------|-------------------|------------------|
| Station Total Emissions | 6.1 | 4.1 | 3.5 | 3.3 | 3.3 |
| Station + Compressor | | | | | |
| Fugitive Emissions | NA | NA | NA | 0.6 | 0.6 |
| Reciprocating Compressor | NA | NA | NA | 2.7 | 2.7 |
| Centrifugal Compressor (wet seals) | NA | NA | NA | NA | NA |
| Centrifugal Compressor (dry seals) | NA | NA | NA | NA | NA |
| <i>Previous-Station Total</i> | <i>6.1</i> | <i>6.7</i> | <i>6.6</i> | <i>6.8</i> | <i>NA</i> |
| <i>Previous-Station Fugitives^a</i> | <i>1.4</i> | <i>1.5</i> | <i>1.5</i> | <i>1.5</i> | <i>NA</i> |
| <i>Previous-Reciprocating Compressor^a</i> | <i>3.9</i> | <i>4.3</i> | <i>4.3</i> | <i>4.4</i> | <i>NA</i> |
| <i>Previous-Centrifugal Compressor (wet seals)^a</i> | <i>0.8</i> | <i>0.8</i> | <i>0.7</i> | <i>0.6</i> | <i>NA</i> |
| <i>Previous-Centrifugal Compressor (dry seals)^a</i> | <i>+</i> | <i>0.1</i> | <i>0.2</i> | <i>0.3</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

* These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the transmission and storage pneumatic controller emissions have been calculated using the GHGRP data on controllers per station and emission factors. The overall impact of using revised emissions data and activity data from GHGRP was a decrease in emissions from transmission station pneumatic controllers and a slight decrease in emissions from storage station pneumatic controllers for recent time series years. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station pneumatic controllers is 5.0 MMT CO₂ Eq. Methane emissions from transmission segment pneumatic controllers are shown in Table 3-57, while methane emissions from storage segment pneumatic controllers are shown in Table 3-58.

In order to create time series consistency between earlier years' pneumatic controller data (1990 to 1992) and the most recent years' data (2011 to 2014) when populating intermediate years, the EPA retained counts and estimates of weighted average emissions per controller in early years, then linearly interpolated the total count and weighted average emissions per controller in year 2011.

Table 3-57: CH₄ Emissions from Transmission Segment Pneumatic Controllers (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|----------------------------|------------|------------|------------|------------|-----------|
| All | 5.3 | 1.8 | 0.9 | 0.7 | 0.7 |
| High bleed | NA | NA | NA | 0.3 | 0.3 |
| Low bleed | NA | NA | NA | 0.3 | 0.4 |
| Intermittent bleed | NA | NA | NA | + | + |
| <i>Previous-All</i> | <i>5.3</i> | <i>5.2</i> | <i>5.3</i> | <i>5.2</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Table 3-58: CH₄ Emissions from Storage Segment Pneumatic Controllers (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|----------------------------|------------|------------|------------|------------|-----------|
| All | 1.1 | 0.9 | 0.7 | 0.8 | 0.7 |
| High bleed | NA | NA | NA | 0.6 | 0.6 |
| Low bleed | NA | NA | NA | 0.1 | 0.1 |
| Intermittent bleed | NA | NA | NA | + | + |
| <i>Previous-All</i> | <i>1.1</i> | <i>1.2</i> | <i>1.2</i> | <i>1.3</i> | <i>NA</i> |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach for revising the inventory methodology to incorporate Zimmerle et al. and GHGRP data in the transmission and storage segment resulted in net emissions being directly calculated for revised sources in each time series year. This obviated the need to apply Gas STAR reductions data for these sources. Previous Inventories have applied Gas STAR reductions to other specific transmission and storage segment sources including compressor engine and pipeline venting. EPA carried forward reported reductions for these sources since they are not being revised to use a net emission factor approach. There are also Gas STAR reductions in the transmission and storage segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 3.6 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA has revised the methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions," without adjustment, in the 2016 (current) Inventory.

Distribution

This section references the final 2016 (current) Inventory Distribution supporting memorandum: “Revisions to Natural Gas Distribution Emissions” (EPA 2016e).⁷⁷ This memorandum contains further details and documentation of recalculations.

For metering and regulating (M&R) stations, for the years from 2011 to 2014, in the 2016 (current) Inventory, the EPA used GHGRP reported activity data for counts of above ground and below ground stations. The EPA scaled the GHGRP station counts to the national level based on the miles of distribution pipeline main reported by GHGRP reporters, compared to the PHMSA national total miles of distribution pipeline main. The EPA then applied the existing inventory (from GRI) break out of station inlet pressure categories to the scaled counts of above ground and below ground M&R stations, and the station-level emission factors from Lamb et al. For years from 1990 to 2010, EPA used the previous inventory activity data for station counts. EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for M&R stations.

For the year 2013, the M&R stations CH₄ emissions decrease due to use of revised emission factors and activity data is approximately 13.6 MMT CO₂ Eq. Methane emissions from M&R stations are shown in Table 3-59.

Table 3-59: CH₄ Emissions from M&R Stations (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|--------------------------|------|------|------|------|------|
| M&R | 10.5 | 4.9 | 1.1 | 0.9 | 0.7 |
| <i>Previous--M&R</i> | 8.2 | 9.1 | 9.0 | 9.3 | NA |
| R-Vault | + | 0.1 | 0.1 | + | + |
| <i>Previous--R-Vault</i> | + | + | + | + | NA |
| Reg | 6.3 | 2.8 | 0.6 | 0.4 | 0.3 |
| <i>Previous--Reg</i> | 4.9 | 5.4 | 5.4 | 5.6 | NA |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

For pipeline leaks, in the 2016 (current) Inventory, the EPA used the previous activity data sources for miles of pipeline by material (PHMSA) and for leaks per mile (GRI), and Lamb et al., data on emissions per leak for recent years of the time series. For the year 2013, the pipeline leaks CH₄ emissions decrease due to use of revised emission factors is approximately 9.2 MMT CO₂ Eq. Methane emissions from pipeline leaks are shown in Table 3-60.

EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for pipeline leaks.

Table 3-60: CH₄ Emissions from Pipeline Leaks (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|---------------------------|------|------|------|------|------|
| Mains | 14.7 | 6.7 | 4.5 | 3.9 | 3.8 |
| <i>Previous--Mains</i> | 14.7 | 11.8 | 11.3 | 10.7 | NA |
| Services | 8.2 | 4.0 | 2.6 | 2.2 | 2.1 |
| <i>Previous--Services</i> | 8.2 | 6.2 | 5.1 | 4.6 | NA |

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the EPA revised the emission factors for residential customer meters and commercial/ industrial customer meters. The EPA recalculated the residential customer meter emission factor by combining data from the 1996 GRI/EPA study (basis for previous Inventory emission factor) with more recent data from a GTI 2009 study and Clearstone 2011 study. The EPA weighted emission factors developed in each study by the number of meters surveyed in each study to develop the revised emission factor. In the 2016 (current) Inventory, the EPA applied the GTI 2009 commercial customer meter emission factor to the total count of commercial and

⁷⁷ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

industrial meters in the GHG Inventory. In addition, the EPA used an updated data source, identified by commenters on the public review Distribution memorandum for national customer meter counts (EIA data); previously, national customer meter counts were scaled from a 1992 base year value, but are now available directly for every year of the time series from EIA. For the year 2013, the customer meters CH₄ emissions increase due to use of revised emission factors and activity data is approximately 0.3 MMT CO₂ Eq. Methane emissions from customer meters are shown in Table 3-61.

For pipeline blowdowns and mishaps/dig-ins, the previous Inventories used base year 1992 distribution main and service miles and scaled the value for non-1992 years using relative residential gas consumption. However, scaling mileage based on residential gas consumption introduced volatility across the time series that does not likely correlate to pipeline mileage trends (as gas consumption is affected by other factors such as equipment efficiency and climate). In the 2016 (current) Inventory, the EPA used PHMSA data directly for the activity data in each time series year. The overall impact of using the revised activity data for pipeline blowdowns and mishaps/dig-ins is an increase in emissions. For the year 2013, the pipeline blowdowns CH₄ emissions increase due to use of revised activity data is approximately 0.04 MMT CO₂ Eq.; and for mishaps/dig-ins is approximately 0.6 MMT CO₂ Eq. Methane emissions from pipeline blowdown and mishaps/dig-ins are shown in Table 3-61.

Table 3-61: CH₄ Emissions for Other Distribution Sources (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2013 | 2014 |
|---|------|------|------|------|------|
| Residential Meters | 1.5 | 1.9 | 1.9 | 2.0 | 2.0 |
| <i>Previous--Residential Meters</i> | 2.6 | 2.8 | 2.8 | 2.9 | NA |
| Commercial/Industry Meters | 1.1 | 1.3 | 1.3 | 1.4 | 1.4 |
| <i>Previous--Commercial/Industry Meters</i> | 0.1 | 0.1 | 0.1 | 0.1 | NA |
| Pressure Relief Valve Releases | + | + | + | + | + |
| <i>Previous--Pressure Relief Valve Releases</i> | + | + | + | + | NA |
| Pipeline Blowdowns | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| <i>Previous--Pipeline Blowdown</i> | 0.1 | 0.1 | 0.1 | 0.1 | NA |
| Mishaps (Dig-ins) | 1.2 | 1.5 | 1.6 | 1.6 | 1.7 |
| <i>Previous--Mishaps (Dig-ins)</i> | 0.9 | 1.0 | 1.0 | 1.0 | NA |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA’s approach for revising the Inventory methodology to incorporate Lamb et al. and subpart W data in the distribution segment resulted in net emissions being directly calculated for M&R stations, pipeline leaks, and customer meters in each time series year. This obviates the need to apply Gas STAR reductions data for these sources. Previous Inventories have also applied Gas STAR reductions to mishaps/dig-ins. EPA carried forward reported reductions for this source since it is not being revised to use a net emission factor approach. There are also Gas STAR reductions in the distribution segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 1.0 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the “other voluntary reductions” might apply to the emission sources for which the EPA has revised methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of “other voluntary reductions.” The EPA has retained Gas STAR reductions classified as “other voluntary reductions” unadjusted in the 2016 (current) Inventory.

Planned Improvements

Production Segment Estimates

In response to the public review draft and earlier released memorandum outlining potential revisions to the production and gathering and boosting segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider

how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. The EPA will also consider calculation of activity factors from GHGRP data (equipment and pneumatic controller counts per well) on a more granular basis, such as by geologic basin. EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active wells (non-associated gas wells and gas wells with hydraulic fracturing) across the time series.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 (current) Inventory). Stakeholders also recommended further investigating the emissions estimation methodology for gathering pipeline emissions, as the current factor is based on leak measurements from distribution mains conducted in the early 1990s. EPA will evaluate available data studies on this emission sources, and also take into account material-specific gathering pipeline activity data that will be available through the GHGRP.

EPA is considering updates to its estimates for liquids unloading. Data from a 2012 report published by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) were used to develop regional activity data and regional emission factors for gas well liquids unloading activities for Natural Gas Systems. EPA is considering how data from GHGRP and/or Allen et al. (2014a) can be used to update the Inventory estimates for this source.⁷⁸ Some commenters supported the use of scaled-up GHGRP data to calculate emissions from this source. Using the general scale up approach used for other production sources gives an approximation of a national estimate of 10 MMT CO₂ Eq. for 2013 (4.6 MMT CO₂ Eq. was reported from liquids unloading in 2013, from a total reported 208,991 wellheads estimated to be in the natural gas segment. The Inventory national well count total for 2013 is 454,491), compared with 6.5 MMT CO₂ Eq. in the current inventory.

EPA received mixed feedback on the update for gathering stations, with some commenters supporting the use of the Marchese et al. data, and others not supporting the update and recommending waiting for GHGRP data to update emissions from this source. Additionally, commenters recommended that EPA separate out emissions from gathering and boosting facilities from those from field production sites and noted that upcoming studies and GHGRP data may inform emissions estimates from this source. In the 2016 (current) Inventory, the EPA has presented gathering facility and gathering pipeline emissions as a "Gathering and Boosting" subsegment within the production segment; EPA will continue to consider how these sources may be presented in future Inventories. To address potential double counting, condensate storage tanks might be disaggregated between well pad facilities and gathering facilities in future Inventories. Stakeholder feedback included suggestions on how data from the Marchese et al. study and GHGRP data might be used, which EPA will consider for next year's inventory. One commenter suggested that the potential overlap count be estimated to be 3.4 percent of the emissions from condensate tanks.

Processing Estimates

Commenters recommended consideration of recent data sources (Marchese et al. 2015 and GHGRP) for revisions to gas processing segment estimates. Commenters had mixed feedback on these data sources with some commenters supporting use of Marchese et al. and other supporting use of GHGRP data.

⁷⁸ Please see the memorandum "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Liquids Unloading Estimates" (EPA 2015e) available at <<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>

Transmission and Storage Estimates

In response to the public review memorandum outlining potential revisions to the transmission and storage segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will consider approaches to developing average emission factors that integrate data from both recent studies and subpart W data. The EPA will seek more data to support or replace the Zimmerle et al. study assumption of 0.89 storage stations per field. The EPA will take into account findings emerging from ongoing research efforts by groups such as API (to better characterize emissions from pneumatic controllers) and Pipeline Research Council International (to analyze subpart W data). The EPA will also investigate potential revisions to certain emission sources not addressed in recent revisions but highlighted by commenters, including reciprocating compressor engines and storage tank dump valves.

In fall of 2015, a well in a California storage field began leaking methane at an estimated rate of 50 tons of CH₄ per day. The well was permanently sealed in February of 2016. EPA plans to include 2015 emissions from this source in next year's inventory (2017 report covering 1990 to 2015 emissions). EPA will review and potentially incorporate estimates of emissions from the leak, such as estimates developed by the California Air Resources Board (CARB). For information on CARB estimates, see http://www.arb.ca.gov/research/aliso_canyon_natural_gas_leak.htm.

Distribution Estimates

In response to the public review memorandum outlining potential revisions to the distribution segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will assess differences between the Lamb et al. study and characteristics of the GHGRP population. The EPA will consider current interpolation approaches to use GRI factors later into the time series (e.g., if information is received indicating a specific time frame for the transition to lower-emitting equipment and practices). The EPA will assess whether available data support methodological revisions to differentiate new versus vintage plastic pipelines in the Inventory. The EPA will assess any new data on commercial or industrial meters to potentially improve the current emission factor. While most commenters supported updates to this segment, several commenters did not, referring to top down (e.g., tall tower) studies indicating the emissions may be higher than previously estimated, not lower. The EPA will continue to assess new top down and bottom up data in this segment.

Upcoming new data

GHGRP

Beginning in March 2016, GHGRP reporters will report data for gathering facilities over the GHGRP reporting threshold. The EPA will consider use of this data to update its estimates in the Inventory.

Commenters on recent Inventory drafts have recommended that EPA analyze and screen GHGRP data and exclude or correct outliers. Commenters have also recommended use of only measured GHGRP data in some cases. The EPA plans to continue reviewing data reported to its GHGRP for potential updates to data and methodology across all segments of natural gas systems.

Methane Challenge

In March 2016, EPA launched the Methane Challenge Program, through which oil and gas companies can make and track ambitious commitments to reduce methane emissions. EPA will assess new data received by the Methane Challenge Program on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

Other Updates

EPA is evaluating several other sources for potential updates to future Inventories.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

The EPA continues to seek stakeholder feedback on natural gas systems super-emitter sources. The EPA will continue reviewing studies that could support potential revisions to inventory estimates, such as information from the Barnett Shale Campaign (e.g., Zavala et al. 2015). Several commenters noted superemitters detected and modeled in the Zimmerle et al. study but not incorporated into the inventory revision. In Zimmerle et al., superemitters were estimated to contribute 2.5 MMT CO₂ Eq. emissions to the study total estimate of emissions transmission and storage sources. The EPA will consider how unassigned superemitter emissions could be incorporated into the Inventory. EPA received mixed feedback on this issue with some commenters urging EPA to incorporate an estimate for superemitters, and others stating that inclusion of an estimate of unassigned superemitter emissions would be inappropriate and could result in double counting.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions in the 2016 (current) Inventory using information provided in recently published studies and the GHGRP Subpart W data, primarily including revisions to: production segment major equipment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility activity and emissions data, transmission and storage station activity and emissions data, distribution pipelines emissions data, distribution M&R station activity and emissions data, and distribution customer meter emissions data. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. At the present time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see the Uncertainty Memorandum (EPA 2016a). As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Note that to compile the top-emitting list of emission sources for natural gas systems, individual emission sources were analyzed at the NEMS region level for the production segment (because certain emission factors vary by region for many production sources), and at the national level for other segments. EPA is considering removing the NEMS region disaggregation in future Inventories, and potentially replacing it with a different level of disaggregation, such as at the sub-basin level. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty (EPA 2016a) for more information on planned improvements regarding uncertainty.”⁷⁹

3.8 Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2014 are reported in Table 3-62.

Table 3-62: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|--------|--------|--------|--------|--------|--------|-------|
| NO _x | 21,106 | 16,602 | 12,004 | 11,796 | 11,051 | 10,557 | 9,995 |

⁷⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

| | | | | | | | |
|---|----------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Mobile Combustion | 10,862 | 10,295 | 7,290 | 7,294 | 6,788 | 6,283 | 5,777 |
| Stationary Combustion | 10,023 | 5,858 | 4,092 | 3,807 | 3,567 | 3,579 | 3,522 |
| Oil and Gas Activities | 139 | 321 | 545 | 622 | 622 | 622 | 622 |
| Waste Combustion | 82 | 128 | 77 | 73 | 73 | 73 | 73 |
| <i>International Bunker Fuels^a</i> | <i>1,956</i> | <i>1,704</i> | <i>1,790</i> | <i>1,553</i> | <i>1,398</i> | <i>1,139</i> | <i>1,138</i> |
| CO | 125,640 | 64,985 | 45,148 | 44,088 | 42,273 | 40,459 | 38,643 |
| Mobile Combustion | 119,360 | 58,615 | 39,475 | 38,305 | 36,491 | 34,676 | 32,861 |
| Stationary Combustion | 5,000 | 4,648 | 4,103 | 4,170 | 4,170 | 4,170 | 4,169 |
| Waste Combustion | 978 | 1,403 | 1,084 | 1,003 | 1,003 | 1,003 | 1,003 |
| Oil and Gas Activities | 302 | 318 | 487 | 610 | 610 | 610 | 610 |
| <i>International Bunker Fuels^a</i> | <i>103</i> | <i>133</i> | <i>136</i> | <i>137</i> | <i>133</i> | <i>129</i> | <i>135</i> |
| NMVOCs | 12,620 | 7,191 | 7,464 | 7,759 | 7,449 | 7,139 | 6,830 |
| Mobile Combustion | 10,932 | 5,724 | 4,591 | 4,562 | 4,252 | 3,942 | 3,632 |
| Oil and Gas Activities | 554 | 510 | 2,205 | 2,517 | 2,517 | 2,517 | 2,517 |
| Stationary Combustion | 912 | 716 | 576 | 599 | 599 | 599 | 599 |
| Waste Combustion | 222 | 241 | 92 | 81 | 81 | 81 | 81 |
| <i>International Bunker Fuels^a</i> | <i>57</i> | <i>54</i> | <i>56</i> | <i>51</i> | <i>46</i> | <i>41</i> | <i>42</i> |

^a These values are presented for informational purposes only and are not included in totals.

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2012, 2013, and 2014 for non-EGU and non-mobile sources are held constant from 2011 in EPA (2015). Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9 International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing

the Framework Convention on Climate Change.⁸⁰ These decisions are reflected in the IPCC methodological guidance, including IPCC (2006), in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).⁸¹

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.⁸² Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO₂, CH₄ and N₂O for marine transport modes, and CO₂ and N₂O for aviation transport modes. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.⁸³

Emissions of CO₂ from aircraft are essentially a function of fuel use. Nitrous oxide emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Recent data suggest that little or no CH₄ is emitted by modern engines (Anderson et al. 2011), and as a result, CH₄ emissions from this category are considered zero. In jet engines, N₂O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2014 from the combustion of international bunker fuels from both aviation and marine activities were 104.2 MMT CO₂ Eq., or 0.3 percent below emissions in 1990 (see Table 3-63 and Table 3-64). Emissions from international flights and international shipping voyages departing from the United States have increased by 82.5 percent and decreased by 48.4 percent, respectively, since 1990. The majority of these emissions were in the form of CO₂; however, small amounts of CH₄ (from marine transport modes) and N₂O were also emitted.

Table 3-63: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (MMT CO₂ Eq.)

| Gas/Mode | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|-------------|--------------|
| CO₂ | 103.5 | 113.1 | 117.0 | 111.7 | 105.8 | 99.8 | 103.2 |
| Aviation | 38.0 | 60.1 | 61.0 | 64.8 | 64.5 | 65.7 | 69.4 |
| <i>Commercial</i> | 30.0 | 55.6 | 57.4 | 61.7 | 61.4 | 62.8 | 66.3 |
| <i>Military</i> | 8.1 | 4.5 | 3.6 | 3.1 | 3.1 | 2.9 | 3.1 |
| Marine | 65.4 | 53.0 | 56.0 | 46.9 | 41.3 | 34.1 | 33.8 |
| CH₄ | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |

⁸⁰ See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

⁸¹ Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

⁸² Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

⁸³ Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

| | | | | | | | | |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|------------|
| Aviation ^a | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Marine | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| N₂O | 0.9 | 1.0 | 1.0 | 1.0 | 0.9 | 0.9 | 0.9 | 0.9 |
| Aviation | 0.4 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 |
| Marine | 0.5 | 0.4 | 0.4 | 0.4 | 0.3 | 0.2 | 0.2 | 0.2 |
| Total | 104.5 | 114.2 | 118.1 | 112.8 | 106.8 | 100.7 | 104.2 | |

^a CH₄ emissions from aviation are estimated to be zero.

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-64: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (kt)

| Gas/Mode | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|----------------|----------------|----------------|----------------|----------------|---------------|----------------|
| CO₂ | 103,463 | 113,139 | 116,992 | 111,660 | 105,805 | 99,763 | 103,201 |
| Aviation | 38,034 | 60,125 | 60,967 | 64,790 | 64,524 | 65,664 | 69,411 |
| Marine | 65,429 | 53,014 | 56,025 | 46,870 | 41,281 | 34,099 | 33,791 |
| CH₄ | 7 | 5 | 6 | 5 | 4 | 3 | 3 |
| Aviation ^a | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Marine | 7 | 5 | 6 | 5 | 4 | 3 | 3 |
| N₂O | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Aviation | 1 | 2 | 2 | 2 | 2 | 2 | 2 |
| Marine | 2 | 1 | 1 | 1 | 1 | 1 | 1 |

^a CH₄ emissions from aviation are estimated to be zero.

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-65: Aviation CO₂ and N₂O Emissions for International Transport (MMT CO₂ Eq.)

| Aviation Mode | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Commercial Aircraft | 30.0 | 55.6 | 57.4 | 61.7 | 61.4 | 62.8 | 66.3 |
| Military Aircraft | 8.1 | 4.5 | 3.6 | 3.1 | 3.1 | 2.9 | 3.1 |
| Total | 38.0 | 60.1 | 61.0 | 64.8 | 64.5 | 65.7 | 69.4 |

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO₂ were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3.1 – CO₂ from Fossil Fuel Combustion. Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2016) and USAF (1998), and heat content for jet fuel was taken from EIA (2016). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.8 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O emissions were obtained from the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.1 for N₂O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH₄ and 0.08 for N₂O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990, 2000 through 2014 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the 2006 IPCC Guidelines (IPCC 2006).

International aviation CO₂ estimates for 1990 and 2000 through 2014 are obtained from FAA’s AEDT model (FAA 2016). The radar-informed method that was used to estimate CO₂ emissions for commercial aircraft for 1990, and 2000 through 2014 is not possible for 1991 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. Because fuel consumption and CO₂ emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through 2005 data.

Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service’s total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data from DoD’s Defense Logistics Agency Energy (DLA Energy 2015). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-66. See Annex 3.8 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce’s Bureau of the Census (DOC 2015) for 1990 through 2001, 2007 through 2014, and the Department of Homeland Security’s Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DLA Energy (2015). The total amount of fuel provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-67.

Table 3-66: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

| Nationality | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| U.S. and Foreign Carriers | 3,222 | 5,983 | 6,173 | 6,634 | 6,604 | 6,748 | 7,126 |
| U.S. Military | 862 | 462 | 367 | 319 | 321 | 294 | 318 |
| Total | 4,084 | 6,445 | 6,540 | 6,953 | 6,925 | 7,042 | 7,445 |

Note: Totals may not sum due to independent rounding.

Table 3-67: Marine Fuel Consumption for International Transport (Million Gallons)

| Fuel Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Residual Fuel Oil | 4,781 | 3,881 | 4,141 | 3,463 | 3,069 | 2,537 | 2,466 |
| Distillate Diesel Fuel & Other | 617 | 444 | 476 | 393 | 280 | 235 | 261 |
| U.S. Military Naval Fuels | 522 | 471 | 448 | 382 | 381 | 308 | 331 |
| Total | 5,920 | 4,796 | 5,065 | 4,237 | 3,730 | 3,081 | 3,058 |

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.⁸⁴ For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO₂ in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also

⁸⁴ See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO₂.⁸⁵

There is also concern regarding the reliability of the existing DOC (2015) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO₂, CH₄, and N₂O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Planned Improvements

The feasibility of including data from a broader range of domestic and international sources for bunker fuels, including data from studies such as the Third IMO GHG Study 2014, is being considered.

3.10 Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol generates CO₂ in addition to CH₄ and N₂O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO₂ emissions from biomass combustion have been estimated separately from fossil fuel CO₂ emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 6), which accounts for the contribution of any resulting CO₂ emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

In 2014, total CO₂ emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 217.7 MMT CO₂ Eq. (217,654 kt) (see Table 3-68 and Table 3-69). As the largest consumer of woody biomass, the industrial sector was responsible for 57.1 percent of the CO₂ emissions from this source. The residential sector was the second largest emitter, constituting 27.5 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

⁸⁵ U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Table 3-68: CO₂ Emissions from Wood Consumption by End-Use Sector (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Industrial | 135.3 | 136.3 | 119.5 | 122.9 | 125.7 | 123.1 | 124.4 |
| Residential | 59.8 | 44.3 | 45.4 | 46.4 | 43.3 | 59.8 | 59.8 |
| Commercial | 6.8 | 7.2 | 7.4 | 7.1 | 6.3 | 7.2 | 7.6 |
| Electricity Generation | 13.3 | 19.1 | 20.2 | 18.8 | 19.6 | 21.4 | 25.9 |
| Total | 215.2 | 206.9 | 192.5 | 195.2 | 194.9 | 211.6 | 217.7 |

Note: Totals may not sum due to independent rounding.

Table 3-69: CO₂ Emissions from Wood Consumption by End-Use Sector (kt)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Industrial | 135,348 | 136,269 | 119,537 | 122,865 | 125,724 | 123,149 | 124,369 |
| Residential | 59,808 | 44,340 | 45,371 | 46,402 | 43,309 | 59,808 | 59,808 |
| Commercial | 6,779 | 7,218 | 7,385 | 7,131 | 6,257 | 7,235 | 7,569 |
| Electricity Generation | 13,252 | 19,074 | 20,169 | 18,784 | 19,612 | 21,389 | 25,908 |
| Total | 215,186 | 206,901 | 192,462 | 195,182 | 194,903 | 211,581 | 217,654 |

Note: Totals may not sum due to independent rounding.

The transportation sector is responsible for most of the ethanol consumption in the United States. Ethanol is currently produced primarily from corn grown in the Midwest, but it can be produced from a variety of biomass feedstocks. Most ethanol for transportation use is blended with gasoline to create a 90 percent gasoline, 10 percent by volume ethanol blend known as E-10 or gasohol.

In 2014, the United States consumed an estimated 1,111.3 trillion Btu of ethanol, and as a result, produced approximately 76.1 MMT CO₂ Eq. (76,075 kt) (see Table 3-70 and Table 3-71) of CO₂ emissions. Ethanol production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-70: CO₂ Emissions from Ethanol Consumption (MMT CO₂ Eq.)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------|------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Transportation ^a | 4.1 | 22.4 | 71.3 | 71.5 | 71.5 | 73.4 | 74.8 |
| Industrial | 0.1 | 0.5 | 1.1 | 1.1 | 1.1 | 1.2 | 1.0 |
| Commercial | + | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Total | 4.2 | 22.9 | 72.6 | 72.9 | 72.8 | 74.7 | 76.1 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Table 3-71: CO₂ Emissions from Ethanol Consumption (kt)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------|--------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Transportation ^a | 4,136 | 22,414 | 71,287 | 71,537 | 71,510 | 73,359 | 74,810 |
| Industrial | 56 | 468 | 1,134 | 1,146 | 1,142 | 1,202 | 987 |
| Commercial | 34 | 60 | 226 | 198 | 175 | 183 | 277 |
| Total | 4,227 | 22,943 | 72,647 | 72,881 | 72,827 | 74,743 | 76,075 |

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2016) (see Table 3-72), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO₂ emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO₂ with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2016) (see Table 3-73).

Table 3-72: Woody Biomass Consumption by Sector (Trillion Btu)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Industrial | 1,441.9 | 1,451.7 | 1,273.5 | 1,308.9 | 1,339.4 | 1,312.0 | 1,325.0 |
| Residential | 580.0 | 430.0 | 440.0 | 450.0 | 420.0 | 580.0 | 580.0 |
| Commercial | 65.7 | 70.0 | 71.6 | 69.2 | 60.7 | 70.2 | 73.4 |
| Electricity Generation | 128.5 | 185.0 | 195.6 | 182.2 | 190.2 | 207.4 | 251.3 |
| Total | 2,216.2 | 2,136.7 | 1,980.7 | 2,010.2 | 2,010.3 | 2,169.5 | 2,229.6 |

Note: Totals may not sum due to independent rounding.

Table 3-73: Ethanol Consumption by Sector (Trillion Btu)

| End-Use Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------|-------------|--------------|----------------|----------------|----------------|----------------|----------------|
| Transportation | 60.4 | 327.4 | 1,041.4 | 1,045.0 | 1,044.6 | 1,071.6 | 1,092.8 |
| Industrial | 0.8 | 6.8 | 16.6 | 16.7 | 16.7 | 17.6 | 14.4 |
| Commercial | 0.5 | 0.9 | 3.3 | 2.9 | 2.6 | 2.7 | 4.1 |
| Total | 61.7 | 335.1 | 1,061.2 | 1,064.6 | 1,063.8 | 1,091.8 | 1,111.3 |

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values for 2013 were revised relative to the previous Inventory based on updated information from EIA's *Monthly Energy Review* (EIA 2016). These revisions of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of 0.1 MMT CO₂ Eq. (less than 0.1 percent) from 1990 through 2013. Ethanol consumption values remained constant relative to the previous Inventory throughout the entire time-series.

Planned Improvements

The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁸⁶ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from biomass combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁸⁷

⁸⁶ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁸⁷ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

4. Industrial Processes and Product Use

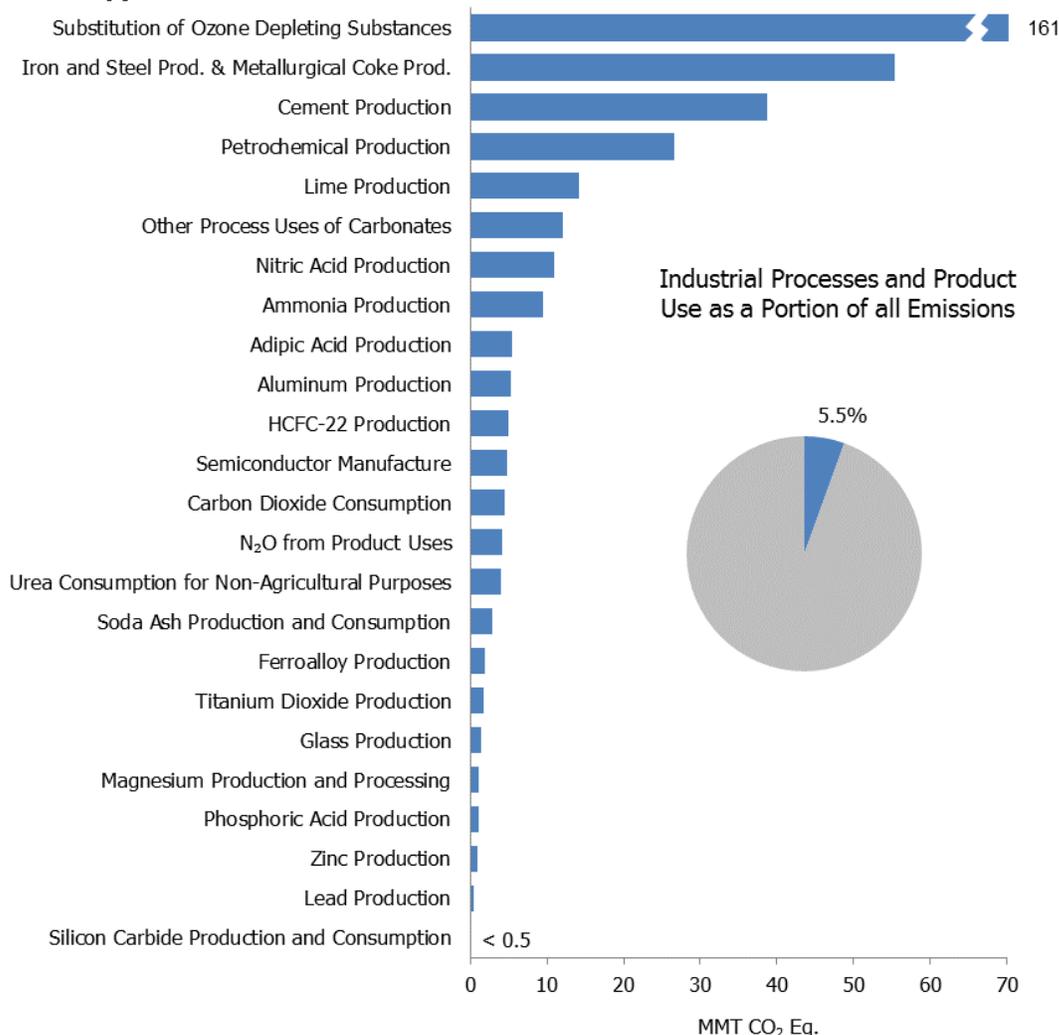
The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products. The industrial processes and product use categories included in this chapter are presented in Figure 4-1.

Greenhouse gas emissions are produced as the byproducts of various non-energy-related industrial activities. That is, these emissions are produced either from an industrial process itself, and are not directly a result of energy consumed during the process. For example, raw materials can be chemically or physically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). The processes included in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), ammonia production and urea consumption, petrochemical production, aluminum production, soda ash production and use, titanium dioxide production, CO₂ consumption, ferroalloy production, glass production, zinc production, phosphoric acid production, lead production, silicon carbide production and consumption, nitric acid production, and adipic acid production.

In addition, greenhouse gases are often used in products or by end-consumers. These gases include industrial sources of man-made compounds such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), nitrogen trifluoride (NF₃), and N₂O. The present contribution of HFCs, PFCs, SF₆, and NF₃ gases to the radiative forcing effect of all anthropogenic greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to accumulate in the atmosphere as long as emissions continue. In addition, many of these gases have high global warming potentials; SF₆ is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Use of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances (ODSs), which are being phased-out under the *Montreal Protocol on Substances that Deplete the Ozone Layer*. Hydrofluorocarbons, PFCs, SF₆, and NF₃ are employed and emitted by a number of other industrial sources in the United States such as aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Nitrous oxide is emitted by the production of adipic acid and nitric acid, semiconductor manufacturing, end-consumers in product uses through the administration of anesthetics, and by industry as a propellant in aerosol products.

In 2014, IPPU generated emissions of 379.2 million metric tons of CO₂ equivalent (MMT CO₂ Eq.), or 5.5 percent of total U.S. greenhouse gas emissions. Carbon dioxide emissions from all industrial processes were 178.1 MMT CO₂ Eq. (178,150 kt CO₂) in 2014, or 3.2 percent of total U.S. CO₂ emissions. Methane emissions from industrial processes resulted in emissions of approximately 0.2 MMT CO₂ Eq. (6 kt CH₄) in 2014, which was less than 1 percent of U.S. CH₄ emissions. Nitrous oxide emissions from IPPU were 20.8 MMT CO₂ Eq. (70 kt N₂O) in 2014, or 5.2 percent of total U.S. N₂O emissions. In 2014 combined emissions of HFCs, PFCs, SF₆, and NF₃ totaled 180.1 MMT CO₂ Eq. Total emissions from IPPU in 2014 were 11.2 percent more than 1990 emissions. Indirect greenhouse gas emissions also result from IPPU, and are presented in Table 4-107 in kilotons (kt).

Figure 4-1: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



The increase in overall IPPU emissions since 1990 reflects a range of emission trends among the emission sources. Emissions resulting from most types of metal production have declined significantly since 1990, largely due to production shifting to other countries, but also due to transitions to less-emissive methods of production (in the case of iron and steel) and to improved practices (in the case of PFC emissions from aluminum production). Emissions from mineral sources have either increased or not changed significantly since 1990 but largely track economic cycles, while CO₂ and CH₄ emissions from chemical sources have either decreased or not changed significantly. Hydrofluorocarbon emissions from the substitution of ODS have increased drastically since 1990, while the emission trends of HFCs, PFCs, SF₆, and NF₃ from other sources are mixed. Nitrous oxide emissions from the production of adipic and nitric acid have decreased, while N₂O emissions from product uses has remained nearly constant over time. Trends are explained further within each emission source category throughout the chapter.

Table 4-1 summarizes emissions for the IPPU chapter in MMT CO₂ Eq. using *IPCC Fourth Assessment Report* (AR4) GWP values, following the requirements of the revised United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines for national inventories (IPCC 2007).¹ Unweighted native gas emissions in kt are also provided in Table 4-2. The source descriptions that follow in the chapter are presented in the order as

¹ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

reported to the UNFCCC in the common reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, SF₆, and NF₃.

Table 4-1: Emissions from Industrial Processes and Product Use (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CO₂ | 207.1 | 190.3 | 168.8 | 172.9 | 169.5 | 171.7 | 178.1 |
| Iron and Steel Production & Metallurgical Coke Production | 99.7 | 66.5 | 55.7 | 59.9 | 54.2 | 52.2 | 55.4 |
| <i>Iron and Steel Production</i> | 97.2 | 64.5 | 53.6 | 58.5 | 53.7 | 50.4 | 53.4 |
| <i>Metallurgical Coke Production</i> | 2.5 | 2.0 | 2.1 | 1.4 | 0.5 | 1.8 | 1.9 |
| Cement Production | 33.3 | 45.9 | 31.3 | 32.0 | 35.1 | 36.1 | 38.8 |
| Petrochemical Production | 21.6 | 27.4 | 27.2 | 26.3 | 26.5 | 26.4 | 26.5 |
| Lime Production | 11.7 | 14.6 | 13.4 | 14.0 | 13.7 | 14.0 | 14.1 |
| Other Process Uses of Carbonates | 4.9 | 6.3 | 9.6 | 9.3 | 8.0 | 10.4 | 12.1 |
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Carbon Dioxide Consumption | 1.5 | 1.4 | 4.4 | 4.1 | 4.0 | 4.2 | 4.5 |
| Urea Consumption for Non-Agricultural Purposes | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Aluminum Production | 6.8 | 4.1 | 2.7 | 3.3 | 3.4 | 3.3 | 2.8 |
| Soda Ash Production and Consumption | 2.8 | 3.0 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 |
| Ferroalloy Production | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| Titanium Dioxide Production | 1.2 | 1.8 | 1.8 | 1.7 | 1.5 | 1.7 | 1.8 |
| Glass Production | 1.5 | 1.9 | 1.5 | 1.3 | 1.2 | 1.3 | 1.3 |
| Phosphoric Acid Production | 1.5 | 1.3 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 |
| Zinc Production | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.4 | 1.0 |
| Lead Production | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Silicon Carbide Production and Consumption | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Magnesium Production and Processing | + | + | + | + | + | + | + |
| CH₄ | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 |
| Petrochemical Production | 0.2 | 0.1 | + | + | 0.1 | 0.1 | 0.1 |
| Ferroalloy Production | + | + | + | + | + | + | + |
| Silicon Carbide Production and Consumption | + | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | + | + | + | + | + | + | + |
| <i>Iron and Steel Production</i> | + | + | + | + | + | + | + |
| <i>Metallurgical Coke Production</i> | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N₂O | 31.6 | 22.8 | 20.1 | 25.5 | 20.4 | 19.1 | 20.8 |
| Nitric Acid Production | 12.1 | 11.3 | 11.5 | 10.9 | 10.5 | 10.7 | 10.9 |
| Adipic Acid Production | 15.2 | 7.1 | 4.2 | 10.2 | 5.5 | 4.0 | 5.4 |
| N ₂ O from Product Uses | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Semiconductor Manufacturing | + | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| HFCs | 46.6 | 119.9 | 149.4 | 154.3 | 155.9 | 158.9 | 166.7 |
| Substitution of Ozone Depleting Substances ^a | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |
| HCFC-22 Production | 46.1 | 20.0 | 8.0 | 8.8 | 5.5 | 4.1 | 5.0 |
| Semiconductor Manufacture | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Magnesium Production and Processing | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| PFCs | 24.3 | 6.7 | 4.5 | 7.0 | 6.0 | 5.8 | 5.6 |
| Semiconductor Manufacture | 2.8 | 3.2 | 2.7 | 3.5 | 3.1 | 2.9 | 3.0 |
| Aluminum Production | 21.5 | 3.4 | 1.9 | 3.5 | 2.9 | 3.0 | 2.5 |
| SF₆ | 31.1 | 14.0 | 9.5 | 10.0 | 7.6 | 7.2 | 7.3 |

| | | | | | | | |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Electrical Transmission and Distribution | 25.4 | 10.6 | 7.0 | 6.8 | 5.6 | 5.4 | 5.6 |
| Magnesium Production and Processing | 5.2 | 2.7 | 2.1 | 2.8 | 1.6 | 1.5 | 1.0 |
| Semiconductor Manufacture | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.7 |
| NF ₃ | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Semiconductor Manufacture | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Total | 340.9 | 354.3 | 353.0 | 370.5 | 360.1 | 363.5 | 379.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Table 4-2: Emissions from Industrial Processes and Product Use (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| CO₂ | 207,054 | 190,273 | 168,781 | 172,898 | 169,472 | 171,714 | 178,150 |
| Iron and Steel Production & Metallurgical Coke Production | 99,669 | 66,543 | 55,671 | 59,928 | 54,229 | 52,201 | 55,355 |
| <i>Iron and Steel Production</i> | <i>97,166</i> | <i>64,499</i> | <i>53,586</i> | <i>58,501</i> | <i>53,686</i> | <i>50,378</i> | <i>53,417</i> |
| <i>Metallurgical Coke Production</i> | <i>2,503</i> | <i>2,044</i> | <i>2,085</i> | <i>1,426</i> | <i>543</i> | <i>1,824</i> | <i>1,938</i> |
| Cement Production | 33,278 | 45,910 | 31,256 | 32,010 | 35,051 | 36,146 | 38,755 |
| Petrochemical Production | 21,609 | 27,380 | 27,246 | 26,326 | 26,464 | 26,437 | 26,509 |
| Lime Production | 11,700 | 14,552 | 13,381 | 13,981 | 13,715 | 14,045 | 14,125 |
| Other Process Uses of Carbonates | 4,907 | 6,339 | 9,560 | 9,335 | 8,022 | 10,414 | 12,077 |
| Ammonia Production | 13,047 | 9,196 | 9,188 | 9,292 | 9,377 | 9,962 | 9,436 |
| Carbon Dioxide Consumption | 1,472 | 1,375 | 4,425 | 4,083 | 4,019 | 4,188 | 4,471 |
| Urea Consumption for Non-Agricultural Purposes | 3,784 | 3,653 | 4,730 | 4,029 | 4,449 | 4,179 | 4,007 |
| Aluminum Production | 6,831 | 4,142 | 2,722 | 3,292 | 3,439 | 3,255 | 2,833 |
| Soda Ash Production and Consumption | 2,822 | 2,960 | 2,697 | 2,712 | 2,763 | 2,804 | 2,827 |
| Ferroalloy Production | 2,152 | 1,392 | 1,663 | 1,735 | 1,903 | 1,785 | 1,914 |
| Titanium Dioxide Production | 1,195 | 1,755 | 1,769 | 1,729 | 1,528 | 1,715 | 1,755 |
| Glass Production | 1,535 | 1,928 | 1,481 | 1,299 | 1,248 | 1,317 | 1,341 |
| Phosphoric Acid Production | 1,529 | 1,342 | 1,087 | 1,151 | 1,093 | 1,119 | 1,095 |
| Zinc Production | 632 | 1,030 | 1,182 | 1,286 | 1,486 | 1,429 | 956 |
| Lead Production | 516 | 553 | 542 | 538 | 527 | 546 | 518 |
| Silicon Carbide Production and Consumption | 375 | 219 | 181 | 170 | 158 | 169 | 173 |
| Magnesium Production and Processing | 1 | 3 | 1 | 3 | 2 | 2 | 2 |
| CH₄ | 12 | 4 | 3 | 3 | 4 | 4 | 6 |
| Petrochemical Production | 9 | 3 | 2 | 2 | 3 | 3 | 5 |
| Ferroalloy Production | 1 | + | + | + | 1 | + | 1 |
| Silicon Carbide Production and Consumption | 1 | + | + | + | + | + | + |
| Iron and Steel Production & Metallurgical Coke Production | 1 | 1 | + | + | + | + | + |
| <i>Iron and Steel Production</i> | <i>1</i> | <i>1</i> | <i>+</i> | <i>+</i> | <i>+</i> | <i>+</i> | <i>+</i> |
| <i>Metallurgical Coke Production</i> | <i>0</i> |
| N₂O | 106 | 76 | 68 | 86 | 69 | 64 | 70 |
| Nitric Acid Production | 41 | 38 | 39 | 37 | 35 | 36 | 37 |
| Adipic Acid Production | 51 | 24 | 14 | 34 | 19 | 13 | 18 |
| N ₂ O from Product Uses | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Semiconductor Manufacturing | + | + | + | 1 | 1 | 1 | 1 |
| HFCs | M |

| | | | | | | | |
|---|----------|----------|----------|----------|----------|----------|----------|
| Substitution of Ozone Depleting Substances ^a | M | M | M | M | M | M | M |
| HCFC-22 Production | 3 | 1 | 1 | 1 | + | + | + |
| Semiconductor Manufacture | + | + | + | + | + | + | + |
| Magnesium Production and Processing | 0 | 0 | + | + | + | + | + |
| PFCs | M |
| Semiconductor Manufacture | M | M | M | M | M | M | M |
| Aluminum Production | M | M | M | M | M | M | M |
| SF₆ | 1 | 1 | + | + | + | + | + |
| Electrical Transmission and Distribution | 1 | + | + | + | + | + | + |
| Magnesium Production and Processing | + | + | + | + | + | + | + |
| Semiconductor Manufacture | + | + | + | + | + | + | + |
| NF₃ | + |
| Semiconductor Manufacture | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

M (Mixture of gases)

^a Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

The UNFCCC incorporated the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)* as the standard for Annex I countries at the Nineteenth Conference of the Parties (Warsaw, November 11-23, 2013). This chapter presents emission estimates calculated in accordance with the methodological guidance provided in these guidelines.

QA/QC and Verification Procedures

For industrial processes and product use sources, a detailed QA/QC plan was developed and implemented. This plan was based on the overall The Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory (QA/QC Management Plan), but was tailored to include specific procedures recommended for these sources. Two types of checks were performed using this plan: (1) general, or Tier 1, procedures that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files; and (2) source-category specific, or Tier 2, procedures that focus on checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process and product use sources. Examples of these procedures include checks to ensure that activity data and emission estimates are consistent with historical trends; that, where possible, consistent and reputable data sources are used across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets and factors are used where applicable. Tier 1 quality assurance and quality control procedures have been performed for all industrial process and product use sources. Tier 2 procedures were performed for more significant emission categories, consistent with the *IPCC Good Practice Guidelines*.

For most industrial process and product use categories, activity data is obtained through a survey of manufacturers conducted by various organizations (specified within each source); the uncertainty of the activity data is a function of the reliability of reported plant-level production data and is influenced by the completeness of the survey response. The emission factors used are defaults from IPCC, derived using calculations that assume precise and efficient chemical reactions, or were based upon empirical data in published references. As a result, uncertainties in the emission coefficients can be attributed to, among other things, inefficiencies in the chemical reactions associated with each production process or to the use of empirically-derived emission factors that are biased; therefore, they may not represent U.S. national averages. Additional assumptions are described within each source.

The uncertainty analysis performed to quantify uncertainties associated with the 2014 emission estimates from industrial processes and product use continues a multi-year process for developing credible quantitative uncertainty estimates for these source categories using the IPCC Tier 2 approach. As the process continues, the type and the

characteristics of the actual probability density functions underlying the input variables are identified and better characterized (resulting in development of more reliable inputs for the model, including accurate characterization of correlation between variables), based primarily on expert judgment. Accordingly, the quantitative uncertainty estimates reported in this section should be considered illustrative and as iterations of ongoing efforts to produce accurate uncertainty estimates. The correlation among data used for estimating emissions for different sources can influence the uncertainty analysis of each individual source. While the uncertainty analysis recognizes very significant connections among sources, a more comprehensive approach that accounts for all linkages will be identified as the uncertainty analysis moves forward.

Box 4-1: Industrial Processes Data from EPA's Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule requiring annual reporting of greenhouse gas data from large greenhouse gas emissions sources in the United States. Implementation of the rule, codified at 40 CFR part 98, is referred to as EPA's Greenhouse Gas Reporting Program (GHGRP). The rule applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons and requires reporting by sources or suppliers in 41 industrial categories. Annual reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year, but reporting is required for all facilities in some industries. Calendar year 2010 was the first year for which data were reported for facilities subject to 40 CFR part 98, though some source categories first reported data for calendar year 2011.

EPA's GHGRP dataset and the data presented in this Inventory report are complementary. EPA presents the data collected by EPA's GHGRP through a data publication tool (ghgdata.epa.gov) that allows data to be viewed in several formats, including maps, tables, charts, and graphs for individual facilities or groups of facilities. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards. This may differ from the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions for source categories in EPA's GHGRP may differ from those used in this Inventory in meeting the UNFCCC reporting guidelines (IPCC 2011). In line with the UNFCCC reporting guidelines, the Inventory report is a comprehensive accounting of all emissions from source categories identified in the IPCC (2006) guidelines. Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the EPA's GHGRP website.

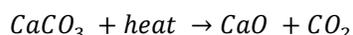
For certain source categories in this Inventory (e.g., nitric acid production and petrochemical production), EPA has also integrated data values that have been calculated by aggregating GHGRP data that are considered confidential business information (CBI) at the facility level. EPA, with industry engagement, has put forth criteria to confirm that a given data aggregation shields underlying CBI from public disclosure. EPA is publishing only data values that meet these aggregation criteria.² Specific uses of aggregated facility-level data are described in the respective methodological sections. For other source categories in this chapter, as indicated in the respective planned improvements sections, EPA is continuing to analyze how facility-level GHGRP data may be used to improve the national estimates presented in this Inventory, giving particular consideration to ensuring time series consistency and completeness.

² U.S. EPA Greenhouse Gas Reporting Program. Developments on Publication of Aggregated Greenhouse Gas Data, November 25, 2014. See <<http://www.epa.gov/ghgreporting/confidential-business-information-ghg-reporting>>.

4.1 Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw material-intensive process that results in the generation of carbon dioxide (CO₂) from both the energy consumed in making the cement and the chemical process itself. Emissions from fuels consumed for energy purposes during the production of cement are accounted for in the Energy chapter.

During the cement production process, calcium carbonate (CaCO₃) is heated in a cement kiln at a temperature of about 1,450 degrees Celsius (2,700 degrees Fahrenheit) to form lime (i.e., calcium oxide or CaO) and CO₂ in a process known as calcination or calcining. The quantity of CO₂ emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of limestone (CaCO₃) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO₂:



Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier byproduct CO₂ being released to the atmosphere. The clinker is then allowed to cool, mixed with a small amount of gypsum and potentially other materials (e.g., slag, etc.), and used to make Portland cement.³

Carbon dioxide emitted from the chemical process of cement production is the second largest source of industrial CO₂ emissions in the United States. Cement is produced in 34 states and Puerto Rico. Texas, California, Missouri, Florida, and Michigan were the five leading cement-producing states in 2014 and accounted for approximately 53 percent of total U.S. production (USGS 2015b). Clinker production in 2014 increased approximately 7 percent from 2013 levels. This increase can be attributed to an increase in spending in new residential construction and nonresidential buildings. In 2014, U.S. clinker production totaled 74,946 kilotons (USGS 2015a). The resulting CO₂ emissions were estimated to be 38.8 MMT CO₂ Eq. (38,755 kt) (see Table 4-3).

Table 4-3: CO₂ Emissions from Cement Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|--------|
| 1990 | 33.3 | 33,278 |
| 2005 | 45.9 | 45,910 |
| 2010 | 31.3 | 31,256 |
| 2011 | 32.0 | 32,010 |
| 2012 | 35.1 | 35,051 |
| 2013 | 36.1 | 36,146 |
| 2014 | 38.8 | 38,755 |

Greenhouse gas emissions from cement production increased every year from 1991 through 2006 (with the exception of a slight decrease in 1997), but decreased in the following years until 2009. Emissions from cement production were at their lowest levels in 2009 (2009 emissions are approximately 28 percent lower than 2008 emissions and 12 percent lower than 1990). Since 2010, emissions have increased slightly. In 2014, emissions from cement production increased by 7 percent from 2013 levels.

Emissions since 1990 have increased by 16 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Emissions increased

³ Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime, etc.) and Portland cement (USGS 2011). Carbon dioxide emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

slightly from 2009 levels in 2010, and continued to gradually increase during the 2011 through 2014 time period due to increasing consumption. Cement continues to be a critical component of the construction industry; therefore, the availability of public and private construction funding, as well as overall economic conditions, have considerable impact on the level of cement production.

Methodology

Carbon dioxide emissions were estimated using the Tier 2 methodology from the *2006 IPCC Guidelines*. The Tier 2 methodology was used because detailed and complete data (including weights and composition) for carbonate(s) consumed in clinker production are not available, and thus a rigorous Tier 3 approach is impractical. Tier 2 specifies the use of aggregated plant or national clinker production data and an emission factor, which is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO₂ released per unit of lime. The U.S. Geological Survey (USGS) mineral commodity expert for cement has confirmed that this is a reasonable assumption for the United States (Van Oss 2013a). This calculation yields an emission factor of 0.51 tons of CO₂ per ton of clinker produced, which was determined as follows:

$$EF_{\text{clinker}} = 0.6460 \text{ CaO} \times [(44.01 \text{ g/mole CO}_2) \div (56.08 \text{ g/mole CaO})] = 0.5070 \text{ tons CO}_2/\text{ton clinker}$$

During clinker production, some of the clinker precursor materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker emission factor. The IPCC recommends that these additional CKD CO₂ emissions should be estimated as two percent of the CO₂ emissions calculated from clinker production (when data on CKD generation are not available). Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).

Furthermore, small amounts of impurities (i.e., not calcium carbonate) may exist in the raw limestone used to produce clinker. The proportion of these impurities is generally minimal, although a small amount (1 to 2 percent) of magnesium oxide (MgO) may be desirable as a flux. Per the IPCC Tier 2 methodology, a correction for MgO is not used, since the amount of MgO from carbonate is likely very small and the assumption of a 100 percent carbonate source of CaO already yields an overestimation of emissions (IPCC 2006). The 1990 through 2012 activity data for clinker production (see Table 4-4) were obtained from USGS (Van Oss 2013b). Clinker production data for 2013 and 2014 were also obtained from USGS (USGS 2015a). The data were compiled by USGS (to the nearest ton) through questionnaires sent to domestic clinker and cement manufacturing plants, including the facilities in Puerto Rico.

Table 4-4: Clinker Production (kt)

| Year | Clinker |
|------|---------|
| 1990 | 64,355 |
| 2005 | 88,783 |
| 2010 | 60,444 |
| 2011 | 61,903 |
| 2012 | 67,784 |
| 2013 | 69,901 |
| 2014 | 74,946 |

Notes: Clinker production from 1990 through 2014 includes Puerto Rico. Data were obtained from USGS (Van Oss 2013a; USGS 2014), whose original data source was USGS and U.S. Bureau of Mines Minerals Yearbooks (2013 data obtained from mineral industry surveys for cement in June 2014; 2014 data obtained from mineral industry surveys for cement in June 2015).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are CaCO₃, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (Van Oss 2013a). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO₂ is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO₂ in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO₂ reabsorbed is thought to be minimal, it was not estimated.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-5. Based on the uncertainties associated with total U.S. clinker production, the CO₂ emission factor for clinker production, and the emission factor for additional CO₂ emissions from CKD, 2014 CO₂ emissions from cement production were estimated to be between 36.5 and 41.1 MMT CO₂ Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 6 percent below and 6 percent above the emission estimate of 38.8 MMT CO₂ Eq.

Table 4-5: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Cement Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-------------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Cement Production | CO ₂ | 38.8 | 36.5 | 41.1 | -6% | +6% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

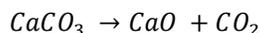
Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP that would be useful to improve the emission estimates for the Cement Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁴ Most facilities reporting under EPA's GHGRP use Continuous Emission Monitoring Systems (CEMS), thus reporting combined process and combustion emissions from kilns. EPA's continued assessment will also focus on feasibility to disaggregate aggregated GHGRP emissions consistent with IPCC and UNFCCC guidelines to present both national process and combustion emissions streams.

⁴ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

4.2 Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Lime production involves three main processes: stone preparation, calcination, and hydration. Carbon dioxide (CO₂) is generated during the calcination stage, when limestone—mostly calcium carbonate (CaCO₃)—is roasted at high temperatures in a kiln to produce calcium oxide (CaO) and CO₂. The CO₂ is given off as a gas and is normally emitted to the atmosphere.



Some of the CO₂ generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.⁵ Emissions from fuels consumed for energy purposes during the production of lime are accounted for in the Energy chapter.

For U.S. operations, the term “lime” actually refers to a variety of chemical compounds. These include CaO, or high-calcium quicklime; calcium hydroxide (Ca(OH)₂), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and dolomitic hydrate ([Ca(OH)₂•MgO] or [Ca(OH)₂•Mg(OH)₂]).

The current lime market is approximately distributed across five end-use categories as follows: metallurgical uses, 38 percent; environmental uses, 31 percent; chemical and industrial uses, 22 percent; construction uses, 8 percent; and refractory dolomite, 1 percent. The major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. Lime is also used as a CO₂ scrubber, and there has been experimentation on the use of lime to capture CO₂ from electric power plants.

Lime production in the United States—including Puerto Rico—was reported to be 19,399 kilotons in 2014 (Corathers 2015). Principal lime producing states are Missouri, Alabama, Kentucky, Ohio, Texas (USGS 2014), Nevada, and Pennsylvania.

U.S. lime production resulted in estimated net CO₂ emissions of 14.1 MMT CO₂ Eq. (14,125 kt) (see Table 4-6 and Table 4-7). The trends in CO₂ emissions from lime production are directly proportional to trends in production, which are described below.

Table 4-6: CO₂ Emissions from Lime Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|--------|
| 1990 | 11.7 | 11,700 |
| 2005 | 14.6 | 14,552 |
| 2010 | 13.4 | 13,381 |
| 2011 | 14.0 | 13,981 |
| 2012 | 13.7 | 13,715 |
| 2013 | 14.0 | 14,045 |
| 2014 | 14.1 | 14,125 |

⁵ PCC is obtained from the reaction of CO₂ with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

Table 4-7: Potential, Recovered, and Net CO₂ Emissions from Lime Production (kt)

| Year | Potential | Recovered ^a | Net Emissions |
|------|-----------|------------------------|---------------|
| 1990 | 11,959 | 259 | 11,700 |
| 2005 | 15,074 | 522 | 14,552 |
| 2010 | 13,776 | 395 | 13,381 |
| 2011 | 14,389 | 407 | 13,981 |
| 2012 | 14,188 | 473 | 13,715 |
| 2013 | 14,513 | 467 | 14,045 |
| 2014 | 14,630 | 505 | 14,125 |

^a For sugar refining and PCC production.

Note: Totals may not sum due to independent rounding.

In 2014, lime production was nearly the same as 2013 levels (increase of 1 percent) at 19,399 kilotons.

Methodology

To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors using the Tier 2 approach from the *2006 IPCC Guidelines* (IPCC 2006). The emission factor is the product of the stoichiometric ratio between CO₂ and CaO, and the average CaO and MgO content for lime. The CaO and MgO content for lime is assumed to be 95 percent for both high-calcium and dolomitic lime (IPCC 2006). The emission factors were calculated as follows:

For high-calcium lime:

$$[(44.01 \text{ g/mole CO}_2) \div (56.08 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.7455 \text{ g CO}_2/\text{g lime}$$

For dolomitic lime:

$$[(88.02 \text{ g/mole CO}_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g CO}_2/\text{g lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H₂O to (Ca(OH)₂ and [Ca(OH)₂•Mg(OH)₂]) (IPCC 2006). These factors set the chemically combined water content to 24.3 percent for high-calcium hydrated lime, and 27.2 percent for dolomitic hydrated lime.

The *2006 IPCC Guidelines* (Tier 2 method) also recommends accounting for emissions from lime kiln dust (LKD) through application of a correction factor. LKD is a byproduct of the lime manufacturing process typically not recycled back to kilns. LKD is a very fine-grained material and is especially useful for applications requiring very small particle size. Most common LKD applications include soil reclamation and agriculture. Currently, data on annual LKD production is not readily available to develop a country specific correction factor. Lime emission estimates were multiplied by a factor of 1.02 to account for emissions from LKD (IPCC 2006).

Lime emission estimates were further adjusted to account for the amount of CO₂ captured for use in on-site processes. All the domestic lime facilities are required to report these data to EPA under its GHGRP. The total national-level annual amount of CO₂ captured for on-site process use was obtained from EPA's GHGRP (EPA 2015) based on reported facility level data for years 2010 through 2014. The amount of CO₂ captured/recovered for on-site process use is deducted from the total potential emissions (i.e., from lime production and LKD). The net lime emissions are presented in Table 4-6 and Table 4-7. GHGRP data on CO₂ removals (i.e., CO₂ captured/recovered) was available only for 2010 through 2014. Since GHGRP data are not available for 1990 through 2009, IPCC "splicing" techniques were used as per the *2006 IPCC Guidelines* on time series consistency (*2006 IPCC Guidelines*, Volume 1, Chapter 5). The prior estimates for CO₂ removal for 1990 through 2009 were adjusted based on the "overlap" technique recommended by IPCC. Refer to the Recalculations Discussion section, below, for more details.

Lime production data (by type, high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2014 (see Table 4-8) were obtained from the U.S. Geological Survey

(USGS) (1992 through 2014; Corathers 2015) and are compiled by USGS to the nearest ton. Natural hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not manufactured in the United States (USGS 2011). Total lime production was adjusted to account for the water content of hydrated lime by converting hydrate to oxide equivalent based on recommendations from the IPCC, and is presented in Table 4-9 (IPCC 2006). The CaO and CaO•MgO contents of lime were obtained from the IPCC (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) were not provided prior to 1997, total lime production for 1990 through 1996 was calculated according to the three year distribution from 1997 to 1999.

Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (kt)

| Year | High-Calcium Quicklime | Dolomitic Quicklime | High-Calcium Hydrated | Dolomitic Hydrated | Dead-Burned Dolomite |
|------|------------------------|---------------------|-----------------------|--------------------|----------------------|
| 1990 | 11,166 | 2,234 | 1,781 | 319 | 342 |
| 2005 | 14,100 | 2,990 | 2,220 | 474 | 200 |
| 2010 | 13,300 | 2,570 | 1,910 | 239 | 200 |
| 2011 | 13,900 | 2,690 | 2,010 | 230 | 200 |
| 2012 | 13,600 | 2,710 | 2,020 | 237 | 200 |
| 2013 | 13,800 | 2,870 | 2,050 | 260 | 200 |
| 2014 | 14,000 | 2,730 | 2,190 | 279 | 200 |

Table 4-9: Adjusted Lime Production (kt)

| Year | High-Calcium | Dolomitic |
|------|--------------|-----------|
| 1990 | 12,466 | 2,800 |
| 2005 | 15,721 | 3,522 |
| 2010 | 14,694 | 2,937 |
| 2011 | 15,367 | 3,051 |
| 2012 | 15,075 | 3,076 |
| 2013 | 15,297 | 3,252 |
| 2014 | 15,599 | 3,125 |

Note: Minus water content of hydrated lime.

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of lime products and CO₂ recovery rates for on-site process use over the time series. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

In addition, a portion of the CO₂ emitted during lime production will actually be reabsorbed when the lime is consumed, especially at captive lime production facilities. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO₂ reacts with the lime to create calcium carbonate (e.g., water softening). Carbon dioxide reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO₂; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. Quantifying the amount of CO₂ that is reabsorbed would require a detailed accounting of lime use in the United States and additional information about the associated processes where both the lime and byproduct CO₂ are “reused” are required to quantify the amount of CO₂ that is reabsorbed. Research conducted thus far has not

yielded the necessary information to quantify CO₂ reabsorption rates.⁶ However, some additional information on the amount of CO₂ consumed on site at lime facilities has been obtained from EPA’s GHGRP.

In some cases, lime is generated from calcium carbonate byproducts at pulp mills and water treatment plants.⁷ The lime generated by these processes is included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic carbon (C) is present from the wood. Kraft mills recover the calcium carbonate “mud” after the causticizing operation and calcine it back into lime—thereby generating CO₂—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO₂ emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net C fluxes from changes in biogenic C reservoirs in wooded or crop lands (see the Land Use, Land-Use Change, and Forestry chapter).

In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the United States.

Another uncertainty is the assumption that calcination emissions for LKD are around 2 percent. The National Lime Association (NLA) has commented that the estimates of emissions from LKD in the United States could be closer to 6 percent. They also note that additional emissions (approximately 2 percent) may also be generated through production of other byproducts/wastes (off-spec lime that is not recycled, scrubber sludge) at lime plants (Seeger 2013). There is limited data publicly available on LKD generation rates and also quantities, types of other byproducts/wastes produced at lime facilities. Further research and data is needed to improve understanding of additional calcination emissions to consider revising the current assumptions that are based on IPCC guidelines. In preparing estimates for the current inventory, EPA initiated a dialogue with NLA to discuss data needs to generate a country specific LKD factor and is reviewing the information provided by NLA.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO₂ emissions for 2014 were estimated to be between 13.8 and 14.5 MMT CO₂ Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 3 percent below and 3 percent above the emission estimate of 14.1 MMT CO₂ Eq.

Table 4-10: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lime Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------|-----------------|---|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Lime Production | CO ₂ | 14.1 | 13.8 | 14.5 | -3% | +3% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

⁶ Representatives of the National Lime Association estimate that CO₂ reabsorption that occurs from the use of lime may offset as much as a quarter of the CO₂ emissions from calcination (Males 2003).

⁷ Some carbide producers may also regenerate lime from their calcium hydroxide byproducts, which does not result in emissions of CO₂. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [CaC₂ + 2H₂O → C₂H₂ + Ca(OH)₂], not calcium carbonate [CaCO₃]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [Ca(OH)₂ + heat → CaO + H₂O] and no CO₂ is released.

Recalculations Discussion

Dead-burned dolomite production data for 2013 were updated relative to the previous Inventory based on the more recent *Minerals Yearbook: Lime 2013 [Advanced Release]* (USGS 2014). This caused a slight decrease in 2013 emissions, by approximately 0.2 percent.

Planned Improvements

Future improvements involve evaluating recently obtained data to improve current assumptions associated with emissions from production of LKD and other byproducts/wastes as discussed in the Uncertainty and Time-Series Consistency section per comments from the NLA. In response to comments, EPA met with NLA on April 7, 2015 to outline specific information required to apply IPCC methods to develop a country-specific correction factor to more accurately estimate emissions from production of LKD. In response to this technical meeting, in January and February 2016, NLA compiled and shared historical emissions information reported by member facilities on an annual basis under voluntary reporting initiatives over 2002 through 2011 associated with generation of total calcined byproducts and LKD (LKD reporting only differentiated starting in 2010). This emissions information was reported on a voluntary basis consistent with NLA's facility-level reporting protocol also recently provided.

4.3 Glass Production (IPCC Source Category 2A3)

Glass production is an energy and raw-material intensive process that results in the generation of CO₂ from both the energy consumed in making glass and the glass process itself. Emissions from fuels consumed for energy purposes during the production of glass are accounted for in the Energy sector.

Glass production employs a variety of raw materials in a glass-batch. These include formers, fluxes, stabilizers, and sometimes colorants. The major raw materials (i.e., fluxes and stabilizers) which emit process-related carbon dioxide (CO₂) emissions during the glass melting process are limestone, dolomite, and soda ash. The main former in all types of glass is silica (SiO₂). Other major formers in glass include feldspar and boric acid (i.e., borax). Fluxes are added to lower the temperature at which the batch melts. Most commonly used flux materials are soda ash (sodium carbonate, Na₂CO₃) and potash (potassium carbonate, K₂O). Stabilizers are used to make glass more chemically stable and to keep the finished glass from dissolving and/or falling apart. Commonly used stabilizing agents in glass production are limestone (CaCO₃), dolomite (CaCO₃MgCO₃), alumina (Al₂O₃), magnesia (MgO), barium carbonate (BaCO₃), strontium carbonate (SrCO₃), lithium carbonate (Li₂CO₃), and zirconia (ZrO₂) (OIT 2002). Glass makers also use a certain amount of recycled scrap glass (cullet), which comes from in-house return of glassware broken in the process or other glass spillage or retention such as recycling or cullet broker services.

The raw materials (primarily limestone, dolomite and soda ash) release CO₂ emissions in a complex high-temperature chemical reaction during the glass melting process. This process is not directly comparable to the calcination process used in lime manufacturing, cement manufacturing, and process uses of carbonates (i.e., limestone/dolomite use), but has the same net effect in terms of CO₂ emissions (IPCC 2006). The U.S. glass industry can be divided into four main categories: containers, flat (window) glass, fiber glass, and specialty glass. The majority of commercial glass produced is container and flat glass (EPA 2009). The United States is one of the major global exporters of glass. Domestically, demand comes mainly from the construction, auto, bottling, and container industries. There are over 1,500 companies that manufacture glass in the United States, with the largest being Corning, Guardian Industries, Owens-Illinois, and PPG Industries.⁸

⁸ Excerpt from Glass & Glass Product Manufacturing Industry Profile, First Research. Available online at: <<http://www.firstresearch.com/Industry-Research/Glass-and-Glass-Product-Manufacturing.html>>.

In 2014, 775 kilotons of limestone and 2,410 kilotons of soda ash were consumed for glass production (USGS 2015a; Willett 2015). Dolomite consumption data for glass manufacturing was reported to be zero for 2014. Use of limestone and soda ash in glass production resulted in aggregate CO₂ emissions of 1.3 MMT CO₂ Eq. (1,341 kt) (see Table 4-11). Overall, emissions have decreased 13 percent from 1990 through 2014.

Emissions from glass production have remained relatively constant over the time series with some fluctuations since 1990. In general, these fluctuations were related to the behavior of the export market and the U.S. economy. Specifically, the extended downturn in residential and commercial construction and automotive industries between 2008 and 2010 resulted in reduced consumption of glass products, causing a drop in global demand for limestone/dolomite and soda ash, and a corresponding decrease in emissions. Furthermore, the glass container sector is one of the leading soda ash consuming sectors in the United States. Some commercial food and beverage package manufacturers are shifting from glass containers towards lighter and more cost effective polyethylene terephthalate (PET) based containers, putting downward pressure on domestic consumption of soda ash (USGS 1995 through 2014).

Table 4-11: CO₂ Emissions from Glass Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 1.5 | 1,535 |
| 2005 | 1.9 | 1,928 |
| 2010 | 1.5 | 1,481 |
| 2011 | 1.3 | 1,299 |
| 2012 | 1.2 | 1,248 |
| 2013 | 1.3 | 1,317 |
| 2014 | 1.3 | 1,341 |

Note: Totals may not sum due to independent rounding

Methodology

Carbon dioxide emissions were calculated based on the 2006 IPCC Guidelines Tier 3 method by multiplying the quantity of input carbonates (limestone, dolomite, and soda ash) by the carbonate-based emission factor (in metric tons CO₂/metric ton carbonate): limestone, 0.43971; dolomite, 0.47732; and soda ash, 0.41492.

Consumption data for 1990 through 2014 of limestone, dolomite, and soda ash used for glass manufacturing were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2015b), 2014 preliminary data from the USGS Crushed Stone Commodity Expert (Willett 2015), the USGS *Minerals Yearbook: Soda Ash Annual Report* (1995 through 2014), USGS Mineral Industry Surveys for Soda Ash in January 2015 (USGS 2015a) and the U.S. Bureau of Mines (1991 and 1993a), which are reported to the nearest ton. During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; or (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years.

There is a large quantity of limestone and dolomite reported to the USGS under the categories “unspecified–reported” and “unspecified–estimated.” A portion of this consumption is believed to be limestone or dolomite used for glass manufacturing. The quantities listed under the “unspecified” categories were, therefore, allocated to glass

manufacturing according to the percent limestone or dolomite consumption for glass manufacturing end use for that year.⁹

Based on the 2014 reported data, the estimated distribution of soda ash consumption for glass production compared to total domestic soda ash consumption is 48 percent (USGS 2015a).

Table 4-12: Limestone, Dolomite, and Soda Ash Consumption Used in Glass Production (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Limestone | 430 | 920 | 999 | 614 | 555 | 693 | 775 |
| Dolomite | 59 | 541 | 0 | 0 | 0 | 0 | 0 |
| Soda Ash | 3,177 | 3,050 | 2,510 | 2,480 | 2,420 | 2,440 | 2,410 |
| Total | 3,666 | 4,511 | 3,509 | 3,094 | 2,975 | 3,133 | 3,185 |

Uncertainty and Time-Series Consistency

The uncertainty levels presented in this section arise in part due to variations in the chemical composition of limestone used in glass production. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals (potassium carbonate, strontium carbonate and barium carbonate, and dead burned dolomite). Similarly, the quality of the limestone (and mix of carbonates) used for glass manufacturing will depend on the type of glass being manufactured.

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer of the input carbonates (limestone, dolomite & soda ash) and not the end user. For 2014, there has been no reported consumption of dolomite for glass manufacturing. This data has been reported to USGS by dolomite manufacturers and not end-users (i.e., glass manufacturers). There is a high uncertainty associated with this estimate, as dolomite is a major raw material consumed in glass production. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone and dolomite used in glass making is especially high. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses. Further research is needed into alternate and more complete sources of data on carbonate-based raw material consumption by the glass industry.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-13. In 2014, glass production CO₂ emissions were estimated to be between 1.3 and 1.4 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below and 5 percent above the emission estimate of 1.3 MMT CO₂ Eq.

Table 4-13: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Glass Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|------------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Glass Production | CO ₂ | 1.3 | 1.3 | 1.4 | -4% | +5% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

⁹ This approach was recommended by USGS.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Limestone and dolomite consumption data for 2013 were revised to reflect updated USGS data (USGS 2015b). This change resulted in an increase of CO₂ emissions by approximately 14 percent. The preliminary data for 2013 was obtained directly from the USGS Crushed Stone Commodity Expert (Willett 2014). In April 2015, USGS published the *2013 Minerals Yearbook* for Crushed Stone and the preliminary data were revised to reflect the latest USGS published data. The published time series was reviewed to ensure time series consistency. Details on the emission trends through time are described in more detail in the Methodology section above.

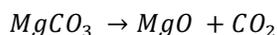
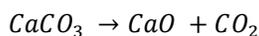
Planned Improvements

Currently, only limestone and soda ash consumption data for glass manufacturing is publicly available. While limestone and soda ash are the predominant carbonates used in glass manufacturing, there are other carbonates that are also consumed for glass manufacturing, although in smaller quantities. Pending resources, future improvements will include research into other sources of data for carbonate consumption by the glass industry, including EPA's Greenhouse Gas Reporting Program (GHGRP).

Additionally, future improvements will also include finalizing assessment and integration of data reported under EPA's GHGRP to improve the emission estimates and completeness for the Glass Production source category. Particular attention will be made to also ensuring time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In addition, EPA's GHGRP has an emission threshold for reporting, so the data do not account for all glass production in the United States. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.¹⁰

4.4 Other Process Uses of Carbonates (IPCC Source Category 2A4)

Limestone (CaCO₃), dolomite (CaCO₃MgCO₃),¹¹ and other carbonates such as soda ash, magnesite, and siderite are basic materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. This section addresses only limestone and dolomite use. For industrial applications, carbonates such as limestone and dolomite are heated sufficiently enough to calcine the material and generate CO₂ as a byproduct.



Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, and as a raw material for the production of glass, lime, and cement. Emissions from limestone and dolomite used in other process sectors such as cement, lime, glass production, and iron and steel, are excluded from this section and reported under their respective source

¹⁰ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

¹¹ Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

categories (e.g., Section 4.3, Glass Production (IPCC Source Category 2A3)). Emission from soda ash consumption is reported under respective categories (e.g., Glass Manufacturing (IPCC Source Category 2A3) and Soda Ash Production and Consumption (IPCC Source Category 2B7)). Emissions from fuels consumed for energy purposes during these processes are accounted for in the Energy chapter.

Limestone is widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. The leading limestone producing states are Texas, Missouri, Florida, Ohio, and Pennsylvania, which contribute 43 percent of the total U.S. output (USGS 2015). Similarly, dolomite deposits are also widespread throughout the world. Dolomite deposits are found in the United States, Canada, Mexico, Europe, Africa, and Brazil. In the United States, the leading dolomite producing states are Illinois, Pennsylvania, and New York, which contribute 55 percent of the total U.S. output (USGS 2015).

In 2014, 25,085 kt of limestone and 3,359 kt of dolomite were consumed for these emissive applications, excluding glass manufacturing (Willett 2015). Usage of limestone and dolomite resulted in aggregate CO₂ emissions of 12.1 MMT CO₂ Eq. (12,077 kt) (see Table 4-14 and Table 4-15). Overall, emissions have increased 146 percent from 1990 through 2014.

Table 4-14: CO₂ Emissions from Other Process Uses of Carbonates (MMT CO₂ Eq.)

| Year | Flux Stone | FGD | Magnesium Production | Other Miscellaneous Uses ^a | Total |
|------|------------|-----|----------------------|---------------------------------------|-------|
| 1990 | 2.6 | 1.4 | 0.1 | 0.8 | 4.9 |
| 2005 | 2.6 | 3.0 | 0.0 | 0.7 | 6.3 |
| 2010 | 1.6 | 7.1 | 0.0 | 0.9 | 9.6 |
| 2011 | 1.5 | 5.4 | 0.0 | 2.4 | 9.3 |
| 2012 | 1.1 | 5.8 | 0.0 | 1.1 | 8.0 |
| 2013 | 2.3 | 6.3 | 0.0 | 1.8 | 10.4 |
| 2014 | 2.9 | 7.2 | 0.0 | 1.9 | 12.1 |

^a “Other miscellaneous uses” include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Note: Totals may not sum due to independent rounding.

Table 4-15: CO₂ Emissions from Other Process Uses of Carbonates (kt)

| Year | Flux Stone | FGD | Magnesium Production | Other Miscellaneous Uses ^a | Total |
|------|------------|-------|----------------------|---------------------------------------|--------|
| 1990 | 2,592 | 1,432 | 64 | 819 | 4,907 |
| 2005 | 2,649 | 2,973 | 0 | 718 | 6,339 |
| 2010 | 1,560 | 7,064 | 0 | 937 | 9,560 |
| 2011 | 1,467 | 5,420 | 0 | 2,449 | 9,335 |
| 2012 | 1,077 | 5,797 | 0 | 1,148 | 8,022 |
| 2013 | 2,307 | 6,309 | 0 | 1,798 | 10,414 |
| 2014 | 2,932 | 7,212 | 0 | 1,933 | 12,077 |

^a “Other miscellaneous uses” include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Note: Totals may not sum due to independent rounding.

Methodology

Carbon dioxide emissions were calculated based on the 2006 IPCC Guidelines Tier 2 method by multiplying the quantity of limestone or dolomite consumed by the emission factor for limestone or dolomite calcination,

respectively, Table 2.1—limestone: 0.43971 metric ton CO₂/metric ton carbonate, and dolomite: 0.47732 metric ton CO₂/metric ton carbonate.¹² This methodology was used for flux stone, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Flux stone used during the production of iron and steel was deducted from the Other Process Uses of Carbonates source category estimate and attributed to the Iron and Steel Production source category estimate. Similarly limestone and dolomite consumption for glass manufacturing, cement, and lime manufacturing are excluded from this category and attributed to their respective categories.

Historically, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO₂ emissions. At the end of 2001, the sole magnesium production plant operating in the United States that produced magnesium metal using a dolomitic process that resulted in the release of CO₂ emissions ceased its operations (USGS 1995b through 2012; USGS 2013a).

Consumption data for 1990 through 2014 of limestone and dolomite used for flux stone, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-16) were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook: Crushed Stone Annual Report* (1995a through 2015), preliminary data for 2014 from USGS Crushed Stone Commodity Expert (Willett 2015), and the U.S. Bureau of Mines (1991 and 1993a), which are reported to the nearest ton. The production capacity data for 1990 through 2014 of dolomitic magnesium metal also came from the USGS (1995b through 2012; USGS 2013a) and the U.S. Bureau of Mines (1990 through 1993b). During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the end-use over the entire time period.

There is a large quantity of crushed stone reported to the USGS under the category “unspecified uses.” A portion of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for “unspecified uses” was, therefore, allocated to each reported end-use according to each end-use’s fraction of total consumption in that year.¹³

Table 4-16: Limestone and Dolomite Consumption (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Flux Stone | 6,737 | 7,022 | 4,440 | 4,396 | 3,666 | 6,345 | 7,648 |
| Limestone | 5,804 | 3,165 | 1,921 | 2,531 | 3,108 | 4,380 | 4,304 |
| Dolomite | 933 | 3,857 | 2,520 | 1,865 | 559 | 1,965 | 3,344 |
| FGD | 3,258 | 6,761 | 16,064 | 12,326 | 13,185 | 14,347 | 16,402 |
| Other Miscellaneous Uses | 1,835 | 1,632 | 2,121 | 5,548 | 2,610 | 3,973 | 4,395 |
| Total | 11,830 | 15,415 | 22,626 | 22,270 | 19,461 | 24,665 | 28,444 |

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

The uncertainty levels presented in this section account for uncertainty associated with activity data. Data on limestone and dolomite consumption are collected by USGS through voluntary national surveys. USGS contacts the

¹² 2006 IPCC Guidelines, Volume 3: Chapter 2.

¹³ This approach was recommended by USGS, the data collection agency.

mines (i.e., producers of various types of crushed stone) for annual sales data. Data on other carbonate consumption are not readily available. The producers report the annual quantity sold to various end-users/industry types. USGS estimates the historical response rate for the crushed stone survey to be approximately 70 percent, the rest is estimated by USGS. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the producer/mines and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

Uncertainty in the estimates also arises in part due to variations in the chemical composition of limestone. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process and the kind of ore processed.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-17. Carbon dioxide emissions from other process uses of carbonates in 2014 were estimated to be between 10.7 and 14.0 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 15 percent above the emission estimate of 12.1 MMT CO₂ Eq.

Table 4-17: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Other Process Uses of Carbonates (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|----------------------------------|-----------------|--|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Other Process Uses of Carbonates | CO ₂ | 12.1 | 10.7 | 14.0 | -12% | +15% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Limestone and dolomite consumption data, by end-use, for 2013 were updated relative to the previous Inventory based on the recently published *2013 Minerals Yearbook: Crushed Stone*. In the previous Inventory report (i.e., 1990 through 2013), preliminary data were used for 2013 and updated for the current Inventory. In April 2015, USGS published the *2013 Minerals Yearbook for Crushed Stone* and the preliminary data were revised to reflect the latest USGS published data. The published time series was reviewed to ensure time series consistency. This update caused an increase in total limestone and dolomite consumption for emissive end uses in 2013 by approximately 120 percent. The revised 2013 emission estimate increased by approximately 135 percent relative to the previous report due to this change.

Planned Improvements

In future Inventory reports, this section will integrate and present emissions from soda ash consumption for other chemical uses (non-glass production). Currently, in this document, these estimates are presented along with emissions from soda ash production (IPCC Category 2B7).

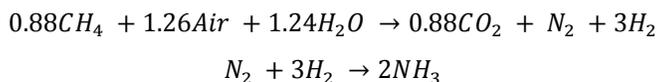
4.5 Ammonia Production (IPCC Source Category 2B1)

Emissions of carbon dioxide (CO₂) occur during the production of synthetic ammonia, primarily through the use of natural gas, petroleum coke, or naphtha as a feedstock. The natural gas-, naphtha-, and petroleum coke-based processes produce CO₂ and hydrogen (H₂), the latter of which is used in the production of ammonia. The brine electrolysis process for production of ammonia does not lead to process-based CO₂ emissions. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter.

In the United States, the majority of ammonia is produced using a natural gas feedstock; however one synthetic ammonia production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some U.S. plants, some of the CO₂ produced by the process is captured and used to produce urea rather than being emitted to the atmosphere. There are approximately 13 companies operating 26 ammonia producing facilities in 17 states. More than 56 percent of domestic ammonia production capacity is concentrated in the states of Louisiana (29 percent), Oklahoma (21 percent), and Texas (6 percent) (USGS 2015).

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts methane (CH₄) to CO₂, carbon monoxide (CO), and H₂ in the presence of a catalyst. Only 30 to 40 percent of the CH₄ feedstock to the primary reformer is converted to CO and CO₂ in this step of the process. The secondary reforming step converts the remaining CH₄ feedstock to CO and CO₂. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO₂ in the presence of a catalyst, water, and air in the shift conversion step. Carbon dioxide is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N₂) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO₂ is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO₂ is released from the solution.

The conversion process for conventional steam reforming of CH₄, including the primary and secondary reforming and the shift conversion processes, is approximately as follows:



To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO₂ and H₂. These gases are separated, and the H₂ is used as a feedstock to the ammonia production process, where it is reacted with N₂ to form ammonia.

Not all of the CO₂ produced during the production of ammonia is emitted directly to the atmosphere. Some of the ammonia and some of the CO₂ produced by the synthetic ammonia process are used as raw materials in the production of urea [CO(NH₂)₂], which has a variety of agricultural and industrial applications.

The chemical reaction that produces urea is:



Only the CO₂ emitted directly to the atmosphere from the synthetic ammonia production process is accounted for in determining emissions from ammonia production. The CO₂ that is captured during the ammonia production process and used to produce urea does not contribute to the CO₂ emission estimates for ammonia production presented in this section. Instead, CO₂ emissions resulting from the consumption of urea are attributed to the urea consumption or urea application source category (under the assumption that the carbon stored in the urea during its manufacture is released into the environment during its consumption or application). Emissions of CO₂ resulting from agricultural applications of urea are accounted for in the *Cropland Remaining Cropland* section of the Land Use, Land-Use Change, and Forestry chapter. Emissions of CO₂ resulting from non-agricultural applications of urea (e.g., use as a feedstock in chemical production processes) are accounted for in the Urea Consumption for Non-Agricultural Purposes section of this chapter.

Total emissions of CO₂ from ammonia production in 2014 were 9.4 MMT CO₂ Eq. (9,436 kt), and are summarized in Table 4-18 and Table 4-19. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia. Since 1990, emissions from ammonia production have decreased by 28 percent. Emissions in 2014 have decreased by approximately 5 percent from the 2013 levels.

Table 4-18: CO₂ Emissions from Ammonia Production (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------|-------------|------------|------------|------------|------------|-------------|------------|
| Ammonia Production | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |
| Total | 13.0 | 9.2 | 9.2 | 9.3 | 9.4 | 10.0 | 9.4 |

Table 4-19: CO₂ Emissions from Ammonia Production (kt)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------|---------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Ammonia Production | 13,047 | 9,196 | 9,188 | 9,292 | 9,377 | 9,962 | 9,436 |
| Total | 13,047 | 9,196 | 9,188 | 9,292 | 9,377 | 9,962 | 9,436 |

Methodology

Carbon dioxide emissions from production of synthetic ammonia from natural gas feedstock is based on the 2006 IPCC Guidelines (IPCC 2006) Tier 1 and 2 method. A country-specific emission factor is developed and applied to national ammonia production to estimate emissions. The method uses a CO₂ emission factor published by the European Fertilizer Manufacturers Association (EFMA) that is based on natural gas-based ammonia production technologies that are similar to those employed in the United States. This CO₂ emission factor of 1.2 metric tons CO₂/metric ton NH₃ (EFMA 2000a) is applied to the percent of total annual domestic ammonia production from natural gas feedstock.

Emissions of CO₂ from ammonia production are then adjusted to account for the use of some of the CO₂ produced from ammonia production as a raw material in the production of urea. The CO₂ emissions reported for ammonia production are reduced by a factor of 0.733 multiplied by total annual domestic urea production. This corresponds to a stoichiometric CO₂/urea factor of 44/60, assuming complete conversion of ammonia (NH₃) and CO₂ to urea (IPCC 2006; EFMA 2000b).

All synthetic ammonia production and subsequent urea production are assumed to be from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from petroleum coke feedstock at one plant located in Kansas. Annual ammonia and urea production are shown in Table 4-20. The CO₂ emission factor for production of ammonia from petroleum coke is based on plant-specific data, wherein all carbon contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO₂ (Bark 2004). Ammonia and urea are assumed to be manufactured in the same manufacturing complex, as both the raw materials needed for urea production are produced by the ammonia production process. The CO₂ emission factor of 3.57 metric tons CO₂/metric ton NH₃ for the petroleum coke feedstock process (Bark 2004) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO₂/metric ton NH₃ for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 2000a). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO₂/metric ton NH₃, with 1.2 metric ton CO₂/metric ton NH₃ as a typical value (EFMA 2000a). Technologies (e.g., catalytic reforming process, etc.) associated with this factor are found to closely resemble those employed in the United States for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH₄ feedstock to the catalytic reforming process is ultimately converted to CO₂. As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. The total ammonia production data for 2011, 2012, 2013, and 2014 were obtained from American Chemistry Council (2015). For years before 2011, ammonia production data (see Table 4-20) were obtained from Coffeyville Resources (Coffeyville 2005,

2006, 2007a, 2007b, 2009, 2010, 2011, and 2012) and the Census Bureau of the U.S. Department of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2010) as reported in Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports. Urea-ammonia nitrate production from petroleum coke for years through 2011 was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010, 2011, and 2012), and from CVR Energy, Inc. Annual Report (CVR 2012, 2014, and 2015) for 2012, 2013, and 2014. Urea production data for 1990 through 2008 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 1994 through 2009). Urea production data for 2009 through 2010 were obtained from the U.S. Census Bureau (U.S. Census Bureau 2010 and 2011). The U.S. Census Bureau ceased collection of urea production statistics, and urea production data for 2011, 2012, and 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2014, 2015). The urea production data for 2014 are not yet published and so 2013 data were used as proxies for 2014.

Table 4-20: Ammonia Production and Urea Production (kt)

| Year | Ammonia Production | Urea Production |
|------|--------------------|-----------------|
| 1990 | 15,425 | 7,450 |
| 2005 | 10,143 | 5,270 |
| 2010 | 10,084 | 5,122 |
| 2011 | 10,325 | 5,430 |
| 2012 | 10,305 | 5,220 |
| 2013 | 10,930 | 5,480 |
| 2014 | 10,515 | 5,480 |

Uncertainty and Time-Series Consistency

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with ammonia production estimates and the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. Uncertainty is also associated with the representativeness of the emission factor used for the petroleum coke-based ammonia process. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material.

Recovery of CO₂ from ammonia production plants for purposes other than urea production (e.g., commercial sale, etc.) has not been considered in estimating the CO₂ emissions from ammonia production, as data concerning the disposition of recovered CO₂ are not available. Such recovery may or may not affect the overall estimate of CO₂ emissions depending upon the end use to which the recovered CO₂ is applied. Further research is required to determine whether byproduct CO₂ is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-21. Carbon dioxide emissions from ammonia production were estimated to be between 8.7 and 10.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 8 percent below and 8 percent above the emission estimate of 9.4 MMT CO₂ Eq.

Table 4-21: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ammonia Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|--------------------|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Ammonia Production | CO ₂ | 9.4 | 8.7 | 10.2 | -8% | +8% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Production estimates for urea production for 2013 were updated relative to the previous Inventory using information obtained from the recent *2013 Minerals Yearbook: Nitrogen* (USGS 2015). For the previous version of the Inventory (i.e., 1990 through 2013), 2012 data was used as a proxy for 2013 as the 2013 data were not published prior to the previous Inventory report. This update resulted in a slight decrease of emissions by approximately 2 percent for 2013 relative to the previous report.

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP to improve the emission estimates for the Ammonia Production source category, in particular new data from updated reporting requirements finalized in October of 2015, that include necessary activity data. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.¹⁴ Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO₂ emissions and incorporate CO₂ capture and storage. Methodologies will also be updated if additional ammonia production plants are found to use hydrocarbons other than natural gas for ammonia production.

4.6 Urea Consumption for Non-Agricultural Purposes

Urea is produced using ammonia and carbon dioxide (CO₂) as raw materials. All urea produced in the United States is assumed to be produced at ammonia production facilities where both ammonia and CO₂ are generated. There are approximately 20 of these facilities operating in the United States.

The chemical reaction that produces urea is:



¹⁴ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

This section accounts for CO₂ emissions associated with urea consumed exclusively for non-agricultural purposes. Carbon dioxide emissions associated with urea consumed for fertilizer are accounted for in the *Cropland Remaining Cropland* section of the Land Use, Land-Use Change, and Forestry chapter.

Urea is used as a nitrogenous fertilizer for agricultural applications and also in a variety of industrial applications. The industrial applications of urea include its use in adhesives, binders, sealants, resins, fillers, analytical reagents, catalysts, intermediates, solvents, dyestuffs, fragrances, deodorizers, flavoring agents, humectants and dehydrating agents, formulation components, monomers, paint and coating additives, photosensitive agents, and surface treatments agents. In addition, urea is used for abating nitrogen oxide (NO_x) emissions from coal-fired power plants and diesel transportation motors.

Emissions of CO₂ from urea consumed for non-agricultural purposes in 2014 were estimated to be 4.0 MMT CO₂ Eq. (4,007 kt), and are summarized in Table 4-22 and Table 4-23. 2014 data on urea production data, urea exports and imports are not yet published. 2013 data has been used as proxy for 2014. Net CO₂ emissions from urea consumption for non-agricultural purposes in 2014 have increased by approximately 6 percent from 1990.

Table 4-22: CO₂ Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|------------|------------|------------|------------|------------|------------|------------|
| Urea Consumption | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |
| Total | 3.8 | 3.7 | 4.7 | 4.0 | 4.4 | 4.2 | 4.0 |

Table 4-23: CO₂ Emissions from Urea Consumption for Non-Agricultural Purposes (kt)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Urea Consumption | 3,784 | 3,653 | 4,730 | 4,029 | 4,449 | 4,179 | 4,007 |
| Total | 3,784 | 3,653 | 4,730 | 4,029 | 4,449 | 4,179 | 4,007 |

Methodology

Emissions of CO₂ resulting from urea consumption for non-agricultural purposes are estimated by multiplying the amount of urea consumed in the United States for non-agricultural purposes by a factor representing the amount of CO₂ used as a raw material to produce the urea. This method is based on the assumption that all of the carbon in urea is released into the environment as CO₂ during use, and consistent with the *2006 IPCC Guidelines* (IPCC 2006).

The amount of urea consumed for non-agricultural purposes in the United States is estimated by deducting the quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Land Use, Land-Use Change, and Forestry chapter (see Table 6-30) and is reported in Table 4-24, from the total domestic supply of urea. The domestic supply of urea is estimated based on the amount of urea produced plus the sum of net urea imports and exports. A factor of 0.733 tons of CO₂ per ton of urea consumed is then applied to the resulting supply of urea for non-agricultural purposes to estimate CO₂ emissions from the amount of urea consumed for non-agricultural purposes. The 0.733 tons of CO₂ per ton of urea emission factor is based on the stoichiometry of producing urea from ammonia and CO₂. This corresponds to a stoichiometric CO₂/urea factor of 44/60, assuming complete conversion of NH₃ and CO₂ to urea (IPCC 2006; EFMA 2000).

Urea production data for 1990 through 2008 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 1994 through 2009). Urea production data for 2009 through 2010 were obtained from the U.S. Census Bureau (2011). The U.S. Census Bureau ceased collection of urea production statistics in 2011, therefore, urea production data for 2011, 2012, and 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2014 through 2015). Urea production data for 2014 are not yet publicly available and so 2013 data have been used as proxy.

Urea import data for 2014 are not yet publicly available and so 2013 data have been used as proxy. Urea import data for 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Urea import data for 2011 and

2012 were taken from U.S. Fertilizer Import/Exports from the United States Department of Agriculture (USDA) Economic Research Service Data Sets (U.S. Department of Agriculture 2012). Urea import data for the previous years were obtained from the U.S. Census Bureau *Current Industrial Reports Fertilizer Materials and Related Products* annual and quarterly reports for 1997 through 2010 (U.S. Census Bureau 1998 through 2011), The Fertilizer Institute (TFI 2002) for 1993 through 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002) for 1990 through 1992 (see Table 4-24). Urea export data for 2014 are not yet publicly available and so 2013 data have been used as proxy. Urea export data for 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Urea export data for 1990 through 2012 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2012).

Table 4-24: Urea Production, Urea Applied as Fertilizer, Urea Imports, and Urea Exports (kt)

| Year | Urea Production | Urea Applied as Fertilizer | Urea Imports | Urea Exports |
|------|-----------------|----------------------------|--------------|--------------|
| 1990 | 7,450 | 3,296 | 1,860 | 854 |
| 2005 | 5,270 | 4,779 | 5,026 | 536 |
| 2010 | 5,122 | 5,152 | 6,631 | 152 |
| 2011 | 5,430 | 5,589 | 5,860 | 207 |
| 2012 | 5,220 | 5,762 | 6,944 | 336 |
| 2013 | 5,480 | 5,921 | 6,470 | 330 |
| 2014 | 5,480 | 6,156 | 6,470 | 330 |

Uncertainty and Time-Series Consistency

There is limited publicly-available data on the quantities of urea produced and consumed for non-agricultural purposes. Therefore, the amount of urea used for non-agricultural purposes is estimated based on a balance that relies on estimates of urea production, urea imports, urea exports, and the amount of urea used as fertilizer. The primary uncertainties associated with this source category are associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source. Because urea production estimates are no longer available from the USGS, there is additional uncertainty associated with urea produced beginning in 2011. There is also uncertainty associated with the assumption that all of the carbon in urea is released into the environment as CO₂ during use.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-25. Carbon dioxide emissions associated with urea consumption for non-agricultural purposes were estimated to be between 3.5 and 4.5 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 12 percent above the emission estimate of 4.0 MMT CO₂ Eq.

Table 4-25: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|--|-----------------|--|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Urea Consumption for Non-Agricultural Purposes | CO ₂ | 4.0 | 3.5 | 4.5 | -12% | +12% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

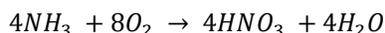
Production estimates for urea production and estimates for urea exports and imports for 2013 were updated using information obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Also, the amount of urea consumed for agricultural purposes in the United States for 2013 was revised based on the most recent data obtained from the Land Use, Land-Use Change, and Forestry chapter (see Table 6-30). These updates resulted in a decrease in the emission estimate relative to the previous report of approximately 10 percent in 2013.

4.7 Nitric Acid Production (IPCC Source Category 2B2)

Nitrous oxide (N₂O) is emitted during the production of nitric acid (HNO₃), an inorganic compound used primarily to make synthetic commercial fertilizers. It is also a major component in the production of adipic acid—a feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured by the high-temperature catalytic oxidation of ammonia (EPA 1998). There are two different nitric acid production methods: weak nitric acid and high-strength nitric acid. The first method utilizes oxidation, condensation, and absorption to produce nitric acid at concentrations between 30 and 70 percent nitric acid. High-strength acid (90 percent or greater nitric acid) can be produced from dehydrating, bleaching, condensing, and absorption of the weak nitric acid. The basic process technology for producing nitric acid has not changed significantly over time. Most U.S. plants were built between 1960 and 2000. As of 2014, there were 34 active weak nitric acid production plants, including one high-strength nitric acid production plant in the United States (EPA 2010; EPA 2015).

During this reaction, N₂O is formed as a byproduct and is released from reactor vents into the atmosphere. Emissions from fuels consumed for energy purposes during the production of nitric acid are accounted for in the Energy chapter.

Nitric acid is made from the reaction of ammonia (NH₃) with oxygen (O₂) in two stages. The overall reaction is:



Currently, the nitric acid industry controls emissions of NO and NO₂ (i.e., NO_x). As such, the industry in the United States uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR) technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N₂O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCR systems were installed in nitric plants built between 1971 and 1977 with NSCRs installed at approximately one-third of the weak acid production plants. U.S. facilities are using both tertiary (i.e., NSCR) and secondary controls (i.e., alternate catalysts).

Nitrous oxide emissions from this source were estimated to be 10.9 MMT CO₂ Eq. (37 kt of N₂O) in 2014 (see Table 4-26). Emissions from nitric acid production have decreased by 10 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions have decreased by 24 percent since 1997, the highest year of production in the time series.

Table 4-26: N₂O Emissions from Nitric Acid Production (MMT CO₂ Eq. and kt N₂O)

| Year | MMT CO ₂ Eq. | kt N ₂ O |
|------|-------------------------|---------------------|
| 1990 | 12.1 | 41 |
| 2005 | 11.3 | 38 |
| 2010 | 11.5 | 39 |
| 2011 | 10.9 | 37 |

| | | |
|------|------|----|
| 2012 | 10.5 | 35 |
| 2013 | 10.7 | 36 |
| 2014 | 10.9 | 37 |

Methodology

Emissions of N₂O were calculated using the estimation methods provided by the *2006 IPCC Guidelines* (IPCC 2006) and country specific methods from EPA’s Greenhouse Gas Reporting Program (GHGRP). The *2006 IPCC Guidelines* Tier 2 method was used to estimate emissions from nitric acid production for 1990 through 2009, and a country-specific approach similar to the IPCC Tier 3 method was used to estimate N₂O emissions for 2010 through 2014.

2010 through 2014

Process N₂O emissions and nitric acid production data were obtained directly from EPA’s GHGRP for 2010 through 2014 by aggregating reported facility-level data (EPA 2015). In the United States, all nitric acid facilities producing weak nitric acid (30 to 70 percent in strength) are required to report annual greenhouse gas emissions data to EPA as per the requirements of its GHGRP. As of 2014, there were 34 facilities that reported to EPA, including the known single high-strength nitric acid production facility in the United States (EPA 2015). All nitric acid (weak acid) facilities are required to calculate process emissions using a site-specific emission factor developed through annual performance testing under typical operating conditions or by directly measuring N₂O emissions using monitoring equipment. The high-strength nitric acid facility also reports N₂O emissions associated with weak acid production and this may capture all relevant emissions, pending additional further EPA research. More details on the calculation and monitoring methods applicable to Nitric Acid facilities can be found under Subpart V: Nitric Acid Production of the regulation, Part 98.¹⁵

1990 through 2009

Using the GHGRP data for 2010,¹⁶ country-specific N₂O emission factors were calculated for nitric acid production with abatement and without abatement (i.e., controlled and uncontrolled emission factors). The following 2010 emission factors were derived for production with abatement and without abatement: 3.3 kg N₂O/metric ton HNO₃ produced at plants using abatement technologies (e.g., tertiary systems such as NSCR systems) and 5.98 kg N₂O/metric ton HNO₃ produced at plants not equipped with abatement technology. Country-specific weighted emission factors were derived by weighting these emission factors by percent production with abatement and without abatement over time periods 1990 through 2008 and 2009. These weighted emission factors were used to estimate N₂O emissions from nitric acid production for years prior to the availability of EPA’s GHGRP data (i.e., 1990 through 2008 and 2009). A separate weighted factor is included for 2009 due to data availability for that year. At that time, EPA had initiated compilation of a nitric acid database to improve estimation of emissions from this industry and obtained updated information on application of controls via review of permits and outreach with facilities and trade associations. The research indicated recent installation of abatement technologies at additional facilities.

Based on the available data, it was assumed that emission factors for 2010 would be more representative of operating conditions in 1990 through 2009 than more recent years. Initial review of historical data indicates that percent production with and without abatement can change over time and also year over year due to changes in application of facility-level abatement technologies, maintenance of abatement technologies, and also due to plant closures and start-ups (EPA 2012, 2013; Desai 2012; CAR 2013). The installation dates of N₂O abatement technologies are not known at most facilities, but it is assumed that facilities reporting abatement technology use

¹⁵ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

¹⁶ National N₂O process emissions, national production, and national share of nitric acid production with abatement and without abatement technology was aggregated from the GHGRP facility-level data for 2010 to 2014 (i.e., percent production with and without abatement).

have had this technology installed and operational for the duration of the time series considered in this report (especially NSCRs).

The country-specific weighted N₂O emission factors were used in conjunction with annual production to estimate N₂O emissions for 1990 through 2009, using the following equations:

$$E_i = P_i \times EF_{weighted,i}$$

$$EF_{weighted,i} = [(\%P_{c,i} \times EF_c) + (\%P_{unc,i} \times EF_{unc})]$$

where,

| | |
|-------------------|---|
| E_i | = Annual N ₂ O Emissions for year i (kg/yr) |
| P_i | = Annual nitric acid production for year i (metric tons HNO ₃) |
| $EF_{weighted,i}$ | = Weighted N ₂ O emission factor for year i (kg N ₂ O/metric ton HNO ₃) |
| $\%P_{c,i}$ | = Percent national production of HNO ₃ with N ₂ O abatement technology (%) |
| EF_c | = N ₂ O emission factor, with abatement technology (kg N ₂ O/metric ton HNO ₃) |
| $\%P_{unc,i}$ | = Percent national production of HNO ₃ without N ₂ O abatement technology (%) |
| EF_{unc} | = N ₂ O emission factor, without abatement technology (kg N ₂ O/metric ton HNO ₃) |
| i | = year from 1990 through 2009 |

- For 2009: Weighted N₂O emission factor – 5.45 kg N₂O/metric ton HNO₃.
- For 1990 through 2008: Weighted N₂O emission factor – 5.65 kg N₂O/metric ton HNO₃.

Nitric acid production data for the United States for 1990 through 2009 were obtained from the U.S. Census Bureau (U.S. Census Bureau 2008, 2009, 2010a, 2010b) (see Table 4-27). Publicly-available information on plant-level abatement technologies was used to estimate the shares of nitric acid production with and without abatement for 2008 and 2009 (EPA 2012, 2013; Desai 2012; CAR 2013). Publicly-available data on use of abatement technologies were not available for 1990 through 2007. Therefore, the share of national production with and without abatement for 2008 was assumed to be constant for 1990 through 2007.

Table 4-27: Nitric Acid Production (kt)

| Year | kt |
|------|-------|
| 1990 | 7,195 |
| 2005 | 6,711 |
| 2010 | 7,444 |
| 2011 | 7,606 |
| 2012 | 7,453 |
| 2013 | 7,572 |
| 2014 | 7,656 |

Uncertainty and Time-Series Consistency

Uncertainty associated with the parameters used to estimate N₂O emissions includes that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series (especially prior to 2010), and the associated emission factors applied to each abatement technology type. While some information has been obtained through outreach with industry associations, limited information is available over the time series (especially prior to 2010) for a variety of facility level variables, including plant specific production levels, plant production technology (e.g., low, high pressure, etc.), and abatement technology type, installation date of abatement technology, and accurate destruction and removal efficiency rates.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-28. Nitrous oxide emissions from nitric acid production were estimated to be between 10.4 and 11.5 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 5 percent below to 5 percent above the 2014 emissions estimate of 10.9 MMT CO₂ Eq.

Table 4-28: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from Nitric Acid Production (MMT CO₂ Eq. and Percent)

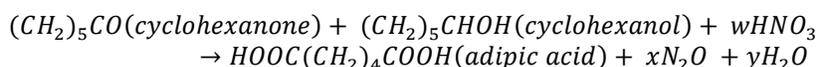
| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|------------------------|------------------|---|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Nitric Acid Production | N ₂ O | 10.9 | 10.4 | 11.5 | -5% | +5% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

4.8 Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid is produced through a two-stage process during which nitrous oxide (N₂O) is generated in the second stage. Emissions from fuels consumed for energy purposes during the production of adipic acid are accounted for in the Energy chapter. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/ cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. Nitrous oxide is generated as a byproduct of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). The second stage is represented by the following chemical reaction:



Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two major adipic acid-producing plants had N₂O abatement technologies in place and, as of 1998, three major adipic acid production facilities had control systems in place (Reimer et al. 1999). One small plant, which last operated in April 2006 and represented approximately two percent of production, did not control for N₂O (VA DEQ 2009; ICIS 2007; VA DEQ 2006). In 2014, catalytic reduction, non-selective catalytic reduction (NSCR) and thermal reduction abatement technologies were applied as N₂O abatement measures at adipic acid facilities (EPA 2015).

Worldwide, only a few adipic acid plants exist. The United States, Europe, and China are the major producers. In 2014, the United States had two companies with a total of three adipic acid production facilities (two in Texas and one in Florida), all of which were operational (EPA 2015). The United States accounts for the largest share of global adipic acid production capacity (30 percent), followed by the European Union (29 percent) and China (22 percent) (SEI 2010). Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters. Eighty-four percent of all adipic acid produced in the United States is used in the production of nylon 6,6; 9 percent is used in the production of polyester polyols; 4 percent is used in the production of plasticizers; and the remaining 4 percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a “tangy” flavor (Thiemens and Trogler 1991).

Nitrous oxide emissions from adipic acid production were estimated to be 5.4 MMT CO₂ Eq. (18 kt N₂O) in 2014 (see Table 4-29). National adipic acid production has increased by approximately 36 percent over the period of 1990 through 2014, to approximately 1,025,000 metric tons (ACC 2015). Over the period 1990 through 2014, emissions have been reduced by 64 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. In April 2006, the smallest of the four facilities ceased production of adipic acid (VA DEQ 2009); furthermore, one of the major adipic acid production facilities was not operational in

2009 or 2010 (Desai 2010). All three remaining facilities were in operation in 2014. Very little information on annual trends in the activity data exist for adipic acid.

Table 4-29: N₂O Emissions from Adipic Acid Production (MMT CO₂ Eq. and kt N₂O)

| Year | MMT CO ₂ Eq. | kt N ₂ O |
|------|-------------------------|---------------------|
| 1990 | 15.2 | 51 |
| 2005 | 7.1 | 24 |
| 2010 | 4.2 | 14 |
| 2011 | 10.2 | 34 |
| 2012 | 5.5 | 19 |
| 2013 | 4.0 | 13 |
| 2014 | 5.4 | 18 |

Methodology

Emissions are estimated using both Tier 2 and Tier 3 methods consistent with the *2006 IPCC Guidelines* (IPCC 2006). Due to confidential business information, plant names are not provided in this section. Therefore, the four adipic acid-producing facilities will be referred to as Plants 1 through 4. Plant 4 was closed in April 2006. Overall, as noted above, the three plants that are currently operating facilities use abatement equipment. Plants 1 and 2 employ catalytic destruction and Plant 3 employs thermal destruction.

2010 through 2014

All emission estimates for 2010 through 2014 were obtained through analysis of EPA’s GHGRP data (EPA 2014 through 2015), which is consistent with the *2006 IPCC Guidelines* (IPCC 2006) Tier 3 method. Facility-level greenhouse gas emissions data were obtained from the GHGRP for the years 2010 through 2014 (EPA 2014 through 2015) and aggregated to national N₂O emissions. Consistent with IPCC Tier 3 methods, all adipic acid production facilities are required to calculate emissions using a facility-specific emission factor developed through annual performance testing under typical operating conditions or by directly measuring N₂O emissions using monitoring equipment. More information on the monitoring methods for process N₂O emissions applicable to adipic acid production facilities under Subpart E can be found in the electronic code of federal regulations.¹⁷

1990 through 2009

For years prior to EPA’s GHGRP reporting, for both Plants 1 and 2, 1990 to 2009 emission estimates were obtained directly from the plant engineer and account for reductions due to control systems in place at these plants during the time series. These prior estimates are considered confidential business information and hence are not published (Desai 2010). These estimates were based on continuous process monitoring equipment installed at the two facilities. In 2009 and 2010, no adipic acid production occurred at Plant 1 per reporting to EPA’s GHGRP (EPA 2012; Desai 2011b).

For the Plant 4, 1990 through 2009 N₂O emissions were estimated using the following Tier 2 equation from the *2006 IPCC Guidelines* until shutdown of the plant in 2006:

$$E_{aa} = Q_{aa} \times EF_{aa} \times (1 - [DF \times UF])$$

where,

E_{aa} = N₂O emissions from adipic acid production, metric tons
 Q_{aa} = Quantity of adipic acid produced, metric tons

¹⁷ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

| | | |
|------------------|---|--|
| EF _{aa} | = | Emission factor, metric ton N ₂ O/metric ton adipic acid produced |
| DF | = | N ₂ O destruction factor |
| UF | = | Abatement system utility factor |

The adipic acid production is multiplied by an emission factor (i.e., N₂O emitted per unit of adipic acid produced), which has been estimated, based on experiments that the reaction stoichiometry for N₂O production in the preparation of adipic acid, to be approximately 0.3 metric tons of N₂O per metric ton of product (IPCC 2006). The “N₂O destruction factor” in the equation represents the percentage of N₂O emissions that are destroyed by the installed abatement technology. The “abatement system utility factor” represents the percentage of time that the abatement equipment operates during the annual production period. No abatement equipment was installed at the Inolex/Allied Signal facility, which last operated in April 2006 (VA DEQ 2009). Plant-specific production data for this facility were obtained across the time series from 1990 through 2006 from the Virginia Department of Environmental Quality (VA DEQ 2010). The plant-specific production data were then used for calculating emissions as described above.

For Plant 3, 2005 through 2009 emissions were obtained directly from the plant (Desai 2011a). For 1990 through 2004, emissions were estimated using plant-specific production data and the IPCC factors as described above for Plant 4. Plant-level adipic acid production for 1990 through 2003 was estimated by allocating national adipic acid production data to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants (ACC 2015; CMR 2001, 1998; CW 1999; C&EN 1992 through 1995). For 2004, actual plant production data were obtained and used for emission calculations (CW 2005).

Plant capacities for 1990 through 1994 were obtained from *Chemical & Engineering News*, “Facts and Figures” and “Production of Top 50 Chemicals” (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the same as 1994 data. The 1997 plant capacities were taken from *Chemical Market Reporter*, “Chemical Profile: Adipic Acid” (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants were obtained from *Chemical Week*, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for 2000 for three of the plants were updated using *Chemical Market Reporter*, “Chemical Profile: Adipic Acid” (CMR 2001). For 2001 through 2003, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2003 for the one remaining plant was kept the same as 1998.

National adipic acid production data (see Table 4-30) from 1990 through 2014 were obtained from the American Chemistry Council (ACC 2015).

Table 4-30: Adipic Acid Production (kt)

| Year | kt |
|------|-------|
| 1990 | 755 |
| 2005 | 865 |
| 2010 | 720 |
| 2011 | 840 |
| 2012 | 950 |
| 2013 | 980 |
| 2014 | 1,025 |

Uncertainty and Time-Series Consistency

Uncertainty associated with N₂O emission estimates includes the methods used by companies to monitor and estimate emissions. While some information has been obtained through outreach with facilities, limited information is available over the time series on these methods, abatement technology destruction and removal efficiency rates and plant specific production levels.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-31. Nitrous oxide emissions from adipic acid production for 2014 were estimated to be between 5.2 and 5.6 MMT CO₂ Eq. at the 95

percent confidence level. These values indicate a range of approximately 4 percent below to 4 percent above the 2014 emission estimate of 5.4 MMT CO₂ Eq.

Table 4-31: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from Adipic Acid Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|------------------------|------------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Adipic Acid Production | N ₂ O | 5.4 | 5.2 | 5.6 | -4% | +4% |

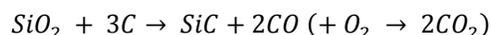
^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

4.9 Silicon Carbide Production and Consumption (IPCC Source Category 2B5)

Carbon dioxide (CO₂) and methane (CH₄) are emitted from the production of silicon carbide (SiC), a material used as an industrial abrasive. Silicon carbide is produced for abrasive, metallurgical, and other non-abrasive applications in the United States. Production for metallurgical and other non-abrasive applications is not available and therefore both CO₂ and CH₄ estimates are based solely upon production estimates of silicon carbide for abrasive applications. Emissions from fuels consumed for energy purposes during the production of silicon carbide are accounted for in the Energy chapter.

To produce SiC, silica sand or quartz (SiO₂) is reacted with carbon in the form of petroleum coke. A portion (about 35 percent) of the carbon contained in the petroleum coke is retained in the SiC. The remaining carbon is emitted as CO₂, CH₄, or carbon monoxide (CO). The overall reaction is shown below (but in practice it does not proceed according to stoichiometry):



Carbon dioxide is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications.

Markets for manufactured abrasives, including SiC, are heavily influenced by activity in the U.S. manufacturing sector, especially in the aerospace, automotive, furniture, housing, and steel manufacturing sectors. The U.S. Geological Survey (USGS) reports that a portion (approximately 50 percent) of SiC is used in metallurgical and other non-abrasive applications, primarily in iron and steel production (USGS 2006a). As a result of the economic downturn in 2008 and 2009, demand for SiC decreased in those years. Low cost imports, particularly from China, combined with high relative operating costs for domestic producers, continue to put downward pressure on the production of SiC in the United States. However, demand for SiC consumption in the United States has recovered somewhat from its low in 2009 (USGS 2012a). Silicon carbide is manufactured at a single facility located in Illinois (USGS 2015a).

Carbon dioxide emissions from SiC production and consumption in 2014 were 0.2 MMT CO₂ Eq. (173 kt CO₂). Approximately 53 percent of these emissions resulted from SiC production while the remainder resulted from SiC consumption. Methane emissions from SiC production in 2014 were 0.01 MMT CO₂ Eq. (0.4 kt CH₄) (see Table 4-32 and Table 4-33). Emissions have fluctuated in recent years, but 2014 emissions are only about 46 percent of emissions in 1990.

Table 4-32: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (MMT CO₂ Eq.)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------------|------------|------------|------------|------------|------------|------------|
| CO ₂ | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| CH ₄ | + | + | + | + | + | + | + |
| Total | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Table 4-33: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (kt)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------|------|------|------|------|------|------|
| CO ₂ | 375 | 219 | 181 | 170 | 158 | 169 | 173 |
| CH ₄ | 1 | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

Methodology

Emissions of CO₂ and CH₄ from the production of SiC were calculated¹⁸ using the Tier 1 method provided by the *2006 IPCC Guidelines* (IPCC 2006). Annual estimates of SiC production were multiplied by the appropriate emission factor, as shown below:

$$E_{sc,CO_2} = EF_{sc,CO_2} \times Q_{sc}$$

$$E_{sc,CH_4} = EF_{sc,CH_4} \times Q_{sc} \times \left(\frac{1 \text{ metric ton}}{1000 \text{ kg}} \right)$$

where,

| | | |
|----------------|---|---|
| E_{sc,CO_2} | = | CO ₂ emissions from production of SiC, metric tons |
| EF_{sc,CO_2} | = | Emission factor for production of SiC, metric ton CO ₂ /metric ton SiC |
| Q_{sc} | = | Quantity of SiC produced, metric tons |
| E_{sc,CH_4} | = | CH ₄ emissions from production of SiC, metric tons |
| EF_{sc,CH_4} | = | Emission factor for production of SiC, kilogram CH ₄ /metric ton SiC |

Emission factors were taken from the *2006 IPCC Guidelines* (IPCC 2006):

- 2.62 metric tons CO₂/metric ton SiC
- 11.6 kg CH₄/metric ton SiC

Emissions of CO₂ from silicon carbide consumption for metallurgical uses were calculated by multiplying the annual utilization of SiC for metallurgical uses (reported annually in the USGS *Minerals Yearbook: Silicon*) by the carbon content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Emissions of CO₂ from silicon carbide consumption for other non-abrasive uses were calculated by multiplying the annual SiC consumption for non-abrasive uses by the carbon content of SiC (31.5 percent). The annual SiC consumption for non-abrasive uses was calculated by multiplying the annual SiC consumption (production plus net imports) by the percent used in metallurgical and other non-abrasive uses (50 percent) (USGS 2006a) and then subtracting the SiC consumption for metallurgical use.

¹⁸ EPA has not integrated aggregated facility-level GHGRP information to inform these estimates. The aggregated information (e.g. activity data and emissions) associated with silicon carbide did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

Production data for 1990 through 2013 were obtained from the *Minerals Yearbook: Manufactured Abrasives* (USGS 1991a through 2015b). Production data for 2014 were obtained from the *Minerals Industry Surveys: Abrasives (Manufactured)* (USGS 2015a). Silicon carbide consumption by major end use for 1990 through 2012 were obtained from the *Minerals Yearbook: Silicon* (USGS 1991b through 2013) (see Table 4-34). Silicon carbide consumption data for 2013 and 2014 are not yet publicly available and so 2012 data were used as proxy. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2015).

Table 4-34: Production and Consumption of Silicon Carbide (Metric Tons)

| Year | Production | Consumption |
|------|------------|-------------|
| 1990 | 105,000 | 172,465 |
| 2005 | 35,000 | 220,149 |
| 2010 | 35,000 | 154,540 |
| 2011 | 35,000 | 136,222 |
| 2012 | 35,000 | 114,265 |
| 2013 | 35,000 | 134,055 |
| 2014 | 35,000 | 140,723 |

Uncertainty and Time-Series Consistency

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH₄, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also uncertainty associated with the use or destruction of methane generated from the process in addition to uncertainty associated with levels of production, net imports, consumption levels, and the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-35. Silicon carbide production and consumption CO₂ emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.17 MMT CO₂ Eq. at the 95 percent confidence level. Silicon carbide production CH₄ emissions were estimated to be between 9 percent below and 10 percent above the emission estimate of 0.01 MMT CO₂ Eq. at the 95 percent confidence level.

Table 4-35: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from Silicon Carbide Production and Consumption (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) (%) | | | |
|--|-----------------|---|---|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Silicon Carbide Production and Consumption | CO ₂ | 0.17 | 0.16 | 0.19 | -9% | +9% |
| Silicon Carbide Production | CH ₄ | + | + | + | -9% | +10% |

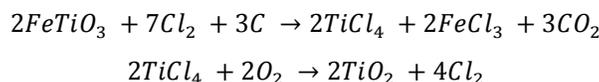
+ Does not exceed 0.05 MMT CO₂ Eq.

^aRange of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

4.10 Titanium Dioxide Production (IPCC Source Category 2B6)

Titanium dioxide (TiO₂) is manufactured using one of two processes: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related carbon dioxide (CO₂). Emissions from fuels consumed for energy purposes during the production of titanium dioxide are accounted for in the Energy chapter. The chloride process is based on the following chemical reactions:



The sulfate process does not use petroleum coke or other forms of carbon as a raw material and does not emit CO₂.

The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and FeTiO₃ (rutile ore) to form CO₂. Since 2004, all TiO₂ produced in the United States has been produced using the chloride process, and a special grade of “calcined” petroleum coke is manufactured specifically for this purpose.

The principal use of TiO₂ is as a pigment in white paint, lacquers, and varnishes; it is also used as a pigment in the manufacture of plastics, paper, and other products. In 2014, U.S. TiO₂ production totaled 1,310,000 metric tons (USGS 2015a). There were a total six plants producing TiO₂ in the United States—two located in Mississippi, and single plants located in Delaware, Louisiana, Ohio, and Tennessee.

Emissions of CO₂ from titanium dioxide production in 2014 were estimated to be 1.8 MMT CO₂ Eq. (1,755 kt CO₂), which represents an increase of 47 percent since 1990 (see Table 4-36).

Table 4-36: CO₂ Emissions from Titanium Dioxide (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 1.2 | 1,195 |
| 2005 | 1.8 | 1,755 |
| 2010 | 1.8 | 1,769 |
| 2011 | 1.7 | 1,729 |
| 2012 | 1.5 | 1,528 |
| 2013 | 1.7 | 1,715 |
| 2014 | 1.8 | 1,755 |

Methodology

Emissions of CO₂ from TiO₂ production were calculated by multiplying annual national TiO₂ production by chloride process-specific emission factors using a Tier 1 approach provided in *2006 IPCC Guidelines* (IPCC 2006). The Tier 1 equation is as follows:

$$E_{td} = EF_{td} \times Q_{td}$$

where,

| | | |
|------------------|---|---|
| E _{td} | = | CO ₂ emissions from TiO ₂ production, metric tons |
| EF _{td} | = | Emission factor (chloride process), metric ton CO ₂ /metric ton TiO ₂ |
| Q _{td} | = | Quantity of TiO ₂ produced |

Data were obtained for the total amount of TiO₂ produced each year. For years prior to 2004, it was assumed that TiO₂ was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate process plant in the United States

closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). The percentage of production from the chloride process is estimated at 100 percent since 2004. An emission factor of 1.34 metric tons CO₂/metric ton TiO₂ was applied to the estimated chloride-process production (IPCC 2006). It was assumed that all TiO₂ produced using the chloride process was produced using petroleum coke, although some TiO₂ may have been produced with graphite or other carbon inputs.

The emission factor for the TiO₂ chloride process was taken from the *2006 IPCC Guidelines* (IPCC 2006). Titanium dioxide production data and the percentage of total TiO₂ production capacity that is chloride process for 1990 through 2013 (see Table 4-37:) were obtained through the *Minerals Yearbook: Titanium Annual Report* (USGS 1991 through 2015b). Production data for 2014 was obtained from the *Minerals Commodity Summary: Titanium and Titanium Dioxide* (USGS 2015a).¹⁹ Data on the percentage of total TiO₂ production capacity that is chloride process were not available for 1990 through 1993, so data from the 1994 USGS *Minerals Yearbook* were used for these years. Because a sulfate process plant closed in September 2001, the chloride process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002, only one sulfate process plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-37: Titanium Dioxide Production (kt)

| Year | kt |
|------|-------|
| 1990 | 979 |
| 2005 | 1,310 |
| 2010 | 1,320 |
| 2011 | 1,290 |
| 2012 | 1,140 |
| 2013 | 1,280 |
| 2014 | 1,310 |

Uncertainty and Time-Series Consistency

Each year, the U.S. Geological Survey (USGS) collects titanium industry data for titanium mineral and pigment production operations. If TiO₂ pigment plants do not respond, production from the operations is estimated on the basis of prior year production levels and industry trends. Variability in response rates varies from 67 to 100 percent of TiO₂ pigment plants over the time series.

Although some TiO₂ may be produced using graphite or other carbon inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO₂ per unit of TiO₂ produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO₂ produced, sufficient data were not available to do so.

As of 2004, the last remaining sulfate-process plant in the United States closed. Since annual TiO₂ production was not reported by USGS by the type of production process used (chloride or sulfate) prior to 2004 and only the percentage of total production capacity by process was reported, the percent of total TiO₂ production capacity that was attributed to the chloride process was multiplied by total TiO₂ production to estimate the amount of TiO₂ produced using the chloride process. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO₂ production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO₂ chloride process; however, this composition information was not available.

¹⁹ EPA has not integrated aggregated facility-level GHGRP information for Titanium Dioxide production facilities (40 CFR Part 98 Subpart EE). The relevant aggregated information (activity data, emission factor) from these facilities did not meet criteria to shield underlying CBI from public disclosure.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-38. Titanium dioxide consumption CO₂ emissions were estimated to be between 1.5 and 2.0 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.8 MMT CO₂ Eq.

Table 4-38: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Titanium Dioxide Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------------------|-----------------|---|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Titanium Dioxide Production | CO ₂ | 1.8 | 1.5 | 2.0 | -12% | +13% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Production data for 2013 were updated relative to the previous Inventory based on recently published data in the USGS *Minerals Yearbook: Titanium 2013* (USGS 2015b). This resulted in a 7 percent increase in 2013 CO₂ emissions from TiO₂ production relative to the previous report.

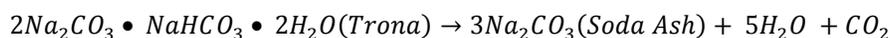
Planned Improvements

Planned improvements include researching the significance of titanium-slag production in electric furnaces and synthetic-rutile production using the Becher process in the United States. Significant use of these production processes will be included in future Inventories.

4.11 Soda Ash Production and Consumption (IPCC Source Category 2B7)

Carbon dioxide (CO₂) is generated as a byproduct of calcining trona ore to produce soda ash, and is eventually emitted into the atmosphere. In addition, CO₂ may also be released when soda ash is consumed. Emissions from fuels consumed for energy purposes during the production and consumption of soda ash are accounted for in the Energy sector.

Calcining involves placing crushed trona ore into a kiln to convert sodium bicarbonate into crude sodium carbonate that will later be filtered into pure soda ash. The emission of CO₂ during trona-based production is based on the following reaction:



Soda ash (sodium carbonate, Na₂CO₃) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. (Emissions from soda ash used in glass production are reported under IPCC Source Category 2A3. Glass production is its own source category and historical soda ash consumption figures have been adjusted to reflect this change.) After glass manufacturing, soda ash is used primarily to manufacture many sodium-based inorganic chemicals, including sodium bicarbonate, sodium chromates, sodium phosphates, and sodium silicates (USGS 2015b). Internationally, two types of soda ash

are produced, natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

The United States represents about one-fourth of total world soda ash output. Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO₂ from Wyoming were calculated due to specifics regarding the production processes employed in the state.²⁰ Based on preliminary 2014 reported data, the estimated distribution of soda ash by end-use in 2014 (excluding glass production) was chemical production, 56 percent; soap and detergent manufacturing, 13 percent; distributors, 10 percent; flue gas desulfurization, 8 percent; other uses, 8 percent; pulp and paper production, 2 percent; and water treatment, 2 percent (USGS 2015a).

U.S. natural soda ash is competitive in world markets because the majority of the world output of soda ash is made synthetically. Although the United States continues to be a major supplier of world soda ash, China, which surpassed the United States in soda ash production in 2003, is the world's leading producer.

In 2014, CO₂ emissions from the production of soda ash from trona were approximately 1.7 MMT CO₂ Eq. (1,685 kt CO₂). Soda ash consumption in the United States generated 1.1 MMT CO₂ Eq. (1,143 kt CO₂) in 2014. Total emissions from soda ash production and consumption in 2014 were 2.8 MMT CO₂ Eq. (2,827 kt CO₂) (see Table 4-39 and Table 4-40).

Total emissions in 2014 increased by approximately 1 percent from emissions in 2013, and have stayed approximately the same as the 1990 levels.

Emissions have remained relatively constant over the time series with some fluctuations since 1990. In general, these fluctuations were related to the behavior of the export market and the U.S. economy. The U.S. soda ash industry continued a trend of increased production and value in 2014 since experiencing a decline in domestic and export sales caused by adverse global economic conditions in 2009. The annual average unit value of soda ash set a record high in 2013, and soda ash exports increased as well, accounting for 56 percent of total production (USGS 2015b).

Table 4-39: CO₂ Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (MMT CO₂ Eq.)

| Year | Production | Consumption | Total |
|------|------------|-------------|-------|
| 1990 | 1.4 | 1.4 | 2.8 |
| 2005 | 1.7 | 1.3 | 3.0 |
| 2010 | 1.5 | 1.1 | 2.7 |
| 2011 | 1.6 | 1.1 | 2.7 |
| 2012 | 1.7 | 1.1 | 2.8 |
| 2013 | 1.7 | 1.1 | 2.8 |
| 2014 | 1.7 | 1.1 | 2.8 |

Note: Totals may not sum due to independent rounding.

²⁰ In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO₂ in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO₂ is generated as a byproduct, the CO₂ is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona in the state. For a brief time, sodium bicarbonate was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Prior to 2004, because the trona was mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

Table 4-40: CO₂ Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt)

| Year | Production | Consumption | Total |
|------|------------|-------------|-------|
| 1990 | 1,431 | 1,390 | 2,822 |
| 2005 | 1,655 | 1,305 | 2,960 |
| 2010 | 1,548 | 1,148 | 2,697 |
| 2011 | 1,607 | 1,105 | 2,712 |
| 2012 | 1,665 | 1,097 | 2,763 |
| 2013 | 1,694 | 1,109 | 2,804 |
| 2014 | 1,685 | 1,143 | 2,827 |

Note: Totals may not sum due to independent rounding.

Methodology

During the production process, trona ore is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. Carbon dioxide and water are generated as byproducts of the calcination process. Carbon dioxide emissions from the calcination of trona can be estimated based on the chemical reaction shown above. Based on this formula, which is consistent with an IPCC Tier 1 approach, approximately 10.27 metric tons of trona are required to generate one metric ton of CO₂, or an emission factor of 0.0974 metric tons CO₂ per metric ton trona (IPCC 2006). Thus, the 17.3 million metric tons of trona mined in 2014 for soda ash production (USGS 2015a) resulted in CO₂ emissions of approximately 1.7 MMT CO₂ Eq. (1,685 kt).

Once produced, most soda ash is consumed in chemical and soap production, with minor amounts in pulp and paper, flue gas desulfurization, and water treatment (excluding soda ash consumption for glass manufacturing). As soda ash is consumed for these purposes, additional CO₂ is usually emitted. In these applications, it is assumed that one mole of carbon is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of carbon (or 0.415 metric tons of CO₂) are released for every metric ton of soda ash consumed. In future Inventory reports, consistent with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, emissions from soda ash consumption in chemical production processes will be reported under Section 4.4 Other Process Uses of Carbonates (IPCC Category 2A4).

The activity data for trona production and soda ash consumption (see Table 4-41) for 1990 to 2014 were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook for Soda Ash* (1994 through 2015b) and USGS *Mineral Industry Surveys for Soda Ash* (USGS 2015a). Soda ash production and consumption data²¹ were collected by the USGS from voluntary surveys of the U.S. soda ash industry. The U.S. Environmental Protection Agency (EPA) will continue to analyze and assess opportunities to use facility-level data from EPA's Greenhouse Gas Reporting Program (GHGRP) to improve the emission estimates for Soda Ash Production source category consistent with IPCC²² and UNFCCC guidelines.

Table 4-41: Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt)

| Year | Production ^a | Consumption ^b |
|------|-------------------------|--------------------------|
| 1990 | 14,700 | 3,351 |

²¹ EPA has assessed feasibility of using emissions information (including activity data) from EPA's GHGRP program. However at this time, the aggregated information associated with production of soda ash did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

²² See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

| | | |
|------|--------|-------|
| 2005 | 17,000 | 3,144 |
| 2010 | 15,900 | 2,768 |
| 2011 | 16,500 | 2,663 |
| 2012 | 17,100 | 2,645 |
| 2013 | 17,400 | 2,674 |
| 2014 | 17,300 | 2,754 |

^a Soda ash produced from trona ore only.

^b Soda ash consumption is sales reported by producers which exclude imports. Historically, imported soda ash is less than 1 percent of the total U.S. consumption (Kostick 2012).

Uncertainty and Time-Series Consistency

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data for trona-based soda ash production. Through EPA's GHGRP, EPA is aware of one facility producing soda ash from a liquid alkaline feedstock process. Soda ash production data was collected by the USGS from voluntary surveys. A survey request was sent to each of the five soda ash producers, all of which responded, representing 100 percent of the total production data (USGS 2014a). One source of uncertainty is the purity of the trona ore used for manufacturing soda ash. The emission factor used for this estimate assumes the ore is 100 percent pure, and likely overestimates the emissions from soda ash manufacture. The average water-soluble sodium carbonate-bicarbonate content for ore mined in Wyoming ranges from 85.5 to 93.8 percent (USGS 1995). For emissions from soda ash consumption, the primary source of uncertainty, however, results from the fact that these emissions are dependent upon the type of processing employed by each end-use. Specific emission factors for each end-use are not available, so a Tier 1 default emission factor is used for all end uses. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-42. Soda Ash Production and Consumption CO₂ emissions were estimated to be between 2.5 and 2.9 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 6 percent above the emission estimate of 2.8 MMT CO₂ Eq.

Table 4-42: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Soda Ash Production and Consumption (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|-------------------------------------|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Soda Ash Production and Consumption | CO ₂ | 2.8 | 2.5 | 2.9 | -7% | +6% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculation Discussion

During the development of the current Inventory, an error in the transcription of the *2006 IPCC Guidelines* default trona production emission factor was identified. This error was corrected in the current Inventory and resulted in a slight change of emissions over the entire time series (approximately 3 percent), compared with the previous Inventory.

Planned Improvements

In future Inventory reports, soda ash consumed for other chemical uses will be extracted from the current soda ash consumption emission estimates and included under those sources or Other Process Uses of Carbonates (IPCC Category 2A4).

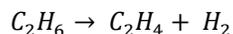
4.12 Petrochemical Production (IPCC Source Category 2B8)

The production of some petrochemicals results in the release of small amounts of carbon dioxide (CO₂) and methane (CH₄) emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. Carbon dioxide emissions from the production of acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, and methanol; and CH₄ emissions from the production of methanol and acrylonitrile are presented here and reported under IPCC Source Category 2B5. The petrochemical industry uses primary fossil fuels (i.e., natural gas, coal, petroleum, etc.) for non-fuel purposes in the production of carbon black and other petrochemicals. Emissions from fuels and feedstocks transferred out of the system for use in energy purposes (e.g., indirect or direct process heat or steam production) are currently accounted for in the Energy sector.

Worldwide more than 90 percent of acrylonitrile (vinyl cyanide, C₃H₃N) is made by way of direct ammoxidation of propylene with ammonia (NH₃) and oxygen over a catalyst. This process is referred to as the SOHIO process, after the Standard Oil Company of Ohio (SOHIO) (IPCC 2006). The primary use of acrylonitrile is as the raw material for the manufacture of acrylic and modacrylic fibers. Other major uses include the production of plastics (acrylonitrile-butadiene-styrene [ABS] and styrene-acrylonitrile [SAN]), nitrile rubbers, nitrile barrier resins, adiponitrile, and acrylamide. All U.S. acrylonitrile facilities use the SOHIO process (AN 2014). The SOHIO process involves a fluidized bed reaction of chemical-grade propylene, ammonia, and oxygen over a catalyst. The process produces acrylonitrile as its primary product and the process yield depends on the type of catalyst used and the process configuration. The ammoxidation process also produces byproduct CO₂, carbon monoxide (CO), and water from the direct oxidation of the propylene feedstock, and produces other hydrocarbons from side reactions in the ammoxidation process.

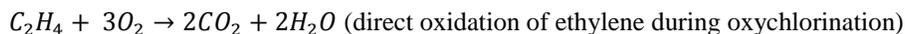
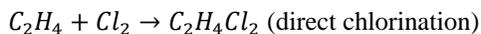
Carbon black is a black powder generated by the incomplete combustion of an aromatic petroleum- or coal-based feedstock at a high temperature. Most carbon black produced in the United States is added to rubber to impart strength and abrasion resistance, and the tire industry is by far the largest consumer. The other major use of carbon black is as a pigment. The predominant process used in the United States is the furnace black (or oil furnace) process. In the furnace black process, carbon black oil (a heavy aromatic liquid) is continuously injected into the combustion zone of a natural gas-fired furnace. Furnace heat is provided by the natural gas and a portion of the carbon black feedstock; the remaining portion of the carbon black feedstock is pyrolyzed to carbon black. The resultant CO₂ and uncombusted CH₄ emissions are released from thermal incinerators used as control devices, process dryers, and equipment leaks. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks (i.e., acetylene black process), by the thermal cracking of other hydrocarbons (i.e., thermal black process), and by the open burning of carbon black feedstock (i.e., lamp black process); each of these processes are used at only one U.S. plant each (EPA 2000).

Ethylene (C₂H₄) is consumed in the production processes of the plastics industry including polymers such as high, low, and linear low density polyethylene (HDPE, LDPE, LLDPE); polyvinyl chloride (PVC); ethylene dichloride; ethylene oxide; and ethylbenzene. Virtually all ethylene is produced from steam cracking of ethane, propane, butane, naphtha, gas oil, and other feedstocks. The representative chemical equation for steam cracking of ethane to ethylene is shown below:



Small amounts of CH₄ are also generated from the steam cracking process. In addition, CO₂ and CH₄ emissions are also generated from combustion units.

Ethylene dichloride (C₂H₄Cl₂) is used to produce vinyl chloride monomer, which is the precursor to polyvinyl chloride (PVC). Ethylene dichloride was used as a fuel additive until 1996 when leaded gasoline was phased out. Ethylene dichloride is produced from ethylene by either direct chlorination, oxychlorination, or a combination of the two processes (i.e., the “balanced process”); most U.S. facilities use the balanced process. The direct chlorination and oxychlorination reactions are shown below:



In addition to the byproduct CO₂ produced from the direct oxidation of the ethylene feedstock, CO₂ and CH₄ emissions are also generated from combustion units.

Ethylene oxide (C₂H₄O) is used in the manufacture of glycols, glycol ethers, alcohols, and amines. Approximately 70 percent of ethylene oxide produced worldwide is used in the manufacture of glycols, including monoethylene glycol. Ethylene oxide is produced by reacting ethylene with oxygen over a catalyst. The oxygen may be supplied to the process through either an air (air process) or a pure oxygen stream (oxygen process). The byproduct CO₂ from the direct oxidation of the ethylene feedstock is removed from the process vent stream using a recycled carbonate solution, and the recovered CO₂ may be vented to the atmosphere or recovered for further utilization in other sectors, such as food production (IPCC 2006). The combined ethylene oxide reaction and byproduct CO₂ reaction is exothermic and generates heat, which is recovered to produce steam for the process. The ethylene oxide process also produces other liquid and off-gas byproducts (e.g., ethane, etc.) that may be burned for energy recovery within the process. Almost all facilities, except one in Texas, use the oxygen process to manufacture ethylene oxide (EPA 2008).

Methanol (CH₃OH) is a chemical feedstock most often converted into formaldehyde, acetic acid and olefins. It is also an alternative transportation fuel, as well as an additive used by municipal wastewater treatment facilities in the denitrification of wastewater. Methanol is most commonly synthesized from a synthesis gas (i.e., “syngas” – a mixture containing H₂, CO, and CO₂) using a heterogeneous catalyst. There are a number of process techniques that can be used to produce syngas. Worldwide, steam reforming of natural gas is the most common method; however, in the United States only two facilities use steam reforming of natural gas. Other syngas production processes in the United States include partial oxidation of natural gas and coal gasification.

Emissions of CO₂ and CH₄ from petrochemical production in 2014 were 26.5 MMT CO₂ Eq. (26,509 kt CO₂) and 0.1 MMT CO₂ Eq. (5 kt CH₄), respectively (see Table 4-43 and Table 4-44). Since 1990, total CO₂ emissions from petrochemical production increased by approximately 23 percent. Methane emissions from petrochemical (methanol and acrylonitrile) production have decreased by approximately 43 percent since 1990, given declining production.

Table 4-43: CO₂ and CH₄ Emissions from Petrochemical Production (MMT CO₂ Eq.)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| CO ₂ | 21.6 | 27.4 | 27.2 | 26.3 | 26.5 | 26.4 | 26.5 |
| CH ₄ | 0.2 | 0.1 | + | + | 0.1 | 0.1 | 0.1 |
| Total | 21.8 | 27.5 | 27.3 | 26.4 | 26.5 | 26.5 | 26.6 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 4-44: CO₂ and CH₄ Emissions from Petrochemical Production (kt)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|--------|--------|--------|--------|--------|--------|--------|
| CO ₂ | 21,609 | 27,380 | 27,246 | 26,326 | 26,464 | 26,437 | 26,509 |
| CH ₄ | 9 | 3 | 2 | 2 | 3 | 3 | 5 |

Methodology

Emissions of CO₂ and CH₄ were calculated using the estimation methods provided by the *2006 IPCC Guidelines* (IPCC 2006) and country-specific methods from EPA's Greenhouse Gas Reporting Program (GHGRP). The *2006 IPCC Guidelines* Tier 1 method was used to estimate CO₂ and CH₄ emissions from production of acrylonitrile and methanol,²³ and a country-specific approach similar to the IPCC Tier 2 method was used to estimate CO₂ emissions from carbon black, ethylene, ethylene oxide, and ethylene dichloride. The Tier 2 method for petrochemicals is a total feedstock C mass balance method used to estimate total CO₂ emissions, but is not applicable for estimating CH₄ emissions. As noted in the *2006 IPCC Guidelines*, the total feedstock C mass balance method (Tier 2) is based on the assumption that all of the C input to the process is converted either into primary and secondary products or into CO₂. Further, the guideline states that while the total C mass balance method estimates total C emissions from the process but does not directly provide an estimate of the amount of the total C emissions emitted as CO₂, CH₄, or non-CH₄ volatile organic compounds (NMVOCs). This method accounts for all the C as CO₂, including CH₄. Note, a subset of facilities reporting under EPA's GHGRP use alternate methods to the C balance approach (e.g., Continuous Emission Monitoring Systems (CEMS) or other engineering approaches) to monitor CO₂ emissions and these facilities are required to also report CH₄ and N₂O emissions. Preliminary analysis of aggregated annual reports shows that these emissions are less than 500 kt/year and thus compilation of this information was not a priority for this report. Pending resources, EPA may include these emissions in future reports to enhance completeness.

Carbon Black, Ethylene, Ethylene Dichloride and Ethylene Oxide

2010-2014

Carbon dioxide emissions and national production were aggregated directly from EPA's GHGRP dataset for 2010 through 2014 (EPA GHGRP 2015). In 2014, GHGRP data reported CO₂ emissions of 3,272,934 metric tons from carbon black production; 18,805,943 metric tons of CO₂ from ethylene production; 591,127 metric tons of CO₂ from ethylene dichloride production; and 1,333,768 metric tons of CO₂ from ethylene oxide production. These emissions reflect application of a country-specific approach similar to the IPCC Tier 2 method and were used to estimate CO₂ emissions from the production of carbon black, ethylene, ethylene dichloride, and ethylene oxide. Since 2010, EPA's GHGRP, under Subpart X, requires all domestic producers of petrochemicals to report annual emissions and supplemental emissions information (e.g., production data, etc.) to facilitate verification of reported emissions. Under EPA's GHGRP, petrochemical production facilities are required to use either a mass balance approach or CEMS to measure and report emissions for each petrochemical process unit to estimate facility-level process CO₂ emissions. The mass balance method is used by most facilities²⁴ and assumes that all the carbon input is converted into primary and secondary products, byproducts, or is emitted to the atmosphere as CO₂. To apply the mass

²³ EPA has not integrated aggregated facility-level GHGRP information for acrylonitrile and methanol production. The aggregated information associated with production of these petrochemicals did not meet criteria to shield underlying CBI from public disclosure.

²⁴ A few facilities producing ethylene dichloride used CO₂ CEMS, those CO₂ emissions have been included in the aggregated GHGRP emissions presented here. For ethylene production processes, nearly all process emissions are from the combustion of process off-gas. Under EPA's GHGRP, Subpart X, ethylene facilities can report CO₂ emissions from burning of process gases using the optional combustion methodology for ethylene production processes, which requires estimating emissions based on fuel quantity and carbon contents of the fuel. This is consistent with the *2006 IPCC Guidelines* (p. 3.57) which recommends including combustion emissions from fuels obtained from feedstocks (e.g., off-gases) in petrochemical production under in the IPPU sector. In 2014, for example, this represented about 20 of the 80 reporting facilities. In addition to CO₂, these facilities are required to report emissions of CH₄ and N₂O from combustion of ethylene process off-gas in flares. Both facilities using CEMS (consistent with a Tier 3 approach) and those using the optional combustion methodology are also required to report emissions of CH₄ and N₂O from combustion of petrochemical process-off gases and flares, as applicable. Preliminary analysis of the aggregated reported CH₄ and N₂O emissions from facilities using CEMS and the optional combustion methodology suggests that these annual emissions are less than 500 kt/yr so not significant enough to prioritize for inclusion in the report at this time. Pending resources and significance, EPA may include these emissions in future reports to enhance completeness.

balance, facilities must measure the volume or mass of each gaseous and liquid feedstock and product, mass rate of each solid feedstock and product, and carbon content of each feedstock and product for each process unit and sum for their facility. More details on the greenhouse gas calculation and monitoring methods applicable to petrochemical facilities can be found under Subpart X (Petrochemical Production) of the regulation (40 CFR Part 98).²⁵

1990 through 2009

For prior years, for these petrochemical types, an average national CO₂ emission factor was calculated based on the 2010 through 2013 GHGRP data and applied to production for earlier years in the time series (i.e., 1990 through 2009) to estimate CO₂ emissions from carbon black, ethylene, ethylene dichloride, and ethylene oxide. Carbon dioxide emission factors were derived from EPA's GHGRP data by dividing annual CO₂ emissions for petrochemical type "i" with annual production for petrochemical type "i" and then averaging the derived emission factors obtained for each calendar year 2010 through 2014 (EPA GHGRP 2015). The average emission factors for each petrochemical type were applied across all prior years because petrochemical production processes in the United States have not changed significantly since 1990, though some operational efficiencies have been implemented at facilities over the time series.

The average country-specific CO₂ emission factors that were calculated from the 2010 through 2014 GHGRP data are as follows:

- 2.59 metric tons CO₂/metric ton carbon black produced
- 0.79 metric tons CO₂/metric ton ethylene produced
- 0.040 metric tons CO₂/metric ton ethylene dichloride produced
- 0.46 metric tons CO₂/metric ton ethylene oxide produced

Annual production data for carbon black for 1990 through 2009 were obtained from the International Carbon Black Association (Johnson 2003 and 2005 through 2010). Annual production data for ethylene and ethylene dichloride for 1990 through 2009 were obtained from the American Chemistry Council's (ACC's) *Guide to the Business of Chemistry* (ACC 2002, 2003, 2005 through 2011). Annual production data for ethylene oxide were obtained from ACC's *U.S. Chemical Industry Statistical Handbook* for 2003 through 2009 (ACC 2014a) and from ACC's *Business of Chemistry* for 1990 through 2002 (ACC 2014b). As noted above, annual 2010 through 2014 production data for carbon black, ethylene, ethylene dichloride, and ethylene oxide, were obtained from EPA's GHGRP (EPA GHGRP 2015).

Acrylonitrile

Carbon dioxide and methane emissions from acrylonitrile production were estimated using the Tier 1 method in the *2006 IPCC Guidelines* (IPCC 2006). Annual acrylonitrile production data were used with IPCC default Tier 1 CO₂ and CH₄ emission factors to estimate emissions for 1990 through 2014. Emission factors used to estimate acrylonitrile production emissions are as follows:

- 0.18 kg CH₄/metric ton acrylonitrile produced
- 1.00 metric tons CO₂/metric ton acrylonitrile produced

Annual acrylonitrile production data for 1990 through 2014 were obtained from ACC's *Business of Chemistry* (ACC 2015).

Methanol

Carbon dioxide and methane emissions from methanol production were estimated using Tier 1 method in the *2006 IPCC Guidelines* (IPCC 2006). Annual methanol production data were used with IPCC default Tier 1 CO₂ and CH₄ emission factors to estimate emissions for 1990 through 2014. Emission factors used to estimate methanol production emissions are as follows:

- 2.3 kg CH₄/metric ton methanol produced

²⁵ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

- 0.67 metric tons CO₂/metric ton methanol produced

Annual methanol production data for 1990 through 2014 were obtained from the ACC's *Business of Chemistry* (ACC 2015).

Table 4-45: Production of Selected Petrochemicals (kt)

| Chemical | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|--------|--------|--------|--------|--------|--------|--------|
| Carbon Black | 1,307 | 1,651 | 1,309 | 1,338 | 1,283 | 1,228 | 1,207 |
| Ethylene | 16,542 | 23,975 | 24,355 | 25,143 | 24,763 | 25,341 | 25,509 |
| Ethylene Dichloride | 6,283 | 11,260 | 8,149 | 8,621 | 11,309 | 11,462 | 11,288 |
| Ethylene Oxide | 2,429 | 3,220 | 2,925 | 3,014 | 3,106 | 3,148 | 3,138 |
| Acrylonitrile | 1,214 | 1,325 | 1,160 | 1,055 | 1,220 | 1,075 | 1,095 |
| Methanol | 3,750 | 1,225 | 730 | 700 | 995 | 1,235 | 2,105 |

Uncertainty and Time-Series Consistency

The CH₄ and CO₂ emission factors used for acrylonitrile and methanol production are based on a limited number of studies. Using plant-specific factors instead of default or average factors could increase the accuracy of the emission estimates; however, such data were not available for the current Inventory report.

The results of the quantitative uncertainty analysis for the CO₂ emissions from carbon black production, ethylene, ethylene dichloride, and ethylene oxide are based on reported GHGRP data. Refer to the Methodology section for more details on how these emissions were calculated and reported to EPA's GHGRP. There is some uncertainty in the applicability of the average emission factors for each petrochemical type across all prior years. While petrochemical production processes in the United States have not changed significantly since 1990, some operational efficiencies have been implemented at facilities over the time series.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-46. Petrochemical production CO₂ emissions were estimated to be between 25.3 and 27.8 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 5 percent below to 5 percent above the emission estimate of 26.5 MMT CO₂ Eq. Petrochemical production CH₄ emissions were estimated to be between 0.05 and 0.15 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 55 percent below to 45 percent above the emission estimate of 0.1 MMT CO₂ Eq.

Table 4-46: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petrochemical Production and CO₂ Emissions from Carbon Black Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|--------------------------|-----------------|--|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Petrochemical Production | CO ₂ | 26.5 | 25.3 | 27.8 | -5% | +5% |
| Petrochemical Production | CH ₄ | 0.1 | 0.05 | 0.15 | -55% | +45% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculation Discussion

Acrylonitrile production data were obtained from ACC (2015). The ACC data included annual production quantities for the 1990 through 2014 time series. These data included revised acrylonitrile production quantities for several years of the time series compared to the production data used in the previous Inventory. This update in the production data caused a change in acrylonitrile emissions compared to the previous Inventory report. As a result of this update, emissions for some years increased and emissions for other years decreased. The change in annual emissions from the previous Inventory ranged from -9 percent (in 2010) to 11 percent (in 2009).

Methanol production data for 1990 through 2014 were also obtained from ACC (2015). In the previous Inventory, methanol production data for 1990 through 2013 were obtained from ACC and Argus Media Inc. (ARGUS JJ&A 2014). As a result of this update, emissions for some years increased slightly and emissions for other years decreased slightly.

Planned Improvements

Improvements include further assessment of CH₄ and N₂O emissions to enhance completeness in reporting of emissions from petrochemical production, pending resources, significance and time series consistency considerations.

Pending resources, a secondary potential improvement for this source category would focus on continuing to analyze the fuel and feedstock data from EPA's GHGRP to better disaggregate energy-related emissions and allocate them more accurately between the Energy and IPPU sectors of the Inventory. Some degree of double counting may occur between CO₂ estimates of non-energy use of fuels in the energy sector and CO₂ process emissions from petrochemical production in this sector. Data integration is not feasible at this time as feedstock data from the Energy Information Administration (EIA) used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g., petrochemical production). EPA, through its GHGRP, currently does not collect complete data on quantities of fuel consumed as feedstocks by petrochemical producers, only feedstock type. Updates to reporting requirements may address this issue future reporting years for the GHGRP data allowing for easier data integration between the non-energy uses of fuels category and the petrochemicals category presented in this chapter.

4.13 HCFC-22 Production (IPCC Source Category 2B9a)

Trifluoromethane (HFC-23 or CHF₃) is generated as a byproduct during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly and has remained near 2009 levels since. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.²⁶ Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform (CHCl₃) and hydrogen fluoride (HF) in the presence of a catalyst, SbCl₅. The reaction of the catalyst and HF produces SbCl_xF_y, (where x + y = 5), which reacts with chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform

²⁶ As construed, interpreted, and applied in the terms and conditions of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. [42 U.S.C. §7671m(b), CAA §614]

and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 (CHCl₂F), HCFC-22 (CHClF₂), HFC-23 (CHF₃), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Two facilities produced HCFC-22 in the U.S. in 2014. Emissions of HFC-23 from this activity in 2014 were estimated to be 5.0 MMT CO₂ Eq. (0.3 kt) (see Table 4-47). This quantity represents a 23 percent increase from 2013 emissions and an 89 percent decline from 1990 emissions. The increase from 2013 emissions and the decrease from 1990 emissions were caused primarily by changes in the HFC-23 emission rate (kg HFC-23 emitted/kg HCFC-22 produced). The long-term decrease in the emission rate is primarily attributable to six factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990; (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22; (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated; (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale; (e) another plant began destroying HFC-23; and (f) the same plant, whose emission factor was higher than that of the other two plants, ceased production of HCFC-22 in 2013.

Table 4-47: HFC-23 Emissions from HCFC-22 Production (MMT CO₂ Eq. and kt HFC-23)

| Year | MMT CO ₂ Eq. | kt HFC-23 |
|------|-------------------------|-----------|
| 1990 | 46.1 | 3 |
| 2005 | 20.0 | 1 |
| 2010 | 8.0 | 0.5 |
| 2011 | 8.8 | 0.6 |
| 2012 | 5.5 | 0.4 |
| 2013 | 4.1 | 0.3 |
| 2014 | 5.0 | 0.3 |

Methodology

To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since 1990, methods comparable to the Tier 3 methods in the *2006 IPCC Guidelines* (IPCC 2006) were used. Emissions for 2010 through 2014 were obtained through reports submitted by U.S. HCFC-22 production facilities to EPA's Greenhouse Gas Reporting Program (GHGRP). EPA's GHGRP mandates that all HCFC-22 production facilities report their annual emissions of HFC-23 from HCFC-22 production processes and HFC-23 destruction processes. Previously, data were obtained by EPA through collaboration with an industry association that received voluntarily reported HCFC-22 production and HFC-23 emissions annually from all U.S. HCFC-22 producers from 1990 through 2009. These emissions were aggregated and reported to EPA on an annual basis.

For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the *2006 IPCC Guidelines* were used. Emissions from these three plants have been calculated using the recommended emission factor for unoptimized plants operating before 1995 (0.04 kg HFC-23/kg HCFC-22 produced).

The five plants that have operated since 1994 measure (or, for the plants that have since closed, measured) concentrations of HFC-23 to estimate their emissions of HFC-23. Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify that the HFC-23 is almost completely destroyed. Plants that release (or historically have released) some of their byproduct HFC-23 periodically measure HFC-23 concentrations in the output stream using gas chromatography. This information is combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

To estimate 1990 through 2009 emissions, reports from an industry association were used that aggregated HCFC-22 production and HFC-23 emissions from all U.S. HCFC-22 producers and reported them to EPA (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). To estimate 2010 through 2014 emissions,

facility-level data (including both HCFC-22 production and HFC-23 emissions) reported through the EPA's GHGRP were analyzed. In 1997 and 2008, comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production were performed (RTI 1997; RTI 2008). The 1997 and 2008 reviews enabled U.S. totals to be reviewed, updated, and where necessary, corrected, and also for plant-level uncertainty analyses (Monte-Carlo simulations) to be performed for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-48.

Table 4-48: HCFC-22 Production (kt)

| Year | kt |
|------|-----|
| 1990 | 139 |
| 2005 | 156 |
| 2010 | 101 |
| 2011 | 110 |
| 2012 | 96 |
| 2013 | C |
| 2014 | C |

Note: HCFC-22 production in 2013 and 2014 is considered Confidential Business Information (CBI) as there were only two producers of HCFC-22 in 2013 and 2014.

Uncertainty and Time-Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo Stochastic Simulation for 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant's estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from the probability density functions for each input. A normal probability density function was assumed for all measurements and biases except the equipment leak estimates for one plant; a log-normal probability density function was used for this plant's equipment leak estimates. The simulation for 2006 yielded a 95-percent confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

The relative errors yielded by the Monte Carlo Stochastic Simulation for 2006 were applied to the U.S. emission estimate for 2014. The resulting estimates of absolute uncertainty are likely to be reasonably accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2006 and 2014 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-49. HFC-23 emissions from HCFC-22 production were estimated to be between 4.7 and 5.5 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 5.0 MMT CO₂ Eq.

Table 4-49: Approach 2 Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|--------------------|--------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| HCFC-22 Production | HFC-23 | 5.0 | 4.7 | 5.5 | -7% | +10% |

^a Range of emissions reflects a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

4.14 Carbon Dioxide Consumption (IPCC Source Category 2B10)

Carbon dioxide (CO₂) is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). Carbon dioxide used for EOR is injected into the underground reservoirs to increase the reservoir pressure to enable additional petroleum to be produced. For the most part, CO₂ used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO₂ used in commercial applications other than EOR is assumed to be emitted to the atmosphere. Carbon dioxide used in EOR applications is discussed in the Energy chapter under “Carbon Capture and Storage, including Enhanced Oil Recovery” and is not discussed in this section.

Carbon dioxide is produced from naturally-occurring CO₂ reservoirs, as a byproduct from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a byproduct from the production of crude oil and natural gas, which contain naturally occurring CO₂ as a component. Only CO₂ produced from naturally occurring CO₂ reservoirs, and as a byproduct from energy and industrial processes, and used in industrial applications other than EOR is included in this analysis. Carbon dioxide captured from biogenic sources (e.g., ethanol production plants) is not included in the Inventory. Carbon dioxide captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy chapter.

Carbon dioxide is produced as a byproduct of crude oil and natural gas production. This CO₂ is separated from the crude oil and natural gas using gas processing equipment, and may be emitted directly to the atmosphere, or captured and reinjected into underground formations, used for EOR, or sold for other commercial uses. A further discussion of CO₂ used in EOR is described in the Energy chapter under the text box titled “Carbon Dioxide Transport, Injection, and Geological Storage.”

In 2014, the amount of CO₂ produced and captured for commercial applications and subsequently emitted to the atmosphere was 4.5 MMT CO₂ Eq. (4,471 kt) (see Table 4-50). This is an increase of approximately 7 percent from the previous year and an increase of approximately 204 percent since 1990.

Table 4-50: CO₂ Emissions from CO₂ Consumption (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 1.5 | 1,472 |
| 2005 | 1.4 | 1,375 |
| 2010 | 4.4 | 4,425 |
| 2011 | 4.1 | 4,083 |
| 2012 | 4.0 | 4,019 |
| 2013 | 4.2 | 4,188 |
| 2014 | 4.5 | 4,471 |

Methodology

Carbon dioxide emission estimates for 1990 through 2014 were based on the quantity of CO₂ extracted and transferred for industrial applications (i.e., non-EOR end-uses). Some of the CO₂ produced by these facilities is used for EOR and some is used in other commercial applications (e.g., chemical manufacturing, food production). It

is assumed that 100 percent of the CO₂ production used in commercial applications other than EOR is eventually released into the atmosphere.

2010 through 2014

For 2010 through 2014, data from EPA's Greenhouse Gas Reporting Program (GHGRP) (Subpart PP) were aggregated from facility-level reports to develop a national-level estimate for use in the Inventory (EPA GHGRP 2015). Facilities report CO₂ extracted or produced from natural reservoirs and industrial sites, and CO₂ captured from energy and industrial processes and transferred to various end-use applications to EPA's GHGRP. This analysis includes only reported CO₂ transferred to food and beverage end-uses. EPA is continuing to analyze and assess integration of CO₂ transferred to other end-uses to enhance the completeness of estimates under this source category. Other end-uses include industrial applications, such as metal fabrication. EPA is analyzing the information reported to ensure that other end-use data excludes non-emissive applications and publication will not reveal confidential business information (CBI). Reporters subject to EPA's GHGRP Subpart PP are also required to report the quantity of CO₂ that is imported and/or exported. Currently, these data are not publicly available through the GHGRP due to data confidentiality issues and hence are excluded from this analysis.

Facilities subject to Subpart PP of EPA's GHGRP are required to measure CO₂ extracted or produced. More details on the calculation and monitoring methods applicable to extraction and production facilities can be found under Subpart PP: Suppliers of Carbon Dioxide of the regulation, Part 98.²⁷ The number of facilities that reported data to EPA's GHGRP Subpart PP (Suppliers of Carbon Dioxide) for 2010 through 2014 is much higher (ranging from 44 to 48) than the number of facilities included in the Inventory for the 1990 to 2009 time period prior to the availability of GHGRP data (4 facilities). The difference is largely due to the fact the 1990 to 2009 data includes only CO₂ transferred to end-use applications from naturally occurring CO₂ reservoirs and excludes industrial sites.

1990 through 2009

For 1990 through 2009, data from EPA's GHGRP are not available. For this time period, CO₂ production data from four naturally-occurring CO₂ reservoirs were used to estimate annual CO₂ emissions. These facilities were Jackson Dome in Mississippi, Brave and West Bravo Domes in New Mexico, and McCallum Dome in Colorado. The facilities in Mississippi and New Mexico produced CO₂ for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). The fourth facility in Colorado (McCallum Dome) produced CO₂ for commercial applications only (New Mexico Bureau of Geology and Mineral Resources 2006).

Carbon dioxide production data and the percentage of production that was used for non-EOR applications for the Jackson Dome, Mississippi facility were obtained from Advanced Resources International (ARI 2006, 2007) for 1990 to 2000, and from the Annual Reports of Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-51). Denbury Resources reported the average CO₂ production in units of MMCF CO₂ per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. Production from 1990 to 1999 was set equal to 2000 production, due to lack of publicly available production data for 1990 through 1999. Carbon dioxide production data for the Bravo Dome and West Bravo Dome were obtained from ARI for 1990 through 2009 (ARI 1990 to 2010). Data for the West Bravo Dome facility were only available for 2009. The percentage of total production that was used for non-EOR applications for the Bravo Dome and West Bravo Dome facilities for 1990 through 2009 were obtained from New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003; New Mexico Bureau of Geology and Mineral Resources 2006). Production data for the McCallum Dome (Jackson County), Colorado facility were obtained from the Colorado Oil and Gas Conservation Commission (COGCC) for 1999 through 2009 (COGCC 2014). Production data for 1990 to 1998 and percentage of production used for EOR were assumed to be the same as for 1999, due to lack of publicly-available data.

²⁷ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

Table 4-51: CO₂ Production (kt CO₂) and the Percent Used for Non-EOR Applications

| Year | Jackson Dome, MS CO ₂ Production (kt) (% Non-EOR) | Bravo Dome, NM CO ₂ Production (kt) (% Non-EOR) | West Bravo Dome, NM CO ₂ Production (kt) (% Non-EOR) | McCallum Dome, CO CO ₂ Production (kt) (% Non-EOR) | Total CO ₂ Production from Extraction and Capture Facilities (kt) | % Non-EOR ^a |
|------|---|---|--|--|--|------------------------|
| 1990 | 1,344 (100%) | 63 (1%) | + | 65 (100%) | NA | NA |
| 2005 | 1,254 (27%) | 58 (1%) | + | 63 (100%) | NA | NA |
| 2010 | NA | NA | NA | NA | 64,724 | 7% |
| 2011 | NA | NA | NA | NA | 66,241 | 6% |
| 2012 | NA | NA | NA | NA | 66,326 | 6% |
| 2013 | NA | NA | NA | NA | 68,435 | 6% |
| 2014 | NA | NA | NA | NA | 71,431 | 6% |

+ Does not exceed 0%.

^a Includes only food & beverage applications.

NA (Not available). For 2010 through 2014, the publicly available GHGRP data were aggregated at the national level. Facility-level data are not publicly available from EPA's GHGRP.

Uncertainty and Time-Series Consistency

There is uncertainty associated with the data reported through EPA's GHGRP. Specifically, there is uncertainty associated with the amount of CO₂ consumed for food and beverage applications given a threshold for reporting under GHGRP applicable to those reporting under Subpart PP, in addition to the exclusion of the amount of CO₂ transferred to all other end-use categories. This latter category might include CO₂ quantities that are being used for non-EOR industrial applications such as firefighting. Second, uncertainty is associated with the exclusion of imports/exports data for CO₂ suppliers. Currently these data are not publicly available through EPA's GHGRP and hence are excluded from this analysis.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-52. Carbon dioxide consumption CO₂ emissions for 2014 were estimated to be between 3.9 and 5.1 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 13 percent above the emission estimate of 4.5 MMT CO₂ Eq.

Table 4-52: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from CO₂ Consumption (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------------------|-----------------|--|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| CO ₂ Consumption | CO ₂ | 4.5 | 3.9 | 5.1 | -12% | +13% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

EPA will continue to evaluate the potential to include additional GHGRP data on other emissive end-uses to improve accuracy and completeness of estimates for this source category. Particular attention will be made to risks for disclosing CBI and ensuring time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from

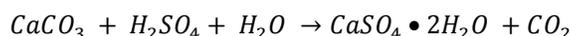
EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.²⁸

4.15 Phosphoric Acid Production (IPCC Source Category 2B10)

Phosphoric acid (H₃PO₄) is a basic raw material used in the production of phosphate-based fertilizers. Phosphoric acid production from natural phosphate rock is a source of carbon dioxide (CO₂) emissions, due to the chemical reaction of the inorganic carbon (calcium carbonate) component of the phosphate rock.

Phosphate rock is mined in Florida, North Carolina, Idaho, and Utah and is used primarily as a raw material for wet-process phosphoric acid production. The composition of natural phosphate rock varies depending upon the location where it is mined. Natural phosphate rock mined in the United States generally contains inorganic carbon in the form of calcium carbonate (limestone) and also may contain organic carbon. The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic carbon that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry.

The phosphoric acid production process involves chemical reaction of the calcium phosphate (Ca₃(PO₄)₂) component of the phosphate rock with sulfuric acid (H₂SO₄) and recirculated phosphoric acid (H₃PO₄) (EFMA 2000). However, the generation of CO₂ is due to the associated limestone-sulfuric acid reaction, as shown below:



Total U.S. phosphate rock production sold or used in 2014 was 28.1 million metric tons (USGS 2015a). Approximately 80 percent of domestic phosphate rock production was mined in Florida and North Carolina, while the remaining 20 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2014 were approximately 2.6 million metric tons (USGS 2015a). Most of the imported phosphate rock (74 percent) is from Morocco, with the remaining 26 percent being from Peru (USGS 2015a). All phosphate rock mining companies are vertically integrated with fertilizer plants that produce phosphoric acid located near the mines. Some additional phosphoric acid production facilities are located in Texas, Louisiana, and Mississippi that used imported phosphate rock.

Over the 1990 to 2014 period, domestic production has decreased by nearly 44 percent. Total CO₂ emissions from phosphoric acid production were 1.1 MMT CO₂ Eq. (1,095 kt CO₂) in 2014 (see Table 4-53). Domestic consumption of phosphate rock in 2014 was estimated to have decreased by approximately 2 percent over 2013 levels, owing to producers drawing from higher than average inventories and the closure of a mine in Florida. Domestic consumption also decreased because of lower phosphoric acid and fertilizer production (USGS 2015a).

Table 4-53: CO₂ Emissions from Phosphoric Acid Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 1.5 | 1,529 |
| 2005 | 1.3 | 1,342 |
| 2010 | 1.1 | 1,087 |
| 2011 | 1.2 | 1,151 |
| 2012 | 1.1 | 1,093 |
| 2013 | 1.1 | 1,119 |
| 2014 | 1.1 | 1,095 |

²⁸ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Methodology

Carbon dioxide emissions from production of phosphoric acid from phosphate rock are estimated by multiplying the average amount of inorganic carbon (expressed as CO₂) contained in the natural phosphate rock as calcium carbonate by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption. The estimation methodology is as follows:

$$E_{pa} = C_{pr} \times Q_{pr}$$

where,

| | | |
|----------|---|---|
| E_{pa} | = | CO ₂ emissions from phosphoric acid production, metric tons |
| C_{pr} | = | Average amount of carbon (expressed as CO ₂) in natural phosphate rock, metric ton CO ₂ /metric ton phosphate rock |
| Q_{pr} | = | Quantity of phosphate rock used to produce phosphoric acid |

The CO₂ emissions calculation methodology is based on the assumption that all of the inorganic C (calcium carbonate) content of the phosphate rock reacts to produce CO₂ in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO₂ and that all of the organic C content remains in the phosphoric acid product.

From 1993 to 2004, the U.S. Geological Survey (USGS) *Mineral Yearbook: Phosphate Rock* disaggregated phosphate rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-54). For the years 1990 through 1992, and 2005 through 2014, only nationally aggregated mining data was reported by USGS. For the years 1990, 1991, and 1992, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using average share of U.S. production in those states from 1993 to 2004 data. For the years 2005 through 2014, the same approximation method is used, but the share of U.S. production in those states data were obtained from the USGS commodity specialist for phosphate rock (USGS 2012). Data for domestic sales or consumption of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2014 were obtained from USGS *Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2015b), and from USGS *Minerals Commodity Summaries: Phosphate Rock in 2015* (USGS 2015a). From 2004 through 2014, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2015b).

The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research (FIPR 2003a). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic carbon. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table 4-55).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO₂ emissions from consumption of phosphate rock mined in Florida and North Carolina (80 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO₂ emissions from consumption of imported phosphate rock. The CO₂ emissions calculation is based on the assumption that all of the domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this single producer (USGS 2006). The USGS confirmed that no significant quantity of domestic production of phosphate rock is in the calcined form (USGS 2012b).

Table 4-54: Phosphate Rock Domestic Consumption, Exports, and Imports (kt)

| Location/Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------|--------|--------|--------|--------|--------|--------|--------|
| U.S. Domestic | | | | | | | |
| Consumption | 49,800 | 35,200 | 28,100 | 28,600 | 27,300 | 28,800 | 28,100 |
| FL and NC | 42,494 | 28,160 | 22,480 | 22,880 | 21,840 | 23,040 | 22,480 |
| ID and UT | 7,306 | 7,040 | 5,620 | 5,720 | 5,460 | 5,760 | 5,620 |
| Exports—FL and NC | 6,240 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | |
|-------------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Imports | 451 | 2,630 | 2,400 | 3,350 | 3,080 | 2,560 | 2,570 |
| Total U.S. Consumption | 44,011 | 37,830 | 30,500 | 31,950 | 30,380 | 31,360 | 30,670 |

Table 4-55: Chemical Composition of Phosphate Rock (Percent by weight)

| Composition | Central Florida | North Florida | North Carolina (calcined) | Idaho (calcined) | Morocco |
|--|------------------------|----------------------|----------------------------------|-------------------------|----------------|
| Total Carbon (as C) | 1.60 | 1.76 | 0.76 | 0.60 | 1.56 |
| Inorganic Carbon (as C) | 1.00 | 0.93 | 0.41 | 0.27 | 1.46 |
| Organic Carbon (as C) | 0.60 | 0.83 | 0.35 | 0.00 | 0.10 |
| Inorganic Carbon (as CO ₂) | 3.67 | 3.43 | 1.50 | 1.00 | 5.00 |

Source: FIPR (2003a).

Uncertainty and Time-Series Consistency

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2014. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006, only total U.S. phosphate rock production was reported. Regional production for 2014 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2014 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO₂ emissions from phosphoric acid production is the carbonate composition of phosphate rock; the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. The Inventory relies on one study (FIPR 2003a) of chemical composition of the phosphate rock; limited data are available beyond this study. Another source of uncertainty is the disposition of the organic carbon content of the phosphate rock. A representative of the Florida Institute of Phosphate Research (FIPR) indicated that in the phosphoric acid production process, the organic C content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003b). Organic carbon is therefore not included in the calculation of CO₂ emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic C in the phosphate rock into CO₂. However, according to air permit information available to the public, at least one facility has calcining units permitted for operation (NCDENR 2013).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO₂ in the elemental phosphorus production process. The calculation for CO₂ emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO₂ emissions from 100 percent of the inorganic carbon content in phosphate rock, but none from the organic carbon content.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-56. Phosphoric acid production CO₂ emissions were estimated to be between 0.9 and 1.4 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 19 percent below and 20 percent above the emission estimate of 1.1 MMT CO₂ Eq.

Table 4-56: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Phosphoric Acid Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|----------------------------|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Phosphoric Acid Production | CO ₂ | 1.1 | 0.9 | 1.4 | -19% | +20% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Relative to the previous Inventory, the phosphate rock consumption data (sold or used and imports for consumption) for 2013 were revised based on updated data publicly available from USGS (USGS 2015). This revision caused a decrease in the 2013 emission estimate by approximately 2 percent.

Additionally, during the development of the current Inventory emission estimates, it was discovered that the phosphate rock CO₂ content had been incorrectly transcribed in the previous Inventory. This error was corrected in the current Inventory and resulted in a slight change of emissions over the entire time series.

Planned Improvements

EPA continues to evaluate potential improvements to the Inventory estimates for this source category, which include direct integration of EPA's Greenhouse Gas Reporting Program (GHGRP) data for 2010 through 2014 and the use of reported GHGRP data to update the inorganic C content of phosphate rock for prior years. Confidentiality of CBI is being assessed, in addition to the applicability of EPA's GHGRP data for the averaged inorganic C content data (by region) from 2010 through 2014 to inform estimates in prior years in the required time series (i.e., 1990 through 2009). In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.²⁹

4.16 Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

Iron and steel production is a multi-step process that generates process-related emissions of carbon dioxide (CO₂) and methane (CH₄) as raw materials are refined into iron and then transformed into crude steel. Emissions from conventional fuels (e.g., natural gas, fuel oil) consumed for energy purposes during the production of iron and steel are accounted for in the Energy chapter.

Iron and steel production includes six distinct production processes: coke production, sinter production, direct reduced iron (DRI) production, pig iron production, electric arc furnace (EAF) steel production, and basic oxygen furnace (BOF) steel production. The number of production processes at a particular plant is dependent upon the specific plant configuration. In addition to the production processes mentioned above, CO₂ is also generated at iron

²⁹ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

and steel mills through the consumption of process byproducts (e.g., blast furnace gas, coke oven gas) used for various purposes including heating, annealing, and electricity generation. Process byproducts sold for use as synthetic natural gas are deducted and reported in the Energy chapter. In general, CO₂ emissions are generated in these production processes through the reduction and consumption of various carbon-containing inputs (e.g., ore, scrap, flux, coke byproducts). In addition, fugitive CH₄ emissions can also be generated from these processes but also sinter, direct iron and pellet production.

Currently, there are between 15 and 20 integrated iron and steel steelmaking facilities that utilize BOFs to refine and produce steel from iron and more than 100 steelmaking facilities that utilize EAFs to produce steel primarily from recycled ferrous scrap. In addition, there are 18 cokemaking facilities, of which 7 facilities are co-located with integrated iron and steel facilities. Slightly more than 62 percent of the raw steel produced in the United States is produced in one of seven states: Alabama, Arkansas, Indiana, Kentucky, Mississippi, Ohio, and Tennessee (AISI 2015a).

Total production of crude steel in the United States between 2000 and 2008 ranged from a low of 99,320,000 tons to a high of 109,880,000 tons (2001 and 2004, respectively). Due to the decrease in demand caused by the global economic downturn (particularly from the automotive industry), crude steel production in the United States sharply decreased to 65,459,000 tons in 2009. In 2010, crude steel production rebounded to 88,731,000 tons as economic conditions improved and then continued to increase to 95,237,000 tons in 2011 and 97,770,000 tons in 2012; crude steel production slightly decreased to 95,766,000 tons in 2013 and then slightly increased to 97,195,000 tons in 2014 (AISI 2015a). The United States was the third largest producer of raw steel in the world, behind China and Japan, accounting for approximately 5.3 percent of world production in 2013 (AISI 2015a).

The majority of CO₂ emissions from the iron and steel production process come from the use of coke in the production of pig iron and from the consumption of other process byproducts, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel.

According to the *2006 IPCC Guidelines* (IPCC 2006), the production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the use of coke in iron and steel production is considered to be an industrial process source. Therefore, the *2006 IPCC Guidelines* suggest that emissions from the production of metallurgical coke should be reported separately in the Energy sector, while emissions from coke consumption in iron and steel production should be reported in the Industrial Processes and Product Use sector. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because much of the relevant activity data is used to estimate emissions from both metallurgical coke production and iron and steel production. For example, some byproducts (e.g., coke oven gas) of the metallurgical coke production process are consumed during iron and steel production, and some byproducts of the iron and steel production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions associated with the consumption of these byproducts are attributed at the point of consumption. Emissions associated with the use of conventional fuels (e.g., natural gas, fuel oil) for electricity generation, heating and annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the Energy chapter.

Metallurgical Coke Production

Emissions of CO₂ from metallurgical coke production in 2014 were 1.9 MMT CO₂ Eq. (1,938 kt CO₂) (see Table 4-57 and Table 4-58). Emissions increased in 2014 from 2013 levels, but have decreased overall since 1990. Domestic coke production data for 2014 are not yet published and so 2013 data were used as proxy for 2014. Coke production in 2014 was 26 percent lower than in 2000 and 45 percent below 1990. Overall, emissions from metallurgical coke production have declined by 23 percent (0.6 MMT CO₂ Eq.) from 1990 to 2014.

Table 4-57: CO₂ Emissions from Metallurgical Coke Production (MMT CO₂ Eq.)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------------|------------|------------|------------|------------|------------|------------|
| CO ₂ | 2.5 | 2.0 | 2.1 | 1.4 | 0.5 | 1.8 | 1.9 |
| Total | 2.5 | 2.0 | 2.1 | 1.4 | 0.5 | 1.8 | 1.9 |

Table 4-58: CO₂ Emissions from Metallurgical Coke Production (kt)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|-------|-------|-------|-------|------|-------|-------|
| CO ₂ | 2,503 | 2,044 | 2,085 | 1,426 | 543 | 1,824 | 1,938 |

Iron and Steel Production

Emissions of CO₂ and CH₄ from iron and steel production in 2014 were 53.4 MMT CO₂ Eq. (53,417 kt) and 0.0094 MMT CO₂ Eq. (0.4 kt), respectively (see Table 4-59 through Table 4-62), totaling approximately 53.4 MMT CO₂ Eq. Emissions decreased in 2014 and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. Carbon dioxide emission estimates include emissions from the consumption of carbonaceous materials in the blast furnace, EAF, and BOF, as well as blast furnace gas and coke oven gas consumption for other activities at the steel mill.

In 2014, domestic production of pig iron decreased by 3 percent from 2013 levels. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2014 was 39 percent lower than in 2000 and 41 percent below 1990. Carbon dioxide emissions from steel production have decreased by 4 percent (0.3 MMT CO₂ Eq.) since 1990, while overall CO₂ emissions from iron and steel production have declined by 45 percent (43.7 MMT CO₂ Eq.) from 1990 to 2014.

Table 4-59: CO₂ Emissions from Iron and Steel Production (MMT CO₂ Eq.)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Sinter Production | 2.4 | 1.7 | 1.0 | 1.2 | 1.2 | 1.1 | 1.1 |
| Iron Production | 45.6 | 17.5 | 17.8 | 18.4 | 10.9 | 11.9 | 16.8 |
| Steel Production | 7.9 | 9.4 | 9.2 | 9.3 | 9.9 | 8.6 | 7.6 |
| Other Activities ^a | 41.2 | 35.9 | 25.5 | 29.7 | 31.7 | 28.7 | 27.9 |
| Total | 97.2 | 64.5 | 53.6 | 58.5 | 53.7 | 50.4 | 53.4 |

^a Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Note: Totals may not sum due to independent rounding.

Table 4-60: CO₂ Emissions from Iron and Steel Production (kt)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Sinter Production | 2,448 | 1,663 | 1,045 | 1,188 | 1,159 | 1,117 | 1,104 |
| Iron Production | 45,592 | 17,545 | 17,802 | 18,375 | 10,917 | 11,934 | 16,754 |
| Steel Production | 7,933 | 9,356 | 9,235 | 9,255 | 9,860 | 8,617 | 7,648 |
| Other Activities ^a | 41,193 | 35,934 | 25,504 | 29,683 | 31,750 | 28,709 | 27,911 |
| Total | 97,166 | 64,499 | 53,586 | 58,501 | 53,686 | 50,378 | 53,417 |

^a Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Note: Totals may not sum due to independent rounding.

Table 4-61: CH₄ Emissions from Iron and Steel Production (MMT CO₂ Eq.)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------|----------|----------|----------|----------|----------|----------|----------|
| Sinter Production | + | + | + | + | + | + | + |
| Total | + |

+ Does not exceed 0.05 MMT CO₂ Eq.

Table 4-62: CH₄ Emissions from Iron and Steel Production (kt)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------|------------|------------|------------|------------|------------|------------|------------|
| Sinter Production | 0.9 | 0.6 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Total | 0.9 | 0.6 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |

Methodology

Emission estimates presented in this chapter are largely based on Tier 2 methodologies provided by the *2006 IPCC Guidelines* (IPCC 2006). These Tier 2 methodologies call for a mass balance accounting of the carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke production process. Tier 1 methods are used for certain iron and steel production processes (i.e., sinter production and DRI production) for which available data are insufficient for utilizing a Tier 2 method.

The Tier 2 methodology equation is as follows:

$$E_{CO_2} = \left[\sum_a (Q_a \times C_a) - \sum_b (Q_b \times C_b) \right] \times \frac{44}{12}$$

where,

| | | |
|------------|---|--|
| E_{CO_2} | = | Emissions from coke, pig iron, EAF steel, or BOF steel production, metric tons |
| a | = | Input material a |
| b | = | Output material b |
| Q_a | = | Quantity of input material a , metric tons |
| C_a | = | Carbon content of input material a , metric tons C/metric ton material |
| Q_b | = | Quantity of output material b , metric tons |
| C_b | = | Carbon content of output material b , metric tons C/metric ton material |
| 44/12 | = | Stoichiometric ratio of CO ₂ to C |

The Tier 1 methodology equations are as follows:

$$E_{s,p} = Q_s \times EF_{s,p}$$

$$E_{d,CO_2} = Q_d \times EF_{d,CO_2}$$

where,

| | | |
|---------------|---|--|
| $E_{s,p}$ | = | Emissions from sinter production process for pollutant p (CO ₂ or CH ₄), metric ton |
| Q_s | = | Quantity of sinter produced, metric tons |
| $EF_{s,p}$ | = | Emission factor for pollutant p (CO ₂ or CH ₄), metric ton p /metric ton sinter |
| E_{d,CO_2} | = | Emissions from DRI production process for CO ₂ , metric ton |
| Q_d | = | Quantity of DRI produced, metric tons |
| EF_{d,CO_2} | = | Emission factor for CO ₂ , metric ton CO ₂ /metric ton DRI |

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical coke that is used primarily as a reducing agent in the production of iron and steel, but is also used in the production of other metals including zinc and lead (see Zinc Production and Lead Production sections of this chapter). Emissions associated with producing metallurgical coke from coking coal are estimated and reported separately from emissions that result from the iron and steel production process. To estimate emissions from metallurgical coke production, a Tier 2 method provided by the *2006 IPCC Guidelines* (IPCC 2006) was utilized. The amount of carbon contained in materials produced during the metallurgical coke production process (i.e., coke, coke breeze, coke oven gas, and coal tar) is deducted from the amount of carbon contained in materials consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, and coking coal). Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due to data limitations. The amount of carbon contained in these materials is calculated by

multiplying the material-specific carbon content by the amount of material consumed or produced (see Table 4-63). The amount of coal tar produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed. The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per ton of coking coal consumed (AISI 2008c; DOE 2000). Data on the consumption of carbonaceous materials (other than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

Table 4-63: Material Carbon Contents for Metallurgical Coke Production

| Material | kg C/kg |
|-------------------|---------|
| Coal Tar | 0.62 |
| Coke | 0.83 |
| Coke Breeze | 0.83 |
| Coking Coal | 0.73 |
| Material | kg C/GJ |
| Coke Oven Gas | 12.1 |
| Blast Furnace Gas | 70.8 |

Source: IPCC (2006), Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

Although the 2006 IPCC Guidelines provide a Tier 1 CH₄ emission factor for metallurgical coke production (i.e., 0.1 g CH₄ per metric ton of coke production), it is not appropriate to use because CO₂ emissions were estimated using the Tier 2 mass balance methodology. The mass balance methodology makes a basic assumption that all carbon that enters the metallurgical coke production process either exits the process as part of a C-containing output or as CO₂ emissions. This is consistent with a preliminary assessment of aggregated facility-level greenhouse gas CH₄ emissions reported by coke production facilities under EPA's Greenhouse Gas Reporting Program (GHGRP). The assessment indicates that CH₄ emissions from coke production are below 500 kt or 0.05 percent of total national emissions. Pending resources and significance, EPA may include these emissions in future reports to enhance completeness.

Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke produced at coke plants were taken from the Energy Information Administration (EIA), *Quarterly Coal Report: October through December* (EIA 1998 through 2015a) (see Table 4-64). Data on the volume of natural gas consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at integrated steel mills were obtained from the American Iron and Steel Institute (AISI), *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-65). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008c). The factor for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Data on natural gas consumption and coke oven gas production at merchant coke plants were not available and were excluded from the emission estimate. Carbon contents for coking coal, metallurgical coke, coal tar, coke oven gas, and blast furnace gas were provided by the 2006 IPCC Guidelines (IPCC 2006). The C content for coke breeze was assumed to equal the C content of coke.

Table 4-64: Production and Consumption Data for the Calculation of CO₂ and CH₄ Emissions from Metallurgical Coke Production (Thousand Metric Tons)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 ^a |
|--|--------|--------|--------|--------|--------|--------|-------------------|
| Metallurgical Coke Production | | | | | | | |
| Coking Coal Consumption at Coke Plants | 35,269 | 21,259 | 19,135 | 19,445 | 18,825 | 19,481 | 19,481 |
| Coke Production at Coke Plants | 25,054 | 15,167 | 13,628 | 13,989 | 13,764 | 13,898 | 13,898 |
| Coal Breeze Production | 2,645 | 1,594 | 1,435 | 1,458 | 1,412 | 1,461 | 1,461 |
| Coal Tar Production | 1,058 | 638 | 574 | 583 | 565 | 584 | 584 |

^a 2013 data were used as a proxy because 2014 data are not yet published.

Table 4-65: Production and Consumption Data for the Calculation of CO₂ Emissions from Metallurgical Coke Production (Million ft³)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------------|---------|---------|--------|---------|---------|---------|---------|
| Metallurgical Coke Production | | | | | | | |
| Coke Oven Gas Production | 250,767 | 114,213 | 95,405 | 109,044 | 113,772 | 108,162 | 102,899 |
| Natural Gas Consumption | 599 | 2,996 | 3,108 | 3,175 | 3,267 | 3,247 | 3,039 |
| Blast Furnace Gas Consumption | 24,602 | 4,460 | 3,181 | 3,853 | 4,351 | 4,255 | 4,346 |

Iron and Steel Production

Emissions of CO₂ from sinter production and direct reduced iron production were estimated by multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO₂ emission factors (see Table 4-66). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-66: CO₂ Emission Factors for Sinter Production and Direct Reduced Iron Production

| Material Produced | Metric Ton CO ₂ /Metric Ton |
|---------------------|--|
| Sinter | 0.2 |
| Direct Reduced Iron | 0.7 |

Source: IPCC (2006), Table 4.1.

To estimate emissions from pig iron production in the blast furnace, the amount of carbon contained in the produced pig iron and blast furnace gas were deducted from the amount of carbon contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, and direct coal injection). The carbon contained in the pig iron, blast furnace gas, and blast furnace inputs was estimated by multiplying the material-specific C content by each material type (see Table 4-67). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO₂ during this process. Carbon contained in blast furnace gas used as a blast furnace input was not included in the deductions to avoid double-counting.

Emissions from steel production in EAFs were estimated by deducting the carbon contained in the steel produced from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of carbon from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of carbon contained in BOF steel were deducted from C contained in inputs such as natural gas, coke oven gas, fluxes, and pig iron. In each case, the carbon was calculated by multiplying material-specific carbon contents by each material type (see Table 4-67). For EAFs, the amount of EAF anode consumed was approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of steel produced (0.002 metric tons EAF anode per metric ton steel produced [AISI 2008c]). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Other Process Uses of Carbonates source category to avoid double-counting.

Carbon dioxide emissions from the consumption of blast furnace gas and coke oven gas for other activities occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these purposes by the material-specific carbon content (see Table 4-67).

Carbon dioxide emissions associated with the sinter production, direct reduced iron production, pig iron production, steel production, and other steel mill activities were summed to calculate the total CO₂ emissions from iron and steel production (see Table 4-59 and Table 4-60).

Table 4-67: Material Carbon Contents for Iron and Steel Production

| Material | kg C/kg |
|-----------------------|---------|
| Coke | 0.83 |
| Direct Reduced Iron | 0.02 |
| Dolomite | 0.13 |
| EAF Carbon Electrodes | 0.82 |

| | |
|-------------------|----------------|
| EAF Charge Carbon | 0.83 |
| Limestone | 0.12 |
| Pig Iron | 0.04 |
| Steel | 0.01 |
| Material | kg C/GJ |
| Coke Oven Gas | 12.1 |
| Blast Furnace Gas | 70.8 |

Source: IPCC (2006), Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production process for sinter results in fugitive emissions of CH₄, which are emitted via leaks in the production equipment, rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors taken from the *2006 IPCC Guidelines* (IPCC 2006) for sinter production (see Table 4-68). Although the *1995 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1995) provide a Tier 1 CH₄ emission factor for pig iron production, it is not appropriate to use because CO₂ emissions were estimated using the Tier 2 mass balance methodology. The mass balance methodology makes a basic assumption that all carbon that enters the pig iron production process either exits the process as part of a carbon-containing output or as CO₂ emissions; the estimation of CH₄ emissions is precluded. A preliminary analysis of facility-level emissions reported during iron production further supports this assumption and indicates that CH₄ emissions are below 500 kt CO₂ Eq. and well below 0.05 percent of total national emissions. The production of direct reduced iron also results in emissions of CH₄ through the consumption of fossil fuels (e.g., natural gas, etc.); however, these emission estimates are excluded due to data limitations. Pending further analysis and resources, EPA may include these emissions in future reports to enhance completeness.

Table 4-68: CH₄ Emission Factors for Sinter and Pig Iron Production

| Material Produced | Factor | Unit |
|-------------------|--------|--------------------------------|
| Sinter | 0.07 | kg CH ₄ /metric ton |

Source: IPCC (2006), Table 4.2.

Sinter consumption data for 1990 through 2014 were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-69). In general, direct reduced iron (DRI) consumption data were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook – Iron and Steel Scrap* (USGS 1991 through 2014) and personal communication with the USGS Iron and Steel Commodity Specialist (Fenton 2015). However, data for DRI consumed in EAFs were not available for the years 1990 and 1991. EAF DRI consumption in 1990 and 1991 was calculated by multiplying the total DRI consumption for all furnaces by the EAF share of total DRI consumption in 1992. Also, data for DRI consumed in BOFs were not available for the years 1990 through 1993. BOF DRI consumption in 1990 through 1993 was calculated by multiplying the total DRI consumption for all furnaces (excluding EAFs and cupola) by the BOF share of total DRI consumption (excluding EAFs and cupola) in 1994.

The Tier 1 CO₂ emission factors for sinter production and direct reduced iron production were obtained through the *2006 IPCC Guidelines* (IPCC 2006). Time series data for pig iron production, coke, natural gas, fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-69 and Table 4-70).

Data for EAF steel production, flux, EAF charge carbon, and natural gas consumption were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2006 through 2015b and 2008c). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (2008c). Data for BOF steel production, flux, natural gas, natural ore, pellet, sinter consumption as well as BOF steel production were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c). Data for EAF and BOF scrap steel, pig iron, and DRI consumption were obtained from the USGS *Minerals Yearbook – Iron and Steel Scrap* (USGS 1991 through 2014). Data on coke oven gas and blast furnace gas consumed at the iron and steel mill (other than in the EAF, BOF, or

blast furnace) were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c).

Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained from EIA's *Natural Gas Annual* (EIA 2015a). Carbon contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by the *2006 IPCC Guidelines* (IPCC 2006). The carbon contents for natural gas, fuel oil, and direct injection coal were obtained from EIA (2015b) and EPA (2010). Heat contents for fuel oil and direct injection coal were obtained from EIA (1992, 2011); natural gas heat content was obtained from Table 37 of AISI's *Annual Statistical Report* (AISI 2004 through 2015a). Heat contents for coke oven gas and blast furnace gas were provided in Table 37 of AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and confirmed by AISI staff (Carroll 2015).

Table 4-69: Production and Consumption Data for the Calculation of CO₂ and CH₄ Emissions from Iron and Steel Production (Thousand Metric Tons)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------|--------|--------|--------|--------|--------|--------|
| Sinter Production | | | | | | | |
| Sinter Production | 12,239 | 8,315 | 5,225 | 5,941 | 5,795 | 5,583 | 5,521 |
| Direct Reduced Iron Production | | | | | | | |
| Direct Reduced Iron Production | 516 | 1,303 | 1,441 | 1,582 | 3,530 | 3,350 | 2,113 |
| Pig Iron Production | | | | | | | |
| Coke Consumption | 24,946 | 13,832 | 10,883 | 11,962 | 9,571 | 9,308 | 11,136 |
| Pig Iron Production | 49,669 | 37,222 | 26,844 | 30,228 | 32,063 | 30,309 | 29,375 |
| Direct Injection Coal Consumption | 1,485 | 2,573 | 2,279 | 2,604 | 2,802 | 2,675 | 2,425 |
| EAF Steel Production | | | | | | | |
| EAF Anode and Charge Carbon Consumption | 67 | 1,127 | 1,189 | 1,257 | 1,318 | 1,122 | 1,127 |
| Scrap Steel Consumption | 42,691 | 46,600 | 47,500 | 50,500 | 50,900 | 47,300 | 48,873 |
| Flux Consumption | 319 | 695 | 640 | 726 | 748 | 771 | 771 |
| EAF Steel Production | 33,511 | 52,194 | 49,339 | 52,108 | 52,415 | 52,641 | 55,174 |
| BOF Steel Production | | | | | | | |
| Pig Iron Consumption | 47,307 | 34,400 | 31,200 | 31,300 | 31,500 | 29,600 | 23,755 |
| Scrap Steel Consumption | 14,713 | 11,400 | 9,860 | 8,800 | 8,350 | 7,890 | 5,917 |
| Flux Consumption | 576 | 582 | 431 | 454 | 476 | 454 | 454 |
| BOF Steel Production | 43,973 | 42,705 | 31,158 | 34,291 | 36,282 | 34,238 | 33,000 |

Table 4-70: Production and Consumption Data for the Calculation of CO₂ Emissions from Iron and Steel Production (Million ft³ unless otherwise specified)

| Source/Activity Data | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|-----------|-----------|---------|-----------|-----------|-----------|-----------|
| Pig Iron Production | | | | | | | |
| Natural Gas Consumption | 56,273 | 59,844 | 47,814 | 59,132 | 62,469 | 48,812 | 47,734 |
| Fuel Oil Consumption (thousand gallons) | 163,397 | 16,170 | 27,505 | 21,378 | 19,240 | 17,468 | 16,674 |
| Coke Oven Gas Consumption | 22,033 | 16,557 | 14,233 | 17,772 | 18,608 | 17,710 | 16,896 |
| Blast Furnace Gas Production | 1,439,380 | 1,299,980 | 911,180 | 1,063,326 | 1,139,578 | 1,026,973 | 1,000,536 |
| EAF Steel Production | | | | | | | |
| Natural Gas Consumption | 15,905 | 19,985 | 10,403 | 6,263 | 11,145 | 10,514 | 9,622 |
| BOF Steel Production | | | | | | | |
| Coke Oven Gas Consumption | 3,851 | 524 | 546 | 554 | 568 | 568 | 524 |
| Other Activities | | | | | | | |
| Coke Oven Gas Consumption | 224,883 | 97,132 | 80,626 | 90,718 | 94,596 | 89,884 | 85,479 |
| Blast Furnace Gas Consumption | 1,414,778 | 1,295,520 | 907,999 | 1,059,473 | 1,135,227 | 1,022,718 | 996,190 |

Uncertainty and Time-Series Consistency

The estimates of CO₂ emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO₂ from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e., coking coal consumption and metallurgical coke production) only.

The estimates of CO₂ emissions from iron and steel production are based on material production and consumption data and average C contents. Current estimates include estimates from pellet consumption, but exclude emissions from pellet production. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal; some of this coal may be used for electricity generation. There is also uncertainty associated with the C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron. For EAF steel production, there is uncertainty associated with the amount of EAF anode and charge carbon consumed due to inconsistent data throughout the time series. Also for EAF steel production, there is uncertainty associated with the assumption that 100 percent of the natural gas attributed to “steelmaking furnaces” by AISI is process-related and nothing is combusted for energy purposes. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (i.e., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and carbon contents produce a relatively accurate estimate of CO₂ emissions. However, there are uncertainties associated with each.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-71 for metallurgical coke production and iron and steel production. Total CO₂ emissions from metallurgical coke production and iron and steel production were estimated to be between 47.2 and 63.6 MMT CO₂ Eq. at the 95 percent confidence level. This

indicates a range of approximately 15 percent below and 15 percent above the emission estimate of 55.4 MMT CO₂ Eq. Total CH₄ emissions from metallurgical coke production and iron and steel production were estimated to be between 0.008 and 0.01 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 19 percent below and 19 percent above the emission estimate of 0.009 MMT CO₂ Eq.

Table 4-71: Approach 2 Quantitative Uncertainty Estimates for CO₂ and CH₄ Emissions from Iron and Steel Production and Metallurgical Coke Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|--|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Metallurgical Coke & Iron and Steel Production | CO ₂ | 55.4 | 47.2 | 63.6 | -15% | +15% |
| Metallurgical Coke & Iron and Steel Production | CH ₄ | + | + | + | -19% | +19% |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Several adjustments were incorporated into the emission calculations for the Iron and Steel Production and Metallurgical Coke Production source categories. These adjustments applied to the entire time series from 1990 to 2014 and are briefly described below.

Previous Inventory reports included CH₄ emissions calculated using a Tier 1 CH₄ emission factor for two different production processes: metallurgical coke and pig iron. However, the use of a Tier 1 CH₄ emission factor was not applicable for the metallurgical coke and pig iron production processes in the United States, because the CO₂ emissions for these production processes were estimated using the Tier 2 mass balance methodology. The Tier 2 mass balance methodology makes a basic assumption that all carbon that enters the specific production process either exits the process as part of a carbon-containing output or as CO₂ emissions; the estimation of CH₄ emissions is necessarily precluded by definition. Because CO₂ emissions for the sinter production process were estimated using a Tier 1 CO₂ emission factor, it is still appropriate to use a Tier 1 CH₄ emission factor for the sinter production process. Due to exclusion of CH₄ emissions from the metallurgical coke and pig iron production processes, CH₄ emissions reported in the Inventory were significantly reduced. This assumption and the revisions are further supported by a preliminary analysis of annual facility-level CH₄ reported to EPA's GHGRP from the iron and coke production processes.

Previous Inventory reports have also relied significantly on activity data (i.e., production and input statistics) from AISI's *Annual Statistical Report* (AISI 2004 through 2015a); three key fuels used in the Tier 2 mass balance methodology were natural gas, coke oven gas, and blast furnace gas. For all three of these fuels, volumetric consumption was multiplied by a heat content to obtain the quantity of energy, which was then multiplied by carbon content to obtain the quantity of carbon. The heat content of natural gas was obtained from EIA's *Natural Gas Annual* (EIA 2015a) and varied from year to year with values ranging from 1,022 to 1,031 BTU/ft³, while the heat contents of coke oven gas (500 BTU/ft³) and blast furnace gas (90 BTU/ft³) were obtained from the report, *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). However, close examination of Table 37 of the AISI's *Annual Statistical Report* (AISI 2004 through 2015a) indicates that the reported quantities of natural gas and blast furnace gas have different reporting bases based on heat contents (i.e., 1,000 BTU/ft³ for natural gas and 95 BTU/ft³ for blast furnace gas); the reporting basis for coke oven gas is identically 500 BTU/ft³. AISI staff confirmed that the reporting bases included in Table 37 of the AISI's *Annual Statistical Report* (AISI 2004 through 2015a) have been used dating back to at least 1990. Therefore, the use of other heat contents with AISI's data is not appropriate. The heat content of natural gas was changed to 1,000 BTU/ft³ for all years in the time series and the heat content of blast furnace gas was changed to 95 BTU/ft³. Because blast furnace gas is used

as both an input and an output in the Tier 2 mass balance methodology, the use of revised heat contents for natural gas and blast furnace gas only resulted in a slight decrease in estimated CO₂ emissions; however, the CO₂ emissions for individual production processes did change noticeably. For instance, across the entire time series, an increase in CO₂ emissions from heating, annealing, and other processes was essentially offset by a decrease in CO₂ emissions from the iron production process.

Planned Improvements

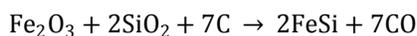
Future improvements involve improving completeness by including emissions from pellet production. The current version of the Inventory includes pellet consumption within the iron & steel sector, but does not include greenhouse gas emissions from pellet production. The EPA has identified a potential activity data source for national-level pellet production and will include this emission source in the future versions of the Inventory. EPA will also evaluate and analyze data reported under EPA's GHGRP by taconite indurating furnaces to improve the emission estimates for this and other Iron and Steel Production process categories. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.³⁰

Additional improvements include accounting for emission estimates for the production of metallurgical coke to the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at merchant coke plants. Other potential improvements include identifying the amount of coal used for direct injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also be made to identify information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes and Product Use chapters.

4.17 Ferroalloy Production (IPCC Source Category 2C2)

Carbon dioxide (CO₂) and methane (CH₄) are emitted from the production of several ferroalloys. Ferroalloys are composites of iron (Fe) and other elements such as silicon (Si), manganese (Mn), and chromium (Cr). Emissions from fuels consumed for energy purposes during the production of ferroalloys are accounted for in the Energy chapter. Emissions from the production of two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (96 to 99 percent silicon), and miscellaneous alloys (32 to 65 percent silicon) have been calculated. Emissions from the production of ferrochromium and ferromanganese are not included here because of the small number of manufacturers of these materials in the United States, and therefore, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO₂ is emitted when metallurgical coke is oxidized during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing environment, CO is initially produced, and eventually oxidized to CO₂. A representative reaction equation for the production of 50 percent ferrosilicon (FeSi) is given below:



While most of the carbon contained in the process materials is released to the atmosphere as CO₂, a percentage is also released as CH₄ and other volatiles. The amount of CH₄ that is released is dependent on furnace efficiency, operation technique, and control technology.

³⁰ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Ferroalloys are used primarily by the iron and steel industry, and production trends closely follow that of the iron and steel industry. Twelve companies in the United States produce ferroalloys (USGS 2015a).

Emissions of CO₂ from ferroalloy production in 2014 were 1.9 MMT CO₂ Eq. (1,914 kt CO₂) (see Table 4-72 and Table 4-73), which is an 11 percent reduction since 1990. Emissions of CH₄ from ferroalloy production in 2014 were 0.01 MMT CO₂ Eq. (0.5 kt CH₄), which is a 21 percent decrease since 1990.

Table 4-72: CO₂ and CH₄ Emissions from Ferroalloy Production (MMT CO₂ Eq.)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------------|------------|------------|------------|------------|------------|------------|
| CO ₂ | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |
| CH ₄ | + | + | + | + | + | + | + |
| Total | 2.2 | 1.4 | 1.7 | 1.7 | 1.9 | 1.8 | 1.9 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Table 4-73: CO₂ and CH₄ Emissions from Ferroalloy Production (kt)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|-------|-------|-------|-------|-------|-------|-------|
| CO ₂ | 2,152 | 1,392 | 1,663 | 1,735 | 1,903 | 1,785 | 1,914 |
| CH ₄ | 1 | + | + | + | 1 | + | 1 |

+ Does not exceed 0.5 kt.

Methodology

Emissions of CO₂ and CH₄ from ferroalloy production were calculated³¹ using a Tier 1 method from the *2006 IPCC Guidelines* (IPCC 2006) by multiplying annual ferroalloy production by material-specific default emission factors provided by IPCC (2006). The Tier 1 equations for CO₂ and CH₄ emissions are as follows:

$$E_{CO_2} = \sum_i (MP_i \times EF_i)$$

where,

| | | |
|-----------------------------|---|--|
| E _{CO₂} | = | CO ₂ emissions, metric tons |
| MP _{<i>i</i>} | = | Production of ferroalloy type <i>i</i> , metric tons |
| EF _{<i>i</i>} | = | Generic emission factor for ferroalloy type <i>i</i> , metric tons CO ₂ /metric ton specific ferroalloy product |

$$E_{CH_4} = \sum_i (MP_i \times EF_i)$$

where,

| | | |
|-----------------------------|---|---|
| E _{CH₄} | = | CH ₄ emissions, kg |
| MP _{<i>i</i>} | = | Production of ferroalloy type <i>i</i> , metric tons |
| EF _{<i>i</i>} | = | Generic emission factor for ferroalloy type <i>i</i> , kg CH ₄ /metric ton specific ferroalloy product |

³¹ EPA has not integrated aggregated facility-level GHGRP information to inform these estimates. The aggregated information (e.g. activity data and emissions) associated with production of ferroalloys did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

Default emission factors were used because country-specific emission factors are not currently available. The following emission factors were used to develop annual CO₂ and CH₄ estimates:

- Ferrosilicon, 25 to 55 percent Si and Miscellaneous Alloys, 32 to 65 percent Si – 2.5 metric tons CO₂/metric ton of alloy produced; 1.0 kg CH₄/metric ton of alloy produced.
- Ferrosilicon, 56 to 95 percent Si – 4.0 metric tons CO₂/metric ton alloy produced; 1.0 kg CH₄/metric ton of alloy produced.
- Silicon Metal – 5.0 metric tons CO₂/metric ton metal produced; 1.2 kg CH₄/metric ton metal produced.

It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke in an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite carbon inputs. The amount of petroleum coke consumed in ferroalloy production was calculated assuming that the petroleum coke used is 90 percent carbon (C) and 10 percent inert material (Onder and Bagdoyan 1993).

Ferroalloy production data for 1990 through 2014 (see Table 4-74) were obtained from the U.S. Geological Survey (USGS) through the *Minerals Yearbook: Silicon* (USGS 1996 through 2013) and the *Mineral Industry Surveys: Silicon* (USGS 2014, 2015b). The following data were available from the USGS publications for the time-series:

- Ferrosilicon, 25 to 55 percent Si: Annual production data were available from 1990 through 2010.
- Ferrosilicon, 56 to 95 percent Si: Annual production data were available from 1990 through 2010.
- Silicon Metal: Annual production data were available from 1990 through 2005. The production data for 2005 were used as proxy for 2006 through 2010.
- Miscellaneous Alloys, 32 to 65 percent Si: Annual production data were available from 1990 to 1999. Starting 2000, USGS reported miscellaneous alloys and ferrosilicon containing 25 to 55 percent silicon as a single category.

Starting with the 2011 publication, USGS reported all the ferroalloy production data as a single category (i.e., Total Silicon Materials Production). This is due to the small number of ferroalloy manufacturers in the United States and government information disclosure rules. Ferroalloy product shares developed from the 2010 production data (i.e., ferroalloy product production/total ferroalloy production) were used with the total silicon materials production quantity to estimate the production quantity by ferroalloy product type for 2011 through 2014 (USGS 2013, 2014, 2015b).

Table 4-74: Production of Ferroalloys (Metric Tons)

| Year | Ferrosilicon 25%-55% | Ferrosilicon 56%-95% | Silicon Metal | Misc. Alloys 32-65% |
|------|-------------------------|-------------------------|---------------|------------------------|
| 1990 | 321,385 | 109,566 | 145,744 | 72,442 |
| 2005 | 123,000 | 86,100 | 148,000 | NA |
| 2010 | 153,000 | 135,000 | 148,000 | NA |
| 2011 | 159,667 | 140,883 | 154,450 | NA |
| 2012 | 175,108 | 154,507 | 169,385 | NA |
| 2013 | 164,229 | 144,908 | 158,862 | NA |
| 2014 | 176,161 | 155,436 | 170,404 | NA |

NA - Not Available for product type, aggregated along with ferrosilicon (25-55% Si)

Uncertainty and Time-Series Consistency

Annual ferroalloy production was reported by the USGS in three broad categories until the 2010 publication: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal (through 2005 only, 2005 value used as proxy for 2005 through 2010). Starting with the *2011 Minerals Yearbook*, USGS started reporting all the ferroalloy production under a single category: total silicon materials production. The total silicon materials quantity was allocated across the three categories based on the 2010 production shares for the three categories. Refer to the Methodology section for further details.

Additionally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by

the USGS to avoid disclosing proprietary company data. Emissions from this production category, therefore, were not estimated.

Also, some ferroalloys may be produced using wood or other biomass as a primary or secondary carbon source (carbonaceous reductants), however information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based carbon is of biogenic origin.³² Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO₂ per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available, and are also often considered confidential business information.

Emissions of CH₄ from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH₄ emissions; however, specific furnace information was not available or included in the CH₄ emission estimates.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-75. Ferroalloy production CO₂ emissions were estimated to be between 1.7 and 2.1 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 12 percent above the emission estimate of 1.9 MMT CO₂ Eq. Ferroalloy production CH₄ emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 MMT CO₂ Eq.

Table 4-75: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ferroalloy Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Ferroalloy Production | CO ₂ | 1.9 | 1.7 | 2.1 | -12% | +12% |
| Ferroalloy Production | CH ₄ | + | + | + | -12% | +12% |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA’s GHGRP that would be useful to improve the emission estimates for the Ferroalloy Production source category. Particular attention will be made to risks for disclosing CBI and ensuring time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA’s GHGRP, with the program’s initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.³³

³² Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

³³ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

4.18 Aluminum Production (IPCC Source Category 2C3)

Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products, including aircraft, automobiles, bicycles, and kitchen utensils. As of recent reporting, the United States was the sixth largest producer of primary aluminum, with approximately 3 percent of the world total production (USGS 2015a). The United States was also a major importer of primary aluminum. The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of carbon dioxide (CO₂) and two perfluorocarbons (PFCs): perfluoromethane (CF₄) and perfluoroethane (C₂F₆).

Carbon dioxide is emitted during the aluminum smelting process when alumina (aluminum oxide, Al₂O₃) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na₃AlF₆). The reduction cells contain a carbon (C) lining that serves as the cathode. Carbon is also contained in the anode, which can be a C mass of paste, coke briquettes, or prebaked C blocks from petroleum coke. During reduction, most of this C is oxidized and released to the atmosphere as CO₂.

Process emissions of CO₂ from aluminum production were estimated to be 2.8 MMT CO₂ Eq. (2,833 kt) in 2014 (see Table 4-76). The C anodes consumed during aluminum production consist of petroleum coke and, to a minor extent, coal tar pitch. The petroleum coke portion of the total CO₂ process emissions from aluminum production is considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO₂ from Fossil Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO₂ process emissions is accounted for here.

Table 4-76: CO₂ Emissions from Aluminum Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 6.8 | 6,831 |
| 2005 | 4.1 | 4,142 |
| 2010 | 2.7 | 2,722 |
| 2011 | 3.3 | 3,292 |
| 2012 | 3.4 | 3,439 |
| 2013 | 3.3 | 3,255 |
| 2014 | 2.8 | 2,833 |

In addition to CO₂ emissions, the aluminum production industry is also a source of PFC emissions. During the smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed “anode effects.” These anode effects cause C from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive emissions of CF₄ and C₂F₆. In general, the magnitude of emissions for a given smelter and level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase.

Since 1990, emissions of CF₄ and C₂F₆ have declined by 89 percent and 83 percent, respectively, to 1.9 MMT CO₂ Eq. of CF₄ (0.3 kt) and 0.6 MMT CO₂ Eq. of C₂F₆ (0.1 kt) in 2014, as shown in Table 4-77 and Table 4-78. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects. These actions include technology and operational changes such as employee training, use of computer monitoring, and changes in alumina feeding techniques. Since 1990, aluminum production has declined by 58 percent, while the combined CF₄ and C₂F₆ emission rate (per metric ton of aluminum produced) has been reduced by 72 percent. Emissions decreased by approximately 18 percent between 2013 and 2014 due to decreases in aluminum production and in the rate of CF₄ and C₂F₆ emissions per metric ton of aluminum produced.

Table 4-77: PFC Emissions from Aluminum Production (MMT CO₂ Eq.)

| Year | CF ₄ | C ₂ F ₆ | Total |
|------|-----------------|-------------------------------|-------|
| 1990 | 17.9 | 3.5 | 21.5 |
| 2005 | 2.9 | 0.6 | 3.4 |
| 2010 | 1.4 | 0.5 | 1.9 |
| 2011 | 2.7 | 0.8 | 3.5 |
| 2012 | 2.3 | 0.7 | 2.9 |
| 2013 | 2.3 | 0.7 | 3.0 |
| 2014 | 1.9 | 0.6 | 2.5 |

Note: Totals may not sum due to independent rounding.

Table 4-78: PFC Emissions from Aluminum Production (kt)

| Year | CF ₄ | C ₂ F ₆ |
|------|-----------------|-------------------------------|
| 1990 | 2.4 | 0.3 |
| 2005 | 0.4 | + |
| 2010 | 0.2 | + |
| 2011 | 0.4 | 0.1 |
| 2012 | 0.4 | 0.1 |
| 2013 | 0.3 | 0.1 |
| 2014 | 0.3 | 0.1 |

+ Does not exceed 0.05 kt.

In 2014, U.S. primary aluminum production totaled approximately 1.7 million metric tons, a 12 percent decrease from 2013 production levels (USAA 2015). In 2014, three companies managed production at nine operational primary aluminum smelters. Four smelters were closed for the entire year in 2014 (USGS 2015b). During 2014, monthly U.S. primary aluminum production was lower for every month in 2014, when compared to the corresponding months in 2013 (USGS 2015c; USGS 2014).

For 2015, total production was approximately 1.6 million metric tons compared to 1.7 million metric tons in 2014, a 7 percent decrease (USAA 2016). Based on the decrease in production, process CO₂ and PFC emissions are likely to be lower in 2015 compared to 2014 if there are no significant changes in process controls at operational facilities.

Methodology

Process CO₂ and PFC—i.e., CF₄ and C₂F₆—emission estimates from primary aluminum production for 2010 through 2014 are available from EPA’s Greenhouse Gas Reporting Program (GHGRP)—Subpart F (Aluminum Production) (EPA 2016). Under EPA’s GHGRP, facilities began reporting primary aluminum production process emissions (for 2010) in 2011; as a result, GHGRP data (for 2010 through 2014) are available to be incorporated into the Inventory. EPA’s GHGRP mandates that all facilities that contain an aluminum production process must report: CF₄ and C₂F₆ emissions from anode effects in all prebake and Söderberg electrolysis cells, CO₂ emissions from anode consumption during electrolysis in all prebake and Söderberg cells, and all CO₂ emissions from onsite anode baking. To estimate the process emissions, EPA’s GHGRP uses the process-specific equations (and certain technology-specific defaults) detailed in subpart F (aluminum production).³⁴ These equations are based on the Tier 2/Tier 3 IPCC (2006) methods for primary aluminum production, and Tier 1 methods when estimating missing data

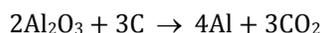
³⁴ Code of Federal Regulations, Title 40: Protection of Environment, Part 98: Mandatory Greenhouse Gas Reporting, Subpart F—Aluminum Production. See <www.epa.gov/ghgreporting/documents/pdf/infosheets/aluminumproduction.pdf>.

elements. It should be noted that the same methods (i.e., *2006 IPCC Guidelines*) were used for estimating the emissions prior to the availability of the reported GHGRP data in the Inventory.

Process CO₂ Emissions from Anode Consumption and Anode Baking

Carbon dioxide emission estimates for the years prior to the introduction of EPA's GHGRP in 2010 were estimated with IPCC (2006) methods, but individual facility reported data were combined with process-specific emissions modeling. These estimates were based on information previously gathered from EPA's Voluntary Aluminum Industrial Partnership (VAIP) program, U.S. Geological Survey (USGS) Mineral Commodity reviews, and The Aluminum Association (USAA) statistics, among other sources. Since pre- and post-GHGRP estimates use the same methodology, emission estimates are comparable across the time series.

Most of the CO₂ emissions released during aluminum production occur during the electrolysis reaction of the C anode, as described by the following reaction:



For prebake smelter technologies, CO₂ is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO₂ emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO₂ emitted from electrolysis at each smelter was estimated from: (1) the smelter's annual anode consumption, (2) the smelter's annual aluminum production and rate of anode consumption (per ton of aluminum produced) for previous and/or following years, or (3) the smelter's annual aluminum production and IPCC default CO₂ emission factors. The first approach tracks the consumption and carbon content of the anode, assuming that all C in the anode is converted to CO₂. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at a C consumption figure. This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to estimate emissions during years for which anode consumption data are not available. This approach avoids substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The last approach corresponds to the IPCC Tier 1 method (2006), and is used in the absence of present or historic anode consumption data.

The equations used to estimate CO₂ emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption, and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and weight of baked anodes produced. For Søderberg cells, the process formula accounts for the weight of paste consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash content.

Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003, 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP were used; however, if the data were incomplete or unavailable, information was supplemented using industry average values recommended by IPCC (2006). Smelter-specific CO₂ process data were provided by 18 of the 23 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in 2007 and 2008, and 3 out of 13 operating smelters in 2009. For years where CO₂ emissions data or CO₂ process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming representative (e.g., previously reported or industry default) values.

In the absence of any previous historical smelter specific process data (i.e., 1 out of 13 smelters in 2009; 1 out of 14 smelters in 2006, 2007, and 2008; 1 out of 15 smelters in 2005; and 5 out of 23 smelters between 1990 and 2003), CO₂ emission estimates were estimated using Tier 1 Søderberg and/or Prebake emission factors (metric ton of CO₂ per metric ton of aluminum produced) from IPCC (2006).

Process PFC Emissions from Anode Effects

Smelter-specific PFC emissions from aluminum production for 2010 through 2014 were reported to EPA under its GHGRP. To estimate their PFC emissions and report them under EPA's GHGRP, smelters use an approach

identical to the Tier 3 approach in the *2006 IPCC Guidelines* (IPCC 2006). Specifically, they use a smelter-specific slope coefficient as well as smelter-specific operating data to estimate an emission factor using the following equation

$$PFC = S \times AE$$

$$AE = F \times D$$

where,

| | | |
|-----|---|---|
| PFC | = | CF ₄ or C ₂ F ₆ , kg/MT aluminum |
| S | = | Slope coefficient, PFC/AE |
| AE | = | Anode effect, minutes/cell-day |
| F | = | Anode effect frequency per cell-day |
| D | = | Anode effect duration, minutes |

They then multiply this emission factor by aluminum production to estimate PFC emissions. All U.S. aluminum smelters are required to report their emissions under EPA's GHGRP.

Perfluorocarbon emissions for the years prior to 2010 were estimated using the same equation, but the slope-factor used for some smelters was technology-specific rather than smelter-specific, making the method a Tier 2 rather than a Tier 3 approach for those smelters. Emissions and background data were reported to EPA under the VAIP. For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were applied (IPCC 2006). The slope coefficients were combined with smelter-specific anode effect data collected by aluminum companies and reported under the VAIP to estimate emission factors over time. For 1990 through 2009, smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S. primary aluminum production. Where smelter-specific anode effect data were not available, representative values (e.g., previously reported or industry averages) were used.

For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference between the production reported under VAIP and the total U.S. production supplied by USGS or USAA, and then allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then aggregated across smelters to estimate national emissions.

Between 1990 and 2009, production data were provided under the VAIP by 21 of the 23 U.S. smelters that operated during at least part of that period. For the non-reporting smelters, production was estimated based on the difference between reporting smelters and national aluminum production levels (from USGS and USAA), with allocation to specific smelters based on reported production capacities (from USGS).

National primary aluminum production data for 2014 were obtained via USAA (2015). For 1990 through 2001, and 2006 (see Table 4-79) data were obtained from USGS *Mineral Industry Surveys: Aluminum Annual Report* (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2013, national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004 through 2006, 2008 through 2014).

Table 4-79: Production of Primary Aluminum (kt)

| Year | kt |
|------|-------|
| 1990 | 4,048 |
| 2005 | 2,478 |
| 2009 | 1,727 |
| 2010 | 1,727 |
| 2011 | 1,986 |
| 2012 | 2,070 |
| 2013 | 1,948 |
| 2014 | 1,710 |

Uncertainty and Time-Series Consistency

Uncertainty was assigned to the CO₂, CF₄, and C₂F₆ emission values reported by each individual facility to EPA's GHGRP. As previously mentioned, the methods for estimating emissions for EPA's GHGRP and this report are the same, and follow the IPCC (2006) methodology. As a result, it was possible to assign uncertainty bounds (and distributions) based on an analysis of the uncertainty associated with the facility-specific emissions estimated for previous Inventory years. Uncertainty surrounding the reported CO₂, CF₄, and C₂F₆ emission values were determined to have a normal distribution with uncertainty ranges of ±6, ±16, and ±20 percent, respectively. A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO₂, CF₄, and C₂F₆ emission estimates for the U.S. aluminum industry as a whole, and the results are provided below.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-80. Aluminum production-related CO₂ emissions were estimated to be between 2.8 and 2.9 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 2 percent below to 2 percent above the emission estimate of 2.8 MMT CO₂ Eq. Also, production-related CF₄ emissions were estimated to be between 1.8 and 2.0 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below to 7 percent above the emission estimate of 1.9 MMT CO₂ Eq. Finally, aluminum production-related C₂F₆ emissions were estimated to be between 0.5 and 0.7 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below to 13 percent above the emission estimate of 0.6 MMT CO₂ Eq.

Table 4-80: Approach 2 Quantitative Uncertainty Estimates for CO₂ and PFC Emissions from Aluminum Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|---------------------|-------------------------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Aluminum Production | CO ₂ | 2.8 | 2.8 | 2.9 | -2% | +2% |
| Aluminum Production | CF ₄ | 1.9 | 1.8 | 2.0 | -7% | +7% |
| Aluminum Production | C ₂ F ₆ | 0.6 | 0.5 | 0.7 | -13% | +13% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for the Aluminum Production category included checking input data, documentation, and calculations to ensure data were properly handled through the inventory process. Errors that were found during this process were corrected as necessary.

4.19 Magnesium Production and Processing (IPCC Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF₆) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than thirty years. A dilute gaseous mixture of SF₆ with dry air and/or carbon dioxide (CO₂) is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF₆ reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF₆ reacting in magnesium production and processing is considered to be negligible and thus all SF₆ used is assumed to be emitted into the atmosphere. Alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 (FK-5-1-12) and dilute sulfur dioxide (SO₂) systems can, and are being used by some facilities in the United States. However, many facilities in the United States are still using traditional SF₆ cover gas systems.

The magnesium industry emitted 1.0 MMT CO₂ Eq. (0.05 kt) of SF₆, 0.14 MMT CO₂ Eq. (0.10 kt) of HFC-134a, and 0.002 MMT CO₂ Eq. (2.3 kt) of CO₂ in 2014. This represents a decrease of approximately 24 percent from total 2013 emissions (see Table 4-81). The decrease can be attributed to reduction in primary, secondary, and die casting SF₆ emissions between 2013 and 2014 as reported through EPA's Greenhouse Gas Reporting Program (GHGRP), with the largest absolute reduction being seen for primary emissions. The reduction in SF₆ emissions is likely due in part to decreased production from reporting facilities in 2014. The decrease in SF₆ emissions can also be attributed to continuing industry efforts to utilize SF₆ alternatives, such as HFC-134a, Novec™612 and SO₂, to reduce greenhouse gas emissions. In 2014, the emissions of HFC-134a increased by 75 percent compared to 2013 emissions mainly due to the increased use of this alternative for primary production. In 2014, total HFC-134a emissions increased from 0.08 MMT CO₂ Eq. to 0.14 MMT CO₂ Eq., while the FK 5-1-12 emissions were constant. The emissions of the carrier gas, CO₂, increased from 2.1 kt in 2013 to 2.3 kt in 2014.

Table 4-81: SF₆, HFC-134a, FK 5-1-12 and CO₂ Emissions from Magnesium Production and Processing (MMT CO₂ Eq.)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|------------|------------|
| SF ₆ | 5.2 | 2.7 | 2.1 | 2.8 | 1.6 | 1.5 | 1.0 |
| HFC-134a | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| CO ₂ | + | + | + | + | + | + | + |
| FK 5-1-12 | 0.0 | 0.0 | + | + | + | + | + |
| Total^a | 5.2 | 2.8 | 2.1 | 2.8 | 1.7 | 1.5 | 1.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Total does not include FK 5-1-12. FK-5-1-12 values shown for informational purposes only.

Note: Totals may not sum due to independent rounding.

Table 4-82: SF₆, HFC-134a, FK 5-1-12 and CO₂ Emissions from Magnesium Production and Processing (kt)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------|------|------|------|------|------|------|
| SF ₆ | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | + |
| HFC-134a | 0.0 | 0.0 | + | + | + | 0.1 | 0.1 |
| CO ₂ | 1.4 | 2.9 | 1.3 | 3.1 | 2.3 | 2.1 | 2.3 |
| FK 5-1-12 | 0.0 | 0.0 | + | + | + | + | + |

+ Does not exceed 0.05 kt.

Methodology

Emission estimates for the magnesium industry incorporate information provided by some industry participants in EPA's SF₆ Emission Reduction Partnership for the Magnesium Industry as well as emissions data reported through subpart T (Magnesium Production and Processing) of the EPA's GHGRP. The Partnership started in 1999 and, in

2010, participating companies represented 100 percent of U.S. primary and secondary production and 16 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). SF₆ Emissions for 1999 through 2010 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF₆ consumption, which was assumed to be equivalent to emissions. Along with SF₆, some Partners also reported their HFC-134a and FK 5-1-12 usage, which is assumed to be equal to emissions. 2010 was the last reporting year under the Partnership. Emissions data for 2011 through 2014 were obtained through EPA's GHGRP. Under the program, owners or operators of facilities that have a magnesium production or casting process must report emissions from use of cover or carrier gases, which include SF₆, HFC-134a, FK 5-1-12 and CO₂. Consequently, cover and carrier gas emissions from magnesium production and processing were estimated for three time periods, depending on the source of the emissions data: 1990 through 1998, 1999 through 2010, and 2011 through 2014. The methodologies described below also make use of magnesium production data published by the U.S. Geological Survey (USGS).

1990 through 1998

To estimate emissions for 1990 through 1998, industry SF₆ emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. For this period, it was assumed that there was no use of HFC-134a or FK 5-1-12 cover gases and hence emissions were not estimated for these alternatives.

Sulfur hexafluoride emission factors from 1990 through 1998 were based on a number of sources and assumptions. Emission factors for primary production were available from U.S. primary producers for 1994 and 1995. The primary production emission factors were 1.2 kg SF₆ per metric ton for 1990 through 1993, and 1.1 kg SF₆ per metric ton for 1994 through 1997. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average Partner value. An emission factor for die casting of 4.1 kg SF₆ per metric ton, which was available for the mid-1990s from an international survey (Gjestland and Magers 1996), was used for years 1990 through 1996. For 1996 through 1998, the emission factor for die casting was assumed to decline linearly to the level estimated based on Partner reports in 1999. This assumption is consistent with the trend in SF₆ sales to the magnesium sector that is reported in the RAND survey of major SF₆ manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 1990 through 2001 were assumed to be the same as the 2002 emission factor. The emission factors for the other processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain constant at levels defined in Table 4-81. These emission factors for the other processes (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives.

The quantities of CO₂ carrier gas used for each production type have been estimated using the 1999 estimated CO₂ emissions data and the annual calculated rate of change of SF₆ use in the 1990 through 1999 time period. For each year and production type, the rate of change of SF₆ use between the current year and the subsequent year was first estimated. This rate of change is then applied to the CO₂ emissions of the subsequent year to determine the CO₂ emission of the current year. The emissions of carrier gases for permanent mold, wrought and anode processes are not estimated in this Inventory.

1999 through 2010

The 1999 through 2010 emissions from primary and secondary production are based on information provided by EPA's industry Partners. In some instances, there were years of missing Partner data, including SF₆ consumption and metal processed. For these situations, emissions were estimated through interpolation where possible, or by holding company-reported emissions (as well as production) constant from the previous year. For alternative cover gases, including HFC-134a and FK 5-1-12, mainly reported data was relied upon. That is, unless a Partner reported using an alternative cover gas, it was not assumed it was used. Emissions of alternate gases were also estimated through linear interpolation where possible.

The die casting emission estimates for 1999 through 2010 are also based on information supplied by industry Partners. When a Partner was determined to be no longer in production, its metal production and usage rates were set to zero. Missing data on emissions or metal input was either interpolated or held constant at the last available reported value. In 1999 and from 2008 through 2010, Partners did not account for all die casting tracked by USGS, and, therefore, it was necessary to estimate the emissions of die casters who were not Partners. For 1999, die casters who were not Partners were assumed to be similar to Partners who cast small parts. Due to process requirements,

these casters consume larger quantities of SF₆ per metric ton of processed magnesium than casters that process large parts. Consequently, emission estimates from this group of die casters were developed using an average emission factor of 5.2 kg SF₆ per metric ton of magnesium. This emission factor was developed using magnesium production and SF₆ usage data for the year 1999. For 2008 through 2010, the characteristics of the die casters who were not Partners were not well known, and therefore the emission factor for these die casters was set equal to 3.0 kg SF₆ per metric ton of magnesium, the average of the emission factors reported over the same period by the die casters who were Partners.

The emissions from other casting operations were estimated by multiplying emission factors (kg SF₆ per metric ton of metal produced or processed) by the amount of metal produced or consumed from USGS, with the exception of some years for which Partner sand casting emissions data are available. The emission factors for sand casting activities were acquired through the data reported by the Partnership for 2002 to 2006. For 1999-2001, the sand casting emission factor was held constant at the 2002 Partner-reported level. For 2007 through 2010, the sand casting Partner did not report and the reported emission factor from 2005 was applied to the Partner and to all other sand casters. Activity data for 2005 was obtained from USGS (USGS 2005b).

The emission factors for primary production, secondary production and sand casting for the 1999 to 2010 are not published to protect company-specific production information. However, the emission factor for primary production has not risen above the average 1995 Partner value of 1.1 kg SF₆ per metric ton. The emission factors for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives. The emission factors for casting activities are provided below in Table 4-83.

The emissions of HFC-134a and FK-5-1-12 were included in the estimates for only instances where Partners reported that information to the Partnership. Emissions of these alternative cover gases were not estimated for instances where emissions were not reported.

Carbon dioxide carrier gas emissions were estimated using the emission factors developed based on GHGRP-reported carrier gas and cover gas data, by production type. It was assumed that the use of carrier gas, by production type, is proportional to the use of cover gases. Therefore, an emission factor, in kg CO₂ per kg cover gas and weighted by the cover gases used, was developed for each of the production types. GHGRP data on which these emissions factors are based was available for primary, secondary, die casting and sand casting. The emission factors were applied to the total quantity of all cover gases used (SF₆, HFC-134a, and FK-5-1-12) by production type in this time period. Carrier gas emissions for the 1999 through 2010 time period were only estimated for those Partner companies that reported using CO₂ as a carrier gas through the GHGRP. Using this approach helped ensure time series consistency. The emissions of carrier gases for permanent mold, wrought and anode processes are not estimated in this Inventory.

Table 4-83: SF₆ Emission Factors (kg SF₆ per metric ton of magnesium)

| Year | Die Casting ^a | Permanent Mold | Wrought | Anodes |
|------|--------------------------|----------------|---------|--------|
| 1999 | 2.14 ^b | 2 | 1 | 1 |
| 2000 | 0.72 | 2 | 1 | 1 |
| 2001 | 0.72 | 2 | 1 | 1 |
| 2002 | 0.71 | 2 | 1 | 1 |
| 2003 | 0.81 | 2 | 1 | 1 |
| 2004 | 0.79 | 2 | 1 | 1 |
| 2005 | 0.77 | 2 | 1 | 1 |
| 2006 | 0.88 | 2 | 1 | 1 |
| 2007 | 0.64 | 2 | 1 | 1 |
| 2008 | 0.10 | 2 | 1 | 1 |
| 2009 | 2.30 | 2 | 1 | 1 |
| 2010 | 2.94 | 2 | 1 | 1 |

^a Weighted average includes all die casters, Partners and non-Partners. For the majority of the time series (2000-2007), Partners made up 100 percent of die casters in the United States.

^b Weighted average that includes an estimated emission factor of 5.2 kg SF₆ per metric ton of magnesium for die casters that do not participate in the Partnership.

2011 through 2014

For 2011 through 2014, for the primary and secondary producers, GHGRP-reported cover and carrier gases emissions data were used. For die and sand casting, some emissions data was obtained through EPA's GHGRP. The balance of the emissions for these industry segments were estimated based on previous Partner reporting (i.e., for Partners that did not report emissions through EPA's GHGRP) or were estimated by multiplying emission factors by the amount of metal produced or consumed. Partners who did not report through EPA's GHGRP were assumed to have continued to emit SF₆ at the last reported level, which was from 2010 in most cases. All Partners were assumed to have continued to consume magnesium at the last reported level. Where the total metal consumption estimated for the Partners fell below the U.S. total reported by USGS, the difference was multiplied by the emission factors discussed in the section above. For the other types of production and processing (i.e., permanent mold, wrought, and anode casting), emissions were estimated by multiplying the industry emission factors with the metal production or consumption statistics obtained from USGS (USGS 2014).

Uncertainty and Time-Series Consistency

Uncertainty surrounding the total estimated emissions in 2014 is attributed to the uncertainties around SF₆, HFC-134a, and CO₂ emission estimates. To estimate the uncertainty surrounding the estimated 2014 SF₆ emissions from magnesium production and processing, the uncertainties associated with three variables were estimated: (1) emissions reported by magnesium producers and processors for 2014 through EPA's GHGRP, (2) emissions estimated for magnesium producers and processors that reported via the Partnership in prior years but did not report 2014 emissions through EPA's GHGRP, and (3) emissions estimated for magnesium producers and processors that did not participate in the Partnership or report through EPA's GHGRP. An uncertainty of 5 percent was assigned to the emissions (usage) data reported by each GHGRP reporter for all the cover and carrier gases (per the *2006 IPCC Guidelines*). If facilities did not report emissions data during the current reporting year through EPA's GHGRP reporting program, SF₆ emissions data were held constant at the most recent available value reported through the Partnership. The uncertainty associated with these values was estimated to be 30 percent for each year of extrapolation. Alternate cover gas and carrier gases data was set equal to zero if the facilities did not report via the GHGRP program. One known sand caster (the lone Partner) has not reported since 2007 and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF₆ usage for the sand casting Partner was 85 percent. For those industry processes that are not represented in the Partnership, such as permanent mold and wrought casting, SF₆ emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-84). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with die casting and sand casting activities utilized emission factors based on Partner reported data with an uncertainties of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF₆ neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Previous measurement studies have identified SF₆ cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-84. Total emissions associated with magnesium production and processing were estimated to be between 1.1 and 1.3 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 9 percent below to 10 percent above the 2014 emission estimate of 1.2 MMT CO₂ Eq. The uncertainty estimates for 2014 are similar relative to the uncertainty reported for 2013 in the previous Inventory report.

Table 4-84: Approach 2 Quantitative Uncertainty Estimates for SF₆, HFC-134a and CO₂ Emissions from Magnesium Production and Processing (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|----------------------|---|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Magnesium Production | SF ₆ , HFC-134a, CO ₂ | 1.2 | 1.1 | 1.3 | -9% | +10% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For one facility, a recalculation for 2013 SF₆ and CO₂ emissions was performed to ensure methodological consistency. The emissions for this facility and year were previously held constant at 2012 levels based on data reported through the GHGRP. This estimate has been revised by interpolating the reported emissions between 2012 and 2014, reported via EPA's GHGRP. This has caused a slight decrease in the SF₆ emissions and slight increase in CO₂ emissions for 2013 compared to the previous Inventory.

Planned Improvements

Cover gas research conducted over the last decade has found that SF₆ used for magnesium melt protection can have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission estimates assume (per the *2006 IPCC Guidelines*) that all SF₆ utilized is emitted to the atmosphere. Additional research may lead to a revision of the *2006 IPCC Guidelines* to reflect this phenomenon and until such time, developments in this sector will be monitored for possible application to the Inventory methodology.

Usage and emission details of carrier gases in permanent mold, wrought and anode processes will be researched as part of a future inventory. Based on this research, it will be determined if CO₂ carrier gas emissions are to be estimated.

4.20 Lead Production (IPCC Source Category 2C5)

Lead production in the United States consists of both primary and secondary processes—both of which emit carbon dioxide (CO₂) (Sjardin 2003). Emissions from fuels consumed for energy purposes during the production of lead are accounted for in the Energy chapter.

Primary production of lead through the direct smelting of lead concentrate produces CO₂ emissions as the lead concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). Primary lead production, in the form of direct smelting, previously occurred at a single smelter in Missouri. This primary lead smelter was closed at the end of 2013. In 2014, the smelter processed a small amount of residual lead during demolition of the site (USGS 2015).

Similar to primary lead production, CO₂ emissions from secondary lead production result when a reducing agent, usually metallurgical coke, is added to the smelter to aid in the reduction process. Carbon dioxide emissions from secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). Secondary production primarily involves the recycling of lead acid batteries and post-consumer scrap at secondary smelters. Of all the domestic secondary smelters operational in 2014, 12 smelters had capacities of 30,000 tons or more and were

collectively responsible for more than 95 percent of secondary lead production in 2014 (USGS 2015). Secondary lead production has increased in the United States over the past decade while primary lead production has decreased. In 2014, secondary lead production accounted for nearly 100 percent of total lead production. The lead-acid battery industry accounted for about 90 percent of the reported U.S. lead consumption in 2014 (USGS 2015).

In 2014, total secondary lead production in the United States was slightly greater than that in 2013. Increased production at a couple of smelters was offset by temporary closure of one smelter. In March 2014, a producer temporarily shut down operations of a lead smelter in Vernon, CA (90,000 metric ton capacity smelter) due to environmental concerns from state regulators. The company intends to restart operations in 2015, after making improvements to the plant. Increases in exports of spent lead-acid batteries in recent years have decreased the amount of scrap available to secondary smelters (USGS 2015).

U.S. primary lead production decreased by approximately 99 percent from 2013 to 2014, and has decreased by almost 100 percent since 1990. This is due to the closure of the only domestic primary lead smelter in 2013 (year-end). In 2014, U.S. secondary lead production was unchanged from 2013 levels, and has increased by 25 percent since 1990 (USGS 1995 through 2013, 2014, 2015).

In 2014, U.S. primary and secondary lead production totaled 1,151,000 metric tons (USGS 2015). The resulting emissions of CO₂ from 2014 lead production were estimated to be 0.5 MMT CO₂ Eq. (518 kt) (see Table 4-85). The majority of 2014 lead production is from secondary processes, which accounted for almost 100 percent of total 2014 CO₂ emissions from lead production. At last reporting, the United States was the third largest mine producer of lead in the world, behind China and Australia, accounting for approximately 7 percent of world production in 2014 (USGS 2015).

Table 4-85: CO₂ Emissions from Lead Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-----|
| 1990 | 0.5 | 516 |
| 2005 | 0.6 | 553 |
| 2010 | 0.5 | 542 |
| 2011 | 0.5 | 538 |
| 2012 | 0.5 | 527 |
| 2013 | 0.5 | 546 |
| 2014 | 0.5 | 518 |

After a steady increase in total emissions from 1995 to 2000, total emissions have gradually decreased since 2000 and are currently at the 1990 levels.

Methodology

The methods used to estimate emissions for lead production³⁵ are based on Sjardin’s work (Sjardin 2003) for lead production emissions and Tier 1 methods from the *2006 IPCC Guidelines* (IPCC 2006). The Tier 1 equation is as follows:

$$CO_2 \text{ Emissions} = (DS \times EF_{DS}) + (S \times EF_S)$$

where,

| | | |
|------------------|---|---|
| DS | = | Lead produced by direct smelting, metric ton |
| S | = | Lead produced from secondary materials |
| EF _{DS} | = | Emission factor for direct Smelting, metric tons CO ₂ /metric ton lead product |

³⁵ EPA has not integrated aggregated facility-level Greenhouse Gas Reporting Program (GHGRP) information to inform these estimates. The aggregated information (e.g. activity data and emissions) associated with Lead Production did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

EF_s = Emission factor for secondary materials, metric tons CO₂/metric ton lead product

For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of 0.25 metric tons CO₂/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an emission factor of 0.25 metric tons CO₂/metric ton lead for direct smelting, as well as an emission factor of 0.2 metric tons CO₂/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). Since the secondary production of lead involves both the use of the direct smelting process and the treatment of secondary raw materials, Sjardin recommends an additive emission factor to be used in conjunction with the secondary lead production quantity. The direct smelting factor (0.25) and the sum of the direct smelting and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production, respectively, to estimate CO₂ emissions.

The 1990 through 2014 activity data for primary and secondary lead production (see Table 4-86) were obtained from the U.S. Geological Survey (USGS 1995 through 2013, 2014, 2015).

Table 4-86: Lead Production (Metric Tons)

| Year | Primary | Secondary |
|------|---------|-----------|
| 1990 | 404,000 | 922,000 |
| 2005 | 143,000 | 1,150,000 |
| 2010 | 115,000 | 1,140,000 |
| 2011 | 118,000 | 1,130,000 |
| 2012 | 111,000 | 1,110,000 |
| 2013 | 114,000 | 1,150,000 |
| 2014 | 1,000 | 1,150,000 |

Uncertainty and Time-Series Consistency

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averaged the values provided by three other studies (Dutrizac et al. 2000; Morris et al. 1983; Ullman 1997). For secondary production, Sjardin (2003) added a CO₂ emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS. This information is collected by USGS via voluntary surveys.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-87. Lead production CO₂ emissions were estimated to be between 0.4 and 0.6 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 15 percent below and 16 percent above the emission estimate of 0.5 MMT CO₂ Eq.

Table 4-87: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lead Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Lead Production | CO ₂ | 0.5 | 0.4 | 0.6 | -15% | +16% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, primary and secondary lead production quantities were revised to reflect the most recent USGS publication (USGS 2015). In the previous Inventory report, the 2013 primary and secondary lead production quantities were based on preliminary USGS estimates that were available at the time. This change resulted in a 4 percent increase in the 2013 emission estimate compared to the previous Inventory report.

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP that would be useful to improve the emission estimates for the Lead Production source category. Particular attention will be made to risks for disclosing CBI and ensuring time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.³⁶

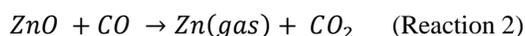
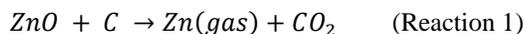
4.21 Zinc Production (IPCC Source Category 2C6)

Zinc production in the United States consists of both primary and secondary processes. Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary processes result in non-energy carbon dioxide (CO₂) emissions (Viklund-White 2000). Emissions from fuels consumed for energy purposes during the production of zinc are accounted for in the Energy chapter.

The majority of zinc produced in the United States is used for galvanizing. Galvanizing is a process where zinc coating is applied to steel in order to prevent corrosion. Zinc is used extensively for galvanizing operations in the automotive and construction industry. Zinc is also used in the production of zinc alloys and brass and bronze alloys (e.g., brass mills, copper foundries, and copper ingot manufacturing). Zinc compounds and dust are also used, to a lesser extent, by the agriculture, chemicals, paint, and rubber industries.

Primary production in the United States is conducted through the electrolytic process, while secondary techniques include the electrothermic and Waelz kiln processes, as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003).

In the electrothermic process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke is added to the electric retort furnace as a carbon-containing reductant. This concentration step, using metallurgical coke and high temperatures, reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process also generates non-energy CO₂ emissions.



In the Waelz kiln process, electric arc furnace (EAF) dust, which is captured during the recycling of galvanized steel, enters a kiln along with a reducing agent (typically carbon-containing metallurgical coke). When kiln temperatures reach approximately 1100 to 1200 degrees Celsius, zinc fumes are produced, which are combusted with air entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic

³⁶ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

precipitator, and is then leached to remove chloride and fluoride. The use of carbon-containing metallurgical coke in a high-temperature fuming process results in non-energy CO₂ emissions. Through this process, approximately 0.33 metric tons of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

The only companies in the United States that use emissive technology to produce secondary zinc products are Horsehead, PIZO, and Steel Dust Recycling. For Horsehead, EAF dust is recycled in Waelz kilns at their Beaumont, TX; Calumet, IL; Palmerton, PA; Rockwood, TN; and Barnwell, SC facilities. These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which was transported to their Monaca, PA facility where the products were smelted into refined zinc using electrothermic technology. In April 2014, Horsehead permanently shut down their Monaca smelter. This was replaced by their new facility in Mooresboro, NC. The new Mooresboro facility uses a hydrometallurgical process (i.e., solvent extraction with electrowinning technology) to produce zinc products. The current capacity of the new facility is 155,000 short tons, with plans to expand to 170,000 short tons per year. Direct consumption of coal, coke, and natural gas have been replaced with electricity consumption at the new Mooresboro facility. The new facility is reported to have a significantly lower greenhouse gas and other air emissions than the Monaca smelter (Horsehead 2012b).

The Mooresboro facility uses leaching and solvent extraction (SX) technology combined with electrowinning, melting, and casting technology. In this process, Waelz Oxide (WOX) is first washed in water to remove soluble elements such as chlorine, potassium, and sodium, and then is leached in a sulfuric acid solution to dissolve the contained zinc creating a pregnant liquor solution (PLS). The PLS is then processed in a solvent extraction step in which zinc is selectively extracted from the PLS using an organic solvent creating a purified zinc-loaded electrolyte solution. The loaded electrolyte solution is then fed into the electrowinning process in which electrical energy is applied across a series of anodes and cathodes submerged in the electrolyte solution causing the zinc to deposit on the surfaces of the cathodes. As the zinc metal builds up on these surfaces, the cathodes are periodically harvested in order to strip the zinc from their surfaces (Horsehead 2015). Hydrometallurgical production processes are assumed to be non-emissive since no carbon is used in these processes (Sjardin 2003).

PIZO and Steel Dust Recycling recycle EAF dust into intermediate zinc products using Waelz kilns, and then sell the intermediate products to companies who smelt it into refined products.

In 2014, U.S. primary and secondary refined zinc production were estimated to total 185,000 metric tons (USGS 2015) (see Table 4-88). Domestic zinc mine production increased slightly in 2014 compared to 2013 levels, primarily owing to an increase in zinc production at the Red Dog mine in Alaska. Zinc metal production decreased by 20 percent owing to a decline in secondary production; Horsehead closed its smelter in Monaca, PA, while starting up its new recycling facility in Mooresboro, NC. However, the new facility experienced delayed ramp-up efforts due to technical issues and did not reach optimum production levels until the end of 2014 (USGS 2015). Primary zinc production (primary slab zinc) increased slightly in 2014, while, secondary zinc production in 2014 decreased relative to 2013.

Emissions of CO₂ from zinc production in 2014 were estimated to be 1.0 MMT CO₂ Eq. (956 kt CO₂) (see Table 4-89). All 2014 CO₂ emissions resulted from secondary zinc production processes. Emissions from zinc production in the United States have increased overall since 1990 due to a gradual shift from non-emissive primary production to emissive secondary production. In 2014, emissions were estimated to be 51 percent higher than they were in 1990.

Table 4-88: Zinc Production (Metric Tons)

| Year | Primary | Secondary |
|-------------|----------------|------------------|
| 1990 | 262,704 | 95,708 |
| 2005 | 191,120 | 156,000 |
| 2010 | 120,000 | 129,000 |
| 2011 | 110,000 | 138,000 |
| 2012 | 114,000 | 147,000 |
| 2013 | 106,000 | 127,000 |
| 2014 | 115,000 | 70,000 |

Table 4-89: CO₂ Emissions from Zinc Production (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|-------|
| 1990 | 0.6 | 632 |
| 2005 | 1.0 | 1,030 |
| 2010 | 1.2 | 1,182 |
| 2011 | 1.3 | 1,286 |
| 2012 | 1.5 | 1,486 |
| 2013 | 1.4 | 1,429 |
| 2014 | 1.0 | 956 |

Methodology

The methods used to estimate non-energy CO₂ emissions from zinc production³⁷ using the electrothermic primary production and Waelz kiln secondary production processes are based on Tier 1 methods from the *2006 IPCC Guidelines* (IPCC 2006). The Tier 1 equation used to estimate emissions from zinc production is as follows:

$$E_{CO_2} = Zn \times EF_{default}$$

where,

| | | |
|----------------|---|--|
| E_{CO_2} | = | CO ₂ emissions from zinc production, metric tons |
| Zn | = | Quantity of zinc produced, metric tons |
| $EF_{default}$ | = | Default emission factor, metric tons CO ₂ /metric ton zinc produced |

The Tier 1 emission factors provided by IPCC for Waelz kiln-based secondary production were derived from coke consumption factors and other data presented in Viklund-White (2000). These coke consumption factors as well as other inputs used to develop the Waelz kiln emission factors are shown below. IPCC does not provide an emission factor for electrothermic processes due to limited information; therefore, the Waelz kiln-specific emission factors were also applied to zinc produced from electrothermic processes. Starting in 2014, refined zinc produced in the United States used hydrometallurgical processes and is assumed to be non-emissive.

For Waelz kiln-based production, IPCC recommends the use of emission factors based on EAF dust consumption, if possible, rather than the amount of zinc produced since the amount of reduction materials used is more directly dependent on the amount of EAF dust consumed. Since only a portion of emissive zinc production facilities consume EAF dust, the emission factor based on zinc production is applied to the non-EAF dust consuming facilities while the emission factor based on EAF dust consumption is applied to EAF dust consuming facilities.

The Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of metallurgical coke consumed for non-energy purposes per ton of zinc produced (i.e., 1.19 metric tons coke/metric ton zinc produced) (Viklund-White 2000), and the following equation:

$$EF_{Waelz\ Kiln} = \frac{1.19\ metric\ tons\ coke}{metric\ tons\ zinc} \times \frac{0.85\ metric\ tons\ C}{metric\ tons\ coke} \times \frac{3.67\ metric\ tons\ CO_2}{metric\ tons\ C} = \frac{3.70\ metric\ tons\ CO_2}{metric\ tons\ zinc}$$

The Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed (i.e., 0.4 metric tons coke/metric ton EAF dust consumed) (Viklund-White 2000), and the following equation:

³⁷ EPA has not integrated aggregated facility-level Greenhouse Gas Reporting Program (GHGRP) information to inform these estimates. The aggregated information (e.g. activity data and emissions) associated with Zinc Production did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

$$EF_{EAF\ Dust} = \frac{0.4\ \text{metric tons coke}}{\text{metric tons EAF Dust}} \times \frac{0.85\ \text{metric tons C}}{\text{metric tons coke}} \times \frac{3.67\ \text{metric tons CO}_2}{\text{metric tons C}} = \frac{1.24\ \text{metric tons CO}_2}{\text{metric tons EAF Dust}}$$

The total amount of EAF dust consumed by Horsehead at their Waelz kilns was available from Horsehead financial reports for years 2006 through 2014 (Horsehead 2007, 2008, 2010a, 2011, 2012a, 2013, 2014, and 2015).

Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States as provided by the U.S. Geological Survey (USGS) *Minerals Yearbook: Zinc* (USGS 1995 through 2006). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor to develop CO₂ emission estimates for Horsehead's Waelz kiln facilities.

The amount of EAF dust consumed by Steel Dust Recycling (SDR) and their total production capacity were obtained from SDR's facility in Alabama for the years 2011 through 2014 (SDR 2012, 2014, and 2015). SDR's facility in Alabama underwent expansion in 2011 to include a second unit (operational since early- to mid-2012). SDR's facility has been operational since 2008. Annual consumption data for SDR was not publicly available for the years 2008, 2009, and 2010. These data were estimated using data for Horsehead's Waelz kilns for 2008 through 2010 (Horsehead 2007, 2008, 2010a, 2010b, and 2011). Annual capacity utilization ratios were calculated using Horsehead's annual consumption and total capacity for the years 2008 through 2010. Horsehead's annual capacity utilization ratios were multiplied with SDR's total capacity to estimate SDR's consumption for each of the years, 2008 through 2010 (SDR 2013).

PIZO Technologies Worldwide LLC's facility in Arkansas has been operational since 2009. The amount of EAF dust consumed by PIZO's facility for 2009 through 2014 was not publicly available. EAF dust consumption for PIZO's facility for 2009 and 2010 were estimated by calculating annual capacity utilization of Horsehead's Waelz kilns and multiplying this utilization ratio by PIZO's total capacity (PIZO 2012). EAF dust consumption for PIZO's facility for 2011 through 2014 were estimated by applying the average annual capacity utilization rates for Horsehead and SDR (Grupo PROMAX) to PIZO's annual capacity (Horsehead 2012, 2013, 2014, and 2015; SDR 2012 and 2014; PIZO 2012 and 2014). The 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor was then applied to PIZO's and Steel Dust Recycling's estimated EAF dust consumption to develop CO₂ emission estimates for those Waelz kiln facilities.

Refined zinc production levels for Horsehead's Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2013 (Horsehead 2008, 2011, 2012, 2013, and 2014). The Monaca facility was permanently shut down in April 2014 and was replaced by Horsehead's new facility in Mooresboro, NC. The new facility uses hydrometallurgical process to produce refined zinc products. This process is assumed to be non-emissive. Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS *Minerals Yearbook: Zinc* (USGS 1995 through 2005). The 3.70 metric tons CO₂/metric ton zinc emission factor was then applied to the Monaca facility's production levels to estimate CO₂ emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since Horsehead's Monaca facility did not consume EAF dust.

Uncertainty and Time-Series Consistency

The uncertainty associated with these estimates is two-fold, relating to activity data and emission factors used.

First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an EAF dust consumption value obtained from the Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for PIZO's facility (2009 through 2010) and SDR's facility (2008 through 2010), the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's website) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Also, the EAF dust consumption for PIZO's facility for 2011 through 2013 was estimated by multiplying the average capacity utilization factor developed from Horsehead Corp. and SDR's annual capacity utilization rates by PIZO's EAF dust recycling capacity. Therefore, there is uncertainty associated with the

assumption used to estimate PIZO and SDR's annual EAF dust consumption values (except SDR's EAF dust consumption for 2011 through 2013, which were obtained from SDR's recycling facility in Alabama).

Second, there is uncertainty associated with the emission factors used to estimate CO₂ emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-90. Zinc production CO₂ emissions were estimated to be between 0.8 and 1.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 19 percent below and 21 percent above the emission estimate of 1.0 MMT CO₂ Eq.

Table 4-90: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Zinc Production (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------|-----------------|---|--|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Zinc Production | CO ₂ | 1.0 | 0.8 | 1.2 | -19% | +21% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

4.22 Semiconductor Manufacture (IPCC Source Category 2E1)

The semiconductor industry uses multiple long-lived fluorinated greenhouse gases in plasma etching and plasma enhanced chemical vapor deposition (PECVD) processes to produce semiconductor products. The gases most commonly employed are trifluoromethane (HFC-23 or CHF₃), perfluoromethane (CF₄), perfluoroethane (C₂F₆), nitrogen trifluoride (NF₃), sulfur hexafluoride (SF₆), and nitrous oxide (N₂O), although other fluorinated compounds such as perfluoropropane (C₃F₈) and perfluorocyclobutane (c-C₄F₈) are also used. The exact combination of compounds is specific to the process employed.

A single 300 mm silicon wafer that yields between 400 to 600 semiconductor products (devices or chips) may require more than 100 distinct fluorinated-gas-using process steps, principally to deposit and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon nitride, is performed to provide pathways for conducting material to connect individual circuit components in each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the atmosphere. PECVD chambers, used for depositing dielectric films, are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless abatement systems are employed, into the atmosphere.

In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere. For example, when C₂F₆ is used in cleaning or etching, CF₄ is generated and emitted as a process byproduct. Besides

dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and refractory metal films like tungsten.

Nitrous oxide is used in manufacturing semiconductor devices to produce thin films by CVD and nitridation processes as well as for N-doping of compound semiconductors and reaction chamber conditioning (Doering 2000).

For 2014, total GWP-weighted emissions of all fluorinated greenhouse gases and nitrous oxide from deposition, etching, and chamber cleaning processes in the U.S. semiconductor industry were estimated to be 4.7 MMT CO₂ Eq. Combined emissions of all greenhouse gases are presented in Table 4-91 and Table 4-92 below for years 1990, 2005 and the period 2010 to 2014. The rapid growth of this industry and the increasing complexity (growing number of layers)³⁸ of semiconductor products led to an increase in emissions of 153 percent between 1990 and 1999, when emissions peaked at 9.1 MMT CO₂ Eq. Emissions began to decline after 1999, declining by 48 percent between 1999 and 2014. Together, industrial growth, adoption of emissions reduction technologies, including but not limited to abatement technologies and shifts in gas usages resulted in a net increase in emissions of 32 percent between 1990 and 2014.

In 2010, the industry was still recovering from slowed economic activity which began in 2008. Between 2010 and 2011 fluorinated gas and N₂O emissions increased by 26 percent; reductions in emissions were then observed between 2011 and 2012, and 2012 and 2013 at 11 percent and 7 percent, respectively. Emissions increased between 2013 and 2014, by 13 percent. (As discussed below, this apparent increase between 2013 and 2014 may be an artifact of a change in the emission factors applied by facilities that report their emissions to EPA under the Greenhouse Gas Reporting Program (GHGRP).

Table 4-91: PFC, HFC, SF₆, NF₃, and N₂O Emissions from Semiconductor Manufacture (MMT CO₂ Eq.)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|------------|------------|------------|------------|------------|------------|------------|
| CF ₄ | 0.8 | 1.1 | 1.1 | 1.4 | 1.3 | 1.2 | 1.5 |
| C ₂ F ₆ | 2.0 | 2.0 | 1.4 | 1.8 | 1.6 | 1.4 | 1.4 |
| C ₃ F ₈ | + | 0.1 | 0.1 | 0.2 | 0.1 | 0.1 | 0.1 |
| C ₄ F ₈ | 0.0 | 0.1 | + | 0.1 | 0.1 | 0.1 | 0.1 |
| HFC-23 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| SF ₆ | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.7 |
| NF ₃ | + | 0.5 | 0.6 | 0.7 | 0.6 | 0.6 | 0.5 |
| Total F-GHGs | 3.6 | 4.6 | 3.8 | 4.8 | 4.3 | 4.0 | 4.5 |
| N ₂ O | + | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| Total | 3.6 | 4.7 | 4.0 | 5.1 | 4.5 | 4.2 | 4.7 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 4-92: PFC, HFC, SF₆, NF₃, and N₂O Emissions from Semiconductor Manufacture (kt)

| Year | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------------|------|------|------|------|------|------|------|
| CF ₄ | 0.11 | 0.14 | 0.15 | 0.19 | 0.17 | 0.17 | 0.20 |
| C ₂ F ₆ | 0.16 | 0.16 | 0.11 | 0.15 | 0.14 | 0.12 | 0.11 |
| C ₃ F ₈ | + | + | + | + | + | + | + |
| C ₄ F ₈ | 0.0 | + | + | + | + | + | + |
| HFC-23 | + | + | + | + | + | + | + |
| SF ₆ | + | + | + | + | + | + | + |
| NF ₃ | + | + | + | + | + | + | + |
| N ₂ O | 0.12 | 0.41 | 0.49 | 0.80 | 0.66 | 0.61 | 0.69 |

+ Does not exceed 0.05 kt.

³⁸ Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

Methodology

Emissions are based on data reported through Subpart I, Electronics Manufacture, of EPA's GHGRP, Partner reported emissions data received through the EPA's PFC³⁹ Reduction/Climate Partnership, EPA's PFC Emissions Vintage Model (PEVM)—a model that estimates industry emissions in the absence of emission control strategies (Burton and Beizaie 2001),⁴⁰ and estimates of industry activity (i.e., total manufactured layer area). The availability and applicability of reported emissions data from the EPA Partnership and EPA's GHGRP, and activity data differs across the 1990 through 2014 time series. Consequently, fluorinated greenhouse gas (F-GHG) emissions from semiconductor manufacturing were estimated using six distinct methods, one each for the periods 1990 through 1994, 1995 through 1999, 2000 through 2006, 2007 through 2010, 2011 through 2012, and 2013 through 2014. Nitrous oxide emissions were estimated using four distinct methods, one each for the period 1990 through 1994, 1995 through 2010, 2011 through 2012, and 2013 through 2014.

1990 through 1994

From 1990 through 1994, Partnership data were unavailable and emissions were modeled using PEVM (Burton and Beizaie 2001).⁴¹ The 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as chemical substitution and abatement were yet to be developed.

PEVM is based on the recognition that fluorinated greenhouse gas emissions from semiconductor manufacturing vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses emissions per unit of manufactured layer-area. Emissions are estimated by multiplying TMLA by this emission factor.

PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers: (1) linewidth technology (the smallest manufactured feature size),⁴² and (2) product type (discrete, memory or logic).⁴³ For each linewidth technology, a weighted average number of layers is estimated using VLSI product-specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per Integrated Circuit (IC) specific to product type (Burton and Beizaie 2001; ITRS 2007). PEVM derives historical consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts and average wafer size (VLSI Research, Inc. 2012).

The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA

³⁹ In the context of the EPA Partnership and PEVM, PFC refers to perfluorocompounds, not perfluorocarbons.

⁴⁰ A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily reported their PFC emissions to the EPA by way of a third party, which aggregated the emissions through 2010.

⁴¹ Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

⁴² By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with 65 nm feature sizes might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality, while a device manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

⁴³ Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e., the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled emissions. The emission factor is used to estimate world uncontrolled emissions using publicly-available data on world silicon consumption.

As it was assumed for this time period that there was no consequential adoption of fluorinated-gas-reducing measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry to estimate gas-specific emissions. This distribution was based upon the average fluorinated-gas purchases made by semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas (Burton and Beizaie 2001).

To estimate N₂O emissions, it is assumed the proportion of N₂O emissions estimated for 1995 (discussed below) remained constant for the period of 1990 through 1994.

1995 through 1999

For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of capacity utilization in a given year) than PEVM estimated emissions, and are used to generate total U.S. emissions when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly (Semiconductor Equipment and Materials Industry 2012 and 2013). Gas-specific emissions were estimated using the same method as for 1990 through 1994.

For this time period, the N₂O emissions were estimated using an emission factor that is applied to the annual, total U.S. TMLA manufactured. The emission factor was developed using a regression-through-the-origin (RTO) model: GHGRP reported N₂O emissions were regressed against the corresponding TMLA of facilities that reported no use of abatement systems. Details on EPA's GHGRP reported emissions and development of emission factor using the RTO model are presented in the 2011 through 2012 section. The total U.S. TMLA was estimated using PEVM.

2000 through 2006

Emissions for the years 2000 through 2006—the period during which Partners began the consequential application of fluorinated greenhouse gas-reduction measures—were estimated using a combination of Partner-reported emissions and adjusted PEVM modeled emissions. The emissions reported by Partners for each year were accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining emissions, those from non-Partners, were estimated using PEVM, with one change. To ensure time series consistency and to reflect the increasing use of remote clean technology (which increases the efficiency of the production process while lowering emissions of fluorinated greenhouse gases), the average non-Partner emission factor (PEVM emission factor) was assumed to begin declining gradually during this period. Specifically, the non-Partner emission factor for each year was determined by linear interpolation, using the end points of 1999 (the original PEVM emission factor) and 2011 (a new emission factor determined for the non-Partner population based on GHGRP-reported data, described below).

The portion of the U.S. total attributed to non-Partners is obtained by multiplying PEVM's total U.S. emissions figure by the non-Partner share of U.S. total silicon capacity for each year as described above.⁴⁴ Gas-specific emissions from non-Partners were estimated using linear interpolation of gas-specific emission distribution of 1999 (assumed same as total U.S. Industry in 1994) and 2011 (calculated from a subset of non-Partner facilities from GHGRP reported emissions data). Annual updates to PEVM reflect published figures for actual silicon

⁴⁴ This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

consumption from VLSI Research, Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC fabrication practices within the semiconductor industry (see ITRS 2008 and Semiconductor Equipment and Materials Industry 2011).^{45,46,47}

The N₂O emissions were estimated using the same methodology as the 1995 through 1999 methodology.

2007 through 2010

For the years 2007 through 2010, emissions were also estimated using a combination of Partner reported emissions and adjusted PEVM modeled emissions to provide estimates for non-Partners; however, two improvements were made to the estimation method employed for the previous years in the time series. First, the 2007 through 2010 emission estimates account for the fact that Partners and non-Partners employ different distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater transistor densities and therefore greater numbers of layers.⁴⁸ Second, the scope of the 2007 through 2010 estimates was expanded relative to the estimates for the years 2000 through 2006 to include emissions from research and development (R&D) fabs. This additional enhancement was feasible through the use of more detailed data published in the WFF. PEVM databases were updated annually as described above. The published world average capacity utilization for 2007 through 2010 was used for production fabs, while for R&D fabs a 20 percent figure was assumed (SIA 2009).

In addition, publicly-available actual utilization data was used to account for differences in fab utilization for manufacturers of discrete and IC products for 2010 emissions for non-Partners. The Semiconductor Capacity Utilization (SICAS) Reports from SIA provides the global semiconductor industry capacity and utilization, differentiated by discrete and IC products (SIA, 2009 through 2011). PEVM estimates were adjusted using technology-weighted capacity shares that reflect the relative influence of different utilization. Gas-specific emissions for non-Partners were estimated using the same method as for 2000 through 2006.

The N₂O emissions were estimated using the same methodology as the 1995 through 1999 methodology.

2011 through 2012

The fifth method for estimating emissions from semiconductor manufacturing covers the period 2011 through 2012,

⁴⁵ Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2–3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFF were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called “wafers/month, 8-inch equivalent,” which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

⁴⁶ In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

⁴⁷ Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

⁴⁸ EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

the years after EPA's Partnership with the semiconductor industry ended (in 2010) and reporting under EPA's GHGRP began. Manufacturers whose estimated uncontrolled emissions equal or exceed 25,000 MT CO₂ Eq. per year (based on default F-GHG-specific emission factors and total capacity in terms of substrate area) are required to report their emissions to EPA. This population of reporters to EPA's GHGRP included both historical Partners of EPA's PFC Reduction/Climate Partnership as well as non-Partners. In EPA's GHGRP, the population of non-Partner facilities also included manufacturers that use GaAs technology in addition to Si technology.⁴⁹ Emissions from the population of manufacturers that were below the reporting threshold were also estimated for this time period using EPA-developed emission factors and estimates of facility-specific production obtained from WFF. Inventory totals reflect the emissions from both populations.

Under EPA's GHGRP, semiconductor manufacturing facilities report emissions of F-GHGs used in etch and clean processes as well as emissions of fluorinated heat transfer fluids. (Fluorinated heat transfer fluids are used to control process temperatures, thermally test devices, and clean substrate surfaces, among other applications.) They also report N₂O emissions from CVD and other processes. The F-GHGs and N₂O were aggregated, by gas, across all semiconductor manufacturing GHGRP reporters to calculate gas-specific emissions for the GHGRP-reporting segment of the U.S. industry. At this time, emissions that result from heat transfer fluid use are not included in emission estimates (see Planned Improvements below).

For the segment of the semiconductor industry that is below EPA's GHGRP reporting threshold, and for R&D facilities, which are not covered by EPA's GHGRP, emission estimates are based on EPA-developed emission factors for the F-GHGs and N₂O and estimates of manufacturing activity. The new emission factors (in units of mass of CO₂ Eq./TMLA [MSI]) are based on the emissions reported by facilities under EPA's GHGRP and TMLA estimates for these facilities from the WFF (SEMI 2012 and SEMI 2013). In a refinement of the method used in prior years to estimate emissions for the non-Partner population, different emission factors were developed for different subpopulations of fabs, one for facilities that manufacture devices on Si wafers and one for facilities that manufacture on GaAs wafers. An analysis of the emission factors of reporting fabs showed that the characteristics that had the largest impacts on emission factors were the substrate (i.e., Si or GaAs) used at the fab, whether the fab contained R&D activities, and whether the fab reported using point-of-use fluorinated greenhouse gas abatement.⁵⁰ For each of these groups, a subpopulation-specific emission factor was obtained using a regression-through-the-origin (RTO) model: facility-reported aggregate emissions of seven F-GHGs (CF₄, C₂F₆, C₃F₈, C₄F₈, CHF₃, SF₆ and NF₃)⁵¹ were regressed against the corresponding TMLA to estimate an aggregate F-GHG emissions factor (CO₂ Eq./MSI TMLA), and facility-reported N₂O emissions were regressed against the corresponding TMLA to estimate a N₂O emissions factor (CO₂ Eq./MSI TMLA). For each subpopulation, the slope of the RTO model is the emission factor for that subpopulation. To estimate emissions from fabs that are solely doing research and development (R&D) or are Pilot fabs (i.e., fabs that are excluded from subpart I reporting requirements), emission factors were estimated based on GHGRP reporting fabs containing R&D activities. EPA applied a scaling factor of 1.15 to the slope of the RTO model to estimate the emission factor applicable to the non-reporting fabs that are only R&D or Pilot fabs. This was done as R&D activities lead to use of more F-GHGs and N₂O for development of chips that are not counted towards the final estimated TMLA. Hence, it is assumed that the fabs with only R&D activities use 15 percent more F-GHGs and N₂O per TMLA.

For 2011 and 2012, estimates of TMLA relied on the capacity utilization of the fabs published by the U.S. Census Bureau's Historical Data Quarterly Survey of Plant Capacity Utilization (USCB 2011, 2012). Unlike the assumption for 2007 through 2010, all the facilities in the United States are assumed to utilize the same percent of the manufacturing capacity without distinguishing whether fabs have R&D activities or produce discrete products. This was done due to the unavailability of the data disaggregated into different fab, or manufacturing, types.

Non-reporting fabs were then broken out into similar subpopulations. Information on the technology and R&D activities of non-reporting fabs was available through the WFF. Information on the use of point-of-use abatement

⁴⁹ GaAs and Si technologies refer to the wafer on which devices are manufactured, which use the same PFCs but in different ways.

⁵⁰ For the non-reporting segment of the industry using GaAs technology, emissions were estimated only for those fabs that manufactured the same products as manufactured by reporters. The products manufactured were categorized as discrete (emissions did not scale up with decreasing feature size).

⁵¹ Only seven gases were aggregated because inclusion of F-GHGs that are not reported in the inventory results in overestimation of emission factor that is applied to the various non-reporting subpopulations.

by non-reporting fabs was not available; thus, EPA conservatively assumed that non-reporting facilities did not use point-of-use abatement. The appropriate emission factor was applied to the total TMLA of each subpopulation of non-reporting facilities to estimate the GWP-weighted emissions of that subpopulation.

Gas-specific, GWP-weighted emissions for each subpopulation of non-reporting facilities were estimated using the corresponding reported distribution of gas-specific, GWP-weighted emissions from which the aggregate emission factors, based on GHGRP reported data, were developed. Estimated in this manner, the non-reporting population accounted for 11, and 10 percent of U.S. emissions in 2011, and 2012, respectively. The GHGRP-reported emissions and the calculated non-reporting population emissions are summed to estimate the total emissions from semiconductor manufacturing.

The methodology used for this time period included emissions from facilities employing Si- and GaAs-using technologies. The use of GaAs technology became evident via analysis of GHGRP emissions and WFF data. However, no adjustment of pre-2011 emissions was made because (1) the use of these technologies appears relatively new, (2) in the aggregate these emissions make a relatively small contribution to total industry emissions (i.e., 3 percent in 2014), and (3) it would require a large effort to retroactively adjust pre-2011 emissions.

2013 through 2014

For the years 2013 through 2014, as for 2011 and 2012, F-GHG and N₂O emissions data received through EPA's GHGRP were aggregated, by gas, across all semiconductor-manufacturing GHGRP reporters to calculate gas-specific emissions for the GHGRP-reporting segment of the U.S. industry. However, because WFF-derived activity data was not available for these years, an updated methodology to estimate emissions for the segment of the industry that are not covered by EPA's GHGRP was used. For the facilities that did not report to the GHGRP (i.e., which are below EPA's GHGRP reporting threshold or are R&D facilities), emissions were estimated based on the proportion of total U.S. emissions attributed to non-reporters for 2011 and 2012. EPA first estimated this proportion for both N₂O and F-GHGs for 2011 and 2012, resulting in one proportion for F-GHGs and one for N₂O, and then applied the average of these years' proportions to the 2013 and 2014 GHGRP reported emissions to estimate the non-reporters' emissions. Fluorinated gas-specific, GWP-weighted emissions for non-reporters were estimated using the corresponding reported distribution of gas-specific, GWP-weighted emissions reported through EPA's GHGRP for 2013 and 2014 respectively. Again, a calculation of emissions from the use of heat transfer fluids was not included in this methodology.

Data Sources

GHGRP reporters, which consist of EPA Partners and non-Partners, estimated their emissions using a default emission factor method established by EPA. Like the Tier 2b Method in the *2006 IPCC Guidelines*, this method uses different emission and by-product generation factors for different F-GHGs and process types, but it goes beyond the Tier 2b Method by requiring use of updated factors for different wafer sizes (i.e., 300mm vs. 150 and 200mm) and CVD clean subtypes (in situ thermal, in situ thermal, and remote plasma). GHGRP-reporting facilities are estimated to have accounted for about 90 percent of F-GHG emissions and 95 percent of N₂O emissions from U.S. semiconductor manufacturing between 2011 and 2014. Historically, partners estimated and reported their emissions using a range of methods documented with varying completeness and consistency. It is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a Methodology, recommended in the *2006 IPCC Guidelines*. Partners are estimated to have accounted for between 56 and 79 percent of F-GHG emissions from U.S. semiconductor manufacturing between 1995 and 2010, with the percentage declining in recent years as Partners increasingly implemented abatement measures. Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the Semiconductor Equipment and Materials Industry (SEMI) WFF (formerly World Fab Watch) database (1996 through 2012) (e.g., Semiconductor Materials and Equipment Industry, 2013). Actual worldwide capacity utilizations for 2008 through 2010 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA 2009 through 2011). Estimates of the number of layers for each linewidth was obtained from International Technology Roadmap for Semiconductors: 2013 Edition (Burton and Beizaie 2001; ITRS 2007; ITRS 2008; ITRS 2011; ITRS 2013). PEVM utilized the WFF, SICAS, and ITRS, as well as historical silicon consumption estimates published by VLSI. Actual quarterly U.S. capacity utilizations for 2011 through 2014 were obtained from the U.S. Census Bureau's Historical Data Quarterly Survey of Plant Capacity Utilization (USCB 2011 through 2014).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Approach 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{Total Emissions (E}_T\text{)} = \text{GHGRP Reported F-GHG Emissions (E}_{R,\text{F-GHG}}\text{)} + \text{Non-Reporters' Estimated F-GHG Emissions (E}_{\text{NR,F-GHG}}\text{)} + \text{GHGRP Reported N}_2\text{O Emissions (E}_{R,\text{N}_2\text{O}}\text{)} + \text{Non-Reporters' Estimated N}_2\text{O Emissions (E}_{\text{NR,N}_2\text{O}}\text{)}$$

where E_R and E_{NR} denote totals for the indicated subcategories of emissions for F-GHG and N_2O , respectively.

The uncertainty in E_T presented in Table 4-93 below results from the convolution of four distributions of emissions, each reflecting separate estimates of possible values of $E_{R,\text{F-GHG}}$, $E_{R,\text{N}_2\text{O}}$, $E_{\text{NR,F-GHG}}$, and $E_{\text{NR,N}_2\text{O}}$. The approach and methods for estimating each distribution and combining them to arrive at the reported 95 percent confidence interval (CI) are described in the remainder of this section.

The uncertainty estimate of $E_{R,\text{F-GHG}}$, or GHGRP-reported F-GHG emissions, is developed based on gas-specific uncertainty estimates of emissions for two industry segments, one processing 200 mm wafers and one processing 300 mm wafers. Uncertainties in emissions for each gas and industry segment were developed during the assessment of emission estimation methods for the subpart I GHGRP rulemaking in 2012 (see *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I*, docket EPA-HQ-OAR-2011-0028).⁵² The 2012 analysis did not take into account the use of abatement. For the industry segment that processed 200 mm wafers, estimates of uncertainties at a 95 percent CI ranged from ± 29 percent for C_3F_8 to ± 10 percent for CF_4 . For the corresponding 300 mm industry segment, estimates of the 95 percent CI ranged from ± 36 percent for C_4F_8 to ± 16 percent for CF_4 . These gas and wafer-specific uncertainty estimates are applied to the total emissions of the facilities that did not abate emissions as reported under EPA's GHGRP.

For those facilities reporting abatement of emissions under EPA's GHGRP, estimates of uncertainties for the no abatement industry segments are modified to reflect the use of full abatement (abatement of *all* gases from *all* cleaning and etching equipment) and partial abatement. These assumptions used to develop uncertainties for the partial and full abatement facilities are identical for 200 mm and 300 mm wafer processing facilities. For all facilities reporting gas abatement, a triangular distribution of destruction or removal efficiency is assumed for each gas. The triangular distributions range from an asymmetric and highly uncertain distribution of zero percent minimum to 90 percent maximum with 70 percent most likely value for CF_4 to a symmetric and less uncertain distribution of 85 percent minimum to 95 percent maximum with 90 percent most likely value for C_4F_8 , NF_3 , and SF_6 . For facilities reporting partial abatement, the distribution of fraction of the gas fed through the abatement device, for each gas, is assumed to be triangularly distributed as well. It is assumed that no more than 50 percent of the gases area abated (i.e., the maximum value) and that 50 percent is the most likely value and the minimum is zero percent. Consideration of abatement then resulted in four additional industry segments, two 200-mm wafer-processing segments (one fully and one partially abating each gas) and two 300-mm wafer-processing segment (one fully and the other partially abating each gas). Gas-specific emission uncertainties were estimated by convolving the distributions of unabated emissions with the appropriate distribution of abatement efficiency for fully and partially abated facilities using a Monte Carlo simulation.

⁵² On November 13, 2013, EPA published a final rule revising subpart I (Electronics Manufacturing) of the GHGRP (78 FR 68162). The revised rule includes updated default emission factors and updated default destruction and removal efficiencies that are slightly different from those that semiconductor manufacturers were required to use to report their 2012 emissions. The uncertainty analyses that were performed during the development of the revised rule focused on these updated defaults, but are expected to be reasonably representative of the uncertainties associated with the older defaults, particularly for estimates at the country level. (They may somewhat underestimate the uncertainties associated with the older defaults at the facility level.) For simplicity, the 2012 estimates are assumed to be unbiased although in some cases, the updated (and therefore more representative) defaults are higher or lower than the older defaults. Multiple models and sensitivity scenarios were run for the subpart I analysis. The uncertainty analysis presented here made use of the Input gas and wafer size model (Model 1) under the following conditions: Year = 2010, $f = 20$, $n = \text{SIA3}$.

The uncertainty in $E_{R,F-GHG}$ is obtained by allocating the estimates of uncertainties to the total GHGRP-reported emissions from each of the six industry segments, and then running a Monte Carlo simulation which results in the 95 percent CI for emissions from GHGRP reporting facilities ($E_{R,F-GHG}$).

The uncertainty in E_{R,N_2O} is obtained by assuming that the uncertainty in the emissions reported by each of the GHGRP reporting facilities results from the uncertainty in quantity of N_2O consumed and the N_2O emission factor (or utilization). Similar to analyses completed for subpart I (see *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities* under Subpart I, docket EPA-HQ-OAR-2011-0028), the uncertainty of N_2O consumed was assumed to be 20 percent. Consumption of N_2O for GHGRP reporting facilities was estimated by back-calculating from emissions reported and assuming no abatement. The quantity of N_2O utilized (the complement of the emission factor) was assumed to have a triangular distribution with a minimum value of zero percent, mode of 20 percent and maximum value of 84 percent. The minimum was selected based on physical limitations, the mode was set equivalent to the subpart I default N_2O utilization rate for chemical vapor deposition, and the maximum was set equal to the maximum utilization rate found in ISMI Analysis of Nitrous Oxide Survey Data (ISMI, 2009). The inputs were used to simulate emissions for each of the GHGRP reporting, N_2O -emitting facilities. The uncertainty for the total reported N_2O emissions was then estimated by combining the uncertainties of each of the facilities reported emissions using Monte Carlo simulation.

The estimate of uncertainty in $E_{NR,F-GHG}$ and E_{NR,N_2O} entailed developing estimates of uncertainties for the proportion of total emissions attributed to non-reporters for 2011 and 2012, which are subsequently dependent on the emissions factors for each non-reporting sub-category and the corresponding estimates of TMLA for the years 2011 and 2012.

The uncertainty in TMLA depends on the uncertainty of two variables—an estimate of the uncertainty in the average annual capacity utilization for each level of production of fabs (e.g., full scale or R&D production) and a corresponding estimate of the uncertainty in the number of layers manufactured. For both variables, the distributions of capacity utilizations and number of manufactured layers are assumed triangular for all categories of non-reporting fabs. For production fabs and for facilities that manufacture discrete devices, the most probable utilization is assumed to be 79 percent for 2011 and 65 percent for 2012, with the highest and lowest utilization assumed to be 84 percent for 2011 and 70 percent for 2012, and 62 percent for 2011 and 51 percent for 2012, respectively. The most probable values for utilization for R&D facilities are assumed to be 79 percent for 2011 and 65 percent for 2012, with the highest utilization also at 79 percent for 2011 and 65 percent for 2012, and the lowest utilization at 40 percent for 2011 and 33 percent for 2012. For the triangular distributions that govern the number of possible layers manufactured, it is assumed the most probable value is one layer less than reported in the ITRS; the smallest number varied by technology generation between one and two layers less than given in the ITRS and largest number of layers corresponded to the figure given in the ITRS.

The uncertainty bounds for the average capacity utilization and the number of layers manufactured are used as inputs in a separate Monte Carlo simulation to estimate the uncertainty around the TMLA of both individual facilities as well as the total non-reporting TMLA of each sub-population for both 2011 and 2012.

The uncertainty around the emission factors for each non-reporting category of facilities (for both 2011 and 2012) is dependent on the uncertainty of the total emissions (MMT CO_2 Eq. units) and the TMLA of each reporting facility in that category. For each subpopulation of reporting facilities, total emissions were regressed on TMLA (with an intercept forced to zero) for 10,000 emissions and 10,000 TMLA values in a Monte Carlo simulation, which results in 10,000 total regression coefficients (emission factors). The 2.5th and the 97.5th percentile of these emission factors are determined and the bounds are assigned as the percent difference from the estimated emission factor.

For simplicity, the results of the Monte Carlo simulations on the bounds of the gas- and wafer size-specific emissions as well as the TMLA and emission factors are assumed to be normally distributed and the uncertainty bounds are assigned at 1.96 standard deviations around the estimated mean. The departures from normality were observed to be small.

The final step in estimating the uncertainty in emissions of non-reporting facilities is convolving the distribution of emission factors with the distribution of TMLA individually for 2011 and 2012, along with the distributions of GHGRP-reported emissions for 2011 and 2012 to estimate the uncertainty around the proportion of total emissions attributed to non-reporters for 2011 and 2012 using Monte Carlo simulation.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-93, which is also obtained by convolving—using Monte Carlo simulation—the distributions of emissions for each reporting and non-reporting

facility. The emissions estimate for total U.S. F-GHG and N₂O emissions from semiconductor manufacturing were estimated to be between 4.5 and 5.0 MMT CO₂ Eq. at a 95 percent confidence level. This range represents 6 percent below to 6 percent above the 2014 emission estimate of 4.7 MMT CO₂ Eq. This range and the associated percentages apply to the estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will be somewhat higher than the aggregate, but were not explicitly modeled.

Table 4-93: Approach 2 Quantitative Uncertainty Estimates for HFC, PFC, SF₆, NF₃ and N₂O Emissions from Semiconductor Manufacture (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|---------------------------|--|--|--|--------------------------|-----------------|-----------------|
| | | | Lower Bound ^b | Upper Bound ^b | Lower Bound (%) | Upper Bound (%) |
| Semiconductor Manufacture | HFC, PFC, SF ₆ , NF ₃ , and N ₂ O | 4.7 | 4.5 | 5.0 | -6% | 6% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

^b Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

The emissions reported under EPA’s GHGRP for 2014, which are included in the overall emissions estimated for 2014, were based on an updated set of default emission factors. This may have affected the trend seen between 2013 and 2014 (a 13-percent increase), which reversed the trend seen between 2011 and 2013. As discussed in the Planned Improvements section, EPA is considering further analysis to determine how much, if any, of the 2013-2014 trend may be attributable to the updated factors.

Recalculations Discussion

Emissions from 2011 through 2013 were updated to reflect updated emissions reporting in EPA’s GHGRP. Further, gas-process specific non-reporter emission factors were updated to reflect the historical changes in GHGRP data as well as updated manufacturing utilizations.

Methodological recalculations were applied to the entire time series to ensure time series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above. From 2000 through 2010, estimates increased slightly due to updated emission factors for 2011 resulting from a new source of utilization data (U.S. Census data) and updated GHGRP data. This has implications for the time series adjustment for 2000 through 2010 (i.e., the Partnership era). Interpolation is used to linearly decrease the non-partner population EF over time (2000 through 2010).

Planned Improvements

This Inventory contains estimates of seven fluorinated gases for semiconductor manufacturing and N₂O. However, other fluorinated gases (e.g., C₅F₈) are used in relatively smaller amounts. Previously, emissions data for these other fluorinated gases was not reported through the EPA Partnership. Through EPA’s GHGRP, these data, as well as heat transfer fluid emission data, are available. Therefore, a point of consideration for future Inventory reports is the inclusion of other fluorinated gases, and emissions from heat transfer fluid (HTF) loss to the atmosphere.

Fluorinated heat transfer fluids, of which some are liquid perfluorinated compounds, are used for temperature control, device testing, cleaning substrate surfaces and other parts, and soldering in certain types of semiconductor manufacturing production processes. Evaporation of these fluids is a source of fluorinated emissions (EPA 2006). The GHGRP-reported HTF emissions along with WWF database could be used to develop emission factors for identified subpopulations. Further research needs to be done to determine if the same subpopulations identified in developing new emission factors for F-GHGs are applicable or new subpopulations have to be studied as HTFs are used primarily by manufacturers of wafer size 300 mm and above.

Along with more emissions information for semiconductor manufacturing, EPA’s GHGRP requires the reporting of emissions from other types of electronics manufacturing, including micro-electro-mechanical systems, flat panel displays, and photovoltaic cells. There currently are no flat panel displays, and photovoltaic cell manufacturing

facilities that are reporting to EPA’s GHGRP, and five reporting MEMs manufacturers. The MEMs manufacturers also report emissions from semiconductor manufacturing and do not distinguish between these two types of manufacturing in their report; thus, emissions from MEMs manufacturers are included in the totals here. Emissions from manufacturing of flat panel displays and photovoltaic cells may be included in future Inventory reports; however, estimation methodologies would need to be developed.

The Inventory methodology uses data reported through the EPA Partnership (for earlier years) and EPA’s GHGRP (for later years) to extrapolate the emissions of the non-reporting population. While these techniques are well developed, the understanding of the relationship between the reporting and non-reporting populations is limited. Further analysis of the reporting and non-reporting populations could aid in the accuracy of the non-reporting population extrapolation in future years.

The Inventory uses utilization from two different sources for various time periods—SEMI to develop PEVM and to estimate non-Partner emissions for the period 1995 to 2010 and U.S. Census Bureau for 2011 through 2014. SEMI reported global capacity utilization for manufacturers through 2011. U.S. Census Bureau capacity utilization include U.S. semiconductor manufacturers as well as assemblers. Further analysis on the impacts of using a new and different source of utilization data could prove to be useful in better understanding of industry trends and impacts of utilization data sources on historical emission estimates.

Starting with 2014 reported emissions, EPA’s GHGRP required semiconductor manufacturers to apply updated emission factors to estimate their F-GHG emissions. EPA is planning to investigate whether and how much this change may have affected the trend seen in estimated emissions between 2013 and 2014.

4.23 Substitution of Ozone Depleting Substances (IPCC Source Category 2F)

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-depleting substances (ODSs) that are being phased out under the terms of the *Montreal Protocol* and the Clean Air Act Amendments of 1990.⁵³ Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial applications including refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are provided in Table 4-94 and Table 4-95.

Table 4-94: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO₂ Eq.)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|------------|-------------|--------------|--------------|--------------|--------------|--------------|
| HFC-23 | + | + | + | + | + | + | + |
| HFC-32 | + | 0.3 | 2.6 | 3.4 | 4.4 | 5.4 | 6.4 |
| HFC-125 | + | 9.5 | 31.4 | 37.2 | 43.6 | 49.9 | 55.9 |
| HFC-134a | + | 73.3 | 77.5 | 72.5 | 67.8 | 62.8 | 60.8 |
| HFC-143a | + | 9.4 | 20.3 | 22.5 | 24.4 | 26.0 | 27.2 |
| HFC-236fa | + | 1.2 | 1.4 | 1.4 | 1.5 | 1.5 | 1.4 |
| CF ₄ | + | + | + | + | + | + | + |
| Others ^a | 0.3 | 5.9 | 7.8 | 8.2 | 8.6 | 9.0 | 9.4 |
| Total | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-43-10mee, HFO-1234yf, C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C₆F₁₄.

⁵³ [42 U.S.C § 7671, CAA Title VI]

Note: Totals may not sum due to independent rounding.

Table 4-95: Emissions of HFCs and PFCs from ODS Substitution (Metric Tons)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|------|--------|--------|--------|--------|--------|--------|
| HFC-23 | + | 1 | 2 | 2 | 2 | 2 | 3 |
| HFC-32 | + | 511 | 3,915 | 5,032 | 6,479 | 7,985 | 9,475 |
| HFC-125 | + | 2,701 | 8,983 | 10,626 | 12,445 | 14,259 | 15,974 |
| HFC-134a | + | 51,293 | 54,203 | 50,720 | 47,388 | 43,900 | 42,491 |
| HFC-143a | + | 2,108 | 4,548 | 5,034 | 5,451 | 5,813 | 6,088 |
| HFC-236fa | + | 125 | 146 | 147 | 148 | 151 | 148 |
| CF ₄ | + | 2 | 3 | 4 | 4 | 4 | 4 |
| Others ^a | M | M | M | M | M | M | M |

+ Does not exceed 0.5 MT.

M (Mixture of Gases)

^a Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-43-10mee, HFO-1234yf, C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in chillers—and HFC-134a in refrigeration end-uses. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-conditioners and in refrigerant blends such as R-404A.⁵⁴ In 1993, the use of HFCs in foam production began, and in 1994 ODS substitutes for halons entered widespread use in the United States as halon production was phased-out. In 1995, these compounds also found applications as solvents.

The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in 1990 to 161.2 MMT CO₂ Eq. in 2014. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely continue over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the *Montreal Protocol*. Improvements in the technologies associated with the use of these gases and the introduction of alternative gases and technologies, however, may help to offset this anticipated increase in emissions.

Table 4-96 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2014. The end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2014 include refrigeration and air-conditioning (139.2 MMT CO₂ Eq., or approximately 86 percent), aerosols (10.8 MMT CO₂ Eq., or approximately 7 percent), and foams (8.0 MMT CO₂ Eq., or approximately 5 percent). Within the refrigeration and air-conditioning end-use sector, motor vehicle air-conditioning was the highest emitting end-use (40.9 MMT CO₂ Eq.), followed by refrigerated retail food and refrigerated transport. Each of the end-use sectors is described in more detail below.

Table 4-96: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO₂ Eq.) by Sector

| Sector | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------------|------------|-------------|--------------|--------------|--------------|--------------|--------------|
| Refrigeration/Air Conditioning | + | 87.8 | 122.8 | 125.9 | 130.0 | 133.6 | 139.2 |
| Aerosols | 0.3 | 7.6 | 9.7 | 10.1 | 10.3 | 10.5 | 10.8 |
| Foams | + | 2.1 | 5.9 | 6.4 | 6.9 | 7.4 | 8.0 |
| Solvents | + | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 |
| Fire Protection | + | 0.7 | 1.1 | 1.2 | 1.3 | 1.3 | 1.4 |
| Total | 0.3 | 99.7 | 141.2 | 145.3 | 150.2 | 154.6 | 161.2 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

⁵⁴ R-404A contains HFC-125, HFC-143a, and HFC-134a.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout is taking effect, most equipment is being or will eventually be retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A,⁵⁵ R-404A, and R-507A.⁵⁶ Low-GWP options such as HFO-1234yf in motor vehicle air-conditioning, R-717 (ammonia) in cold storage and industrial applications, and R-744 (carbon dioxide) in retail food refrigeration, are also being used. These refrigerants are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Many pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have replaced the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry has started to use HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most non-medical consumer aerosol products have not transitioned to HFCs, but to “not-in-kind” technologies, such as solid roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. Other low-GWP options such as HFO-1234ze(E) are being used as well. These propellants are released into the atmosphere as the aerosol products are used.

Foams

Chlorofluorocarbons and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the *Montreal Protocol*, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as carbon dioxide (CO₂), methylene chloride, and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce polyurethane appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a, HFC-134a and CO₂ are used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Low-GWP fluorinated foam blowing agents in use include HFO-1234ze(E) and -1233zd(E). Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

Solvents

Chlorofluorocarbons, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride (CCl₄) were historically used as solvents in a wide range of cleaning applications, including precision, electronics, and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and selective solvency. These applications rely on HFC-43-10mee, HFC-365mfc, HFC-245fa, and to a lesser extent,

⁵⁵ R-410A contains HFC-32 and HFC-125.

⁵⁶ R-507A, also called R-507, contains HFC-125 and HFC-143a.

PFCs. Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and optical components, that require a high level of cleanliness and generally have complex shapes, small clearances, and other cleaning challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

Fire Protection

Fire protection applications include portable fire extinguishers (“streaming” applications) that originally used halon 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the production and import of virgin halons were banned in the United States in 1994, the halon replacement agent of choice in the streaming sector has been dry chemical, although HFC-236fa is also used to a limited extent. In the total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that require clean agents. Other HFCs, such as HFC-23 and HFC-125, are used in smaller amounts. The majority of HFC-227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile weapons systems, oil/gas/other process industries, and merchant shipping. Fluoroketone FK-5-1-12 is also used as a low-GWP option. As fire protection equipment is tested or deployed, emissions of these HFCs occur.

Methodology

A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact that it tracks the use and emissions of various compounds for the annual “vintages” of new equipment that enter service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in emissions from equipment as they leak over time. By aggregating the data for more than 60 different end-uses, the model produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is contained in Annex 3.9.

Uncertainty and Time-Series Consistency

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from 66 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 6 other end-uses. These 27 end-uses comprise 97 percent of the total emissions, equivalent to 156.4 MMT CO₂ Eq. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years’ uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex “vintaging” aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert

judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for residential unitary air-conditioners, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-97. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 154.2 and 172.5 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 1.4 percent below to 10.3 percent above the emission estimate of 156.4 MMT CO₂ Eq., which comprises 97 percent of total emissions.

Table 4-97: Approach 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (MMT CO₂ Eq. and Percent)

| Source | Gases | 2014 Emission Estimate (MMT CO ₂ Eq.) ^a | Uncertainty Range Relative to Emission Estimate ^b | | | |
|--|---------------|---|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Substitution of Ozone Depleting Substances | HFCs and PFCs | 156.4 | 154.2 | 172.5 | -1.4% | +10.3% |

^a 2014 emission estimates and the uncertainty range presented in this table correspond to selected end-uses within the aerosols, foams, solvents, fire extinguishing agents, and refrigerants sectors that comprise 97 percent of total emissions, but not for other remaining categories. Therefore, because the uncertainty associated with emissions from “other” ODS substitutes was not estimated, they were excluded in the uncertainty estimates reported in this table.

^b Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Comparison of Reported Consumption to Modeled Consumption of HFCs

Data from EPA’s Greenhouse Gas Reporting Program (GHGRP) was also used to perform quality control on the modeled emissions from this source category. To do so, reported consumption patterns demonstrated through GHGRP Subpart OO: Suppliers of Industrial Greenhouse Gases reported data were compared to the modeled demand for new saturated HFCs (excluding HFC-23) used as ODS substitutes from the Vintaging Model. The collection of data from suppliers of HFCs enables EPA to calculate the reporters’ aggregated net supply—the sum of the quantities of chemical produced or imported into the United States less the sum of the quantities of chemical transformed (used as a feedstock in the production of other chemicals), destroyed, or exported from the United States.⁵⁷ This allows for a quality control check on emissions from this source because the Vintaging Model uses modeled demand for new chemical as a proxy for total amount supplied, which is similar to net supply, as an input to the emission calculations in the model.

Reported Net Supply (GHGRP Top-Down Estimate)

Under EPA’s GHGRP, suppliers (i.e., producers, importers, and exporters) of HFCs began annually reporting their production, transformation, destruction, imports, and exports to EPA in 2011 (for supply that occurred in 2010). For the first time in 2015, bulk consumption data for aggregated HFCs were made publicly available under EPA’s GHGRP. Data include all saturated HFCs (except HFC-23) reported to EPA across the GHGRP-reporting time series (2010 through 2014). The data include all 19 such saturated HFCs listed in Table A-1 of 40 CFR Part 98, where regulations for EPA’s GHGRP are promulgated, though not all species were reported in each reporting year.

⁵⁷ Chemical that is exported, transformed, or destroyed—unless otherwise imported back to the United States—will never be emitted in the United States.

Modeled Consumption (Vintaging Model Bottom-Up Estimate)

The Vintaging Model, used to estimate emissions from this source category, calculates chemical demand based on the quantity of equipment and products sold, serviced and retired each year, and the amount of the chemical required to manufacture and/or maintain the equipment and products.⁵⁸ It is assumed that the total demand equals the amount supplied by either new production, chemical import, or quantities recovered (usually reclaimed) and placed back on the market. In the Vintaging Model, demand for new chemical, as a proxy for consumption, is calculated as any chemical demand (either for new equipment or for servicing existing equipment) that cannot be met through recycled or recovered material. No distinction is made in the Vintaging Model between whether that need is met through domestic production or imports. To calculate emissions, the Vintaging Model estimates the quantity released from equipment over time. Thus, verifying the Vintaging Model's calculated consumption against GHGRP reported data is one way to check the Vintaging Model's emission estimates.

There are ten saturated HFC species modeled in the Vintaging Model: HFC-23, HFC-32, HFC-125, HFC-134a, HFC-143a, HFC-152a, HFC-227ea, HFC-236fa, HFC-245fa, and HFC-43-10mee. For the purposes of this comparison, only nine HFC species are included (HFC-23 is excluded), to more closely align with the aggregated total reported under EPA's GHGRP. While some amounts of less-used saturated HFCs, including isomers of those included in the Vintaging Model, are reportable under EPA's GHGRP, the data are believed to represent an amount comparable to the modeled estimates as a quality control check.

Comparison Results and Discussion

Comparing the estimates of consumption from these two approaches ultimately supports and improves estimates of emissions, as noted in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (which refer to fluorinated greenhouse gas consumption based on supplies as "potential emissions"):

[W]hen considered along with estimates of actual emissions, the potential emissions approach can assist in validation of completeness of sources covered and as a QC check by comparing total domestic consumption as calculated in this 'potential emissions approach' per compound with the sum of all activity data of the various uses (IPCC 2006).

Table 4-98 compares the net supply of saturated HFCs (excluding HFC-23) in million metric tons of CO₂ Eq. as determined from Subpart OO of EPA's GHGRP for the years 2010 through 2014 and the chemical demand as calculated by the Vintaging Model for the same time series.

Table 4-98: U.S. HFC Consumption (MMT CO₂ Eq.)

| | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------------|-----------|-----------|------------|-----------|------------|
| Reported Net Supply (GHGRP) | 235 | 241 | 227 | 278 | 254 |
| Modeled Supply (Vintaging Model) | 256 | 256 | 273 | 278 | 282 |
| Percent Difference | 9% | 6% | 20% | 0% | 11% |

As shown, the estimates from the Vintaging Model are higher than the GHGRP estimates by an average of 9 percent across the time series (i.e., 2010 through 2014). Potential reasons for these differences include:

- The Vintaging Model includes fewer HFCs than are reported to EPA's GHGRP. However, the additional reported HFCs represent a small fraction of total HFC use for this source category, both in GWP-weighted and unweighted terms, and as such, it is not expected that the additional HFCs reported to EPA are a major driver for the difference between the two sets of estimates. To the extent lower-GWP isomers were used in lieu of the modeled chemicals (e.g., HFC-134 instead of HFC-134a), lower CO₂ Eq. amounts in the EPA's GHGRP data compared to the modeled estimates would be expected.
- Because the top-down data are reported at the time of actual production or import and the bottom-up data are calculated at the time of actual placement on the market, there could be a temporal discrepancy when

⁵⁸ The model builds an inventory of the in-use stock of equipment and products and ODSs and HFCs in each of the sub-applications. Emissions are subsequently estimated by applying annual and disposal emission rates to each population of equipment and products.

comparing data. Because the EPA’s GHGRP data generally increases over time (although some year-to-year variations exist) and the Vintaging Model estimates also increase, EPA would expect the modeled estimates to be slightly higher than the corresponding GHGRP data due to this temporal effect.

- Under EPA’s GHGRP, all facilities that produce HFCs are required to report their quantities, whereas importers or exporters of HFCs are only required to report if either their total imports or their total exports of greenhouse gases are greater than or equal to 25,000 metric tons of CO₂ Eq. per year. Thus, some imports may not be accounted for in the GHGRP data. On the other hand, some exports might also not be accounted for in this data.
- In some years, imports and exports may be greater than consumption because the excess is being used to increase chemical stockpiles; in other years, the opposite may hold true. Averaging imports and exports over multiple years can minimize the impact of such fluctuations. For example, when the 2012 and 2013 net additions to the supply are averaged, as shown in Table 4-99, the percent difference between the consumption estimates decreases compared to the 2012-only estimates.

Table 4-99: Averaged U.S. HFC Demand (MMT CO₂ Eq.)

| | 2010-2011 Avg. | 2011-2012 Avg. | 2012-2013 Avg. | 2013-2014 Avg. |
|----------------------------------|----------------|----------------|----------------|----------------|
| Reported Net Supply (GHGRP) | 238 | 234 | 253 | 266 |
| Modeled Demand (Vintaging Model) | 256 | 264 | 275 | 280 |
| Percent Difference | 7% | 13% | 9% | 5% |

- The Vintaging Model does not reflect the dynamic nature of reported HFC consumption, with significant differences seen in each year. Whereas the Vintaging Model projects a slowly increasing overall demand, actual consumption for specific chemicals may vary over time and could even switch from positive to negative (indicating more chemical exported, transformed, or destroyed than produced or imported in a given year). Furthermore, consumption as calculated in the Vintaging Model is a function of demand not met by disposal recovery. If, in any given year, a significant number of units are disposed, there will be a large amount of additional recovery in that year that can cause an unexpected and not modeled decrease in demand and thus a decrease in consumption. On the other hand, if market, economic, or other factors cause less than expected disposal and recovery, actual supply would decrease, and hence consumption would increase to meet that demand not satisfied by recovered quantities, increasing the GHGRP data and bringing those totals closer to the Vintaging Model estimates.
- The Vintaging Model is used to estimate the emissions that occur in the United States. As such, equipment or products that contain ODS or alternatives, including saturated HFCs, are assumed to consume and emit chemicals equally as like equipment or products originally produced in the United States. Therefore, the GHGRP data may include HFCs produced or imported and used to fill or manufacture products that are then exported from the United States. The Vintaging Model estimates of demand and supply are not meant to incorporate such chemical. Likewise, chemicals may be used outside the United States to create products or charge equipment that is then imported to and used in the United States. The Vintaging Model estimates of demand and supply are meant to capture this chemical, as it will lead to emissions inside the United States. Depending on whether the United States is a net importer or net exporter of such chemical, this factor may account for some of the difference shown above or might lead to a further discrepancy. Reporting under the EPA’s GHGRP Subpart QQ: Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams could be analyzed in the future to investigate this issue further.

One factor, however, would only lead to modeled estimates to be even higher than the estimates shown and hence higher than EPA’s GHGRP data:

- Saturated HFCs are also known to be used as a cover gas in the production of magnesium. The Vintaging Model estimates here do not include the amount of HFCs for this use, but rather only the amount for uses that traditionally were served by ODS. Nonetheless, EPA expects that this supply not included in the Vintaging Model estimates to be very small compared to the ODS substitute use for the years analyzed. An indication of the different magnitudes of these categories is seen in the fact that the 2014 emissions from that non-modeled source (0.1 MMT CO₂ Eq.) are much smaller than those for the ODS substitute sector (161.2 MMT CO₂ Eq).

Using a Tier 2 bottom-up modeling methodology to estimate emissions requires assumptions and expert judgement. Comparing the Vintaging Model's estimates to GHGRP reported estimates, particularly for more widely used chemicals, can help validate the model but it is expected that the model will have limitations. This comparison shows that Vintaging Model consumption estimates are well within the same order of magnitude as the actual consumption data as reported to EPA's GHGRP although the differences in reported net supply and modeled demand are still significant in some of the years. Although it can be difficult to capture the observed market variability, the Vintaging Model is periodically reviewed and updated to ensure that the model reflects the current and future trajectory of ODS and ODS substitutes across all end-uses and the Vintaging Model will continue to be compared to available top-down estimates in order to ensure the model accurately estimates HFC consumption and emissions.

Recalculations Discussion

For the current Inventory, reviews of the large retail food and refrigerated transport end-uses resulted in revisions to the Vintaging Model since the previous Inventory report. In addition, a vending machine end-use was added to the Vintaging Model since the previous Inventory. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014.

For the large retail food end-use, assumptions regarding new installations by system type and refrigerant transitions were revised based on a review of data collected by EPA's GreenChill Partnership and the California Air Resources Board's Refrigerant Management Program. Based on a literature review of technical reports and relevant datasets, the refrigerated transport end-use was updated from an aggregate end-use that covered all the various refrigerated transport modes through average assumptions of charge size, leak rates, stock, and lifetimes to separate end-uses by mode, including road transport, intermodal containers, merchant fishing, reefer ships, and vintage and modern rail. The vending machine end-use was added based on a review of technical reports and sales data. Combined, these assumption changes and additions decreased CO₂-equivalent greenhouse gas emissions on average by 5 percent between 1990 and 2014.

4.24 Electrical Transmission and Distribution (IPCC Source Category 2G1)

The largest use of sulfur hexafluoride (SF₆), both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. Sulfur hexafluoride has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF₆ can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF₆ from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 5.6 MMT CO₂ Eq. (0.2 kt) in 2014. This quantity represents a 78 percent decrease from the estimate for 1990 (see Table 4-100 and Table 4-101). There are two potential causes for this decrease: (1) a sharp increase in the price of SF₆ during the 1990s and (2) a growing awareness of the magnitude and environmental impact of SF₆ emissions through programs such as EPA's voluntary SF₆ Emission Reduction Partnership for Electric Power Systems (Partnership) and EPA's Greenhouse Gas Reporting Program (GHGRP). Utilities participating in the Partnership have lowered their emission factor (kg SF₆ emitted per kg of nameplate capacity) by more than 80 percent since the Partnership began in 1999. Sulfur hexafluoride emissions reported by electric power systems to EPA's GHGRP have also decreased significantly since 2011, with much of the reduction seen from utilities that are not participants in the Partnership. These utilities may be making relatively large reductions in emissions as they take advantage of relatively large and/or inexpensive emission reduction opportunities (i.e., "low hanging fruit,"

such as replacing major leaking circuit breakers) that Partners have already taken advantage of under the voluntary program (Ottinger et al. 2014).

Table 4-100: SF₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (MMT CO₂ Eq.)

| Year | Electric Power Systems | Electrical Equipment Manufacturers | Total |
|------|------------------------|------------------------------------|-------|
| 1990 | 25.1 | 0.3 | 25.4 |
| 2005 | 9.8 | 0.8 | 10.6 |
| 2010 | 6.2 | 0.9 | 7.0 |
| 2011 | 5.7 | 1.1 | 6.8 |
| 2012 | 4.5 | 1.1 | 5.6 |
| 2013 | 4.2 | 1.2 | 5.4 |
| 2014 | 4.6 | 1.0 | 5.6 |

Note: Totals may not sum due to independent rounding.

Table 4-101: SF₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (kt)

| Year | Emissions |
|------|-----------|
| 1990 | 1.1 |
| 2005 | 0.5 |
| 2010 | 0.3 |
| 2011 | 0.3 |
| 2012 | 0.2 |
| 2013 | 0.2 |
| 2014 | 0.2 |

Methodology

The estimates of emissions from Electrical Transmission and Distribution are comprised of emissions from electric power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating both sets of emissions are described below.

1990 through 1998 Emissions from Electric Power Systems

Emissions from electric power systems from 1990 through 1998 were estimated based on (1) the emissions estimated for this source category in 1999, which, as discussed in the next section, were based on the emissions reported during the first year of EPA's SF₆ Emission Reduction Partnership for Electric Power Systems (Partnership), and (2) the RAND survey of global SF₆ emissions. Because most utilities participating in the Partnership reported emissions only for 1999 through 2011, modeling was used to estimate SF₆ emissions from electric power systems for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the RAND survey of global SF₆ sales were used, together with the following equation for estimating emissions, which is derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the 2006 IPCC Guidelines (IPCC 2006).⁵⁹ (Although Equation 7.3 of the 2006 IPCC Guidelines appears in the

⁵⁹ Ideally, sales to utilities in the United States between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF₆ during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

discussion of substitutes for ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is periodically serviced during its lifetime.)

$$\text{Emissions (kilograms SF}_6\text{)} = \text{SF}_6 \text{ purchased to refill existing equipment (kilograms)} + \text{nameplate capacity of retiring equipment (kilograms)}^{60}$$

Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF₆ purchased by utilities for this purpose.

Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND (2004) survey. To estimate the quantity of SF₆ released or recovered from retiring equipment, the nameplate capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased by electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC default SF₆ emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield estimates of global SF₆ emissions from 1990 through 1999.

U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the estimated global emissions from 1999. The result was a time series of factors that express each year's global emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor for each respective year by the estimated U.S. emissions of SF₆ from electric power systems in 1999 (estimated to be 14.3 MMT CO₂ Eq.).

Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is utilities' inventories of SF₆ in storage containers. When SF₆ prices rise, utilities are likely to deplete internal inventories before purchasing new SF₆ at the higher price, in which case SF₆ sales will fall more quickly than emissions. On the other hand, when SF₆ prices fall, utilities are likely to purchase more SF₆ to rebuild inventories, in which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing to utility SF₆ sales data. The other factor that may affect the relationship between the RAND sales trends and actual global emissions is the level of imports from and exports to Russia and China. Sulfur hexafluoride production in these countries is not included in the RAND survey and is not accounted for in any other manner by RAND. However, atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was real (see the Uncertainty and Time-Series Consistency section below).

1999 through 2014 Emissions from Electric Power Systems

Emissions from electric power systems from 1999 to 2014 were estimated based on: (1) reporting from utilities participating in EPA's SF₆ Emission Reduction Partnership for Electric Power Systems (Partners), which began in 1999; (2) reporting from utilities covered by the EPA's GHGRP, which began in 2012 for emissions occurring in 2011 (GHGRP-Only Reporters); and (3) the relationship between utilities' reported emissions and their transmission miles as reported in the 2001, 2004, 2007, 2010, and 2013 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors (UDI 2001, 2004, 2007, 2010, 2013), which was applied to the electric power systems that do not report to EPA (Non-Reporters). (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV).

Partners

Over the period from 1999 to 2014, Partner utilities, which for inventory purposes are defined as utilities that either currently are or previously have been part of the Partnership, represented between 43 percent and 48 percent of total U.S. transmission miles. Partner utilities estimated their emissions using a Tier 3 utility-level mass balance approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated between years for which data were available or extrapolated based on Partner-specific transmission mile growth

⁶⁰ Nameplate capacity is defined as the amount of SF₆ within fully charged electrical equipment.

rates. In 2012, many Partners began reporting their emissions (for 2011 and later years) through EPA's GHGRP (discussed further below) rather than through the Partnership. In 2014, approximately 0.2 percent of the total emissions attributed to Partner utilities were reported through Partnership reports. Approximately 92 percent of the total emissions attributed to Partner utilities were reported and verified through EPA's GHGRP. Partners without verified 2014 data accounted for approximately 8 percent of the total emissions attributed to Partner utilities.⁶¹

GHGRP-Only Reporters

EPA's GHGRP requires users of SF₆ in electric power systems to report emissions if the facility has a total SF₆ nameplate capacity that exceeds 17,820 pounds. (This quantity is the nameplate capacity that would result in annual SF₆ emissions of approximately 25,000 metric tons of CO₂ equivalent at the historical emission rate reported under the Partnership.) As under the Partnership, electric power systems that report their SF₆ emissions under EPA's GHGRP are required to use the Tier 3 utility-level mass-balance approach. Many Partners began reporting their emissions through EPA's GHGRP in 2012 (reporting emissions for 2011 and later years) because their nameplate capacity exceeded the reporting threshold. Partners who did not report through EPA's GHGRP continued to report through the Partnership.

In addition, many non-Partners began reporting to EPA for the first time through its GHGRP in 2012. Non-Partner emissions reported and verified under EPA's GHGRP were compiled to form a new category of reported data (GHGRP-Only Reporters). GHGRP-Only Reporters accounted for 24 percent of U.S. transmission miles and 26 percent of estimated U.S. emissions from electric power system in 2014.⁶²

Non-Reporters

Emissions from Non-Reporters (i.e., utilities other than Partners and GHGRP-Only Reporters) in every year since 1999 were estimated using the results of a regression analysis that correlated emissions from reporting utilities (using verified data from both Partners and GHGRP-Only Reporters) with their transmission miles.⁶³ Two equations were developed, one for "non-large" and one for "large" utilities (i.e., with fewer or greater than 10,000 transmission miles, respectively). The distinction between utility sizes was made because the regression analysis showed that the relationship between emissions and transmission miles differed for non-large and large transmission networks. As noted above, non-Partner emissions were reported to EPA for the first time through its GHGRP in 2012 (representing 2011 emissions). This set of reported data was of particular interest because it provided insight into the emission rate of non-Partners, which previously was assumed to be equal to the historical (1999) emission rate of Partners for both large and non-large utilities. The availability of non-Partner emissions estimates allowed the regression analysis to be modified for both large and non-large groups. Specifically, emissions were estimated for Non-Reporters as follows:

⁶¹ It should be noted that data reported through EPA's GHGRP must go through a verification process; only data verified as of September 1, 2015 could be used in the emission estimates for 2014. For Partners whose GHGRP data was not yet verified, emissions were extrapolated based upon historical Partner-specific transmission mile growth rates, and those Partners are included in the 'non-reporting Partners' category.

For electric power systems, verification involved a series of electronic range, completeness, and algorithm checks for each report submitted. In addition, EPA manually reviewed the reported data and compared each facility's reported transmission miles with the corresponding quantity in the UDI 2013 database (UDI 2013). In the first year of GHGRP reporting, EPA followed up with reporters where the discrepancy between the reported miles and the miles published by UDI was greater than 10 percent, with a goal to improve data quality. Only GHGRP data verified as of September 1, 2015 was included in the emission estimates for 2011, 2012, 2013, and 2014.

⁶² Also, GHGRP-reported emissions from 17 facilities that had one or fewer transmission miles were included in the emission estimates for 2011. Emissions from these facilities comprise approximately 1.2 percent of total reported and verified emissions. In 2012, 16 facilities had one or fewer transmission miles, comprising 1.4 percent of verified emissions and in 2013, 16 facilities had one or fewer transmission miles, comprising 3.2 percent of verified emissions. In 2014, there were 12 such facilities that comprised 0.5 percent of verified emissions. These facilities were not included in the development of the regression equations (discussed further below). EPA is continuing to investigate whether or not these emissions are already implicitly accounted for in the relationship between transmission miles and emissions, and whether to update the regression analysis to better capture emissions from non-reporters that may have zero transmission miles.

⁶³ In the United States, SF₆ is contained primarily in transmission equipment rated above 34.5 kV.

- **Non-Reporters, 1999 to 2011:** First, the 2011 emission rates (per kg nameplate capacity and per transmission mile) reported by Partners and GHGRP-Only Reporters were reviewed to determine whether there was a statistically significant difference between these two groups. Transmission mileage data for 2011 was reported through GHGRP, with the exception of transmission mileage data for Partners that did not report through GHGRP, which was obtained from UDI. It was determined that there is no statistically significant difference between the emission rates of Partners and GHGRP-Only reporters; therefore, Partner and GHGRP-Only reported data for 2011 were combined to develop regression equations to estimate the emissions of Non-Reporters for both “non-large” and “large” utilities. Historical emissions from Non-Reporters for both “non-large” and “large” utilities were estimated by linearly interpolating between the 1999 regression coefficients (based on 1999 Partner data) and the 2011 regression coefficients.
- **Non-Reporters, 2012 to Present:** It was determined that there continued to be no statistically significant difference between the emission rates reported by Partners and by GHGRP-Only Reporters. Therefore, the emissions data from both groups were combined to develop regression equations for 2012. This was repeated for 2013 and 2014 using Partner and GHGRP-Only Reporter data for 2013 and 2014.
 - **“Non-large” utilities (less than 10,000 transmission miles):** The 2014 regression equation for “non-large” utilities was developed based on the emissions reported by a subset of 88 Partner utilities and GHGRP-Only utilities (representing approximately 51 percent of total U.S. transmission miles for utilities with fewer than 10,000 transmission miles). The regression equation for 2014 is:

$$\text{Emissions (kg)} = 0.26 \times \text{Transmission Miles}$$

- **“Large” utilities (more than 10,000 transmission miles):** The 2014 regression equation was developed based on the emissions reported by a subset of 21 Partners and GHGRP-only utilities (representing approximately 86 percent of total U.S. transmission miles for utilities with greater than 10,000 transmission miles). The regression equation for 2014 is:

$$\text{Emissions (kg)} = 0.22 \times \text{Transmission Miles}$$

Table 4-102 below shows the percentage of transmission miles covered by reporters (i.e., associated with reported data) and the regression coefficient for both large and non-large reporters for 1999 (the first year data was reported), and for 2011 through 2014 (the first three years with GHGRP reported data). The coefficient for non-large utilities increased between 2013 and 2014 and the coefficient for and large utilities decreased slightly between 2013 and 2014.

Table 4-102: Transmission Mile Coverage and Regression Coefficients for Large and Non-Large Utilities

| | Non-large | | | | | Large | | | | |
|---|-----------|------|------|------|------|-------|------|------|------|------|
| | 1999 | 2011 | 2012 | 2013 | 2014 | 1999 | 2011 | 2012 | 2013 | 2014 |
| Percentage of Miles Covered by Reporters | 31 | 45 | 44 | 47 | 51 | 86 | 97 | 88 | 83 | 86 |
| Regression Coefficient^a | 0.89 | 0.33 | 0.23 | 0.22 | 0.26 | 0.58 | 0.26 | 0.22 | 0.22 | 0.22 |

^a Regression coefficient is defined as emissions (in kg) divided by transmission miles.

Note: “Non-large” represents reporters with fewer than 10,000 transmission miles.

Data on transmission miles for each Non-Reporter for the years 2000, 2003, 2006, and 2009, and 2012 were obtained from the 2001, 2004, 2007, 2010, and 2013 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010, 2013). The U.S. transmission system grew by over 25,000 miles between 2000 and 2003 yet declined by almost 4,000 miles between 2003 and 2006. Given these fluctuations, periodic increases are assumed to occur gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.2 percent between 2000 and 2003 and decrease by 0.20 percent between 2003 and 2006. This growth rate grew to 3 percent from 2006 to 2009 as transmission miles increased by more than 59,000 miles. The annual growth rate for 2009 through 2012 was calculated to be 2.0 percent as transmission miles grew by approximately 43,000 during this time period.

Total Industry Emissions

As a final step, total electric power system emissions from 1999 through 2014 were determined for each year by summing the Partner reported and estimated emissions (reported data was available through the EPA's SF₆ Emission Reduction Partnership for Electric Power Systems), the GHGRP-Only reported emissions, and the non-reporting utilities' emissions (determined using the regression equations).

1990 through 2014 Emissions from Manufacture of Electrical Equipment

The 1990 to 2013 emission estimates for original equipment manufacturers (OEMs) were derived by assuming that manufacturing emissions equal 10 percent of the quantity of SF₆ provided with new equipment. The quantity of SF₆ provided with new equipment was estimated based on statistics compiled by the National Electrical Manufacturers Association (NEMA). These statistics were provided for 1990 to 2000; the quantities of SF₆ provided with new equipment for 2001 to 2014 were estimated using Partner reported data and the total industry SF₆ nameplate capacity estimate (196.4 MMT CO₂ Eq. in 2013). Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for which new nameplate capacity data was available from 1999 to 2014 was calculated. These ratios were then multiplied by the total industry nameplate capacity estimate for each year to derive the amount of SF₆ provided with new equipment for the entire industry. The 10 percent emission rate is the average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002).

Uncertainty and Time-Series Consistency

To estimate the uncertainty associated with emissions of SF₆ from Electrical Transmission and Distribution, uncertainties associated with four quantities were estimated: (1) emissions from Partners, (2) emissions from GHGRP-Only Reporters, (3) emissions from Non-Reporters, and (4) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF₆ Emission Reduction Partnership include emissions from both reporting (through the Partnership or GHGRP) and non-reporting Partners. For reporting Partners, individual Partner-reported SF₆ data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner-reported data was estimated to be 4.7 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

For GHGRP-Only Reporters, reported SF₆ data was assumed to have an uncertainty of 20 percent.⁶⁴ Based on a Monte Carlo analysis, the cumulative uncertainty of all GHGRP-Only reported data was estimated to be 6.1 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2013 from Non-Reporters: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for Non-Reporters. Uncertainties were also estimated regarding (1) the quantity of SF₆ supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF₆ nameplate capacity estimates, and (2) the manufacturers' SF₆ emissions rate.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-103. Electrical Transmission and Distribution SF₆ emissions were estimated to be between 4.6 and 6.9 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 23 percent above the emission estimate of 5.6 MMT CO₂ Eq.

⁶⁴ Uncertainty is assumed to be higher for the GHGRP-only category, because 2011 is the first year that those utilities have reported to EPA.

Table 4-103: Approach 2 Quantitative Uncertainty Estimates for SF₆ Emissions from Electrical Transmission and Distribution (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to 2014 Emission Estimate ^a | | | |
|--|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Electrical Transmission and Distribution | SF ₆ | 5.6 | 4.6 | 6.9 | -17% | +23% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

In addition to the uncertainty quantified above, there is uncertainty associated with using global SF₆ sales data to estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of SF₆ appears to reflect the trend in global emissions implied by changing SF₆ concentrations in the atmosphere. That is, emissions based on global sales declined by 29 percent between 1995 and 1998 (RAND 2004), and emissions based on atmospheric measurements declined by 17 percent over the same period (Levin et al. 2010).

Several pieces of evidence indicate that U.S. SF₆ emissions were reduced as global emissions were reduced. First, the decreases in sales and emissions coincided with a sharp increase in the price of SF₆ that occurred in the mid-1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major manufacturer of SF₆ recycling equipment, stated that most U.S. utilities began recycling rather than venting SF₆ within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported its emissions for all the years from 1990 through 1999 under the Partnership showed a downward trend beginning in the mid-1990s.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

The historical emissions estimated for this source category have undergone some minor revisions. SF₆ emission estimates for the period 1990 through 2013 were updated relative to the previous report based on revisions to interpolated and extrapolated non-reported Partner data.⁶⁵ The regression coefficients to estimate emissions from non-reporting utilities were adjusted between the years 2011 and 2013 after correcting a spreadsheet error, and as a result, there were minor changes to the emissions from non-reporting utilities. Additionally, correction of a different spreadsheet error led to updated leak rates and OEM growth rates, which are used to calculate OEM emissions. These leak rates are used to estimate the nameplate capacity of non-reporters during these years, and are interpolated back through 1999 to calculate Non-Reporter nameplate capacity over the entire time series.⁶⁶

As a result of the recalculations, SF₆ emissions from electrical transmission and distribution increased by 6 percent for 2013 relative to the previous report. On average, the change in SF₆ emission estimates for the entire time series is approximately 0.1 percent per year.

Planned Improvements

EPA is exploring the use of OEM data that is reported under EPA's GHGRP to use for future Inventory reports instead of estimating those emissions based on elements reported by utilities to the GHGRP and Partner data.

⁶⁵ The earlier year estimates within the time series (i.e., 1990-1998) were updated based on revisions to the 1999 U.S. emission estimate because emissions for 1990-1998 are estimated by multiplying a series of annual factors by the estimated U.S. emissions of SF₆ from electric power systems in 1999 (see Methodology section).

⁶⁶ Nameplate capacity estimates affect sector emissions because OEM emission estimation is calculated using total industry nameplate capacity.

Specifically, using the GHGRP-reported OEM emissions and the estimated nameplate capacity increase estimated for users of electrical equipment (available in the existing methodology), a leak rate would be calculated. This approach would require estimating the portion of industry not reporting to EPA’s GHGRP program, which would require market research. Once a new leak rate is established, leak rates could be interpolated for years between 2000 (at 10 percent) and 2011. In implementing improvements and integration of data from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁶⁷

4.25 Nitrous Oxide from Product Uses (IPCC Source Category 2G3)

Nitrous oxide (N₂O) is a clear, colorless, oxidizing liquefied gas, with a slightly sweet odor which is used in a wide variety of specialized product uses and applications. The amount of N₂O that is actually emitted depends upon the specific product use or application.

There are a total of three N₂O production facilities currently operating in the United States (Ottinger 2014). Nitrous oxide is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia, and as an anesthetic in various dental and veterinary applications. The second main use of N₂O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. Small quantities of N₂O also are used in the following applications:

- Oxidizing agent and etchant used in semiconductor manufacturing;
- Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- Production of sodium azide, which is used to inflate airbags;
- Fuel oxidant in auto racing; and
- Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

Production of N₂O in 2014 was approximately 15 kt (see Table 4-104).

Table 4-104: N₂O Production (kt)

| Year | kt |
|------|----|
| 1990 | 16 |
| 2005 | 15 |
| 2010 | 15 |
| 2011 | 15 |
| 2012 | 15 |
| 2013 | 15 |
| 2014 | 15 |

Nitrous oxide emissions were 4.2 MMT CO₂ Eq. (14 kt N₂O) in 2014 (see Table 4-105). Production of N₂O stabilized during the 1990s because medical markets had found other substitutes for anesthetics, and more medical procedures were being performed on an outpatient basis using local anesthetics that do not require N₂O. The use of N₂O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products packaged in reusable plastic tubs (Heydorn 1997).

⁶⁷ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Table 4-105: N₂O Emissions from N₂O Product Usage (MMT CO₂ Eq. and kt)

| Year | MMT CO ₂ Eq. | kt |
|------|-------------------------|----|
| 1990 | 4.2 | 14 |
| 2005 | 4.2 | 14 |
| 2010 | 4.2 | 14 |
| 2011 | 4.2 | 14 |
| 2012 | 4.2 | 14 |
| 2013 | 4.2 | 14 |
| 2014 | 4.2 | 14 |

Methodology

Emissions from N₂O product uses were estimated using the following equation:

$$E_{pu} = \sum_a (P \times S_a \times ER_a)$$

where,

| | | |
|----------|---|---|
| E_{pu} | = | N ₂ O emissions from product uses, metric tons |
| P | = | Total U.S. production of N ₂ O, metric tons |
| a | = | specific application |
| S_a | = | Share of N ₂ O usage by application a |
| ER_a | = | Emission rate for application a , percent |

The share of total quantity of N₂O usage by end-use represents the share of national N₂O produced that is used by the specific subcategory (e.g., anesthesia, food processing). In 2014, the medical/dental industry used an estimated 86.5 percent of total N₂O produced, followed by food processing propellants at 6.5 percent. All other categories combined used the remainder of the N₂O produced. This subcategory breakdown has changed only slightly over the past decade. For instance, the small share of N₂O usage in the production of sodium azide has declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out in this market subcategory, most of the N₂O usage for sodium azide production is assumed to have ceased after 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption subcategory (Heydorn 1997). The N₂O was allocated across the following categories: medical applications, food processing propellant, and sodium azide production (pre-1996). A usage emissions rate was then applied for each sector to estimate the amount of N₂O emitted.

Only the medical/dental and food propellant subcategories were estimated to release emissions into the atmosphere, and therefore these subcategories were the only usage subcategories with emission rates. For the medical/dental subcategory, due to the poor solubility of N₂O in blood and other tissues, none of the N₂O is assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an emission factor of 100 percent was used for this subcategory (IPCC 2006). For N₂O used as a propellant in pressurized and aerosol food products, none of the N₂O is reacted during the process and all of the N₂O is emitted to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the remaining subcategories, all of the N₂O is consumed/reacted during the process, and therefore the emission rate was considered to be zero percent (Tupman 2002).

The 1990 through 1992 N₂O production data were obtained from SRI Consulting's *Nitrous Oxide, North America* report (Heydorn 1997). Nitrous oxide production data for 1993 through 1995 were not available. Production data for 1996 was specified as a range in two data sources (Heydorn 1997; Tupman 2002). In particular, for 1996, Heydorn (1997) estimates N₂O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by Heydorn (1997). Tupman (2003) data are considered more industry-specific and current. Therefore, the midpoint of the narrower production range was used to estimate N₂O emissions for years 1993 through 2001

(Tupman 2003). The 2002 and 2003 N₂O production data were obtained from the Compressed Gas Association Nitrous Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For example, in 2003, CGA (2003) estimates N₂O production to range between 13.6 and 15.9 thousand metric tons. Due to the unavailability of data, production estimates for years 2004 through 2014 were held constant at the 2003 value.

The 1996 share of the total quantity of N₂O used by each subcategory was obtained from SRI Consulting’s *Nitrous Oxide, North America* report (Heydorn 1997). The 1990 through 1995 share of total quantity of N₂O used by each subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001 share of total quantity of N₂O usage by sector was obtained from communication with a N₂O industry expert (Tupman 2002). The 2002 and 2003 share of total quantity of N₂O usage by sector was obtained from CGA (2002, 2003). Due to the unavailability of data, the share of total quantity of N₂O usage data for years 2004 through 2014 was assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained from SRI Consulting’s *Nitrous Oxide, North America* report (Heydorn 1997), and confirmed by a N₂O industry expert (Tupman 2002). The emissions rate for all other subcategories was obtained from communication with a N₂O industry expert (Tupman 2002). The emissions rate for the medical/dental subcategory was obtained from the *2006 IPCC Guidelines*.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2014 N₂O emission estimate from N₂O product usage was calculated using the *2006 IPCC Guidelines* (2006) Approach 2 methodology. Uncertainty associated with the parameters used to estimate N₂O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-106. Nitrous oxide emissions from N₂O product usage were estimated to be between 3.2 and 5.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 24 percent below to 24 percent above the emission estimate of 4.2 MMT CO₂ Eq.

Table 4-106: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from N₂O Product Usage (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|------------------------------------|------------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| N ₂ O from Product Uses | N ₂ O | 4.2 | 3.2 | 5.2 | -24% | +24% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure consistency in emissions from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Pending resources, planned improvements include a continued evaluation of alternative production statistics for cross verification, a reassessment of N₂O product use subcategories to accurately represent trends, investigation of production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N₂O. Additionally, planned improvements include considering imports and exports of N₂O for product uses. Finally, for future Inventories EPA will examine data from EPA’s Greenhouse Gas Reporting Program (GHGRP) to improve the emission estimates for the N₂O product use subcategory. Particular attention will be made to ensure aggregated information can be published without disclosing confidential business information and time series consistency, as the facility-level reporting data from EPA’s GHGRP are not available for all inventory years as required in this Inventory.

4.26 Industrial Processes and Product Use Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, many industrial processes can result in emissions of various ozone precursors (i.e., indirect greenhouse gases). As some of industrial applications also employ thermal incineration as a control technology, combustion byproducts, such as carbon monoxide (CO) and nitrogen oxides (NO_x), are also reported with this source category. Non-CH₄ volatile organic compounds (NMVOCs), commonly referred to as “hydrocarbons,” are the primary gases emitted from most processes employing organic or petroleum based products, and can also result from the product storage and handling. Accidental releases of greenhouse gases associated with product use and handling can constitute major emissions in this category. In the United States, emissions from product use are primarily the result of solvent evaporation, whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The major categories of product uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (e.g., electronics), dry cleaning, and non-industrial uses (e.g., uses of paint thinner). Product usage in the United States also results in the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included under Substitution of Ozone Depleting Substances in this chapter.

Total emissions of NO_x, CO, and NMVOCs from non-energy industrial processes and product use from 1990 to 2014 are reported in Table 4-107.

Table 4-107: NO_x, CO, and NMVOC Emissions from Industrial Processes and Product Use (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| NO_x | 592 | 572 | 472 | 452 | 452 | 452 | 452 |
| Industrial Processes | | | | | | | |
| Other Industrial Processes | 343 | 437 | 339 | 320 | 320 | 320 | 320 |
| Metals Processing | 88 | 60 | 67 | 64 | 64 | 64 | 64 |
| Chemical and Allied Product | | | | | | | |
| Manufacturing | 152 | 55 | 48 | 47 | 47 | 47 | 47 |
| Storage and Transport | 3 | 15 | 15 | 18 | 18 | 18 | 18 |
| Miscellaneous ^a | 5 | 2 | 2 | 3 | 3 | 3 | 3 |
| Product Use | | | | | | | |
| Surface Coating | 1 | 3 | 2 | 1 | 1 | 1 | 1 |
| Graphic Arts | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Degreasing | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Dry Cleaning | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Industrial Processes ^b | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Industrial Processes ^c | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | NA | 0 | 0 | 0 | 0 | 0 | 0 |
| CO | 4,129 | 1,557 | 1,280 | 1,229 | 1,229 | 1,229 | 1,229 |
| Industrial Processes | | | | | | | |
| Metals Processing | 2,395 | 752 | 717 | 695 | 695 | 695 | 695 |
| Other Industrial Processes | 487 | 484 | 333 | 306 | 306 | 306 | 306 |
| Chemical and Allied Product | | | | | | | |
| Manufacturing | 1,073 | 189 | 157 | 152 | 152 | 152 | 152 |
| Miscellaneous ^a | 101 | 32 | 48 | 51 | 51 | 51 | 51 |
| Storage and Transport | 69 | 97 | 22 | 25 | 25 | 25 | 24 |
| Product Use | | | | | | | |
| Surface Coating | + | 2 | 3 | 2 | 2 | 2 | 2 |
| Other Industrial Processes ^b | 4 | 0 | 0 | 0 | 0 | 0 | 0 |
| Dry Cleaning | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Degreasing | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Graphic Arts | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Industrial Processes ^c | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | NA | 0 | 0 | 0 | 0 | 0 | 0 |

| NMVOCs | 7,638 | 5,849 | 4,133 | 3,929 | 3,929 | 3,929 | 3,928 |
|---|-------|-------|-------|-------|-------|-------|-------|
| Industrial Processes | | | | | | | |
| Storage and Transport | 1,352 | 1,308 | 992 | 947 | 947 | 947 | 946 |
| Other Industrial Processes | 364 | 414 | 308 | 298 | 298 | 298 | 298 |
| Chemical and Allied Product | | | | | | | |
| Manufacturing | 575 | 213 | 77 | 76 | 76 | 76 | 75 |
| Metals Processing | 111 | 45 | 32 | 31 | 31 | 31 | 31 |
| Miscellaneous ^a | 20 | 17 | 26 | 27 | 27 | 27 | 27 |
| Product Use | | | | | | | |
| Surface Coating | 2,289 | 1,578 | 1,105 | 1,045 | 1,045 | 1,045 | 1,045 |
| Non-Industrial Processes ^c | 1,724 | 1,446 | 1,013 | 957 | 957 | 957 | 957 |
| Degreasing | 675 | 280 | 196 | 186 | 186 | 186 | 186 |
| Dry Cleaning | 195 | 230 | 161 | 152 | 152 | 152 | 152 |
| Graphic Arts | 249 | 194 | 136 | 128 | 128 | 128 | 128 |
| Other Industrial Processes ^b | 85 | 88 | 61 | 58 | 58 | 58 | 58 |
| Other | + | 36 | 25 | 24 | 24 | 24 | 24 |

+ Does not exceed 0.5 kt

NA (Not Available)

^a Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.

^b Includes rubber and plastics manufacturing, and other miscellaneous applications.

^c Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Data were collected for emissions of CO, NO_x, volatile organic compounds (VOCs), and sulfur dioxide (SO₂) from metals processing, chemical manufacturing, other industrial processes, transport and storage, and miscellaneous sources. Emission estimates for 2013 for non-electric generating unit (EGU) and non-mobile sources are held constant from 2011 in EPA (2015). Emissions were calculated either for individual source categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed or the amount of solvent purchased) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Emissions for product use were calculated by aggregating product use data based on information relating to product uses from different applications such as degreasing, graphic arts, etc. Emission factors for each consumption category were then applied to the data to estimate emissions. For example, emissions from surface coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate product-specific emission factors to the amount of products used for surface coatings, an estimate of NMVOC emissions was obtained. Emissions of CO and NO_x under product use result primarily from thermal and catalytic incineration of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's *Compilation of Air Pollutant Emission Factors*, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

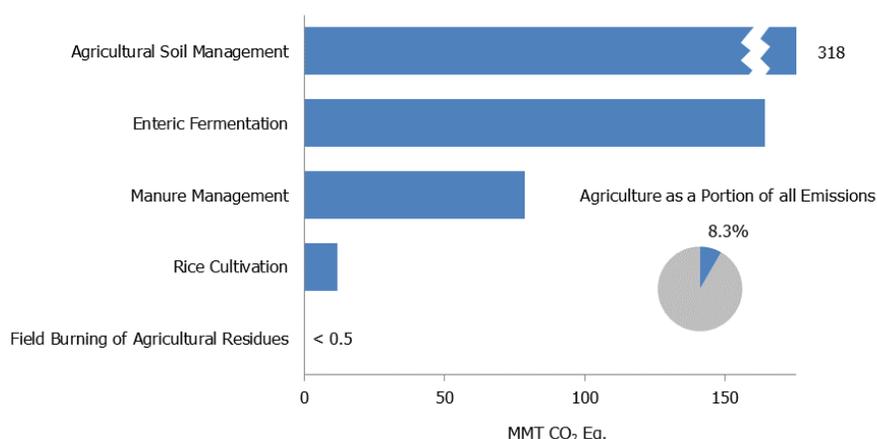
Uncertainties in these estimates are partly due to the accuracy of the emission factors and activity data used. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

5. Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes. This chapter provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues (see Figure 5-1). Carbon dioxide (CO₂) emissions and removals from agriculture-related land-use activities, such as liming and conversion of grassland to cultivated land, are presented in the Land Use, Land-Use Change, and Forestry chapter. Carbon dioxide emissions from on-farm energy use are accounted for in the Energy chapter.

Figure 5-1: 2014 Agriculture Chapter Greenhouse Gas Emission Sources (MMT CO₂ Eq.)



In 2014, the Agriculture sector was responsible for emissions of 573.6 MMT CO₂ Eq.,¹ or 8.3 percent of total U.S. greenhouse gas emissions. Methane (CH₄) and nitrous oxide (N₂O) were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represent 22.5 percent and 8.4 percent of total CH₄ emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH₄. Rice cultivation and field burning of agricultural residues were minor sources of CH₄. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N₂O emissions, accounting for 78.9 percent. Manure management and field burning of agricultural residues were also small sources of N₂O emissions.

¹ Following the revised reporting requirements under the United Nations Framework Convention on Climate Change (UNFCCC), this Inventory report presents CO₂ equivalent values based on the *IPCC Fourth Assessment Report (AR4)* GWP values. See the Introduction chapter for more information.

Table 5-1 and Table 5-2 present emission estimates for the Agriculture sector. Between 1990 and 2014, CH₄ emissions from agricultural activities increased by 10.7 percent, while N₂O emissions fluctuated from year to year, but overall increased by 5.9 percent.

Table 5-1: Emissions from Agriculture (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 214.7 | 238.4 | 244.4 | 242.5 | 242.6 | 239.0 | 237.7 |
| Enteric Fermentation | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |
| Manure Management | 37.2 | 56.3 | 60.9 | 61.5 | 63.7 | 61.4 | 61.2 |
| Rice Cultivation | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |
| Field Burning of Agricultural Residues | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| N₂O | 317.4 | 313.8 | 338.0 | 340.6 | 340.7 | 336.2 | 336.0 |
| Agricultural Soil Management | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |
| Manure Management | 14.0 | 16.5 | 17.2 | 17.4 | 17.5 | 17.5 | 17.5 |
| Field Burning of Agricultural Residues | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total | 532.0 | 552.2 | 582.3 | 583.1 | 583.3 | 575.3 | 573.6 |

Note: Totals may not sum due to independent rounding.

Table 5-2: Emissions from Agriculture (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 8,587 | 9,537 | 9,776 | 9,702 | 9,705 | 9,562 | 9,506 |
| Enteric Fermentation | 6,566 | 6,755 | 6,853 | 6,757 | 6,670 | 6,619 | 6,572 |
| Manure Management | 1,486 | 2,254 | 2,437 | 2,460 | 2,548 | 2,455 | 2,447 |
| Rice Cultivation | 525 | 521 | 474 | 474 | 476 | 477 | 476 |
| Field Burning of Agricultural Residues | 10 | 8 | 11 | 11 | 11 | 11 | 11 |
| N₂O | 1,065 | 1,053 | 1,134 | 1,143 | 1,143 | 1,128 | 1,127 |
| Agricultural Soil Management | 1,018 | 997 | 1,076 | 1,084 | 1,084 | 1,069 | 1,068 |
| Manure Management | 47 | 55 | 58 | 58 | 59 | 59 | 59 |
| Field Burning of Agricultural Residues | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

Note: Totals may not sum due to independent rounding.

5.1 Enteric Fermentation (IPCC Source Category 3A)

Methane is produced as part of normal digestive processes in animals. During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH₄ as a byproduct, which can be exhaled or eructated by the animal. The amount of CH₄ produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes.

Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH₄ because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which microbial fermentation breaks down the feed they consume into products that can be absorbed and metabolized. The microbial fermentation that occurs in the rumen enables them to digest coarse plant material that non-ruminant animals cannot. Ruminant animals, consequently, have the highest CH₄ emissions per unit of body mass among all animal types.

Non-ruminant animals (e.g., swine, horses, and mules and asses) also produce CH₄ emissions through enteric fermentation, although this microbial fermentation occurs in the large intestine. These non-ruminants emit

significantly less CH₄ on a per-animal-mass basis than ruminants because the capacity of the large intestine to produce CH₄ is lower.

In addition to the type of digestive system, an animal's feed quality and feed intake also affect CH₄ emissions. In general, lower feed quality and/or higher feed intake leads to higher CH₄ emissions. Feed intake is positively correlated to animal size, growth rate, level of activity and production (e.g., milk production, wool growth, pregnancy, or work). Therefore, feed intake varies among animal types as well as among different management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

Methane emission estimates from enteric fermentation are provided in Table 5-3 and Table 5-4. Total livestock CH₄ emissions in 2014 were 164.3 MMT CO₂ Eq. (6,572 kt). Beef cattle remain the largest contributor of CH₄ emissions from enteric fermentation, accounting for 71 percent in 2014. Emissions from dairy cattle in 2014 accounted for 26 percent, and the remaining emissions were from horses, sheep, swine, goats, American bison, mules and asses.

From 1990 to 2014, emissions from enteric fermentation have increased by 0.1 percent. While emissions generally follow trends in cattle populations, over the long term there are exceptions as population decreases have been coupled with production increases or minor decreases. For example, beef cattle emissions decreased 2.0 percent from 1990 to 2014, while beef cattle populations actually declined by 7 percent and beef production increased (USDA 2015), and while dairy emissions increased 6.5 percent over the entire time series, the population has declined by 5 percent and milk production increased 40 percent (USDA 2015). This trend indicates that while emission factors per head are increasing, emission factors per unit of product are going down. Generally, from 1990 to 1995 emissions from beef increased and then decreased from 1996 to 2004. These trends were mainly due to fluctuations in beef cattle populations and increased digestibility of feed for feedlot cattle. Beef cattle emissions generally increased from 2004 to 2007, as beef populations underwent increases and an extensive literature review indicated a trend toward a decrease in feed digestibility for those years. Beef cattle emissions decreased again from 2008 to 2014 as populations again decreased. Emissions from dairy cattle generally trended downward from 1990 to 2004, along with an overall dairy population decline during the same period. Similar to beef cattle, dairy cattle emissions rose from 2004 to 2007 due to population increases and a decrease in feed digestibility (based on an analysis of more than 350 dairy cow diets). Dairy cattle emissions have continued to trend upward since 2007, in line with dairy population increases. Regarding trends in other animals populations of sheep have steadily declined, with an overall decrease of 54 percent since 1990. Horse populations are 56 percent greater than they were in 1990, but their numbers have been declining by about 2 percent annually since 2007. Goat populations increased by about 20 percent through 2007 but have since dropped below 1990 numbers, while swine populations have increased 19 percent since 1990. The population of American bison more than tripled over the 1990 through 2014 time period, while mules and asses have more than quadrupled.

Table 5-3: CH₄ Emissions from Enteric Fermentation (MMT CO₂ Eq.)

| Livestock Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Beef Cattle | 119.1 | 125.2 | 124.6 | 121.8 | 119.1 | 118.0 | 116.7 |
| Dairy Cattle | 39.4 | 37.6 | 40.7 | 41.1 | 41.7 | 41.6 | 41.9 |
| Swine | 2.0 | 2.3 | 2.4 | 2.5 | 2.5 | 2.5 | 2.4 |
| Horses | 1.0 | 1.7 | 1.7 | 1.7 | 1.6 | 1.6 | 1.6 |
| Sheep | 2.3 | 1.2 | 1.1 | 1.1 | 1.1 | 1.1 | 1.0 |
| Goats | 0.3 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 |
| American Bison | 0.1 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 |
| Mules and Asses | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total | 164.2 | 168.9 | 171.3 | 168.9 | 166.7 | 165.5 | 164.3 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 5-4: CH₄ Emissions from Enteric Fermentation (kt)

| Livestock Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------|-------|-------|-------|-------|-------|-------|-------|
| Beef Cattle | 4,763 | 5,007 | 4,984 | 4,873 | 4,763 | 4,722 | 4,667 |
| Dairy Cattle | 1,574 | 1,503 | 1,627 | 1,645 | 1,670 | 1,664 | 1,677 |
| Swine | 81 | 92 | 97 | 98 | 100 | 98 | 96 |
| Horses | 40 | 70 | 68 | 67 | 65 | 64 | 62 |

| | | | | | | | |
|-----------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Sheep | 91 | 49 | 45 | 44 | 43 | 43 | 42 |
| Goats | 13 | 14 | 14 | 14 | 13 | 13 | 12 |
| American Bison | 4 | 17 | 15 | 14 | 13 | 13 | 12 |
| Mules and Asses | 1 | 2 | 3 | 3 | 3 | 3 | 3 |
| Total | 6,566 | 6,755 | 6,853 | 6,757 | 6,670 | 6,619 | 6,572 |

Note: Totals may not sum due to independent rounding.

Methodology

Livestock enteric fermentation emission estimate methodologies fall into two categories: cattle and other domesticated animals. Cattle, due to their large population, large size, and particular digestive characteristics, account for the majority of enteric fermentation CH₄ emissions from livestock in the United States. A more detailed methodology (i.e., Intergovernmental Panel on Climate Change [IPCC] Tier 2) was therefore applied to estimate emissions for all cattle. Emission estimates for other domesticated animals (horses, sheep, swine, goats, American bison, and mules and asses) were handled using a less detailed approach (i.e., IPCC Tier 1).

While the large diversity of animal management practices cannot be precisely characterized and evaluated, significant scientific literature exists that provides the necessary data to estimate cattle emissions using the IPCC Tier 2 approach. The Cattle Enteric Fermentation Model (CEFM), developed by the U.S. Environmental Protection Agency (EPA) and used to estimate cattle CH₄ emissions from enteric fermentation, incorporates this information and other analyses of livestock population, feeding practices, and production characteristics.

National cattle population statistics were disaggregated into the following cattle sub-populations:

- Dairy Cattle
 - Calves
 - Heifer Replacements
 - Cows
- Beef Cattle
 - Calves
 - Heifer Replacements
 - Heifer and Steer Stockers
 - Animals in Feedlots (Heifers and Steer)
 - Cows
 - Bulls

Calf birth rates, end-of-year population statistics, detailed feedlot placement information, and slaughter weight data were used to create a transition matrix that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Annex 3.10. These variables include performance factors such as pregnancy and lactation as well as average weights and weight gain. Annual cattle population data were obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service (NASS) QuickStats database (USDA 2015).

Diet characteristics were estimated by region for dairy, foraging beef, and feedlot beef cattle. These diet characteristics were used to calculate digestible energy (DE) values (expressed as the percent of gross energy intake digested by the animal) and CH₄ conversion rates (Y_m) (expressed as the fraction of gross energy converted to CH₄) for each regional population category. The IPCC recommends Y_m ranges of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for other well-fed cattle consuming temperate-climate feed types (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed. The diet characterizations and estimation of DE and Y_m values were based on information from state agricultural extension specialists, a review of published forage quality studies and scientific literature, expert opinion, and modeling of animal physiology.

The diet characteristics for dairy cattle were based on Donovan (1999) and an extensive review of nearly 20 years of literature from 1990 through 2009. Estimates of DE were national averages based on the feed components of the diets observed in the literature for the following year groupings: 1990 through 1993, 1994 through 1998, 1999

through 2003, 2004 through 2006, 2007, and 2008 onward.² Base year Y_m values by region were estimated using Donovan (1999). A ruminant digestion model (COWPOLL, as selected in Kebreab et al. 2008) was used to evaluate Y_m for each diet evaluated from the literature, and a function was developed to adjust regional values over time based on the national trend. Dairy replacement heifer diet assumptions were based on the observed relationship in the literature between dairy cow and dairy heifer diet characteristics.

For feedlot animals, the DE and Y_m values used for 1990 were recommended by Johnson (1999). Values for DE and Y_m for 1991 through 1999 were linearly extrapolated based on the 1990 and 2000 data. DE and Y_m values for 2000 onwards were based on survey data in Galyean and Gleghorn (2001) and Vasconcelos and Galyean (2007).

For grazing beef cattle, Y_m values were based on Johnson (2002), DE values for 1990 through 2006 were based on specific diet components estimated from Donovan (1999), and DE values from 2007 onwards were developed from an analysis by Archibeque (2011), based on diet information in Preston (2010) and USDA:APHIS:VS (2010). Weight and weight gains for cattle were estimated from Holstein (2010), Doren et al. (1989), Enns (2008), Lippke et al. (2000), Pinchack et al. (2004), Platter et al. (2003), Skogerboe et al. (2000), and expert opinion. See Annex 3.10 for more details on the method used to characterize cattle diets and weights in the United States.

Calves younger than 4 months are not included in emission estimates because calves consume mainly milk and the IPCC recommends the use of a Y_m of zero for all juveniles consuming only milk. Diets for calves aged 4 to 6 months are assumed to go through a gradual weaning from milk decreasing to 75 percent at 4 months, 50 percent at age 5 months, and 25 percent at age 6 months. The portion of the diet made up with milk still results in zero emissions. For the remainder of the diet, beef calf DE and Y_m are set equivalent to those of beef replacement heifers, while dairy calf DE is set equal to that of dairy replacement heifers and dairy calf Y_m is provided at 4 and 7 months of age by Soliva (2006). Estimates of Y_m for 5 and 6 month old dairy calves are linearly interpolated from the values provided for 4 and 7 months.

To estimate CH₄ emissions, the population was divided into state, age, sub-type (i.e., dairy cows and replacements, beef cows and replacements, heifer and steer stockers, heifers and steers in feedlots, bulls, beef calves 4 to 6 months, and dairy calves 4 to 6 months), and production (i.e., pregnant, lactating) groupings to more fully capture differences in CH₄ emissions from these animal types. The transition matrix was used to simulate the age and weight structure of each sub-type on a monthly basis in order to more accurately reflect the fluctuations that occur throughout the year. Cattle diet characteristics were then used in conjunction with Tier 2 equations from IPCC (2006) to produce CH₄ emission factors for the following cattle types: dairy cows, beef cows, dairy replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, heifer feedlot animals, bulls, and calves. To estimate emissions from cattle, monthly population data from the transition matrix were multiplied by the calculated emission factor for each cattle type. More details are provided in Annex 3.10.

Emission estimates for other animal types were based on average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH₄ emissions from livestock in the United States from 1990 through 2014. Additionally, the variability in emission factors for each of these other animal types (e.g., variability by age, production system, and feeding practice within each animal type) is less than that for cattle. Annual livestock population data for sheep; swine; goats; horses; mules and asses; and American bison were obtained for available years from USDA NASS (USDA 2015). Horse, goat and mule and ass population data were available for 1987, 1992, 1997, 2002, 2007, and 2012 (USDA 1992, 1997, 2015); the remaining years between 1990 and 2014 were interpolated and extrapolated from the available estimates (with the exception of goat populations being held constant between 1990 and 1992). American bison population estimates were available from USDA for 2002, 2007, and 2012 (USDA 2014) and from the National Bison Association (1999) for 1997 through 1999. Additional years were based on observed trends from the National Bison Association (1999), interpolation between known data points, and extrapolation beyond 2012, as described in more detail in Annex 3.10. Methane emissions from sheep, goats, swine, horses, American bison, and mules and asses were estimated by using emission factors utilized in Crutzen et al. (1986, cited in IPCC 2006). These emission factors are representative of typical animal sizes, feed intakes, and feed characteristics in developed countries. For American bison the emission factor for buffalo was used and adjusted based on the ratio of live weights to the 0.75 power. The methodology is the same as that recommended by IPCC (2006).

² Due to inconsistencies in the 2003 literature values, the 2002 values were used for 2003 as well.

See Annex 3.10 for more detailed information on the methodology and data used to calculate CH₄ emissions from enteric fermentation.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis for this source category was performed using the IPCC-recommended Approach 2 uncertainty estimation methodology based on a Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report (i.e., 2003 submission to the UNFCCC). There have been no significant changes to the methodology since that time; consequently, these uncertainty estimates were directly applied to the 2014 emission estimates in this Inventory report.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to ensure only positive values would be simulated. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

The uncertainty ranges associated with the activity data-related input variables were plus or minus 10 percent or lower. However, for many emission factor-related input variables, the lower- and/or the upper-bound uncertainty estimates were over 20 percent. The results of the quantitative uncertainty analysis are summarized in Table 5-5. Based on this analysis, enteric fermentation CH₄ emissions in 2014 were estimated to be between 146.2 and 193.9 MMT CO₂ Eq. at a 95 percent confidence level, which indicates a range of 11 percent below to 18 percent above the 2014 emission estimate of 164.3 MMT CO₂ Eq. Among the individual cattle sub-source categories, beef cattle account for the largest amount of CH₄ emissions, as well as the largest degree of uncertainty in the emission estimates—due mainly to the difficulty in estimating the diet characteristics for grazing members of this animal group. Among non-cattle, horses represent the largest percent of uncertainty in the previous uncertainty analysis because the Food and Agricultural Organization of the United Nations (FAO) population estimates used for horses at that time had a higher degree of uncertainty than for the USDA population estimates used for swine, goats, and sheep. The horse populations are now from the same USDA source as the other animal types, and therefore the uncertainty range around horses is likely overestimated. Cattle calves, American bison, mules and asses were excluded from the initial uncertainty estimate because they were not included in emission estimates at that time.

Table 5-5: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Enteric Fermentation (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^{a, b, c} | | | |
|----------------------|-----------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Enteric Fermentation | CH ₄ | 164.3 | 146.2 | 193.9 | -11% | 18% |

^a Range of emissions estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

^b Note that the relative uncertainty range was estimated with respect to the 2001 emission estimates from the 2003 submission and applied to the 2014 estimates.

^c The overall uncertainty calculated in 2003, and applied to the 2014 emission estimate, did not include uncertainty estimates for calves, American bison, and mules and asses. Additionally, for bulls the emissions estimate was based on the Tier 1 methodology. Since bull emissions are now estimated using the Tier 2 method, the uncertainty surrounding their estimates is likely lower than indicated by the previous uncertainty analysis.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section.

QA/QC and Verification

In order to ensure the quality of the emission estimates from enteric fermentation, the IPCC Tier 1 and Tier 2 Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. QA/QC plan. Tier 2 QA procedures included independent peer review of emission estimates. Over the past few years, particular importance has been placed on harmonizing the data exchange between the enteric fermentation and manure management source categories. The current Inventory now utilizes the transition matrix from the CEFM for estimating cattle populations and weights for both source categories, and the CEFM is used to output volatile solids and nitrogen excretion estimates using the diet assumptions in the model in conjunction with the energy balance equations from the IPCC (2006). This approach facilitates the QA/QC process for both of these source categories.

Recalculations Discussion

For the current Inventory, differences can be seen in emission estimates for years prior to 2014 when compared against the same years in the previous Inventory—from 2008 through 2013 in particular. These recalculations were due to changes made to historical data and corrections made to erroneous formulas in the CEFM. No modifications were made to the methodology.

Revisions to input data include the following:

- The USDA published minor revisions in several categories that affected historical emissions estimated for cattle for 2008 and subsequent years, including the following:
 - Cattle populations for all animal types were revised for many states for 2009 and subsequent years;
 - Dairy cow milk production values were revised for several states for 2008 and subsequent years;
 - Beef cattle feedlot placement data were revised for 2008 and subsequent years;
 - Slaughter values were revised for 2008 and subsequent years;
 - Calf birth data were revised for 2010 and subsequent years; and
 - Cattle on feed data were revised for many states for 2009 and subsequent years.
- The USDA also revised population estimates for some categories of non-cattle animals, which affected historical emissions estimated for “other” livestock. Changes included:
 - Revised 2008 through 2012 populations for market and breeding swine in some states; and
 - Revised 2011 and 2012 populations of sheep for some states.

In addition to these changes in input data, there were transcription and formula cell reference errors in the CEFM calculations for the state-by-state estimates of cattle on feed. These errors, when corrected, affected emission estimates for 2009 and subsequent years for all stockers and feedlot cattle.

These recalculations had an insignificant impact on the overall emission estimates.

Planned Improvements

Continued research and regular updates are necessary to maintain an emissions inventory that reflects the current base of knowledge. Future improvements for enteric fermentation could include some of the following options:

- Further research to improve the estimation of dry matter intake (as gross energy intake) using data from appropriate production systems;
- Updating input variables that are from older data sources, such as beef births by month and beef cow lactation rates;
- Investigation of the availability of annual data for the DE, Y_m , and crude protein values of specific diet and feed components for foraging and feedlot animals;
- Further investigation on additional sources or methodologies for estimating DE for dairy, given the many challenges in characterizing dairy diets;

- Further evaluation of the assumptions about weights and weight gains for beef cows, such that trends beyond 2007 are updated, rather than held constant;
- Further evaluation of the estimated weight for dairy cows (i.e., 1,500 lbs) that is based solely on Holstein cows as mature dairy cow weight is likely slightly overestimated, based on knowledge of the breeds of dairy cows in the United States;
- Potentially updating to a Tier 2 methodology for other animal types (i.e., sheep, swine, goats, horses);
- Investigation of methodologies and emission factors for including enteric fermentation emission estimates from poultry;
- Comparison of the current CEFM processing of animal population data to estimates developed using annual average populations to determine if the model could be simplified to use annual population data; and
- Recent changes that have been implemented to the CEFM warrant an assessment of the current uncertainty analysis; therefore, a revision of the quantitative uncertainty surrounding emission estimates from this source category will be initiated.

5.2 Manure Management (IPCC Source Category 3B)

The treatment, storage, and transportation of livestock manure can produce anthropogenic CH₄ and N₂O emissions. Methane is produced by the anaerobic decomposition of manure. Nitrous oxide emissions are produced through both direct and indirect pathways. Direct N₂O emissions are produced as part of the nitrogen (N) cycle through the nitrification and denitrification of the organic N in livestock dung and urine.³ There are two pathways for indirect N₂O emissions. The first is the result of the volatilization of N in manure (as NH₃ and NO_x) and the subsequent deposition of these gases and their products (NH₄⁺ and NO₃⁻) onto soils and the surface of lakes and other waters. The second pathway is the runoff and leaching of N from manure to the groundwater below, in riparian zones receiving drain or runoff water, or in the ditches, streams, rivers, and estuaries into which the land drainage water eventually flows.

When livestock or poultry manure are stored or treated in systems that promote anaerobic conditions (e.g., as a liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of the volatile solids component in the manure tends to produce CH₄. When manure is handled as a solid (e.g., in stacks or drylots) or deposited on pasture, range, or paddock lands, it tends to decompose aerobically and produce little or no CH₄. Ambient temperature, moisture, and manure storage or residency time affect the amount of CH₄ produced because they influence the growth of the bacteria responsible for CH₄ formation. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and humidity) can promote CH₄ production. Manure composition, which varies by animal diet, growth rate, and type, including the animal's digestive system, also affects the amount of CH₄ produced. In general, the greater the energy content of the feed, the greater the potential for CH₄ emissions. However, some higher-energy feeds also are more digestible than lower quality forages, which can result in less overall waste excreted from the animal.

The production of direct N₂O emissions from livestock manure depends on the composition of the manure and urine, the type of bacteria involved in the process, and the amount of oxygen and liquid in the manure system. For direct N₂O emissions to occur, the manure must first be handled aerobically where ammonia (NH₃) or organic N is converted to nitrates and nitrites (nitrification), and then handled anaerobically where the nitrates and nitrites are reduced to dinitrogen gas (N₂), with intermediate production of N₂O and nitric oxide (NO) (denitrification)

³ Direct and indirect N₂O emissions from dung and urine spread onto fields either directly as daily spread or after it is removed from manure management systems (i.e., lagoon, pit, etc.) and from livestock dung and urine deposited on pasture, range, or paddock lands are accounted for and discussed in the Agricultural Soil Management source category within the Agriculture sector.

(Groffman et al. 2000). These emissions are most likely to occur in dry manure handling systems that have aerobic conditions, but that also contain pockets of anaerobic conditions due to saturation. A very small portion of the total N excreted is expected to convert to N₂O in the waste management system (WMS). Indirect N₂O emissions are produced when nitrogen is lost from the system through volatilization (as NH₃ or NO_x) or through runoff and leaching. The vast majority of volatilization losses from these operations are NH₃. Although there are also some small losses of NO_x, there are no quantified estimates available for use, so losses due to volatilization are only based on NH₃ loss factors. Runoff losses would be expected from operations that house animals or store manure in a manner that is exposed to weather. Runoff losses are also specific to the type of animal housed on the operation due to differences in manure characteristics. Little information is known about leaching from manure management systems as most research focuses on leaching from land application systems. Since leaching losses are expected to be minimal, leaching losses are coupled with runoff losses and the runoff/leaching estimate provided in this chapter does not account for any leaching losses.

Estimates of CH₄ emissions from manure management in 2014 were 61.2 MMT CO₂ Eq. (2,447 kt); in 1990, emissions were 37.2 MMT CO₂ Eq. (1,486 kt). This represents a 65 percent increase in emissions from 1990. Emissions increased on average by 1.0 MMT CO₂ Eq. (2.6 percent) annually over this period. The majority of this increase is due to swine and dairy cow manure, where emissions increased 44 and 118 percent, respectively. From 2013 to 2014, there was a 0.3 percent decrease in total CH₄ emissions from manure management, mainly due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

Although the majority of managed manure in the United States is handled as a solid, producing little CH₄, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of liquid systems. Also, new regulations controlling the application of manure nutrients to land have shifted manure management practices at smaller dairies from daily spread systems to storage and management of the manure on site. Although national dairy animal populations have generally been decreasing since 1990, some states have seen increases in their dairy populations as the industry becomes more concentrated in certain areas of the country and the number of animals contained on each facility increases. These areas of concentration, such as California, New Mexico, and Idaho, tend to utilize more liquid-based systems to manage (flush or scrape) and store manure. Thus the shift toward larger dairy and swine facilities has translated into an increasing use of liquid manure management systems, which have higher potential CH₄ emissions than dry systems. This significant shift in both the dairy and swine industries was accounted for by incorporating state and WMS-specific CH₄ conversion factor (MCF) values in combination with the 1992, 1997, 2002, and 2007 farm-size distribution data reported in the *Census of Agriculture* (USDA 2014a).

In 2014, total N₂O emissions from manure management were estimated to be 17.5 MMT CO₂ Eq. (59 kt); in 1990, emissions were 14.0 MMT CO₂ Eq. (47 kt). These values include both direct and indirect N₂O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N₂O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N₂O emissions showed a 25 percent increase from 1990 to 2014 and a 0.1 percent decrease from 2013 through 2014. Overall shifts toward liquid systems have driven down the emissions per unit of nitrogen excreted.

Table 5-6 and Table 5-7 provide estimates of CH₄ and N₂O emissions from manure management by animal category.

Table 5-6: CH₄ and N₂O Emissions from Manure Management (MMT CO₂ Eq.)

| Gas/Animal Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| CH₄^a | 37.2 | 56.3 | 60.9 | 61.5 | 63.7 | 61.4 | 61.2 |
| Dairy Cattle | 14.7 | 26.4 | 30.4 | 31.1 | 32.6 | 31.8 | 32.2 |
| Beef Cattle | 3.1 | 3.3 | 3.3 | 3.3 | 3.2 | 3.0 | 3.0 |
| Swine | 15.6 | 22.9 | 23.6 | 23.6 | 24.3 | 23.0 | 22.4 |
| Sheep | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Goats | + | + | + | + | + | + | + |
| Poultry | 3.3 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 |
| Horses | 0.2 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| American Bison | + | + | + | + | + | + | + |
| Mules and Asses | + | + | + | + | + | + | + |
| N₂O^b | 14.0 | 16.5 | 17.2 | 17.4 | 17.5 | 17.5 | 17.5 |

| | | | | | | | |
|-----------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Dairy Cattle | 5.3 | 5.6 | 5.7 | 5.8 | 5.9 | 5.9 | 5.9 |
| Beef Cattle | 5.9 | 7.2 | 7.6 | 7.7 | 7.7 | 7.7 | 7.8 |
| Swine | 1.2 | 1.7 | 1.9 | 1.9 | 1.9 | 1.9 | 1.8 |
| Sheep | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Goats | + | + | + | + | + | + | + |
| Poultry | 1.4 | 1.6 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 |
| Horses | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| American Bison | NA |
| Mules and Asses | + | + | + | + | + | + | + |
| Total | 51.1 | 72.9 | 78.1 | 78.9 | 81.2 | 78.9 | 78.7 |

+ Does not exceed 0.05 MMT CO₂ Eq.

NA - Not available

^a Accounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.

^b Includes both direct and indirect N₂O emissions.

Notes: Totals may not sum due to independent rounding. American bison are maintained entirely on unmanaged WMS; there are no American bison N₂O emissions from managed systems.

Table 5-7: CH₄ and N₂O Emissions from Manure Management (kt)

| Gas/Animal Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄^a | 1,486 | 2,254 | 2,437 | 2,460 | 2,548 | 2,455 | 2,447 |
| Dairy Cattle | 590 | 1,057 | 1,217 | 1,245 | 1,306 | 1,271 | 1,289 |
| Beef Cattle | 126 | 133 | 132 | 131 | 128 | 121 | 120 |
| Swine | 622 | 916 | 945 | 942 | 972 | 920 | 896 |
| Sheep | 7 | 3 | 3 | 3 | 3 | 3 | 3 |
| Goats | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Poultry | 131 | 129 | 129 | 127 | 128 | 128 | 130 |
| Horses | 9 | 12 | 10 | 10 | 10 | 9 | 9 |
| American Bison | + | + | + | + | + | + | + |
| Mules and Asses | + | + | + | + | + | + | + |
| N₂O^b | 47 | 55 | 58 | 58 | 59 | 59 | 59 |
| Dairy Cattle | 18 | 19 | 19 | 19 | 20 | 20 | 20 |
| Beef Cattle | 20 | 24 | 25 | 26 | 26 | 26 | 26 |
| Swine | 4 | 6 | 6 | 6 | 6 | 6 | 6 |
| Sheep | + | 1 | 1 | 1 | 1 | 1 | 1 |
| Goats | + | + | + | + | + | + | + |
| Poultry | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Horses | + | + | + | + | + | + | + |
| American Bison | NA |
| Mules and Asses | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

NA - Not available

^a Accounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.

^b Includes both direct and indirect N₂O emissions.

Notes: Totals may not sum due to independent rounding. American bison are maintained entirely on unmanaged WMS; there are no American bison N₂O emissions from managed systems.

Methodology

The methodologies presented in IPCC (2006) form the basis of the CH₄ and N₂O emission estimates for each animal type. This section presents a summary of the methodologies used to estimate CH₄ and N₂O emissions from manure management. See Annex 3.11 for more detailed information on the methodology and data used to calculate CH₄ and N₂O emissions from manure management.

Methane Calculation Methods

The following inputs were used in the calculation of CH₄ emissions:

- Animal population data (by animal type and state);
- Typical animal mass (TAM) data (by animal type);
- Portion of manure managed in each WMS, by state and animal type;
- Volatile solids (VS) production rate (by animal type and state or United States);
- Methane producing potential (B₀) of the volatile solids (by animal type); and
- Methane conversion factors (MCF), the extent to which the CH₄ producing potential is realized for each type of WMS (by state and manure management system, including the impacts of any biogas collection efforts).

Methane emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources are described below:

- Annual animal population data for 1990 through 2014 for all livestock types, except goats, horses, mules and asses, and American bison were obtained from the USDA NASS. For cattle, the USDA populations were utilized in conjunction with birth rates, detailed feedlot placement information, and slaughter weight data to create the transition matrix in the CEFM that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Section 5.1 and in more detail in Annex 3.10. Goat population data for 1992, 1997, 2002, 2007, and 2012; horse and mule and ass population data for 1987, 1992, 1997, 2002, 2007, and 2012; and American bison population for 2002, 2007 and 2012 were obtained from the *Census of Agriculture* (USDA 2014a). American bison population data for 1990 through 1999 were obtained from the National Bison Association (1999).
- The TAM is an annual average weight that was obtained for animal types other than cattle from information in USDA's *Agricultural Waste Management Field Handbook* (USDA 1996), the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998) and others (Meagher 1986; EPA 1992; Safley 2000; ERG 2003b; IPCC 2006; ERG 2010a). For a description of the TAM used for cattle, see Section 5.1.
- WMS usage was estimated for swine and dairy cattle for different farm size categories using data from USDA (USDA APHIS 1996; Bush 1998; Ott 2000; USDA 2014a) and EPA (ERG 2000a; EPA 2002a and 2002b). For beef cattle and poultry, manure management system usage data were not tied to farm size but were based on other data sources (ERG 2000a; USDA APHIS 2000; UEP 1999). For other animal types, manure management system usage was based on previous estimates (EPA 1992). American bison WMS usage was assumed to be the same as not on feed (NOF) cattle, while mules and asses were assumed to be the same as horses.
- VS production rates for all cattle except for calves were calculated by head for each state and animal type in the CEFM. VS production rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996 and 2008; ERG 2010b and 2010c) and data that was not available in the most recent *Handbook* were obtained from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998) or the *2006 IPCC Guidelines* (IPCC 2006). American bison VS production was assumed to be the same as NOF bulls.
- The maximum CH₄-producing capacity of the VS (B₀) was determined for each animal type based on literature values (Morris 1976; Bryant et al. 1976; Hashimoto 1981; Hashimoto 1984; EPA 1992; Hill 1982; Hill 1984).
- MCFs for dry systems were set equal to default IPCC factors based on state climate for each year (IPCC 2006). MCFs for liquid/slurry, anaerobic lagoon, and deep pit systems were calculated based on the forecast performance of biological systems relative to temperature changes as predicted in the van't Hoff-Arrhenius equation which is consistent with IPCC (2006) Tier 2 methodology.
- Data from anaerobic digestion systems with CH₄ capture and combustion were obtained from the EPA AgSTAR Program, including information presented in the *AgSTAR Digest* (EPA 2000, 2003, 2006) and the

AgSTAR project database (EPA 2012). Anaerobic digester emissions were calculated based on estimated methane production and collection and destruction efficiency assumptions (ERG 2008).

- For all cattle except for calves, the estimated amount of VS (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM, assuming American bison VS production to be the same as NOF bulls. For animals other than cattle, the annual amount of VS (kg per year) from manure excreted in each WMS was calculated for each animal type, state, and year. This calculation multiplied the animal population (head) by the VS excretion rate (kg VS per 1,000 kg animal mass per day), the TAM (kg animal mass per head) divided by 1,000, the WMS distribution (percent), and the number of days per year (365.25).

The estimated amount of VS managed in each WMS was used to estimate the CH₄ emissions (kg CH₄ per year) from each WMS. The amount of VS (kg per year) were multiplied by the maximum CH₄ producing capacity of the VS (B₀) (m³ CH₄ per kg VS), the MCF for that WMS (percent), and the density of CH₄ (kg CH₄ per m³ CH₄). The CH₄ emissions for each WMS, state, and animal type were summed to determine the total U.S. CH₄ emissions.

Nitrous Oxide Calculation Methods

The following inputs were used in the calculation of direct and indirect N₂O emissions:

- Animal population data (by animal type and state);
- TAM data (by animal type);
- Portion of manure managed in each WMS (by state and animal type);
- Total Kjeldahl N excretion rate (N_{ex});
- Direct N₂O emission factor (EF_{WMS});
- Indirect N₂O emission factor for volatilization (EF_{volatilization});
- Indirect N₂O emission factor for runoff and leaching (EF_{runoff/leach});
- Fraction of N loss from volatilization of NH₃ and NO_x (Frac_{gas}); and
- Fraction of N loss from runoff and leaching (Frac_{runoff/leach}).

N₂O emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources (except for population, TAM, and WMS, which were described above) are described below:

- Nex rates for all cattle except for calves were calculated by head for each state and animal type in the CEFM. Nex rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996 and 2008; ERG 2010b and 2010c) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998) and IPCC (2006). American bison Nex rates were assumed to be the same as NOF bulls.⁴
- All N₂O emission factors (direct and indirect) were taken from IPCC (2006). These data are appropriate because they were developed using U.S. data.
- Country-specific estimates for the fraction of N loss from volatilization (Frac_{gas}) and runoff and leaching (Frac_{runoff/leach}) were developed. Frac_{gas} values were based on WMS-specific volatilization values as estimated from EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). Frac_{runoff/leaching} values were based on regional cattle runoff data from EPA's Office of Water (EPA 2002b; see Annex 3.11).

To estimate N₂O emissions for cattle (except for calves), the estimated amount of N excreted (kg per animal-year) that is managed in each WMS for each animal type, state, and year were taken from the CEFM. For calves and other animals, the amount of N excreted (kg per year) in manure in each WMS for each animal type, state, and year was calculated. The population (head) for each state and animal was multiplied by TAM (kg animal mass per head)

⁴ The N₂O emissions from N excreted (N_{ex}) by American bison on grazing lands are accounted for and discussed in the Agricultural Soil Management source category and included under pasture, range and paddock (PRP) emissions. Because American bison are maintained entirely on unmanaged WMS and N₂O emissions from unmanaged WMS are not included in the Manure Management category, there are no N₂O emissions from American bison included in the Manure Management category.

divided by 1,000, the nitrogen excretion rate (N_{ex} , in kg N per 1,000 kg animal mass per day), WMS distribution (percent), and the number of days per year.

Direct N_2O emissions were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the N_2O direct emission factor for that WMS (EF_{WMS} , in kg N_2O -N per kg N) and the conversion factor of N_2O -N to N_2O . These emissions were summed over state, animal, and WMS to determine the total direct N_2O emissions (kg of N_2O per year).

Next, indirect N_2O emissions from volatilization (kg N_2O per year) were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through volatilization ($Frac_{tas}$) divided by 100, and the emission factor for volatilization ($EF_{volatilization}$, in kg N_2O per kg N), and the conversion factor of N_2O -N to N_2O . Indirect N_2O emissions from runoff and leaching (kg N_2O per year) were then calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through runoff and leaching ($Frac_{runoff/leach}$) divided by 100, and the emission factor for runoff and leaching ($EF_{runoff/leach}$, in kg N_2O per kg N), and the conversion factor of N_2O -N to N_2O . The indirect N_2O emissions from volatilization and runoff and leaching were summed to determine the total indirect N_2O emissions.

The direct and indirect N_2O emissions were summed to determine total N_2O emissions (kg N_2O per year).

Uncertainty and Time-Series Consistency

An analysis (ERG 2003a) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report (i.e., 2003 submission to the UNFCCC) to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Approach 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was performed for each state. These uncertainty estimates were directly applied to the 2014 emission estimates as there have not been significant changes in the methodology since that time.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 5-8. Manure management CH_4 emissions in 2014 were estimated to be between 50.2 and 73.4 MMT CO_2 Eq. at a 95 percent confidence level, which indicates a range of 18 percent below to 20 percent above the actual 2014 emission estimate of 61.2 MMT CO_2 Eq. At the 95 percent confidence level, N_2O emissions were estimated to be between 14.7 and 21.7 MMT CO_2 Eq. (or approximately 16 percent below and 24 percent above the actual 2014 emission estimate of 17.5 MMT CO_2 Eq.).

Table 5-8: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O (Direct and Indirect) Emissions from Manure Management (MMT CO_2 Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO_2 Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-------------------|--------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Manure Management | CH_4 | 61.2 | 50.2 | 73.4 | -18% | 20% |
| Manure Management | N_2O | 17.5 | 14.7 | 21.7 | -16% | 24% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Tier 2 activities focused on comparing estimates for the previous and current Inventories for N₂O emissions from managed systems and CH₄ emissions from livestock manure. All errors identified were corrected. Order of magnitude checks were also conducted, and corrections made where needed. Manure N data were checked by comparing state-level data with bottom up estimates derived at the county level and summed to the state level. Similarly, a comparison was made by animal and WMS type for the full time series, between national level estimates for N excreted and the sum of county estimates for the full time series.

Any updated data, including population, are validated by experts to ensure the changes are representative of the best available U.S.-specific data. The U.S.-specific values for TAM, Nex, VS, B_o, and MCF were also compared to the IPCC default values and validated by experts. Although significant differences exist in some instances, these differences are due to the use of U.S.-specific data and the differences in U.S. agriculture as compared to other countries. The U.S. manure management emission estimates use the most reliable country-specific data, which are more representative of U.S. animals and systems than the IPCC (2006) default values.

For additional verification, the implied CH₄ emission factors for manure management (kg of CH₄ per head per year) were compared against the default IPCC (2006) values. Table 5-9 presents the implied emission factors of kg of CH₄ per head per year used for the manure management emission estimates as well as the IPCC (2006) default emission factors. The U.S. implied emission factors fall within the range of the IPCC (2006) default values, except in the case of sheep, goats, and some years for horses and dairy cattle. The U.S. implied emission factors are greater than the IPCC (2006) default value for those animals due to the use of U.S.-specific data for typical animal mass and VS excretion. There is an increase in implied emission factors for dairy and swine across the time series. This increase reflects the dairy and swine industry trend towards larger farm sizes; large farms are more likely to manage manure as a liquid and therefore produce more CH₄ emissions.

Table 5-9: IPCC (2006) Implied Emission Factor Default Values Compared with Calculated Values for CH₄ from Manure Management (kg/head/year)

| Animal Type | IPCC Default CH ₄ Emission Factors (kg/head/year) | Implied CH ₄ Emission Factors (kg/head/year) | | | | | | |
|-----------------|---|---|------|------|------|------|------|------|
| | | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Dairy Cattle | 48-112 | 30.2 | 59.4 | 66.5 | 67.5 | 70.3 | 68.7 | 69.7 |
| Beef Cattle | 1-2 | 1.5 | 1.6 | 1.6 | 1.7 | 1.7 | 1.6 | 1.6 |
| Swine | 10-45 | 11.5 | 15.0 | 14.6 | 14.4 | 14.6 | 14.1 | 14.0 |
| Sheep | 0.19-0.37 | 0.6 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Goats | 0.13-0.26 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Poultry | 0.02-1.4 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Horses | 1.56-3.13 | 4.3 | 3.1 | 2.6 | 2.6 | 2.7 | 2.5 | 2.5 |
| American Bison | NA | 1.8 | 2.0 | 2.1 | 2.1 | 2.1 | 2.0 | 2.0 |
| Mules and Asses | 0.76-1.14 | 0.9 | 1.0 | 0.9 | 1.0 | 1.0 | 0.9 | 0.9 |

NA - Not Applicable

In addition, default IPCC (2006) emission factors for N₂O were compared to the U.S. Inventory implied N₂O emission factors. Default N₂O emission factors from the *2006 IPCC Guidelines* were used to estimate N₂O emission from each WMS in conjunction with U.S.-specific Nex values. The implied emission factors differed from the U.S. Inventory values due to the use of U.S.-specific Nex values and differences in populations present in each WMS throughout the time series.

Recalculations Discussion

The CEFM produces population, VS and Nex data for cattle, excepting calves, that are used in the manure management inventory. As a result, all changes to the CEFM described in Section 5.1 contributed to changes in the population, VS and Nex data used for calculating CH₄ and N₂O cattle emissions from manure management. In

addition, the manure management emission estimates included the following recalculations relative to the previous Inventory:

- State animal populations were updated to reflect updated USDA NASS datasets, which resulted in population changes for poultry in 2013, both beef and dairy calves from 2009 through 2013, sheep in 2011 and 2012, and swine from 2008 through 2013.
- Indirect N₂O emissions for daily spread were added, as they are not accounted for in the Agricultural Soil Management category. This inclusion increased indirect and total N₂O emissions for dairy cows and dairy heifers. Indirect N₂O emissions increased between 0.9 and 5.2 percent per year, while total N₂O emissions increased between 0.6 to 1.4 percent per year.

Planned Improvements

The uncertainty analysis for manure management will be updated in future Inventories to more accurately assess uncertainty of emission calculations. This update is necessary due to the extensive changes in emission calculation methodology, including estimation of emissions at the WMS level and the use of new calculations and variables for indirect N₂O emissions.

In the next Inventory report, updated AgSTAR anaerobic digester data will be incorporated. In addition, potential data sources (such as the USDA Agricultural Resource Management Survey) for updated WMS distribution estimates will be reviewed and discussed with USDA. Further, future Inventories may present emissions on a monthly basis to show seasonal emission changes for each WMS; this update would help compare these Inventory data to other data and models.

5.3 Rice Cultivation (IPCC Source Category 3C)

Most of the world's rice is grown on flooded fields (Baicich 2013), and flooding creates anaerobic conditions that foster CH₄ production through a process known as methanogenesis. Approximately 60 to 90 percent of the CH₄ produced by methanogenic bacteria is oxidized in the soil and converted to CO₂ by methanotrophic bacteria. The remainder is emitted to the atmosphere (Holzapfel-Pschorn et al. 1985; Sass et al. 1990) or transported as dissolved CH₄ into groundwater and waterways (Neue et al. 1997). Methane is transported to the atmosphere primarily through the rice plants, but some CH₄ also escapes via ebullition (i.e., bubbling through the water) and to a much lesser extent by diffusion through the water (van Bodegom et al. 2001).

Water management is arguably the most important factor affecting CH₄ emissions, and improved water management has the largest potential to mitigate emissions (Yan et al. 2009). Upland rice fields are not flooded, and therefore do not produce CH₄, but large amounts of CH₄ can be emitted in continuously irrigated fields, which is the most common practices in the United States (USDA 2012). Single or multiple aeration events with drainage of a field during the growing season can significantly reduce these emissions (Wassmann et al. 2000a), but drainage may also increase N₂O emissions. Deepwater rice fields (i.e., fields with flooding depths greater than one meter, such as natural wetlands) tend to have less living stems reaching the soil, thus reducing the amount of CH₄ transport to the atmosphere through the plant compared to shallow-flooded systems (Sass 2001).

Other management practices also influence CH₄ emissions from flooded rice fields including rice residue straw management and application of organic amendments, in addition to cultivar selection due to differences in the amount of root exudates⁵ among rice varieties (Neue et al. 1997). These practices influence the amount of organic matter available for methanogenesis, and some practices, such as mulching rice straw or composting organic amendments, can reduce the amount of labile carbon and limit CH₄ emissions (Wassmann et al. 2000b). Fertilization practices also influences CH₄ emissions, particularly the use of fertilizers with sulfate (Wassmann et al. 2000b; Linquist et al. 2012). Other environmental variables also impact the methanogenesis process such as soil

⁵ The roots of rice plants add organic material to the soil through a process called “root exudation.” Root exudation is thought to enhance decomposition of the soil organic matter and release nutrients that the plant can absorb and use to stimulate more production. The amount of root exudate produced by a rice plant over a growing season varies among rice varieties.

temperature and soil type. Soil temperature is an important factor regulating the activity of methanogenic bacteria which in turn affects the rate of CH₄ production. Soil texture influences decomposition of soil organic matter, but is also thought to have an impact on oxidation of CH₄ in the soil (Sass et al. 1994).

Rice is currently cultivated in twelve states, including Arkansas, California, Florida, Illinois, Louisiana, Minnesota, Mississippi, Missouri, New York, South Carolina, Tennessee and Texas. Soil types, rice varieties, and cultivation practices vary across the United States, but most farmers apply fertilizers and do not harvest crop residues. In addition, a second, ratoon rice crop is sometimes grown in the Southeast. Ratoon crops are produced from regrowth of the stubble remaining after the harvest of the first rice crop. Methane emissions from ratoon crops are higher than those from the primary crops due to the increased amount of labile organic matter available for anaerobic decomposition in the form of relatively fresh crop residue straw. Emissions tend to be higher in rice fields if the residues have been in the field for less than 30 days before planting the next rice crop (Lindau and Bollich 1993; IPCC 2006; Wang et al. 2013).

Overall, rice cultivation is a minor source of CH₄ emissions in the United States relative to other source categories (see Table 5-10 and Table 5-11). In 2014, CH₄ emissions from rice cultivation were 11.9 MMT CO₂ Eq. (476 kt). Annual emissions fluctuate between 1990 and 2014, and emissions in 2014 represented a 9 percent decrease compared to 1990. Variation in emissions is largely due to differences in the amount of rice harvested areas over time. In Arkansas and California, rice harvested areas increased by 33 percent and 39 percent respectively from 1990 to 2014, while rice harvested area declined in Louisiana and Texas by 14 percent and 78 percent respectively (see Table 5-12).

Table 5-10: CH₄ Emissions from Rice Cultivation (MMT CO₂ Eq.)

| State | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Arkansas | 2.8 | 4.2 | 4.5 | 4.5 | 4.6 | 4.6 | 4.6 |
| California | 1.7 | 2.5 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |
| Florida | + | + | + | + | + | + | + |
| Illinois | + | + | + | + | + | + | + |
| Louisiana | 2.4 | 2.7 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 |
| Minnesota | + | + | + | + | + | + | + |
| Mississippi | 0.5 | 0.4 | 0.2 | 0.2 | 0.3 | 0.2 | 0.2 |
| Missouri | 0.3 | 0.5 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| New York | + | + | + | + | + | + | + |
| South Carolina | + | + | + | + | + | + | + |
| Tennessee | + | + | + | + | + | + | + |
| Texas | 5.5 | 2.5 | 1.3 | 1.4 | 1.4 | 1.4 | 1.3 |
| Total | 13.1 | 13.0 | 11.9 | 11.8 | 11.9 | 11.9 | 11.9 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 5-11: CH₄ Emissions from Rice Cultivation (kt)

| State | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------|------------|------------|------------|------------|------------|------------|------------|
| Arkansas | 113 | 169 | 182 | 182 | 182 | 182 | 182 |
| California | 70 | 101 | 94 | 94 | 94 | 94 | 94 |
| Florida | + | 2 | + | + | + | + | + |
| Illinois | + | + | + | + | + | + | + |
| Louisiana | 95 | 109 | 105 | 104 | 106 | 107 | 106 |
| Minnesota | 1 | 2 | + | + | + | + | + |
| Mississippi | 18 | 18 | 10 | 10 | 10 | 10 | 10 |
| Missouri | 10 | 20 | 29 | 29 | 29 | 29 | 29 |
| New York | + | + | + | + | + | + | + |
| South Carolina | + | + | + | + | + | + | + |
| Tennessee | + | + | + | + | + | + | + |
| Texas | 218 | 100 | 54 | 54 | 54 | 54 | 54 |
| Total | 525 | 521 | 474 | 474 | 476 | 477 | 476 |

+ Does not exceed 0.5 kt.

Note: Totals may not sum due to independent rounding.

Methodology

The methodology used to estimate CH₄ emissions from rice cultivation is based on a combination of IPCC Tier 1 and 3 approaches. The Tier 3 method utilizes a process-based model (DAYCENT) to estimate CH₄ emissions from rice cultivation (Cheng et al. 2013), and has been tested in the United States (See Annex 3.12) and Asia (Cheng et al. 2013, 2014). The model simulates hydrological conditions and thermal regimes, organic matter decomposition, root exudation, rice plant growth and its influence on oxidation of CH₄, as well as CH₄ transport through the plant and via ebullition (Cheng et al. 2013). The method simulates the influence of organic amendments and rice straw management on methanogenesis in the flooded soils. In addition to CH₄ emissions, DAYCENT simulates soil C stock changes and N₂O emissions (Parton et al. 1987 and 1998; Del Grosso et al. 2010), and allows for a seamless set of simulations for crop rotations that include both rice and non-rice crops.

The Tier 1 method is applied to estimate CH₄ emissions from rice when grown in rotation with crops that are not simulated by DAYCENT, such as vegetables and perennial/horticultural crops. The Tier 1 method is used for areas converted between agriculture (i.e., cropland and grassland) and other land uses, such as forest land, wetland, and settlements. In addition, the Tier 1 method is used to estimate CH₄ emissions from organic soils (i.e., Histosols) and from areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume). The Tier 3 method using DAYCENT has not been fully tested for estimating emissions associated with these crops and rotations, land uses, as well as organic soils or cobbly, gravelly, and shaley mineral soils.

The Tier 1 method for estimating CH₄ emissions from rice production utilizes a default base emission rate and scaling factors (IPCC 2006). The base emission factor represents emissions for continuously flooded fields with no organic amendments. Scaling factors are used to adjust for water management and organic amendments that differ from continuous flooding with no organic amendments. The method accounts for pre-season and growing season flooding; types and amounts of organic amendments; and the number of rice production seasons within a single year (i.e., single cropping, ratooning, etc.). The Tier 1 analysis is implemented in the Agriculture and Land Use National Greenhouse Gas Inventory (ALU) software (Ogle et al. 2016).⁶

Rice cultivation areas are based on cropping and land use histories recorded in the USDA National Resources Inventory (NRI) survey (USDA-NRCS 2013). The NRI is a statistically-based sample of all non-federal land, and includes 380,956 survey points of which 2,072 are in locations with rice cultivation. The Tier 3 method is used to estimate CH₄ emissions from 1,852 of the NRI survey locations, and the remaining 220 survey locations are estimated with the Tier 1 method. Each NRI survey point is associated with an “expansion factor” that allows scaling of CH₄ emissions from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some management information in the NRI (e.g., crop type, soil attributes, and irrigation) were collected on a 5-year cycle beginning in 1982, along with cropping rotation data in 4 out of 5 years for each 5 year time period (i.e., 1979 to 1982, 1984 to 1987, 1989 to 1992, and 1994 to 1997). The NRI program began collecting annual data in 1998, with data currently available through 2012 (USDA-NRCS 2015). This Inventory only uses NRI data through 2010 because newer data were not made available in time to incorporate the additional years of data. The harvested rice areas in each state are presented in Table 5-12.

Table 5-12: Rice Area Harvested (1,000 Hectares)

| State/Crop | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------|------|------|------|------|------|------|------|
| Arkansas | 601 | 839 | 800 | 800 | 801 | 801 | 800 |
| California | 197 | 270 | 274 | 274 | 274 | 274 | 274 |
| Florida | 0 | 4 | 0 | 0 | 0 | 0 | 0 |
| Illinois | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| Louisiana | 365 | 375 | 315 | 313 | 317 | 316 | 315 |
| Minnesota | 5 | 6 | 1 | 1 | 1 | 1 | 1 |
| Mississippi | 104 | 113 | 53 | 53 | 53 | 53 | 53 |
| Missouri | 46 | 82 | 105 | 105 | 105 | 105 | 105 |
| New York | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Carolina | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

⁶ See <<http://www.nrel.colostate.edu/projects/ALUsoftware/>>.

| | | | | | | | |
|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Tennessee | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| Texas | 323 | 161 | 73 | 73 | 73 | 73 | 72 |
| Total | 1,641 | 1,852 | 1,621 | 1,619 | 1,624 | 1,622 | 1,620 |

Notes: Totals may not sum due to independent rounding. States are included if NRI reports rice areas at any time between 1990 and 2014.

The Southeastern states have sufficient growing periods for a ratoon crop in some years. For example, in Arkansas, the length of growing season is occasionally sufficient for ratoon crops on an average of 1 percent of the rice fields. No data are available about ratoon crops in Missouri or Mississippi, and the average amount of ratooning in Arkansas was assigned to these states. Ratoon cropping occurs much more frequently in Louisiana (LSU 2015 for years 2000 through 2013, 2015) and Texas (TAMU 2015 for years 1993 through 2014), averaging 32 percent and 48 percent of rice acres planted, respectively. Florida also has a large fraction of area with a ratoon crop (45 percent). Ratoon rice crops are not grown in California. Ratooned crop area as a percent of primary crop area is presented in Table 5-13.

Table 5-13: Average Ratooned Area as Percent of Primary Growth Area (Percent)

| State | 1990-2014 |
|--------------------------|-----------|
| Arkansas ^a | 1% |
| California | 0% |
| Florida ^b | 45% |
| Louisiana ^c | 32% |
| Mississippi ^a | 1% |
| Missouri ^a | 1% |
| Texas ^d | 48% |

^a Arkansas: 1990–2000 (Slaton 1999 through 2001); 2001–2011 (Wilson 2002 through 2007, 2009 through 2012); 2012–2013 (Hardke 2013, 2014).

^b Florida - Ratoon: 1990–2000 (Schueneman 1997, 1999 through 2001); 2001 (Deren 2002); 2002–2003 (Kirstein 2003 through 2004, 2006); 2004 (Cantens 2004 through 2005); 2005–2013 (Gonzalez 2007 through 2014)

^c Louisiana: 1990–2013 (Linscombe 1999, 2001 through 2014).

^d Texas: 1990–2002 (Klosterboer 1997, 1999 through 2003); 2003–2004 (Stansel 2004 through 2005); 2005 (Texas Agricultural Experiment Station 2006); 2006–2013 (Texas Agricultural Experiment Station 2007 through 2014).

While rice crop production in the United States includes a minor amount of land with mid-season drainage or alternate wet-dry periods, the majority of rice growers use continuously flooded water management systems (Hardke 2015; UCCE 2015; Hollier 1999; Way et al. 2014). Therefore, continuous flooding was assumed in the DAYCENT simulations and the Tier 1 method. Variation in flooding can be incorporated in the future Inventories if water management data are collected.

Winter flooding is another key practice associated with water management in rice fields, and the impact of winter flooding on CH₄ emissions is addressed in the Tier 3 and Tier 1 analyses. Flooding is used to prepare fields for the next growing season, and to create waterfowl habitat (Young 2013; Miller et al. 2010; Fleskes et al. 2005). Fitzgerald et al. (2000) suggests that as much as 50 percent of the annual emissions may occur during the winter flood. Winter flooding is a common practice with an average of 34 percent of fields managed with winter flooding in California (Miller et al. 2010; Fleskes et al. 2005), and approximately 21 percent of the fields managed with winter flooding in Arkansas (Wilson and Branson 2005 and 2006; Wilson and Runsick 2007 and 2008; Wilson et al. 2009 and 2010; Hardke and Wilson 2013 and 2014; Hardke 2015). No data are available on winter flooding for Texas, Louisiana, Florida, Missouri, or Mississippi. For these states, the average amount of flooding is assumed to be similar to Arkansas. In addition, the amount of flooding is assumed to be relatively constant over the Inventory time period.

Uncertainty and Time-Series Consistency

Sources of uncertainty in the Tier 3 method include management practices, uncertainties in model structure (i.e., algorithms and parameterization), and variance associated with the NRI sample. Sources of uncertainty in the IPCC (2006) Tier 1 method include the emission factors, management practices, and variance associated with the NRI sample. A Monte Carlo analysis was used to propagate uncertainties in the Tier 1 and 3 methods, and the uncertainties from each approach are combined to produce the final CH₄ emissions estimate using simple error

propagation (IPCC 2006). Additional details on the uncertainty methods are provided in Annex 3.12. Rice cultivation CH₄ emissions in 2014 were estimated to be between 9.9 and 13.9 MMT CO₂ Eq. at a 95 percent confidence level, which indicates a range of 17 percent below to 17 percent above the actual 2014 emission estimate of 11.9 MMT CO₂ Eq. (see Table 5-14).

Table 5-14: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Rice Cultivation (MMT CO₂ Eq. and Percent)

| Source | Inventory Method | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-------------------------|------------------|-----------------------|--|--|-------------|-------------|-------------|
| | | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Rice Cultivation | Tier 3 | CH ₄ | 10.7 | 8.8 | 12.6 | -18% | 18% |
| Rice Cultivation | Tier 1 | CH ₄ | 1.2 | 0.8 | 1.6 | -33% | 40% |
| Rice Cultivation | Total | CH₄ | 11.9 | 9.9 | 13.9 | -17% | 17% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations are applied to the entire time series to ensure time-series consistency from 1990 through 2014 using the Tier 1 and 3 methods. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Quality control measures include checking input data, model scripts, and results to ensure data are properly handled throughout the inventory process. Some errors were found in the handling of the cropping rotations and management data for the DAYCENT simulations that were corrected. Data inputs to the ALU software for the Tier 1 method are checked to ensure proper handling of the data through the software. There was an error in the cultivation period that was corrected in the calculation of the emission factor. Inventory reporting forms and text are reviewed and revised as needed to correct transcription errors. No errors were found in the reporting forms and text.

Model results are compared to field measurements to verify if results adequately represent CH₄ emissions. The comparisons included over 15 long-term experiments, representing about 800 combinations of management treatments across all of the sites. A statistical relationship was developed to assess uncertainties in the model structure and adjust for model bias and assess precision in the resulting estimates (methods are described in Ogle et al. 2007). See Annex 3.12 for more information.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements: (1) using the DAYCENT model to estimate CH₄ emissions from the majority of flooded rice production, (2) estimating CH₄ emissions from the remainder of the flooded rice area using a Tier 1 method, and (3) driving the DAYCENT simulations with updated input data for land management from the National Resources Inventory extending the time series through 2010. These changes resulted in an increase in emissions of approximately 30 percent on average relative to the previous Inventory and a decrease in uncertainty from confidence interval with a lower bound of 50 percent and upper bound of 91 percent to a confidence interval with an upper and lower bound of 17 percent.

Planned Improvements

Improvements are underway to update the land use and management data from the 2012 USDA NRI so that the time series of activity data are extended through 2012. Fertilization, tillage activity data, and water management will also be updated as part of this improvement to the extent that new data are available on these practices.

5.4 Agricultural Soil Management (IPCC Source Category 3D)

Nitrous oxide is naturally produced in soils through the microbial processes of nitrification and denitrification that is driven by the availability of mineral nitrogen (N) (Firestone and Davidson 1989).⁷ Mineral N is made available in soils through decomposition of soil organic matter and plant litter, as well as asymbiotic fixation of N from the atmosphere.⁸ A number of agricultural activities increase mineral N availability in soils that lead to direct N₂O emissions from nitrification and denitrification at the site of a management activity (see Figure 5-2) (Mosier et al. 1998), including fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage of organic soils (i.e., soils with a high organic matter content, otherwise known as Histosols⁹) in croplands and grasslands (IPCC 2006). Additionally, agricultural soil management activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence N mineralization by impacting moisture and temperature regimes in soils. Indirect emissions of N₂O occur when N is transported from a site and is subsequently converted to N₂O; there are two pathways for indirect emissions: (1) volatilization and subsequent atmospheric deposition of applied/mineralized N, and (2) surface runoff and leaching of applied/mineralized N into groundwater and surface water.¹⁰

Direct and indirect emissions from agricultural lands are included in this section (i.e., cropland and grassland as defined in Section 6.1 Representation of the U.S. Land Base; N₂O emissions from Forest Land and Settlements are found in Chapter 6). The U.S. Inventory includes all greenhouse gas emissions from managed land based on guidance in IPCC (2006), and consequently N mineralization from decomposition of soil organic matter and asymbiotic N fixation are also included in this section to fully address emissions from the managed land base (see Methodology section for more information).

⁷ Nitrification and denitrification are driven by the activity of microorganisms in soils. Nitrification is the aerobic microbial oxidation of ammonium (NH₄⁺) to nitrate (NO₃⁻), and denitrification is the anaerobic microbial reduction of nitrate to N₂. Nitrous oxide is a gaseous intermediate product in the reaction sequence of denitrification, which leaks from microbial cells into the soil and then into the atmosphere. Nitrous oxide is also produced during nitrification, although by a less well-understood mechanism (Nevison 2000).

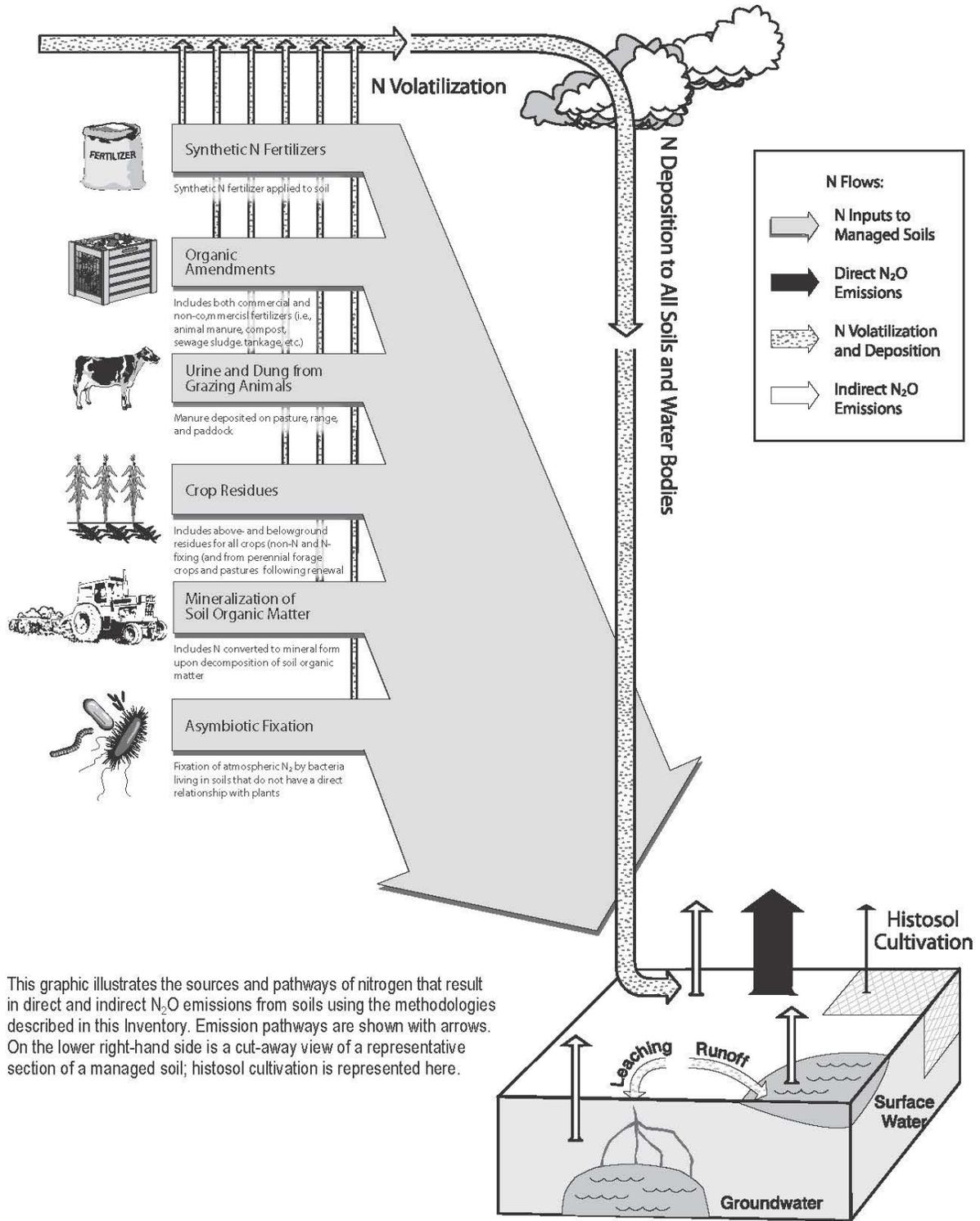
⁸ Asymbiotic N fixation is the fixation of atmospheric N₂ by bacteria living in soils that do not have a direct relationship with plants.

⁹ Drainage of organic soils in former wetlands enhances mineralization of N-rich organic matter, thereby increasing N₂O emissions from these soils.

¹⁰ These processes entail volatilization of applied or mineralized N as NH₃ and NO_x, transformation of these gases within the atmosphere (or upon deposition), and deposition of the N primarily in the form of particulate NH₄⁺, nitric acid (HNO₃), and NO_x.

Figure 5-2: Sources and Pathways of N that Result in N₂O Emissions from Agricultural Soil Management

Sources and Pathways of N that Result in N₂O Emissions from Agricultural Soil Management



This graphic illustrates the sources and pathways of nitrogen that result in direct and indirect N₂O emissions from soils using the methodologies described in this Inventory. Emission pathways are shown with arrows. On the lower right-hand side is a cut-away view of a representative section of a managed soil; histosol cultivation is represented here.

Agricultural soils produce the majority of N₂O emissions in the United States. Estimated emissions from this source in 2014 are 318.4 MMT CO₂ Eq. (1,068 kt) (see Table 5-15 and Table 5-16). Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2014, although overall emissions are 5 percent higher in 2014 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. From 1990 to 2014, on average cropland accounted for approximately 70 percent of total direct emissions, while grassland accounted for approximately 30 percent. The percentages for indirect emissions on average are approximately 65 percent for croplands, 35 percent for grasslands. Estimated direct and indirect N₂O emissions by sub-source category are shown in Table 5-17 and Table 5-18.

Table 5-15: N₂O Emissions from Agricultural Soils (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Direct | 245.0 | 248.3 | 263.8 | 264.5 | 264.5 | 261.2 | 261.0 |
| Cropland | 171.9 | 174.4 | 185.7 | 186.9 | 187.9 | 185.2 | 185.0 |
| Grassland | 73.2 | 73.9 | 78.1 | 77.6 | 76.6 | 76.0 | 76.0 |
| Indirect | 58.2 | 48.9 | 56.9 | 58.6 | 58.5 | 57.4 | 57.3 |
| Cropland | 36.2 | 34.0 | 39.7 | 40.6 | 41.1 | 40.3 | 40.2 |
| Grassland | 22.1 | 14.9 | 17.2 | 17.9 | 17.5 | 17.2 | 17.2 |
| Total | 303.3 | 297.2 | 320.7 | 323.1 | 323.1 | 318.6 | 318.4 |

Note: Totals may not sum due to independent rounding.

Table 5-16: N₂O Emissions from Agricultural Soils (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|--------------|------------|--------------|--------------|--------------|--------------|--------------|
| Direct | 822 | 833 | 885 | 888 | 888 | 877 | 876 |
| Cropland | 577 | 585 | 623 | 627 | 630 | 621 | 621 |
| Grassland | 246 | 248 | 262 | 260 | 257 | 255 | 255 |
| Indirect | 195 | 164 | 191 | 196 | 196 | 193 | 192 |
| Cropland | 121 | 114 | 133 | 136 | 138 | 135 | 135 |
| Grassland | 74 | 50 | 58 | 60 | 59 | 58 | 58 |
| Total | 1,018 | 997 | 1,076 | 1,084 | 1,084 | 1,069 | 1,068 |

Note: Totals may not sum due to independent rounding.

Table 5-17: Direct N₂O Emissions from Agricultural Soils by Land Use Type and N Input Type (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Cropland | 171.9 | 174.4 | 185.7 | 186.9 | 187.9 | 185.2 | 185.0 |
| Mineral Soils | 168.6 | 171.2 | 182.6 | 183.9 | 184.9 | 182.2 | 182.0 |
| Synthetic Fertilizer | 59.2 | 61.4 | 59.3 | 61.0 | 61.8 | 59.5 | 59.3 |
| Organic Amendment ^a | 11.9 | 12.9 | 13.4 | 13.5 | 13.6 | 13.5 | 13.5 |
| Residue N ^b | 25.9 | 26.6 | 27.8 | 27.6 | 27.5 | 27.5 | 27.6 |
| Mineralization and Asymbiotic Fixation | 71.6 | 70.3 | 82.2 | 81.8 | 82.0 | 81.6 | 81.6 |
| Drained Organic Soils | 3.2 | 3.2 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| Grassland | 73.2 | 73.9 | 78.1 | 77.6 | 76.6 | 76.0 | 76.0 |
| Mineral Soils | 70.3 | 71.0 | 75.5 | 74.9 | 74.0 | 73.3 | 73.3 |
| Synthetic Fertilizer | 1.1 | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | 1.4 |
| PRP Manure | 13.4 | 12.3 | 12.5 | 11.9 | 11.0 | 10.3 | 10.3 |
| Managed Manure ^c | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Sewage Sludge | 0.2 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 |
| Residue N ^d | 19.7 | 21.0 | 21.8 | 21.7 | 21.7 | 21.7 | 21.6 |
| Mineralization and Asymbiotic Fixation | 35.8 | 35.8 | 39.1 | 39.4 | 39.4 | 39.4 | 39.2 |
| Drained Organic Soils | 2.9 | 2.9 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| Total | 245.0 | 248.3 | 263.8 | 264.5 | 264.5 | 261.2 | 261.0 |

^a Organic amendment inputs include managed manure, daily spread manure, and commercial organic fertilizers (i.e., dried blood, dried manure, tankage, compost, and other).

^b Cropland residue N inputs include N in unharvested legumes as well as crop residue N.

^c Managed manure inputs include managed manure and daily spread manure amendments that are applied to grassland soils.

^d Grassland residue N inputs include N in ungrazed legumes as well as ungrazed grass residue N.

Table 5-18: Indirect N₂O Emissions from Agricultural Soils (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Cropland | 36.2 | 34.0 | 39.7 | 40.6 | 41.1 | 40.3 | 40.2 |
| Volatilization & Atm. | | | | | | | |
| Deposition | 13.0 | 13.8 | 13.9 | 14.3 | 14.5 | 14.2 | 14.2 |
| Surface Leaching & Run-Off | 23.2 | 20.2 | 25.8 | 26.4 | 26.6 | 26.0 | 26.0 |
| Grassland | 22.1 | 14.9 | 17.2 | 17.9 | 17.5 | 17.2 | 17.2 |
| Volatilization & Atm. | | | | | | | |
| Deposition | 4.4 | 4.7 | 4.8 | 4.7 | 4.6 | 4.5 | 4.5 |
| Surface Leaching & Run-Off | 17.7 | 10.2 | 12.4 | 13.2 | 12.9 | 12.6 | 12.6 |
| Total | 58.2 | 48.9 | 56.9 | 58.6 | 58.5 | 57.4 | 57.3 |

Note: Totals may not sum due to independent rounding.

Figure 5-3 and Figure 5-4 show regional patterns for direct N₂O emissions for croplands and grasslands, and Figure 5-5 and Figure 5-6 show N losses from volatilization, leaching, and runoff that lead to indirect N₂O emissions. Annual emissions and N losses in 2014 are shown for the Tier 3 Approach only.

Direct N₂O emissions from croplands tend to be high in the Corn Belt (Illinois, Iowa, Indiana, Ohio, southern and western Minnesota, and eastern Nebraska), where a large portion of the land is used for growing highly fertilized corn and N-fixing soybean crops (see Figure 5-3). Kansas has high direct emissions associated with N management in wheat production systems, in addition to high emissions in North and South Dakota. Hay production in Missouri also contribute relatively large amounts of direct N₂O emissions, along with a combination of irrigated cropping in west Texas and hay production in east Texas. Direct emissions are low in many parts of the eastern United States because only a small portion of land is cultivated as well as in many western states where rainfall and access to irrigation water are limited.

Direct emissions from grasslands are highest in the central and western United States (see Figure 5-4) where a high proportion of the land is used for cattle grazing. In contrast, most areas in the Great Lake states, the Northeast, and Southeast have moderate to low emissions due to less land dedicated to livestock grazing. However, emissions from the Northeast and Great Lake states tend to be higher on a per unit area basis compared to other areas in the country. This effect is likely due to a larger impact of freeze-thaw cycles in these regions, and possibly greater water-filled pore space in the soil, which are key drivers of N₂O emissions (Kessavalou et al. 1998; Bateman and Baggs 2005).

Nitrogen losses from croplands and grasslands that lead to indirect N₂O emissions (Figure 5-5 and Figure 5-6) have similar spatial patterns as direct N₂O emissions. This is not surprising because N losses leading to indirect N₂O emissions are influenced by the same variables that drive direct N₂O emissions (N inputs, weather patterns, and soil characteristics). However, there are some exceptions to the similarity in patterns. For example, there are limited amounts of nitrate leaching from western grasslands due to lower precipitation and leaching through the soil profile, compared to grasslands in the central United States, whereas the N₂O emissions are higher in the western grasslands.

Figure 5-3: Crops, 2014 Annual Direct N₂O Emissions Estimated Using the Tier 3 DAYCENT Model (MMT CO₂ Eq./year)

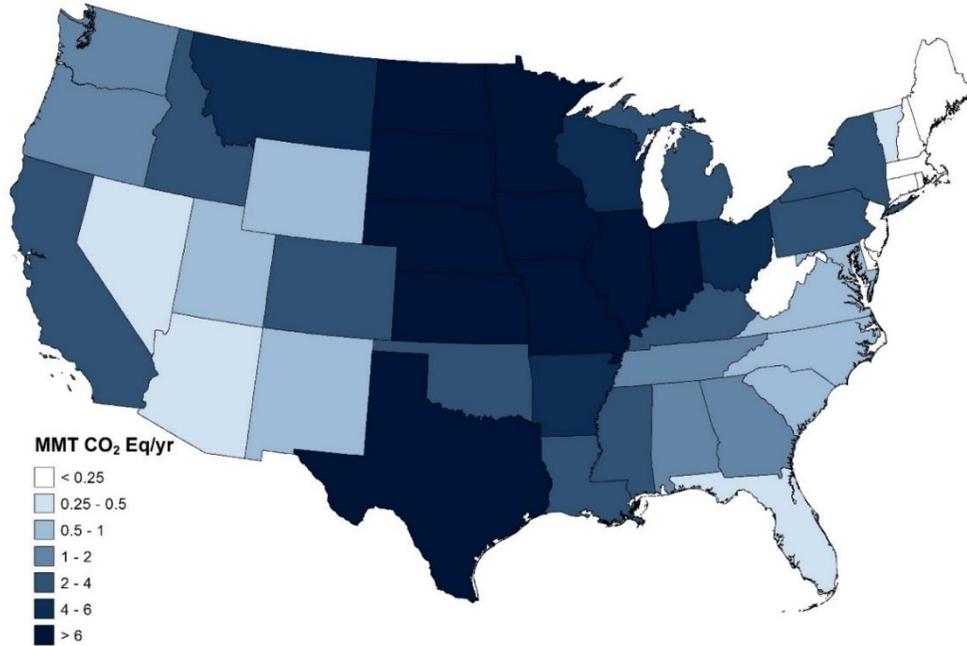


Figure 5-4: Grasslands, 2014 Annual Direct N₂O Emissions Estimated Using the Tier 3 DAYCENT Model (MMT CO₂ Eq./year)

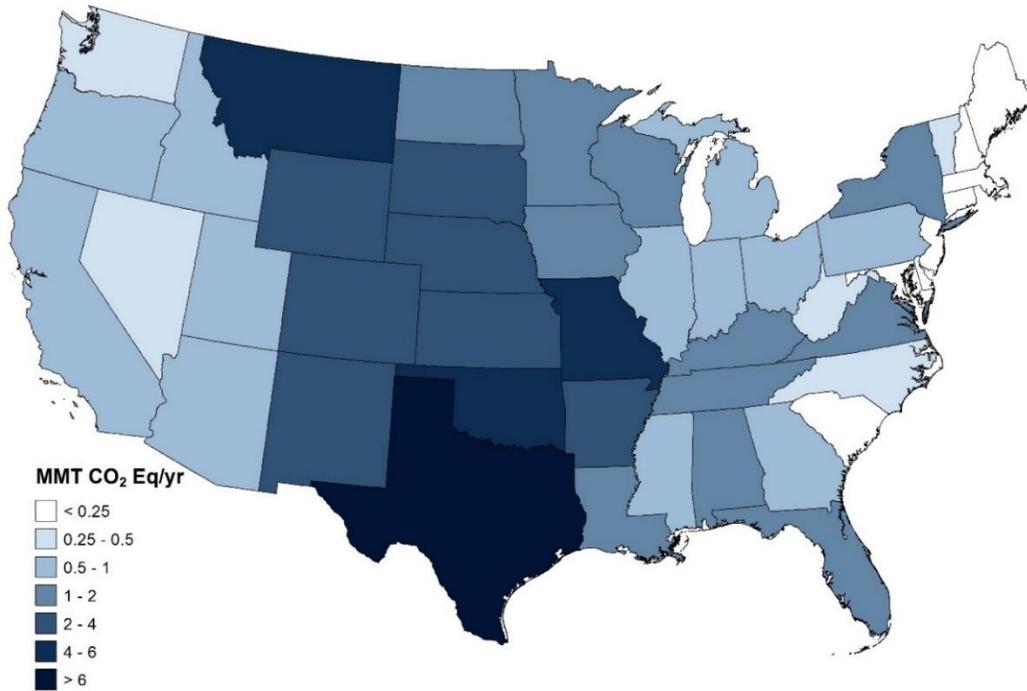


Figure 5-5: Crops, 2014 Average Annual N Losses Leading to Indirect N₂O Emissions Estimated Using the Tier 3 DAYCENT Model (kt N/year)

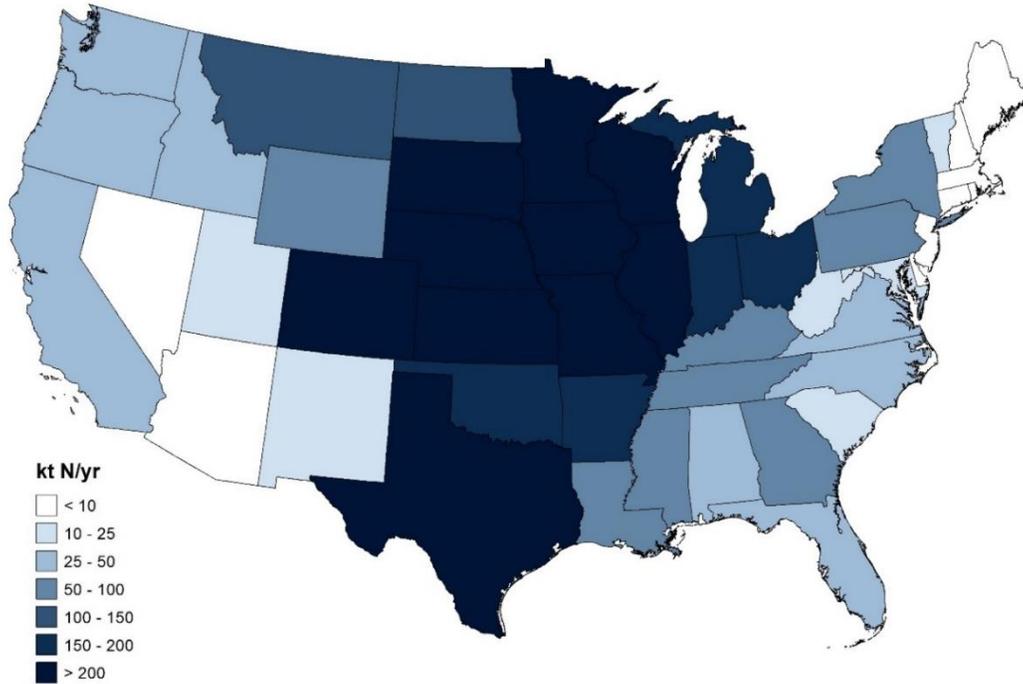
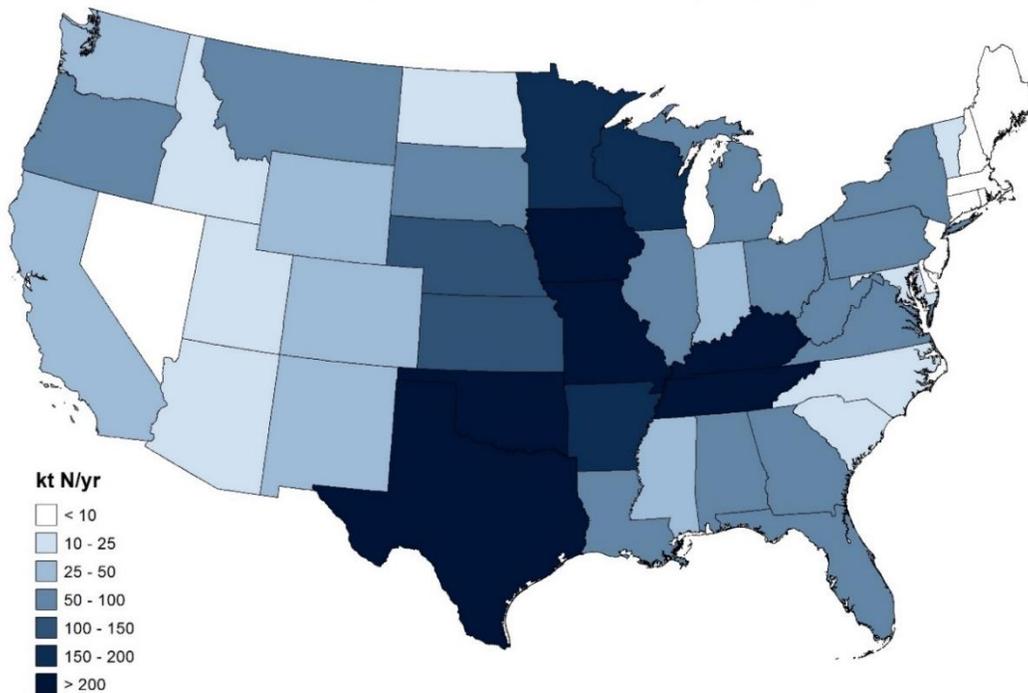


Figure 5-6: Grasslands, 2014 Average Annual N Losses Leading to Indirect N₂O Emissions Estimated Using the Tier 3 DAYCENT Model (kt N/year)



Methodology

The 2006 IPCC Guidelines (IPCC 2006) divide emissions from the Agricultural Soil Management source category into five components, including (1) direct emissions from N additions to cropland and grassland mineral soils from synthetic fertilizers, sewage sludge applications, crop residues, organic amendments, and biological N fixation associated with planting of legumes on cropland and grassland soils; (2) direct emissions from soil organic matter mineralization due to land use and management change; (3) direct emissions from drainage of organic soils in croplands and grasslands; (4) direct emissions from soils due to manure deposited by livestock on PRP grasslands; and (5) indirect emissions from soils and water from N additions and manure deposition to soils that lead to volatilization, leaching, or runoff of N and subsequent conversion to N₂O.

The United States has adopted methods in the IPCC (2006) for the Agricultural Soil Management source category. These methods include (1) estimating the contribution of N in crop residues to indirect soil N₂O emissions; (2) adopting the revised emission factor for direct N₂O emissions for Tier 1 methods used in the Inventory (described later in this section); (3) removing double counting of emissions from N-fixing crops associated with biological N fixation and crop residue N input categories; (4) using revised crop residue statistics to compute N inputs to soils from harvest yield data; and (5) estimating emissions associated with land use and management change (which can significantly change the N mineralization rates from soil organic matter). The Inventory also reports on total emissions from all managed land, which is a proxy for anthropogenic impacts on greenhouse gas emissions (IPCC 2006), including direct and indirect N₂O emissions from asymbiotic fixation¹¹ and mineralization of soil organic matter and litter. One recommendation from IPCC (2006) that has not been completely adopted is the estimation of emissions from grassland pasture renewal, which involves occasional plowing to improve forage production in pastures. Currently no data are available to address pasture renewal.

Direct N₂O Emissions

The methodology used to estimate direct N₂O emissions from agricultural soil management in the United States is based on a combination of IPCC Tier 1 and 3 approaches (IPCC 2006; Del Grosso et al. 2010). A Tier 3 process-based model (DAYCENT) is used to estimate direct emissions from a variety of crops that are grown on mineral (i.e., non-organic) soils, including alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat; as well as the direct emissions from non-federal grasslands with the exception of sewage sludge amendments (Del Grosso et al. 2010). The Tier 3 approach has been specifically designed and tested to estimate N₂O emissions in the United States, accounting for more of the environmental and management influences on soil N₂O emissions than the IPCC Tier 1 method (see Box 5-1 for further elaboration). Moreover, the Tier 3 approach allows for the Inventory to address direct N₂O emissions and soil C stock changes from mineral cropland soils in a single analysis. Carbon and N dynamics are linked in plant-soil systems through biogeochemical processes of microbial decomposition and plant production (McGill and Cole 1981). Coupling the two source categories (i.e., agricultural soil C and N₂O) in a single inventory analysis ensures that there is consistent activity data and treatment of the processes, and interactions are taken into account between C and N cycling in soils.

The Tier 3 approach is based on the cropping and land use histories recorded in the USDA NRI survey (USDA-NRCS 2013). The NRI is a statistically-based sample of all non-federal land, and includes 380,956 points on agricultural land for the conterminous United States that are included in the Tier 3 method. The Tier 1 approach is used to estimate the emissions from the remaining 92,013 in the NRI survey that are designated as cropland or grassland (discussed later in this section). Each point is associated with an “expansion factor” that allows scaling of N₂O emissions from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. For cropland, data were collected in 4 out of 5 years in the cycle (i.e., 1979 through 1982, 1984 through 1987, 1989 through 1992, and 1994 through 1997). In 1998, the NRI program began collecting annual data, the annual

¹¹ N inputs from asymbiotic N fixation are not directly addressed in 2006 IPCC Guidelines, but are a component of the total emissions from managed lands and are included in the Tier 3 approach developed for this source.

data are currently available through 2012 (USDA-NRCS 2015) although this Inventory only uses NRI data through 2010 because newer data were not made available in time to incorporate the additional years into this Inventory.

Box 5-1: Tier 1 vs. Tier 3 Approach for Estimating N₂O Emissions

The IPCC (2006) Tier 1 approach is based on multiplying activity data on different N inputs (i.e., synthetic fertilizer, manure, N fixation, etc.) by the appropriate default IPCC emission factors to estimate N₂O emissions on an input-by-input basis. The Tier 1 approach requires a minimal amount of activity data, readily available in most countries (e.g., total N applied to crops); calculations are simple; and the methodology is highly transparent. In contrast, the Tier 3 approach developed for this Inventory employs a process-based model (i.e., DAYCENT) that represents the interaction of N inputs, land use and management, as well as environmental conditions at specific locations. Consequently, the Tier 3 approach produces more accurate estimates; it accounts more comprehensively for land-use and management impacts and their interaction with environmental factors (i.e., weather patterns and soil characteristics), which will enhance or dampen anthropogenic influences. However, the Tier 3 approach requires more detailed activity data (e.g., crop-specific N amendment rates), additional data inputs (i.e., daily weather, soil types, etc.), and considerable computational resources and programming expertise. The Tier 3 methodology is less transparent, and thus it is critical to evaluate the output of Tier 3 methods against measured data in order to demonstrate that the method is an improvement over lower tier methods for estimating emissions (IPCC 2006). Another important difference between the Tier 1 and Tier 3 approaches relates to assumptions regarding N cycling. Tier 1 assumes that N added to a system is subject to N₂O emissions only during that year and cannot be stored in soils and contribute to N₂O emissions in subsequent years. This is a simplifying assumption that is likely to create bias in estimated N₂O emissions for a specific year. In contrast, the process-based model used in the Tier 3 approach includes the legacy effect of N added to soils in previous years that is re-mineralized from soil organic matter and emitted as N₂O during subsequent years.

DAYCENT is used to estimate N₂O emissions associated with production of alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat, but is not applied to estimate N₂O emissions from other crops or rotations with other crops,¹² such as sugarcane, some vegetables, tobacco, and perennial/horticultural crops. Areas that are converted between agriculture (i.e., cropland and grassland) and other land uses, such as forest land, wetland and settlements, are not simulated with DAYCENT. DAYCENT is also not used to estimate emissions from land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume), or to estimate emissions from drained organic soils (Histosols). The Tier 3 method has not been fully tested for estimating N₂O emissions associated with these crops and rotations, land uses, as well as organic soils or cobbly, gravelly, and shaley mineral soils. In addition, federal grassland areas are not simulated with DAYCENT due to limited activity on land use histories. For areas that are not included in the DAYCENT simulations, the Tier 1 IPCC (2006) methodology is used to estimate (1) direct emissions from crops on mineral soils that are not simulated by DAYCENT; (2) direct emissions from Pasture/Range/Paddock (PRP) on federal grasslands; and (3) direct emissions from drained organic soils in croplands and grasslands.

Tier 3 Approach for Mineral Cropland Soils

The DAYCENT biogeochemical model (Parton et al. 1998; Del Grosso et al. 2001 and 2011) is used to estimate direct N₂O emissions from mineral cropland soils that are managed for production of a wide variety of crops based on the cropping histories in the 2010 NRI (USDA-NRCS 2013). The crops include alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat. Crops simulated by DAYCENT are grown on approximately 91 percent of total cropland area in the United States. For agricultural systems in the central region of the United States, crop production for key crops (i.e., corn, soybeans, sorghum, cotton, and wheat) is simulated in DAYCENT with a

¹² A small proportion of the major commodity crop production, such as corn and wheat, is included in the Tier 1 analysis because these crops are rotated with other crops or land uses (e.g., forest lands) that are not simulated by DAYCENT.

NASA-CASA production algorithm (Potter et al. 1993; Potter et al. 2007) using the Moderate Resolution Imaging Spectroradiometer (MODIS) Enhanced Vegetation Index (EVI) products, MOD13Q1 and MYD13Q1, with a pixel resolution of 250m.¹³

DAYCENT is used to estimate direct N₂O emissions due to mineral N available from the following sources: (1) the application of synthetic fertilizers; (2) the application of livestock manure; (3) the retention of crop residues and subsequent mineralization of N during microbial decomposition (i.e., leaving residues in the field after harvest instead of burning or collecting residues); (4) mineralization of soil organic matter; and (5) asymbiotic fixation. Note that commercial organic fertilizers (TVA 1991 through 1994; AAPFCO 1995 through 2014) are addressed with the Tier 1 method because county-level application data would be needed to simulate applications in DAYCENT, and currently data are only available at the national scale. The third and fourth sources are generated internally by the DAYCENT model.

Synthetic fertilizer data are based on fertilizer use and rates by crop type for different regions of the United States that are obtained primarily from the USDA Economic Research Service Cropping Practices Survey (USDA-ERS 1997, 2011) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of livestock manure application to cropland during 1997 are estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. The adjustments are based on county-scale ratios of manure available for application to soils in other years relative to 1997 (see Annex 3.12 for further details). Greater availability of managed manure N relative to 1997 is assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 is assumed to reduce the amended area. Data on the county-level N available for application is estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and including the addition of N from bedding materials. Nitrogen losses include direct N₂O emissions, volatilization of ammonia and NO_x, runoff and leaching, and poultry manure used as a feed supplement. For unmanaged systems, it is assumed that no N losses or additions occur prior to the application of manure to the soil. More information on livestock manure production is available in the Manure Management Section 5.2 and Annex 3.11.

The IPCC approach considers crop residue N and N mineralized from soil organic matter as activity data. However, they are not treated as activity data in DAYCENT simulations because residue production, symbiotic N fixation (e.g., legumes), mineralization of N from soil organic matter, and asymbiotic N fixation are internally generated by the model as part of the simulation. In other words, DAYCENT accounts for the influence of symbiotic N fixation, mineralization of N from soil organic matter and crop residue retained in the field, and asymbiotic N fixation on N₂O emissions, but these are not model inputs. The N₂O emissions from crop residues are reduced by approximately 3 percent to avoid double-counting associated with non-CO₂ greenhouse gas emissions from agricultural residue burning. The estimate of residue burning is based on state inventory data (ILENR 1993; Oregon Department of Energy 1995; Noller 1996; Wisconsin Department of Natural Resources 1993; Cibrowski 1996).

Additional sources of data are used to supplement the mineral N (USDA ERS 1997, 2011), livestock manure (Edmonds et al. 2003), and land-use information (USDA-NRCS 2013). The Conservation Technology Information Center (CTIC 2004) provided annual data on tillage activity with adjustments for long-term adoption of no-till agriculture (Towery 2001). Tillage data has an influence on soil organic matter decomposition and subsequent soil N₂O emissions. The time series of tillage data began in 1989 and ended in 2004, so further changes in tillage practices since 2004 are not currently captured in the Inventory. Daily weather data are used as an input in the model simulations, based on gridded weather data at a 32 km scale from the North America Regional Reanalysis Product (NARR) (Mesinger et al. 2006). Soil attributes are obtained from the Soil Survey Geographic Database (SSURGO) (Soil Survey Staff 2011).

Each 2010 NRI point is run 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulations for the analysis. Soil N₂O emission estimates from DAYCENT are adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Del Grosso et al. 2010). Soil N₂O emissions and 95 percent confidence intervals are estimated for each year between 1990 and 2010, but emissions from 2011 to 2014 are assumed to be similar to 2010. Annual data are currently available through 2012

¹³ See <https://lpdaac.usgs.gov/products/modis_products_table>.

(USDA-NRCS 2015), however this Inventory only uses NRI data through 2010 because newer data were not available in time to incorporate the additional years.

Nitrous oxide emissions from managed agricultural lands are the result of interactions among anthropogenic activities (e.g., N fertilization, manure application, tillage) and other driving variables, such as weather and soil characteristics. These factors influence key processes associated with N dynamics in the soil profile, including immobilization of N by soil microbial organisms, decomposition of organic matter, plant uptake, leaching, runoff, and volatilization, as well as the processes leading to N₂O production (nitrification and denitrification). It is not possible to partition N₂O emissions into each anthropogenic activity directly from model outputs due to the complexity of the interactions (e.g., N₂O emissions from synthetic fertilizer applications cannot be distinguished from those resulting from manure applications). To approximate emissions by activity, the amount of mineral N added to the soil is determined for each source of mineral N and then divided by the total amount of mineral N in the soil according to the DAYCENT model simulation. The percentages are then multiplied by the total of direct N₂O emissions in order to approximate the portion attributed to key practices. This approach is only an approximation because it assumes that all N made available in soil has an equal probability of being released as N₂O, regardless of its source, which is unlikely to be the case (Delgado et al. 2009). However, this approach allows for further disaggregation of emissions by source of N, which is valuable for reporting purposes and is analogous to the reporting associated with the IPCC (2006) Tier 1 method, in that it associates portions of the total soil N₂O emissions with individual sources of N.

Tier 1 Approach for Mineral Cropland Soils

The IPCC (2006) Tier 1 methodology is used to estimate direct N₂O emissions for mineral cropland soils that are not simulated by DAYCENT. For the Tier 1 Approach, estimates of direct N₂O emissions from N applications are based on mineral soil N that is made available from the following practices: (1) the application of synthetic commercial fertilizers; (2) application of managed manure and non-manure commercial organic fertilizers; and (3) decomposition and mineralization of nitrogen from above- and below-ground crop residues in agricultural fields (i.e., crop biomass that is not harvested). Non-manure, commercial organic amendments are not included in the DAYCENT simulations because county-level data are not available.¹⁴ Consequently, commercial organic fertilizer, as well as additional manure that is not added to crops in the DAYCENT simulations, are included in the Tier 1 analysis. The following sources are used to derive activity data:

- A process-of-elimination approach is used to estimate synthetic N fertilizer additions for crop areas not simulated by DAYCENT. The total amount of fertilizer used on farms has been estimated at the county-level by the USGS from sales records (Ruddy et al. 2006), and these data are aggregated to obtain state-level N additions to farms. For 2002 through 2014, state-level fertilizer for on-farm use is adjusted based on annual fluctuations in total U.S. fertilizer sales (AAPFCO 1995 through 2007; AAPFCO 2008 through 2014).¹⁵ After subtracting the portion of fertilizer applied to crops and grasslands simulated by DAYCENT (see Tier 3 Approach for Cropland Mineral Soils Section and Grasslands Section for information on data sources), the remainder of the total fertilizer used on farms is assumed to be applied to crops that are not simulated by DAYCENT.
- Similarly, a process-of-elimination approach is used to estimate manure N additions for crops that are not simulated by DAYCENT. The amount of manure N applied in the Tier 3 approach to crops and grasslands is subtracted from total manure N available for land application (see Tier 3 Approach for Cropland Mineral Soils Section and Grasslands Section for information on data sources), and this difference is assumed to be applied to crops that are not simulated by DAYCENT.
- Commercial organic fertilizer additions are based on organic fertilizer consumption statistics, which are converted to units of N using average organic fertilizer N content (TVA 1991 through 1994, AAPFCO 1995 through 2011). Commercial fertilizers do include some manure and sewage sludge, but the amounts

¹⁴ Commercial organic fertilizers include dried blood, tankage, compost, and other, but the dried manure and sewage sludge is removed from the dataset in order to avoid double counting with other datasets that are used for manure N and sewage sludge.

¹⁵ Values are not available for 2013 and 2014 so a “least squares line” statistical extrapolation using the previous 5 years of data is used to arrive at an approximate value for these two years.

are removed from the commercial fertilizer data to avoid double counting with the manure N dataset described above and the sewage sludge amendment data discussed later in this section.

- Crop residue N is derived by combining amounts of above- and below-ground biomass, which are determined based on NRI crop area data (USDA-NRCS 2013), crop production yield statistics (USDA-NASS 2014), dry matter fractions (IPCC 2006), linear equations to estimate above-ground biomass given dry matter crop yields from harvest (IPCC 2006), ratios of below-to-above-ground biomass (IPCC 2006), and N contents of the residues (IPCC 2006).

The total increase in soil mineral N from applied fertilizers and crop residues is multiplied by the IPCC (2006) default emission factor to derive an estimate of direct N₂O emissions using the Tier 1 Approach.

Drainage of Organic Soils in Croplands and Grasslands

The IPCC (2006) Tier 1 methods are used to estimate direct N₂O emissions due to drainage of organic soils in croplands or grasslands at a state scale. State-scale estimates of the total area of drained organic soils are obtained from the 2010 NRI (USDA-NRCS 2013) using soils data from the Soil Survey Geographic Database (SSURGO) (Soil Survey Staff 2011). Temperature data from Daly et al. (1994 and 1998) are used to subdivide areas into temperate and tropical climates using the climate classification from IPCC (2006). Annual data are available between 1990 and 2010. Emissions are assumed to be similar to 2010 from 2011 to 2014 because no additional activity data are currently available from the NRI for the latter years. To estimate annual emissions, the total temperate area is multiplied by the IPCC default emission factor for temperate regions, and the total tropical area is multiplied by the IPCC default emission factor for tropical regions (IPCC 2006).

Direct N₂O Emissions from Grassland Soils

As with N₂O from croplands, the Tier 3 process-based DAYCENT model and Tier 1 method described in IPCC (2006) are combined to estimate emissions from non-federal grasslands and PRP manure N additions for federal grasslands, respectively. Grassland includes pasture and rangeland that produce grass forage primarily for livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are typically seeded grassland (possibly following tree removal) that may also have additional management, such as irrigation or interseeding legumes. DAYCENT is used to simulate N₂O emissions from NRI survey locations (USDA-NRCS 2013) on non-federal grasslands resulting from manure deposited by livestock directly onto pastures and rangelands (i.e., PRP manure), N fixation from legume seeding, managed manure amendments (i.e., manure other than PRP manure such as Daily Spread), and synthetic fertilizer application. Other N inputs are simulated within the DAYCENT framework, including N input from mineralization due to decomposition of soil organic matter and N inputs from senesced grass litter, as well as asymbiotic fixation of N from the atmosphere. The simulations used the same weather, soil, and synthetic N fertilizer data as discussed under the Tier 3 Approach for Mineral Cropland Soils section. Managed manure N amendments to grasslands are estimated from Edmonds et al. (2003) and adjusted for annual variation using data on the availability of managed manure N for application to soils, according to methods described in the Manure Management section (Section 5.2) and Annex 3.11. Biological N fixation is simulated within DAYCENT, and therefore is not an input to the model.

Manure N deposition from grazing animals in PRP systems (i.e., PRP manure) is another key input of N to grasslands. The amounts of PRP manure N applied on non-federal grasslands for each NRI point are based on amount of N excreted by livestock in PRP systems. The total amount of N excreted in each county is divided by the grassland area to estimate the N input rate associated with PRP manure. The resulting input rates are used in the DAYCENT simulations. DAYCENT simulations of non-federal grasslands accounted for approximately 72 percent of total PRP manure N in aggregate across the country. The remainder of the PRP manure N in each state is assumed to be excreted on federal grasslands, and the N₂O emissions are estimated using the IPCC (2006) Tier 1 method with IPCC default emission factors. Sewage sludge is assumed to be applied on grasslands because of the heavy metal content and other pollutants in human waste that limit its use as an amendment to croplands. Sewage sludge application is estimated from data compiled by EPA (1993, 1999, 2003), McFarland (2001), and NEBRA (2007). Sewage sludge data on soil amendments to agricultural lands are only available at the national scale, and it is not possible to associate application with specific soil conditions and weather at the county scale. Therefore, DAYCENT could not be used to simulate the influence of sewage sludge amendments on N₂O emissions from grassland soils, and consequently, emissions from sewage sludge are estimated using the IPCC (2006) Tier 1 method.

Grassland area data are obtained from the U.S. Department of Agriculture NRI (Nusser and Goebel 1998) and the U.S. Geological Survey (USGS) National Land Cover Dataset (Vogelman et al. 2001), which are reconciled with the Forest Inventory and Analysis Data. The area data for pastures and rangeland are aggregated to the county level to estimate non-federal and federal grassland areas.

N₂O emissions for the PRP manure N deposited on federal grasslands and applied sewage sludge N are estimated using the Tier 1 method by multiplying the N input by the appropriate emission factor. Emissions from manure N are estimated at the state level and aggregated to the entire country, but emissions from sewage sludge N are calculated exclusively at the national scale.

As previously mentioned, each NRI point is simulated 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulation runs for the analysis. Soil N₂O emission estimates from DAYCENT are adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Del Grosso et al. 2010). Soil N₂O emissions and 95 percent confidence intervals are estimated for each year between 1990 and 2010, but emissions from 2011 to 2014 are assumed to be similar to 2010. The annual data are currently available through 2012 (USDA-NRCS 2015), however this Inventory only uses NRI data through 2010 because newer data were not made available in time to incorporate the additional years into this Inventory.

Total Direct N₂O Emissions from Cropland and Grassland Soils

Annual direct emissions from the Tier 1 and 3 approaches for mineral and drained organic soils occurring in both croplands and grasslands are summed to obtain the total direct N₂O emissions from agricultural soil management (see Table 5-15 and Table 5-16).

Indirect N₂O Emissions

This section describes the methods used for estimating indirect soil N₂O emissions from croplands and grasslands. Indirect N₂O emissions occur when mineral N made available through anthropogenic activity is transported from the soil either in gaseous or aqueous forms and later converted into N₂O. There are two pathways leading to indirect emissions. The first pathway results from volatilization of N as NO_x and NH₃ following application of synthetic fertilizer, organic amendments (e.g., manure, sewage sludge), and deposition of PRP manure. Nitrogen made available from mineralization of soil organic matter and residue, including N incorporated into crops and forage from symbiotic N fixation, and input of N from asymbiotic fixation also contributes to volatilized N emissions. Volatilized N can be returned to soils through atmospheric deposition, and a portion of the deposited N is emitted to the atmosphere as N₂O. The second pathway occurs via leaching and runoff of soil N (primarily in the form of NO₃⁻) that is made available through anthropogenic activity on managed lands, mineralization of soil organic matter and residue, including N incorporated into crops and forage from symbiotic N fixation, and inputs of N into the soil from asymbiotic fixation. The NO₃⁻ is subject to denitrification in water bodies, which leads to N₂O emissions. Regardless of the eventual location of the indirect N₂O emissions, the emissions are assigned to the original source of the N for reporting purposes, which here includes croplands and grasslands.

Indirect N₂O Emissions from Atmospheric Deposition of Volatilized N

The Tier 3 DAYCENT model and IPCC (2006) Tier 1 methods are combined to estimate the amount of N that is volatilized and eventually emitted as N₂O. DAYCENT is used to estimate N volatilization for land areas whose direct emissions are simulated with DAYCENT (i.e., most commodity and some specialty crops and most grasslands). The N inputs included are the same as described for direct N₂O emissions in the Tier 3 Approach for Cropland Mineral Soils section and Grasslands section. Nitrogen volatilization for all other areas is estimated using the Tier 1 method and default IPCC fractions for N subject to volatilization (i.e., N inputs on croplands not simulated by DAYCENT, PRP manure N excreted on federal grasslands, sewage sludge application on grasslands). For the volatilization data generated from both the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor is used to estimate indirect N₂O emissions occurring due to re-deposition of the volatilized N (see Table 5-18).

Indirect N₂O Emissions from Leaching/Runoff

As with the calculations of indirect emissions from volatilized N, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 method are combined to estimate the amount of N that is subject to leaching and surface runoff into water bodies, and eventually emitted as N₂O. DAYCENT is used to simulate the amount of N transported from lands in the Tier 3 Approach. Nitrogen transport from all other areas is estimated using the Tier 1 method and the IPCC (2006) default factor for the proportion of N subject to leaching and runoff. This N transport estimate includes N applications on croplands that are not simulated by DAYCENT, sewage sludge amendments on grasslands, and PRP manure N excreted on federal grasslands. For both the DAYCENT Tier 3 and IPCC (2006) Tier 1 methods, nitrate leaching is assumed to be an insignificant source of indirect N₂O in cropland and grassland systems in arid regions, as discussed in IPCC (2006). In the United States, the threshold for significant nitrate leaching is based on the potential evapotranspiration (PET) and rainfall amount, similar to IPCC (2006), and is assumed to be negligible in regions where the amount of precipitation plus irrigation does not exceed 80 percent of PET. For leaching and runoff data estimated by the Tier 3 and Tier 1 approaches, the IPCC (2006) default emission factor is used to estimate indirect N₂O emissions that occur in groundwater and waterways (see Table 5-18).

Uncertainty and Time-Series Consistency

Uncertainty is estimated for each of the following five components of N₂O emissions from agricultural soil management: (1) direct emissions simulated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) simulated by DAYCENT; (3) direct emissions approximated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) approximated with the IPCC (2006) Tier 1 method; and (5) indirect emissions estimated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N₂O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT are estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al. 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Approach 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Approach 1 method, and indirect N₂O emissions are estimated with a simple error propagation approach (IPCC 2006). Uncertainties from the Approach 1 and Approach 3 (i.e., DAYCENT) estimates are combined using simple error propagation (IPCC 2006). Additional details on the uncertainty methods are provided in Annex 3.12. Table 5-19 shows the combined uncertainty for direct soil N₂O emissions ranged from 16 percent below to 24 percent above the 2014 emissions estimate of 261.0 MMT CO₂ Eq., and the combined uncertainty for indirect soil N₂O emissions range from 47 percent below to 139 percent above the 2014 estimate of 57.3 MMT CO₂ Eq.

Table 5-19: Quantitative Uncertainty Estimates of N₂O Emissions from Agricultural Soil Management in 2014 (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate (%) | | | |
|--|------------------|--|---|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Direct Soil N ₂ O Emissions | N ₂ O | 261.0 | 219.4 | 323.8 | -16% | 24% |
| Indirect Soil N ₂ O Emissions | N ₂ O | 57.3 | 30.6 | 137.0 | -47% | 139% |

Notes: Due to lack of data, uncertainties in managed manure N production, PRP manure N production, other organic fertilizer amendments, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

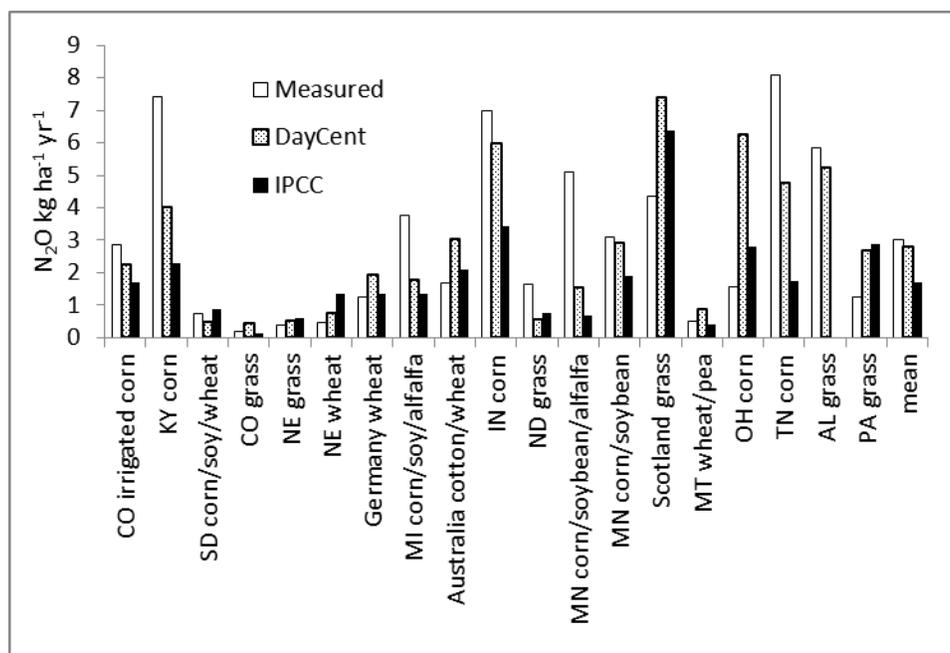
Additional uncertainty is associated with an incomplete estimation of all N₂O emissions from managed croplands and grasslands in Hawaii and Alaska. The Inventory only includes the N₂O emissions from mineral fertilizer additions in Alaska and Hawaii, and drained organic soils in Hawaii. Agriculture is not extensive in either state, so the emissions are likely to be small for the other sources of N (e.g., manure amendments), which are not currently included in the Inventory, compared to the conterminous United States.

Methodological recalculations are applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends are described in more detail in the Methodology section above.

QA/QC and Verification

DAYCENT results for N₂O emissions and NO₃⁻ leaching are compared with field data representing various cropland and grassland systems, soil types, and climate patterns (Del Grosso et al. 2005; Del Grosso et al. 2008), and further evaluated by comparing the model results to emission estimates produced using the IPCC (2006) Tier 1 method for the same sites. Nitrous oxide measurement data are available for 27 sites, which mostly occur in the United States, with four in Europe and one in Australia, representing over 75 different combinations of fertilizer treatments and cultivation practices. Nitrate leaching data are available for four sites in the United States, representing 12 different combinations of fertilizer amendments/tillage practices. DAYCENT estimates of N₂O emissions are closer to measured values at most sites compared to the IPCC Tier 1 estimate (see Figure 5-7). In general, the IPCC Tier 1 methodology tends to over-estimate emissions when observed values are low and under-estimate emissions when observed values are high, while DAYCENT estimates have less bias. DAYCENT accounts for key site-level factors (i.e., weather, soil characteristics, and management) that are not addressed in the IPCC Tier 1 Method, and thus the model is better able to represent the variability in N₂O emissions. DAYCENT does have a tendency to under-estimate very high N₂O emission rates; and estimates are adjusted using the statistical model derived from the comparison of model estimates to measurements (see Annex 3.12 for more information). Regardless, the comparison demonstrates that DAYCENT provides relatively high predictive capability for N₂O emissions, and is an improvement over the IPCC Tier 1 method.

Figure 5-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model and IPCC Tier 1 Approach (kg N₂O per ha per year)



Spreadsheets containing input data and probability distribution functions required for DAYCENT simulations of croplands and grasslands and unit conversion factors have been checked, in addition to the program scripts that are used to run the Monte Carlo uncertainty analysis. Links between spreadsheets have been checked, updated, and corrected when necessary. Spreadsheets containing input data, emission factors, and calculations required for the Tier 1 approach have been checked and updated as needed.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements: (1) driving the DAYCENT simulations with updated input data for land management from the National Resources Inventory extending the time series through 2010; (2) accounting for N inputs from residues associated with additional crops not simulated by DAYCENT including most vegetable crops; (3) modifying the number of experimental study sites used to quantify model uncertainty for direct N₂O emissions; and (4) using DAYCENT for direct N₂O emissions from most flooded rice lands, instead of using the Tier 1 approach for all rice lands. These changes resulted in an increase in emissions of approximately 24 percent on average relative to the previous Inventory and a decrease in the upper bound of the 95 percent confidence interval for direct N₂O emissions from 26 to 24 percent. The differences in emissions and uncertainty are mainly due to increasing the number of study sites used to quantify model uncertainty.

Planned Improvements

Several planned improvements are underway.

- Land use and management data will be updated with the 2012 USDA NRI so that the time series of activity data are extended through 2012. Fertilization and tillage activity data will also be updated as part of this improvement. In addition, the remote-sensing based data on the EVI will be extended through 2012 in order to use the EVI data to drive crop production in DAYCENT.
- The DAYCENT biogeochemical model will be improved with a better representation of plant phenology, particularly senescence events following grain filling in crops. In addition, crop parameters associated with temperature effects on plant production will be further improved in DAYCENT with additional model calibration. Model development is underway to represent the influence of nitrification inhibitors and slow-release fertilizers (e.g., polymer-coated fertilizers) on N₂O emissions. An improved representation of drainage is also under development. Experimental study sites will continue to be added for quantifying model structural uncertainty, and studies that have continuous (daily) measurements of N₂O (e.g., Scheer et al. 2013) will be given priority.
- Improvements are underway to simulate crop residue burning in the DAYCENT model based on the amount of crop residues burned according to the data that is used in the Field Burning of Agricultural Residues source category (see Section 5.5). See the Planned Improvement section in the Field Burning of Agricultural Residues section for more information.
- Alaska and Hawaii are not included in the current Inventory for agricultural soil management, with the exception of N₂O emissions from drained organic soils in croplands and grasslands for Hawaii. A planned improvement over the next two years is to add these states into the Inventory analysis.
- Use the new Tier 1 emission factor for N₂O emissions from drained organic soils that is provided in the 2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands (IPCC 2013).

5.5 Field Burning of Agricultural Residues (IPCC Source Category 3F)

Crop production creates large quantities of agricultural crop residues, which farmers manage in a variety of ways. For example, crop residues can be left in the field and possibly incorporated into the soil with tillage; collected and used as fuel, animal bedding material, supplemental animal feed, or construction material; composted and applied to soils; transported to landfills; or burned in the field. Field burning of crop residues is not considered a net source of CO₂ emissions because the C released to the atmosphere as CO₂ during burning is reabsorbed during the next growing season for the crop. However, crop residue burning is a net source of CH₄, N₂O, CO, and NO_x, which are released during combustion.

In the United States, field burning of agricultural residues commonly occurs in southeastern states, the Great Plains, and the Pacific Northwest (McCarty 2011). The primary crops that are managed with residue burning include corn, cotton, lentils, rice, soybeans, sugarcane, and wheat (McCarty 2009). Rice, sugarcane, and wheat residues account for approximately 70 percent of all crop residue burning and emissions (McCarty 2011). In 2014, CH₄ and N₂O emissions from field burning of agricultural residues were 0.3 MMT CO₂ Eq. (11 kt) and 0.1 MMT CO₂ Eq. (0.3 kt), respectively. Furthermore, annual emissions from this source from 1990 to 2014 have remained relatively constant, averaging approximately 0.3 MMT CO₂ Eq. (10 kt) of CH₄ and 0.1 MMT CO₂ Eq. (0.3 kt) of N₂O (see Table 5-20 and Table 5-21).

Table 5-20: CH₄ and N₂O Emissions from Field Burning of Agricultural Residues (MMT CO₂ Eq.)

| Gas/Crop Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|------------|------------|------------|------------|------------|------------|------------|
| CH₄ | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Wheat | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Rice | 0.1 | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Sugarcane | + | + | + | + | + | + | + |
| Corn | + | + | + | + | + | + | + |
| Cotton | + | + | + | + | + | + | + |
| Soybeans | + | + | + | + | + | + | + |
| Lentil | + | + | + | + | + | + | + |
| N₂O | 0.1 |
| Wheat | + | + | + | + | + | + | + |
| Rice | + | + | + | + | + | + | + |
| Sugarcane | + | + | + | + | + | + | + |
| Corn | + | + | + | + | + | + | + |
| Cotton | + | + | + | + | + | + | + |
| Soybeans | + | + | + | + | + | + | + |
| Lentil | + | + | + | + | + | + | + |
| Total | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 5-21: CH₄, N₂O, CO, and NO_x Emissions from Field Burning of Agricultural Residues (kt)

| Gas/Crop Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|------------|------------|------------|------------|------------|------------|------------|
| CH₄ | 10 | 8 | 11 | 11 | 11 | 11 | 11 |
| Wheat | 5 | 4 | 5 | 5 | 5 | 5 | 5 |
| Rice | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Sugarcane | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| Corn | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| Soybeans | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Lentil | + | + | + | + | + | + | + |
| Cotton | + | + | + | + | + | + | + |
| N₂O | + |
| Wheat | + | + | + | + | + | + | + |
| Rice | + | + | + | + | + | + | + |
| Sugarcane | + | + | + | + | + | + | + |
| Corn | + | + | + | + | + | + | + |
| Cotton | + | + | + | + | + | + | + |
| Soybeans | + | + | + | + | + | + | + |
| Lentil | + | + | + | + | + | + | + |
| CO | 202 | 177 | 229 | 233 | 234 | 238 | 238 |
| NO_x | 6 | 6 | 7 | 8 | 8 | 8 | 8 |

+ Does not exceed 0.5 kt.

Note: Totals may not sum due to independent rounding

Methodology

A U.S.-specific Tier 2 method was used to estimate greenhouse gas emissions from field burning of agricultural residues (for more details, see Box 5-2). In order to estimate the amounts of C and N released during burning, the following equation was used:

$$\text{C or N released} = \Sigma \text{ for all crop types and states } \left(\frac{\text{AB}}{\text{CAH} \times \text{CP} \times \text{RCR} \times \text{DMF} \times \text{BE} \times \text{CE} \times (\text{FC or FN})} \right)$$

where,

| | |
|-------------------------------|---|
| Area Burned (AB) | = Total area of crop burned, by state |
| Crop Area Harvested (CAH) | = Total area of crop harvested, by state |
| Crop Production (CP) | = Annual production of crop in kt, by state |
| Residue: Crop Ratio (RCR) | = Amount of residue produced per unit of crop production |
| Dry Matter Fraction (DMF) | = Amount of dry matter per unit of biomass for a crop |
| Fraction of C or N (FC or FN) | = Amount of C or N per unit of dry matter for a crop |
| Burning Efficiency (BE) | = The proportion of prefire fuel biomass consumed ¹⁶ |
| Combustion Efficiency (CE) | = The proportion of C or N released with respect to the total amount of C or N available in the burned material, respectively |

Crop Production and Crop Area Harvested were available by state and year from USDA (2014) for all crops (except rice in Florida and Oklahoma, as detailed below). The amount C or N released was used in the following equation to determine the CH₄, CO, N₂O, and NO_x emissions from the field burning of agricultural residues:

$$\text{CH}_4 \text{ and CO, or N}_2\text{O and NO}_x \text{ Emissions from Field Burning of Agricultural Residues} = \text{C or N Released} \times \text{ER} \times \text{CF}$$

where,

| | |
|------------------------|---|
| Emissions Ratio (ER) | = g CH ₄ -C or CO-C/g C released, or g N ₂ O-N or NO _x -N/g N released |
| Conversion Factor (CF) | = conversion, by molecular weight ratio, of CH ₄ -C to C (16/12), or CO-C to C (28/12), or N ₂ O-N to N (44/28), or NO _x -N to N (30/14) |

Box 5-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

Emissions from field burning of agricultural residues were calculated using a Tier 2 methodology that is based on method developed by the IPCC/UNEP/OECD/IEA (1997) and incorporates crop- and country-specific emission factors and variables. The rationale for using the IPCC/UNEP/OECD/IEA (1997) approach rather than the method provided in the *2006 IPCC Guidelines* is as follows: (1) the equations from both guidelines rely on the same underlying variables (though the formats differ); (2) the IPCC (2006) equation was developed to be broadly applicable to all types of biomass burning, and, thus, is not specific to agricultural residues; and (3) the IPCC (2006) default factors are provided only for four crops (corn, rice, sugarcane, and wheat) while this Inventory includes emissions from seven crops (corn, cotton, lentils, rice, soybeans, sugarcane, and wheat).

A comparison of the methods and factors used in: (1) the current Inventory and (2) the default IPCC (2006) approach was undertaken in the 1990 through 2014 Inventory report to determine the difference in overall estimates between the two approaches. To estimate greenhouse gas emissions from field burning of agricultural residue using the IPCC (2006) methodology, the following equation—cf. IPCC (2006) Equation 2.27—was used:

$$\text{Emissions (kt)} = \text{AB} \times (\text{M}_B \times \text{C}_f) \times \text{G}_{\text{ef}} \times 10^{-6}$$

¹⁶ In IPCC/UNEP/OECD/IEA (1997), the equation for C or N released contains the variable ‘fraction oxidized in burning’. This variable is equivalent to (burning efficiency × combustion efficiency).

where,

| | |
|----------------------------------|--|
| Area Burned (AB) | = Total area of crop burned (ha) |
| Mass Burned ($M_B \times C_f$) | = IPCC (2006) default fuel biomass consumption (metric tons dry matter burnt ha^{-1}) |
| Emission Factor (G_{ef}) | = IPCC (2006) emission factor ($g\ kg^{-1}$ dry matter burnt) |

The IPCC (2006) default approach resulted in 5 percent higher emissions of CH_4 and 21 percent higher emissions of N_2O compared to this Inventory (and are within the uncertainty ranges estimated for this source category). The IPCC/UNEP/OECD/IEA (1997) is considered a more appropriate method for U.S. conditions because it is more flexible for incorporating country-specific data compared to IPCC (2006) approach for Tier 1 and 2 methods.

Crop yield data (except rice in Florida) were based on USDA's QuickStats (USDA 2015), and crop area data were based on the 2010 NRI (USDA 2013). In order to estimate total crop production, the crop yield data from USDA Quick Stats crop yields was multiplied by the NRI crop areas. Rice yield data for Florida was estimated separately because yield data were not collected by USDA. Total rice production for Florida was determined using NRI crop areas and total yields were based on average primary and ratoon rice yields from Schueneman and Deren (2002). Relative proportions of ratoon crops were derived from information in several publications (Schueneman 1999, 2000, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2014). The production data for the crop types whose residues are burned are presented in Table 5-22. Crop weight by bushel was obtained from Murphy (1993).

The fraction of crop area burned was calculated using data on area burned by crop type and state¹⁷ from McCarty (2010) for corn, cotton, lentils, rice, soybeans, sugarcane, and wheat.¹⁸ McCarty (2010) used remote sensing data from MODIS to estimate area burned by crop. State-level area burned data were divided by state-level crop area harvested data to estimate the percent of crop area burned by crop type for each state. The average percentage of crop area burned at the national scale is shown in Table 5-23. Data on fraction of crop area burned were only available from McCarty (2010) for the years 2003 through 2007. For other years in the time series, the percent area burned was set equal to the average over the five-year period from 2003 to 2007. Table 5-23 shows the resulting percentage of crop residue burned at the national scale by crop type. State-level estimates are also available upon request.

All residue: crop product mass ratios except sugarcane and cotton were obtained from Strehler and Stützel (1987). The ratio for sugarcane is from Kinoshita (1988) and the ratio for cotton is from Huang et al. (2007). The residue: crop ratio for lentils was assumed to be equal to the average of the values for peas and beans. Residue dry matter fractions for all crops except soybeans, lentils, and cotton were obtained from Turn et al. (1997). Soybean and lentil dry matter fractions were obtained from Strehler and Stützel (1987); the value for lentil residue was assumed to equal the value for bean straw. The cotton dry matter fraction was taken from Huang et al. (2007). The residue C contents and N contents for all crops except soybeans and cotton are from Turn et al. (1997). The residue C content for soybeans is the IPCC default (IPCC/UNEP/OECD/IEA 1997), and the N content of soybeans is from Barnard and Kristoferson (1985). The C and N contents of lentils were assumed to equal those of soybeans. The C and N contents of cotton are from Lachnicht et al. (2004). The burning efficiency was assumed to be 93 percent, and the combustion efficiency was assumed to be 88 percent, for all crop types, except sugarcane (EPA 1994). For sugarcane, the burning efficiency was assumed to be 81 percent (Kinoshita 1988) and the combustion efficiency was assumed to be 68 percent (Turn et al. 1997). See Table 5-24 for a summary of the crop-specific conversion factors. Emission ratios and mole ratio conversion factors for all gases were based on the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) (see Table 5-25).

¹⁷ Alaska and Hawaii were excluded.

¹⁸ McCarty (2009) also examined emissions from burning of Kentucky bluegrass and a general "other crops/fallow" category, but USDA crop area and production data were insufficient to estimate emissions from these crops using the methodology employed in the Inventory. McCarty (2009) estimates that approximately 18 percent of crop residue emissions result from burning of the Kentucky bluegrass and "other crops" categories.

Table 5-22: Agricultural Crop Production (kt of Product)

| Crop | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------|---------|---------|---------|---------|---------|---------|---------|
| Corn ^a | 229,257 | 300,965 | 335,669 | 321,920 | 270,310 | 350,472 | 378,574 |
| Cotton | 4,446 | 6,811 | 4,814 | 4,369 | 5,156 | 4,841 | 5,104 |
| Lentils | 38 | 248 | 406 | 234 | 251 | 271 | 156 |
| Rice | 8,907 | 12,596 | 11,376 | 11,795 | 12,547 | 12,932 | 12,874 |
| Soybeans | 55,178 | 86,908 | 94,467 | 90,761 | 86,922 | 95,473 | 103,588 |
| Sugarcane | 31,827 | 32,496 | 30,333 | 32,469 | 34,925 | 34,186 | 34,160 |
| Wheat | 79,011 | 70,074 | 71,017 | 62,131 | 71,094 | 68,772 | 64,748 |

^a Corn for grain (i.e., excludes corn for silage).

Table 5-23: U.S. Average Percent Crop Area Burned by Crop (Percent)

| State | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------|------|------|------|------|------|------|------|
| Corn | + | + | + | + | + | + | + |
| Cotton | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Lentils | 2% | + | + | 1% | 1% | 1% | 1% |
| Rice | 9% | 5% | 7% | 7% | 7% | 7% | 7% |
| Soybeans | + | + | + | + | + | + | + |
| Sugarcane | 10% | 14% | 23% | 25% | 23% | 22% | 24% |
| Wheat | 2% | 2% | 2% | 3% | 2% | 2% | 2% |

+ Does not exceed 0.5 percent.

Table 5-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues

| Crop | Residue: Crop Ratio | Dry Matter Fraction | C Fraction | N Fraction | Burning Efficiency (Fraction) | Combustion Efficiency (Fraction) |
|-----------|---------------------|---------------------|------------|------------|-------------------------------|----------------------------------|
| Corn | 1.0 | 0.91 | 0.448 | 0.006 | 0.93 | 0.88 |
| Cotton | 1.6 | 0.90 | 0.445 | 0.012 | 0.93 | 0.88 |
| Lentils | 2.0 | 0.85 | 0.450 | 0.023 | 0.93 | 0.88 |
| Rice | 1.4 | 0.91 | 0.381 | 0.007 | 0.93 | 0.88 |
| Soybeans | 2.1 | 0.87 | 0.450 | 0.023 | 0.93 | 0.88 |
| Sugarcane | 0.2 | 0.62 | 0.424 | 0.004 | 0.81 | 0.68 |
| Wheat | 1.3 | 0.93 | 0.443 | 0.006 | 0.93 | 0.88 |

Table 5-25: Greenhouse Gas Emission Ratios and Conversion Factors

| Gas | Emission Ratio | Conversion Factor |
|--------------------|--------------------|-------------------|
| CH ₄ :C | 0.005 ^a | 16/12 |
| CO:C | 0.060 ^a | 28/12 |
| N ₂ O:N | 0.007 ^b | 44/28 |
| NO _x :N | 0.121 ^b | 30/14 |

^a Mass of C compound released (units of C) relative to mass of total C released from burning (units of C).

^b Mass of N compound released (units of N) relative to mass of total N released from burning (units of N).

Uncertainty and Time-Series Consistency

The results of the Approach 2 Monte Carlo uncertainty analysis are summarized in Table 5-26. Methane emissions from field burning of agricultural residues in 2014 were estimated to be between 0.16 and 0.38 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 40 percent below and 40 percent above the 2014 emission estimate of 0.3 MMT CO₂ Eq. Also at the 95 percent confidence level, N₂O emissions were estimated to be between

0.07 and 0.12 MMT CO₂ Eq., or approximately 29 percent below and 29 percent above the 2014 emission estimate of 0.1 MMT CO₂ Eq.

Table 5-26: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Field Burning of Agricultural Residues (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate (MMT CO ₂ Eq.) (%) | | | |
|--|------------------|--|---|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Field Burning of Agricultural Residues | CH ₄ | 0.3 | 0.16 | 0.38 | -40% | 40% |
| Field Burning of Agricultural Residues | N ₂ O | 0.1 | 0.07 | 0.12 | -29% | 29% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Due to data limitations, there are additional uncertainties in agricultural residue burning, particularly the omission of burning associated with Kentucky bluegrass and “other crop” residues. Methodological recalculations were applied to the entire time series, ensuring time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section above.

QA/QC and Verification

A source-specific QA/QC plan for field burning of agricultural residues was implemented with Tier 1 and 2 analyses. The Tier 1 analysis conducted this year uncovered a data transcription error in the corn production data for 1990. No other errors were found.

Recalculations Discussion

The source data for crop areas was changed from USDA NASS QuickStats to the 2010 NRI. This change ensures greater consistency in the land representation across cropland source categories, including direct and indirect soil nitrous oxide emissions in Agricultural Soil Management, and soil carbon stock changes in the *Cropland Remaining Cropland* and *Land Converted to Cropland* sections, which also rely on the NRI data as the basis for crop areas. The NRI data were used to recalculate percent crop area burned and total crop production. This change resulted in higher crop production estimates (ranging from 4 to 40 percent) and lower burned area percentages (ranging from -2 to -42 percent), compared to the previous Inventory. However, the overall impact on the recalculated emissions was relatively small, with CH₄ and N₂O emissions decreasing by 12 and 7 percent respectively. Correcting a transcription error in crop production for corn in 1990 (see Table 5-22) led to a larger recalculation in emissions for 1990 relative to the other years.

Planned Improvements

A new method is in development that will directly link agricultural residue burning with the Tier 3 methods that are used in several other source categories, including Agricultural Soil Management, *Cropland Remaining Cropland*, and *Land Converted to Cropland* chapters of the Inventory. The method is based on the DAYCENT model, and burning events will be simulated directly within the process-based model framework using information derived from remote sensing fire products. This improvement will lead to greater consistency in the methods for these sources, and better ensure mass balance of C and N in the Inventory analysis.

6. Land Use, Land-Use Change, and Forestry

This chapter provides an assessment of the net greenhouse gas flux resulting from the use and conversion of land-use categories in the United States.¹ The Intergovernmental Panel on Climate Change *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) recommends reporting fluxes according to changes within and conversions between certain land-use types termed: Forest Land, Cropland, Grassland, Settlements, Wetlands (as well as Other Land). The greenhouse gas flux from *Forest Land Remaining Forest Land* is reported using estimates of changes in forest ecosystem carbon (C) stocks, harvested wood pools, non-carbon dioxide (non-CO₂) emissions from forest fires, and the application of synthetic fertilizers to forest soils. Only fluxes for C stock changes from mineral soils are included for *Land Converted to Forest Land*. Fluxes are reported for four agricultural land use/land-use change categories: *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. The reported greenhouse gas fluxes from these agricultural lands include changes in organic C stocks in mineral and organic soils due to land use and management, emissions of CO₂ due to the application of crushed limestone and dolomite to managed land (i.e., soil liming), urea fertilization and the change in aboveground biomass C stocks for *Forest Land Converted to Cropland* and *Forest Land Converted to Grassland*.² Fluxes from *Wetlands Remaining Wetlands* include CO₂, methane (CH₄) and nitrous oxide (N₂O) emissions from managed peatlands; estimates for *Land Converted to Wetlands* are currently not available. Fluxes resulting from *Settlements Remaining Settlements* include those from urban trees and application of nitrogen fertilizer to soils; fluxes from *Land Converted to Settlements* are currently not available. Landfilled yard trimmings and food scraps are accounted for separately under *Other*.

Land use, land-use change, and forestry (LULUCF) activities in 2014 resulted in a net increase in C stocks (i.e., net CO₂ removals) of 787.0 MMT CO₂ Eq. (214.6 MMT C).³ This represents an offset of approximately 11.5 percent of total (i.e., gross) greenhouse gas emissions in 2014. Emissions from land use, land-use change, and forestry activities in 2014 are 24.6 MMT CO₂ Eq. and represent 0.4 percent of total greenhouse gas emissions.⁴

Total C sequestration in the LULUCF sector increased by approximately 4.5 percent between 1990 and 2014. This increase was primarily due to an increase in the rate of net C accumulation in forest and urban tree C stocks.⁵ Net C accumulation in *Forest Land Remaining Forest Land* and *Settlements Remaining Settlements* increased, while net C

¹ The term “flux” is used to describe the net emissions of greenhouse gases accounting for both the emissions of CO₂ to and the removals of CO₂ from the atmosphere. Removal of CO₂ from the atmosphere is also referred to as “carbon sequestration”.

² Direct and indirect emissions of N₂O from inputs of N to cropland and grassland soils are included in the Agriculture Chapter.

³ Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land*, *Land Converted to Forest Land*, *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Other*.

⁴ LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

⁵ Carbon sequestration estimates are net figures. The C stock in a given pool fluctuates due to both gains and losses. When losses exceed gains, the C stock decreases, and the pool acts as a source. When gains exceed losses, the C stock increases, and the pool acts as a sink; also referred to as net C sequestration or removal.

accumulation in *Land Converted to Forest Land*, *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, and *Landfilled Yard Trimmings and Food Scraps* slowed over this period. Emissions from *Land Converted to Cropland* and *Wetlands Remaining Wetlands* decreased, while emissions from *Land Converted to Grassland* increased. Net C stock change from LULUCF is summarized in Table 6-1.

Table 6-1: Net C Stock Change from Land Use, Land-Use Change, and Forestry (MMT CO₂ Eq.)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Forest Land Remaining Forest Land | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Changes in Forest Carbon Stock ^a | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Land Converted to Forest Land | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Changes in Forest Carbon Stock | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Cropland Remaining Cropland | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| Changes in Agricultural Carbon Stock ^b | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| Land Converted to Cropland | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Changes in Agricultural Carbon Stock ^b | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Grassland Remaining Grassland | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Changes in Agricultural Carbon Stock ^b | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Land Converted to Grassland | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Changes in Agricultural Carbon Stock ^b | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Settlements Remaining Settlements | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| Changes in Carbon Stocks in Urban | | | | | | | |
| Trees | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| Other | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| Landfilled Yard Trimmings and Food Scraps | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| LULUCF Total Net Flux | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |

^a Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^b Estimates include C stock changes in all pools.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from LULUCF activities are shown in Table 6-2. Liming and urea fertilization in 2014 resulted in CO₂ emissions of 8.7 MMT CO₂ Eq. (8,653 kt of CO₂). Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO₂ emissions of 0.8 MMT CO₂ Eq. (842 kt of CO₂), CH₄ emissions of less than 0.05 MMT CO₂ Eq., and N₂O emissions of less than 0.05 MMT CO₂ Eq. The application of synthetic fertilizers to forest soils in 2014 resulted in N₂O emissions of 0.5 MMT CO₂ Eq. (2 kt of N₂O). Nitrous oxide emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, N₂O emissions from fertilizer application to settlement soils in 2014 accounted for 2.4 MMT CO₂ Eq. (8 kt of N₂O). This represents an increase of 78 percent since 1990. Forest fires in 2014 resulted in CH₄ emissions of 7.3 MMT CO₂ Eq. (294 kt of N₂O), and N₂O emissions of 4.8 MMT CO₂ Eq. (16 kt of N₂O). Emissions and removals from LULUCF are summarized in Table 6-3 by land-use and category, and Table 6-4 and Table 6-5 by gas in MMT CO₂ Eq. and kt, respectively.

Table 6-2: Emissions from Land Use, Land-Use Change, and Forestry by Gas (MMT CO₂ Eq.)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------|------------|------------|------------|-------------|------------|------------|
| CO₂ | 8.1 | 9.0 | 9.6 | 8.9 | 11.0 | 9.0 | 9.5 |
| Cropland Remaining Cropland: CO ₂ | | | | | | | |
| Emissions from Urea Fertilization | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |
| Cropland Remaining Cropland: CO ₂ | | | | | | | |
| Emissions from Liming | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |
| Wetlands Remaining Wetlands: | | | | | | | |
| Peatlands Remaining Peatlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| CH₄ | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.4 |
| Forest Land Remaining Forest Land: | | | | | | | |
| Non-CO ₂ Emissions from Forest Fires | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.3 |
| Wetlands Remaining Wetlands: | | | | | | | |
| Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| N₂O | 3.6 | 9.3 | 5.0 | 7.3 | 10.3 | 7.7 | 7.7 |
| Forest Land Remaining Forest Land: | | | | | | | |
| | 2.2 | 6.5 | 2.2 | 4.4 | 7.3 | 4.8 | 4.8 |

| | | | | | | | | |
|--|-------------|-------------|-------------|-------------|-------------|-------------|-------------|--|
| Non-CO ₂ Emissions from Forest Fires | | | | | | | | |
| Settlements Remaining Settlements: | | | | | | | | |
| N ₂ O Fluxes from Settlement Soils ^a | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 | |
| Forest Land Remaining Forest Land: | | | | | | | | |
| N ₂ O Fluxes from Forest Soils ^b | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | |
| Wetlands Remaining Wetlands: | | | | | | | | |
| Peatlands Remaining Peatlands | + | + | + | + | + | + | + | |
| LULUCF Emissions | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 | |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^b Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Note: Totals may not sum due to independent rounding.

Table 6-3: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry by Land Use and Land-Use Change Category (MMT CO₂ Eq.)

| Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Forest Land Remaining Forest Land | (718.0) | (675.0) | (736.2) | (725.2) | (717.1) | (726.5) | (729.7) |
| Changes in Forest Carbon Stock ^a | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Non-CO ₂ Emissions from Forest Fires | 5.4 | 16.5 | 5.4 | 11.0 | 18.3 | 12.2 | 12.2 |
| N ₂ O Fluxes from Forest Soils ^b | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Land Converted to Forest Land | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Changes in Forest Carbon Stock | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Cropland Remaining Cropland | (27.2) | (6.3) | 10.3 | (4.5) | (1.0) | (1.0) | 0.2 |
| Changes in Agricultural Carbon Stock ^c | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| CO ₂ Emissions from Liming | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |
| CO ₂ Emissions from Urea Fertilization | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |
| Land Converted to Cropland | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Changes in Agricultural Carbon Stock ^c | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Grassland Remaining Grassland | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Changes in Agricultural Carbon Stock ^c | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Land Converted to Grassland | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Changes in Agricultural Carbon Stock ^c | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Wetlands Remaining Wetlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| Peatlands Remaining Peatlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| Settlements Remaining Settlements | (59.0) | (78.2) | (83.8) | (84.8) | (85.8) | (87.1) | (88.2) |
| Changes in Carbon Stocks in Urban Trees | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| N ₂ O Fluxes from Settlement Soils ^d | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| Other | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| Landfilled Yard Trimmings and Food Scraps | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| LULUCF Emissions^e | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 |
| LULUCF Total Net Flux^f | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| LULUCF Sector Total^g | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^b Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

^c Estimates include C stock changes in all pools.

^d Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^e LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^f LULUCF Total Net Flux includes any C sequestration gains and losses from all land use and land use conversion categories.

^g The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-4: Emissions and Removals (Net Flux) from Land Use, Land-Use Change, and Forestry by Gas (MMT CO₂ Eq.)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Net CO₂ Flux^a | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| Forest Land Remaining Forest Land ^b | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |
| Land Converted to Forest Land | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Cropland Remaining Cropland | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |
| Land Converted to Cropland | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |
| Grassland Remaining Grassland | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |
| Land Converted to Grassland | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |
| Settlements Remaining Settlements | (60.4) | (80.5) | (86.1) | (87.3) | (88.4) | (89.5) | (90.6) |
| Other: Landfilled Yard Trimmings and Food Scraps | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |
| CO₂ | 8.1 | 9.0 | 9.6 | 8.9 | 11.0 | 9.0 | 9.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Urea Fertilization | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |
| Cropland Remaining Cropland: CO ₂ Emissions from Liming | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| CH₄ | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.4 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.3 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| N₂O | 3.6 | 9.3 | 5.0 | 7.3 | 10.3 | 7.7 | 7.7 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 2.2 | 6.5 | 2.2 | 4.4 | 7.3 | 4.8 | 4.8 |
| Settlements Remaining Settlements: N ₂ O Fluxes from Settlement Soils ^c | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| Forest Land Remaining Forest Land: N ₂ O Fluxes from Forest Soils ^d | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| LULUCF Emissions^e | 15.0 | 28.2 | 17.8 | 22.9 | 32.3 | 24.1 | 24.6 |
| LULUCF Total Net Flux^a | (753.0) | (726.7) | (784.3) | (784.9) | (782.0) | (783.7) | (787.0) |
| LULUCF Sector Total^f | (738.0) | (698.5) | (766.4) | (762.0) | (749.7) | (759.6) | (762.5) |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.*

^b Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^c Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^d Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

^e LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^f The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-5: Emissions and Removals (Flux) from Land Use, Land-Use Change, and Forestry by Gas (kt)

| Gas/Land-Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Net CO₂ Flux^a | (752,993) | (726,692) | (784,268) | (784,882) | (782,024) | (783,680) | (787,045) |
| Forest Land Remaining Forest Land ^b | (723,536) | (691,873) | (742,040) | (736,690) | (735,837) | (739,112) | (742,328) |
| Land Converted to Forest Land | (677) | (819) | (374) | (372) | (352) | (350) | (349) |
| Cropland Remaining Cropland | (34,326) | (14,116) | 1,787 | (12,484) | (11,179) | (9,273) | (8,428) |
| Land Converted to Cropland | 65,710 | 32,168 | 23,695 | 21,601 | 22,048 | 22,097 | 22,104 |
| Grassland Remaining Grassland | (12,865) | (3,254) | (7,315) | 3,112 | 3,552 | 3,769 | 3,772 |
| Land Converted to Grassland | 39,083 | 43,087 | 39,308 | 39,859 | 40,358 | 40,380 | 40,383 |
| Settlements Remaining Settlements | (60,408) | (80,523) | (86,129) | (87,250) | (88,372) | (89,493) | (90,614) |
| Other: Landfilled Yard Trimmings and Food Scraps | (25,975) | (11,360) | (13,200) | (12,659) | (12,242) | (11,698) | (11,585) |
| CO₂ | 8,139 | 8,955 | 9,584 | 8,898 | 11,015 | 9,021 | 9,495 |
| Cropland Remaining Cropland: CO ₂ Emissions from Urea Fertilization | 2,417 | 3,504 | 3,778 | 4,099 | 4,225 | 4,342 | 4,514 |
| Cropland Remaining Cropland: CO ₂ Emissions from Liming | 4,667 | 4,349 | 4,784 | 3,873 | 5,978 | 3,909 | 4,139 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | 1,055 | 1,101 | 1,022 | 926 | 812 | 770 | 842 |
| CH₄ | 131 | 397 | 131 | 265 | 443 | 294 | 294 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 131 | 397 | 131 | 265 | 443 | 294 | 294 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |
| N₂O | 12 | 31 | 17 | 25 | 34 | 26 | 26 |
| Forest Land Remaining Forest Land: Non-CO ₂ Emissions from Forest Fires | 7 | 22 | 7 | 15 | 24 | 16 | 16 |
| Settlements Remaining Settlements: N ₂ O Fluxes from Settlement Soils ^c | 5 | 8 | 8 | 8 | 9 | 8 | 8 |
| Forest Land Remaining Forest Land: N ₂ O Fluxes from Forest Soils ^d | + | 2 | 2 | 2 | 2 | 2 | 2 |
| Wetlands Remaining Wetlands: Peatlands Remaining Peatlands | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt

^a Net CO₂ flux is the net C stock change from the following categories: *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, and Other.*

^b Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^c Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements.*

^d Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land.*

Box 6-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the gross emissions total presented in this report for the United States excludes emissions and sinks

from LULUCF. The net emissions total presented in this report for the United States includes emissions and sinks from LULUCF. All emissions and sinks estimates are calculated using internationally-accepted methods provided by the IPCC.⁶ Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.⁷ The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

6.1 Representation of the U.S. Land Base

A national land-use categorization system that is consistent and complete, both temporally and spatially, is needed in order to assess land use and land-use change status and the associated greenhouse gas fluxes over the Inventory time series. This system should be consistent with IPCC (2006), such that all countries reporting on national greenhouse gas fluxes to the UNFCCC should: (1) describe the methods and definitions used to determine areas of managed and unmanaged lands in the country (Table 6-6), (2) describe and apply a consistent set of definitions for land-use categories over the entire national land base and time series (i.e., such that increases in the land areas within particular land-use categories are balanced by decreases in the land areas of other categories unless the national land base is changing) (Table 6-7), and (3) account for greenhouse gas fluxes on all managed lands. The IPCC (2006, Vol. IV, Chapter 1) considers all anthropogenic greenhouse gas emissions and removals associated with land use and management to occur on managed land, and all emissions and removals on managed land should be reported based on this guidance (see IPCC 2010 for further discussion). Consequently, managed land serves as a proxy for anthropogenic emissions and removals. This proxy is intended to provide a practical framework for conducting an inventory, even though some of the greenhouse gas emissions and removals on managed land are influenced by natural processes that may or may not be interacting with the anthropogenic drivers. Guidelines for factoring out natural emissions and removals may be developed in the future, but currently the managed land proxy is considered the most practical approach for conducting an inventory in this sector (IPCC 2010). The implementation of such a system helps to ensure that estimates of greenhouse gas fluxes are as accurate as possible, and does allow for potentially subjective decisions in regards to subdividing natural and anthropogenic driven emissions. This section of the Inventory has been developed in order to comply with this guidance.

Three databases are used to track land management in the United States and are used as the basis to classify U.S. land area into the thirty-six IPCC land-use and land-use change categories (Table 6-7) (IPCC 2006). The primary databases are the U.S. Department of Agriculture (USDA) National Resources Inventory (NRI)⁸ and the USDA Forest Service (USFS) Forest Inventory and Analysis (FIA)⁹ Database. The Multi-Resolution Land Characteristics Consortium (MRLC) National Land Cover Dataset (NLCD)¹⁰ is also used to identify land uses in regions that were not included in the NRI or FIA.

⁶ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

⁷ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

⁸ NRI data is available at <<http://www.nrcs.usda.gov/wps/portal/nrcs/site/national/home>>.

⁹ FIA data is available at <<http://www.fia.fs.fed.us/tools-data/default.asp>>.

¹⁰ NLCD data is available at <<http://www.mrlc.gov/>> and MRLC is a consortium of several U.S. government agencies.

The total land area included in the U.S. Inventory is 936 million hectares across the 50 states.¹¹ Approximately 890 million hectares of this land base is considered managed and 46 million hectares is unmanaged, which has not changed by much over the time series of the Inventory (Table 6-7). In 2014, the United States had a total of 295 million hectares of managed Forest Land (3.2 percent increase since 1990), 164 million hectares of Cropland (6.3 percent decrease since 1990), 321 million hectares of managed Grassland (1.7 percent decrease since 1990), 42 million hectares of managed Wetlands (7.2 percent decrease since 1990), 43 million hectares of Settlements (28 percent increase since 1990), and 25 million hectares of managed Other Land (Table 6-7). Wetlands are not differentiated between managed and unmanaged, and are reported solely as managed. In addition, C stock changes are not currently estimated for the entire land base, which leads to discrepancies between the managed land area data presented here and in the subsequent sections of the Inventory (e.g., *Grassland Remaining Grassland*, interior Alaska).¹² Planned improvements are under development to account for C stock changes on all managed land (e.g., Grasslands and Forest Lands in Alaska) and ensure consistency between the total area of managed land in the land-representation description and the remainder of the Inventory.

Dominant land uses vary by region, largely due to climate patterns, soil types, geology, proximity to coastal regions, and historical settlement patterns, although all land uses occur within each of the 50 states (Table 6-6). Forest Land tends to be more common in the eastern states, mountainous regions of the western United States, and Alaska. Cropland is concentrated in the mid-continent region of the United States, and Grassland is more common in the western United States and Alaska. Wetlands are fairly ubiquitous throughout the United States, though they are more common in the upper Midwest and eastern portions of the country. Settlements are more concentrated along the coastal margins and in the eastern states.

Table 6-6: Managed and Unmanaged Land Area by Land-Use Categories for All 50 States (Thousands of Hectares)

| Land-Use Categories | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Managed Lands | 890,019 | 890,016 | 890,017 | 890,017 | 890,017 | 890,017 | 890,017 |
| Forest Land | 285,837 | 292,106 | 294,175 | 294,585 | 294,988 | 294,988 | 294,988 |
| Croplands | 174,678 | 166,064 | 163,745 | 163,745 | 163,752 | 163,752 | 163,752 |
| Grasslands | 326,526 | 323,239 | 321,717 | 321,421 | 321,118 | 321,118 | 321,118 |
| Settlements | 33,420 | 40,450 | 42,645 | 42,645 | 42,648 | 42,648 | 42,648 |
| Wetlands | 45,361 | 43,004 | 42,336 | 42,223 | 42,113 | 42,112 | 42,113 |
| Other Land | 24,197 | 25,154 | 25,398 | 25,398 | 25,399 | 25,399 | 25,399 |
| Unmanaged Lands | 46,211 | 46,214 | 46,213 | 46,213 | 46,213 | 46,213 | 46,213 |
| Forest Land | 9,634 | 9,634 | 9,634 | 9,634 | 9,634 | 9,634 | 9,634 |
| Croplands | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Grasslands | 25,782 | 25,782 | 25,782 | 25,782 | 25,782 | 25,782 | 25,782 |
| Settlements | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wetlands | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Land | 10,795 | 10,797 | 10,797 | 10,797 | 10,797 | 10,797 | 10,797 |
| Total Land Areas | 936,230 |
| Forest Land | 295,471 | 301,740 | 303,810 | 304,219 | 304,622 | 304,622 | 304,622 |
| Croplands | 174,678 | 166,064 | 163,745 | 163,745 | 163,752 | 163,752 | 163,752 |
| Grasslands | 352,308 | 349,021 | 347,499 | 347,203 | 346,900 | 346,900 | 346,900 |
| Settlements | 33,420 | 40,450 | 42,645 | 42,645 | 42,648 | 42,648 | 42,648 |
| Wetlands | 45,361 | 43,004 | 42,336 | 42,223 | 42,113 | 42,112 | 42,113 |
| Other Land | 34,992 | 35,951 | 36,195 | 36,195 | 36,196 | 36,196 | 36,196 |

¹¹ The current land representation does not include areas from U.S. Territories, but there are planned improvements to include these regions in future reports.

¹² These “managed area” discrepancies also occur in the Common Reporting Format (CRF) tables submitted to the UNFCCC.

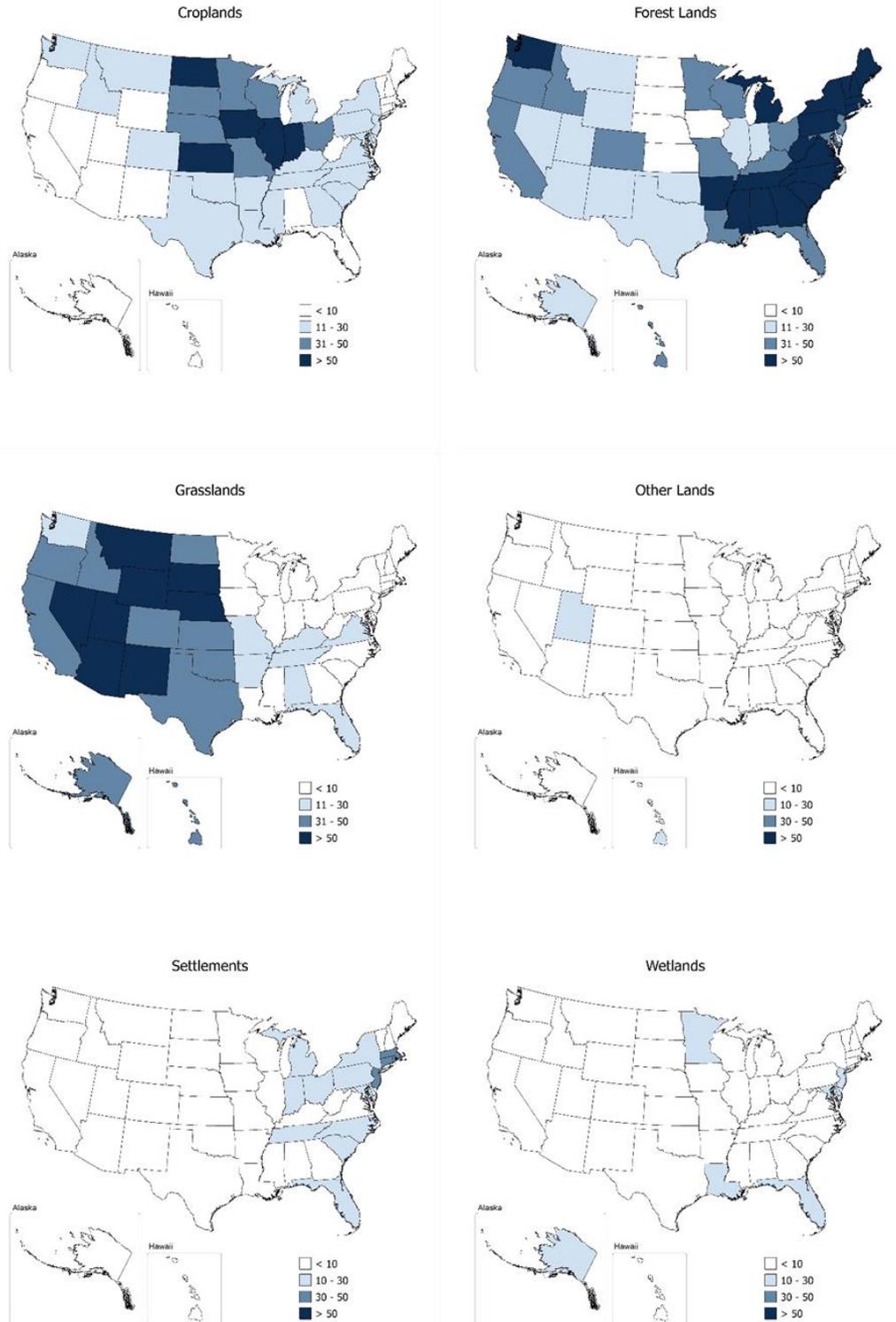
Table 6-7: Land Use and Land-Use Change for the U.S. Managed Land Base for All 50 States (Thousands of Hectares)

| Land-Use & Land-Use Change Categories ^a | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Total Forest Land | 285,837 | 292,106 | 294,175 | 294,585 | 294,988 | 294,988 | 294,988 |
| FF | 284,642 | 291,098 | 293,234 | 293,644 | 294,051 | 294,051 | 294,051 |
| CF | 233 | 215 | 189 | 189 | 183 | 183 | 183 |
| GF | 841 | 635 | 637 | 637 | 638 | 638 | 638 |
| WF | 20 | 23 | 23 | 23 | 23 | 23 | 23 |
| SF | 15 | 15 | 16 | 16 | 15 | 15 | 15 |
| OF | 86 | 120 | 77 | 77 | 77 | 77 | 77 |
| Total Cropland | 174,678 | 166,064 | 163,745 | 163,745 | 163,752 | 163,752 | 163,752 |
| CC | 161,960 | 151,903 | 152,079 | 152,079 | 152,084 | 152,084 | 152,084 |
| FC | 252 | 91 | 48 | 48 | 49 | 49 | 49 |
| GC | 12,066 | 13,581 | 11,215 | 11,215 | 11,215 | 11,215 | 11,215 |
| WC | 141 | 166 | 114 | 114 | 114 | 114 | 114 |
| SC | 77 | 78 | 72 | 72 | 72 | 72 | 72 |
| OC | 182 | 245 | 217 | 217 | 217 | 217 | 217 |
| Total Grassland | 326,526 | 323,239 | 321,717 | 321,421 | 321,118 | 321,118 | 321,118 |
| GG | 316,489 | 303,987 | 303,284 | 302,989 | 302,687 | 302,688 | 302,687 |
| FG | 899 | 1,538 | 1,481 | 1,481 | 1,479 | 1,479 | 1,479 |
| CG | 8,396 | 16,335 | 15,776 | 15,776 | 15,776 | 15,776 | 15,776 |
| WG | 283 | 437 | 250 | 250 | 250 | 250 | 250 |
| SG | 53 | 115 | 119 | 119 | 119 | 119 | 119 |
| OG | 406 | 827 | 806 | 806 | 806 | 806 | 806 |
| Total Wetlands | 45,361 | 43,004 | 42,336 | 42,223 | 42,113 | 42,112 | 42,113 |
| WW | 44,649 | 41,785 | 41,280 | 41,167 | 41,056 | 41,056 | 41,056 |
| FW | 38 | 41 | 35 | 35 | 35 | 35 | 35 |
| CW | 214 | 362 | 321 | 321 | 321 | 321 | 321 |
| GW | 396 | 770 | 661 | 661 | 661 | 661 | 661 |
| SW | 2 | 1 | 2 | 2 | 2 | 2 | 2 |
| OW | 63 | 45 | 38 | 38 | 38 | 38 | 38 |
| Total Settlements | 33,420 | 40,450 | 42,645 | 42,645 | 42,648 | 42,648 | 42,648 |
| SS | 30,632 | 32,188 | 34,870 | 34,870 | 34,870 | 34,870 | 34,870 |
| FS | 232 | 339 | 362 | 362 | 365 | 365 | 365 |
| CS | 1,227 | 3,530 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 |
| GS | 1,268 | 4,164 | 3,981 | 3,981 | 3,981 | 3,981 | 3,981 |
| WS | 6 | 26 | 24 | 24 | 24 | 24 | 24 |
| OS | 55 | 201 | 204 | 204 | 204 | 204 | 204 |
| Total Other Land | 24,197 | 25,154 | 25,398 | 25,398 | 25,399 | 25,399 | 25,399 |
| OO | 23,162 | 23,312 | 23,475 | 23,475 | 23,476 | 23,476 | 23,476 |
| FO | 37 | 54 | 61 | 61 | 61 | 61 | 61 |
| CO | 328 | 706 | 812 | 812 | 812 | 812 | 812 |
| GO | 531 | 966 | 969 | 969 | 969 | 969 | 969 |
| WO | 135 | 109 | 70 | 70 | 70 | 70 | 70 |
| SO | 4 | 7 | 12 | 12 | 12 | 12 | 12 |
| Grand Total | 890,019 | 890,016 | 890,017 | 890,017 | 890,017 | 890,017 | 890,017 |

^a The abbreviations are “F” for Forest Land, “C” for Cropland, “G” for Grassland, “W” for Wetlands, “S” for Settlements, and “O” for Other Lands. Lands remaining in the same land-use category are identified with the land-use abbreviation given twice (e.g., “FF” is *Forest Land Remaining Forest Land*), and land-use change categories are identified with the previous land use abbreviation followed by the new land-use abbreviation (e.g., “CF” is *Cropland Converted to Forest Land*).

Note: All land areas reported in this table are considered managed. A planned improvement is underway to deal with an exception for Wetlands, which based on the definitions for the current U.S. Land Representation Assessment includes both managed and unmanaged lands. U.S. Territories have not been classified into land uses and are not included in the U.S. Land Representation Assessment. See the Planned Improvements section for discussion on plans to include territories in future inventories. In addition, C stock changes are not currently estimated for the entire land base, which leads to discrepancies between the managed land area data presented here and in the subsequent sections of the Inventory.

Figure 6-1: Percent of Total Land Area for Each State in the General Land-Use Categories for 2014



Methodology

IPCC Approaches for Representing Land Areas

IPCC (2006) describes three approaches for representing land areas. Approach 1 provides data on the total area for each individual land-use category, but does not provide detailed information on changes of area between categories and is not spatially explicit other than at the national or regional level. With Approach 1, total net conversions between categories can be detected, but not the individual changes (i.e., additions and/or losses) between the land-use categories that led to those net changes. Approach 2 introduces tracking of individual land-use changes between the categories (e.g., Forest Land to Cropland, Cropland to Forest Land, and Grassland to Cropland), using survey samples or other forms of data, but does not provide location data on all parcels of land. Approach 3 extends Approach 2 by providing location data on all parcels of land, such as maps, along with the land-use history. The three approaches are not presented as hierarchical tiers and are not mutually exclusive.

According to IPCC (2006), the approach or mix of approaches selected by an inventory agency should reflect calculation needs and national circumstances. For this analysis, the NRI, FIA, and the NLCD have been combined to provide a complete representation of land use for managed lands. These data sources are described in more detail later in this section. NRI and FIA are Approach 2 data sources that do not provide spatially-explicit representations of land use and land-use conversions, even though land use and land-use conversions are tracked explicitly at the survey locations. NRI and FIA data are aggregated and used to develop a land-use conversion matrix for a political or ecologically-defined region. NLCD is a spatially-explicit time series of land-cover data that is used to inform the classification of land use, and is therefore Approach 3 data. Lands are treated as remaining in the same category (e.g., *Cropland Remaining Cropland*) if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified in a land-use change category based on the current use and most recent use before conversion to the current use (e.g., *Cropland Converted to Forest Land*).

Definitions of Land Use in the United States

Managed and Unmanaged Land

The United States definition of managed land is similar to the basic IPCC (2006) definition of managed land, but with some additional elaboration to reflect national circumstances. Based on the following definitions, most lands in the United States are classified as managed:

- *Managed Land*: Land is considered managed if direct human intervention has influenced its condition. Direct intervention occurs mostly in areas accessible to human activity and includes altering or maintaining the condition of the land to produce commercial or non-commercial products or services; to serve as transportation corridors or locations for buildings, landfills, or other developed areas for commercial or non-commercial purposes; to extract resources or facilitate acquisition of resources; or to provide social functions for personal, community, or societal objectives where these areas are readily accessible to society.¹³
- *Unmanaged Land*: All other land is considered unmanaged. Unmanaged land is largely comprised of areas inaccessible to society due to the remoteness of the locations. Though these lands may be influenced

¹³ Wetlands are an exception to this general definition, because these lands, as specified by IPCC (2006), are only considered managed if they are created through human activity, such as dam construction, or the water level is artificially altered by human activity. Distinguishing between managed and unmanaged wetlands in the United States is difficult due to limited data availability. Wetlands are not characterized by use within the NRI. Therefore, unless wetlands are managed for cropland or grassland, it is not possible to know if they are artificially created or if the water table is managed based on the use of NRI data. As a result, all Wetlands are reported as managed. See the Planned Improvements section of the Inventory for work being done to refine the Wetland area estimates.

indirectly by human actions such as atmospheric deposition of chemical species produced in industry or CO₂ fertilization, they are not influenced by a direct human intervention.¹⁴

In addition, land that is previously managed remains in the managed land base for 20 years before re-classifying the land as unmanaged in order to account for legacy effects of management on C stocks.

Land-Use Categories

As with the definition of managed lands, IPCC (2006) provides general non-prescriptive definitions for the six main land-use categories: Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land. In order to reflect national circumstances, country-specific definitions have been developed, based predominantly on criteria used in the land-use surveys for the United States. Specifically, the definition of Forest Land is based on the FIA definition of forest,¹⁵ while definitions of Cropland, Grassland, and Settlements are based on the NRI.¹⁶ The definitions for Other Land and Wetlands are based on the IPCC (2006) definitions for these categories.

- *Forest Land*: A land-use category that includes areas at least 120 feet (36.6 meters) wide and at least one acre (0.4 hectare) in size with at least 10 percent cover (or equivalent stocking) by live trees including land that formerly had such tree cover and that will be naturally or artificially regenerated. Trees are woody plants having a more or less erect perennial stem(s) capable of achieving at least 3 inches (7.6 centimeters) in diameter at breast height, or 5 inches (12.7 cm) diameter at root collar, and a height of 16.4 feet (5 m) at maturity in situ. Forest Land includes all areas recently having such conditions and currently regenerating or capable of attaining such condition in the near future. Forest Land also includes transition zones, such as areas between forest and non-forest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 120 feet (36.6 m) wide or an acre (0.4 ha) in size. However, land is not classified as Forest Land if completely surrounded by urban or developed lands, even if the criteria are consistent with the tree area and cover requirements for Forest Land. These areas are classified as Settlements. In addition, Forest Land does not include land that is predominantly under an agricultural land use (Oswalt et al. 2014).
- *Cropland*: A land-use category that includes areas used for the production of adapted crops for harvest; this category includes both cultivated and non-cultivated lands. Cultivated crops include row crops or close-grown crops and also hay or pasture in rotation with cultivated crops. Non-cultivated cropland includes continuous hay, perennial crops (e.g., orchards) and horticultural cropland. Cropland also includes land with agroforestry, such as alley cropping and windbreaks,¹⁷ if the dominant use is crop production, assuming the stand or woodlot does not meet the criteria for Forest Land. Lands in temporary fallow or enrolled in conservation reserve programs (i.e., set-asides¹⁸) are also classified as Cropland, as long as these areas do not meet the Forest Land criteria. Roads through Cropland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Cropland area estimates and are, instead, classified as Settlements.
- *Grassland*: A land-use category on which the plant cover is composed principally of grasses, grass-like plants (i.e., sedges and rushes), forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands. This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Grassland may have three or fewer years of

¹⁴ There are some areas, such as Forest Land and Grassland in Alaska that are classified as unmanaged land due to the remoteness of their location.

¹⁵ See <<http://www.fia.fs.fed.us/library/field-guides-methods-proc/docs/2015/Core-FIA-FG-7.pdf>>, page 22.

¹⁶ See <<http://www.nrcs.usda.gov/wps/portal/nrcs/site/national/home>>.

¹⁷ Currently, there is no data source to account for biomass C stock change associated with woody plant growth and losses in alley cropping systems and windbreaks in cropping systems, although these areas are included in the Cropland land base.

¹⁸ A set-aside is cropland that has been taken out of active cropping and converted to some type of vegetative cover, including, for example, native grasses or trees.

hay production¹⁹ that is otherwise pasture or rangelands. Savannas, deserts, and tundra are considered Grassland.²⁰ Drained wetlands are considered Grassland if the dominant vegetation meets the plant cover criteria for Grassland. Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices, such as silvipasture and windbreaks, if the land is principally grasses, grass-like plants, forbs, and shrubs suitable for grazing and browsing, and assuming the stand or woodlot does not meet the criteria for Forest Land. Roads through Grassland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Grassland and are, instead, classified as Settlements.

- *Wetlands*: A land-use category that includes land covered or saturated by water for all or part of the year, in addition to the areas of lakes, reservoirs, and rivers. Managed Wetlands are those where the water level is artificially changed, or were created by human activity. Certain areas that fall under the managed Wetlands definition are included in other land uses based on the IPCC guidance, including Cropland (drained wetlands for crop production and also systems that are flooded for most or just part of the year, such as rice cultivation and cranberry production), Grassland (drained wetlands dominated by grass cover), and Forest Land (including drained or un-drained forested wetlands).
- *Settlements*: A land-use category representing developed areas consisting of units of 0.25 acres (0.1 ha) or more that includes residential, industrial, commercial, and institutional land; construction sites; public administrative sites; railroad yards; cemeteries; airports; golf courses; sanitary landfills; sewage treatment plants; water control structures and spillways; parks within urban and built-up areas; and highways, railroads, and other transportation facilities. Also included are tracts of less than 10 acres (4.05 ha) that may meet the definitions for Forest Land, Cropland, Grassland, or Other Land but are completely surrounded by urban or built-up land, and so are included in the Settlements category. Rural transportation corridors located within other land uses (e.g., Forest Land, Cropland, and Grassland) are also included in Settlements.
- *Other Land*: A land-use category that includes bare soil, rock, ice, and all land areas that do not fall into any of the other five land-use categories, which allows the total of identified land areas to match the managed land base. Following the guidance provided by the IPCC (2006), C stock changes and non-CO₂ emissions are not estimated for Other Lands because these areas are largely devoid of biomass, litter and soil C pools. However, C stock changes and non-CO₂ emissions are estimated for *Land Converted to Other Land* during the first 20 years following conversion to account for legacy effects.

Land-Use Data Sources: Description and Application to U.S. Land Area Classification

U.S. Land-Use Data Sources

The three main sources for land-use data in the United States are the NRI, FIA, and the NLCD (Table 6-8). These data sources are combined to account for land use in all 50 states. FIA and NRI data are used when available for an area because the surveys contain additional information on management, site conditions, crop types, biometric measurements, and other data from which to estimate C stock changes on those lands. If NRI and FIA data are not available for an area, however, then the NLCD product is used to represent the land use.

¹⁹ Areas with four or more years of continuous hay production are Cropland because the land is typically more intensively managed with cultivation, greater amounts of inputs, and other practices.

²⁰ 2006 IPCC Guidelines do not include provisions to separate desert and tundra as land-use categories.

Table 6-8: Data Sources Used to Determine Land Use and Land Area for the Conterminous United States, Hawaii, and Alaska

| | NRI | FIA | NLCD |
|--|-----|-----|------|
| Forest Land | | | |
| Conterminous United States | | | |
| <i>Non-Federal</i> | | • | |
| <i>Federal</i> | | • | |
| Hawaii | | | |
| <i>Non-Federal</i> | • | | |
| <i>Federal</i> | | | • |
| Alaska | | | |
| <i>Non-Federal</i> | | | • |
| <i>Federal</i> | | | • |
| Croplands, Grasslands, Other Lands, Settlements, and Wetlands | | | |
| Conterminous United States | | | |
| <i>Non-Federal</i> | • | | |
| <i>Federal</i> | | | • |
| Hawaii | | | |
| <i>Non-Federal</i> | • | | |
| <i>Federal</i> | | | • |
| Alaska | | | |
| <i>Non-Federal</i> | | | • |
| <i>Federal</i> | | | • |

National Resources Inventory

For the Inventory, the NRI is the official source of data on all land uses on non-federal lands in the conterminous United States and Hawaii (except Forest Land), and is also used as the resource to determine the total land base for the conterminous United States and Hawaii. The NRI is a statistically-based survey conducted by the USDA Natural Resources Conservation Service and is designed to assess soil, water, and related environmental resources on non-federal lands. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the United States Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit (typically a 160 acre [64.75 ha] square quarter-section), three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). The NRI survey utilizes data derived from remote sensing imagery and site visits in order to provide detailed information on land use and management, particularly for Croplands and Grasslands, and is used as the basis to account for C stock changes in agricultural lands (except federal Grasslands). The NRI survey was conducted every 5 years between 1982 and 1997, but shifted to annualized data collection in 1998. The land use between five-year periods from 1982 and 1997 are assumed to be the same for a five-year time period if the land use is the same at the beginning and end of the five-year period. (Note: most of the data has the same land use at the beginning and end of the five-year periods.) If the land use had changed during a five-year period, then the change is assigned at random to one of the five years. For crop histories, years with missing data are estimated based on the sequence of crops grown during years preceding and succeeding a missing year in the NRI history. This gap-filling approach allows for development of a full time series of land-use data for non-federal lands in the conterminous United States and Hawaii. This Inventory incorporates data through 2010 from the NRI. The land use patterns are assumed to remain the same from 2010 through 2014 for this Inventory, but the time series will be updated when new data are released.

Forest Inventory and Analysis

The FIA program, conducted by the USFS, is another statistically-based survey for the conterminous United States, and the official source of data on Forest Land area and management data for the Inventory in this region of the country. FIA engages in a hierarchical system of sampling, with sampling categorized as Phases 1 through 3, in which sample points for phases are subsets of the previous phase. Phase 1 refers to collection of remotely-sensed data (either aerial photographs or satellite imagery) primarily to classify land into forest or non-forest and to identify landscape patterns like fragmentation and urbanization. Phase 2 is the collection of field data on a network of ground plots that enable classification and summarization of area, tree, and other attributes associated with forest-land uses. Phase 3 plots are a subset of Phase 2 plots where data on indicators of forest health are measured. Data

from all three phases are also used to estimate C stock changes for Forest Land. Historically, FIA inventory surveys have been conducted periodically, with all plots in a state being measured at a frequency of every five to 14 years. A new national plot design and annual sampling design was introduced by FIA about ten years ago. Most states, though, have only recently been brought into this system. Annualized sampling means that a portion of plots throughout each state is sampled each year, with the goal of measuring all plots once every five years. See Annex 3.13 to see the specific survey data available by state. The most recent year of available data varies state by state (range of most recent data is from 2012 through 2014; see Table A-255).

National Land Cover Dataset

While the NRI survey sample covers the conterminous United States and Hawaii, land use data are only collected on non-federal lands. In addition, FIA only records data for forest land across the land base in the conterminous United States and a portion of Alaska.²¹ Consequently, major gaps exist in the land use classification when the datasets are combined, such as federal grassland operated by Bureau of Land Management (BLM), USDA, and National Park Service, as well as Alaska.²² The NLCD is used as a supplementary database to account for land use on federal lands in the conterminous United States and Hawaii, in addition to federal and non-federal lands in Alaska.

NLCD products provide land-cover for 1992, 2001, 2006, and 2011 in the conterminous United States (Homer et al. 2007), and also for Alaska and Hawaii in 2001. For the conterminous United States, the NLCD data have been further processed to derive Land Cover Change Products for 2001, 2006, and 2011 (Fry et al. 2011, Homer et al. 2007, Jin et al. 2013). A change product is not available for Alaska and Hawaii because the data are only available for one year, i.e., 2001). The NLCD products are based primarily on Landsat Thematic Mapper imagery at a 30 meter resolution, and contain 21 categories of land-cover information, which have been aggregated into the 36 IPCC land-use categories for the conterminous United States and into the 6 IPCC land-use categories for Hawaii and Alaska.

The aggregated maps of IPCC land-use categories were used in combination with the NRI database to represent land use and land-use change for federal lands, as well as federal and non-federal lands in Alaska. Specifically, NRI survey locations designated as federal lands were assigned a land use/land use change category based on the NLCD maps that had been aggregated into the IPCC categories. This analysis addressed shifts in land ownership across years between federal or non-federal classes as represented in the NRI survey (i.e., the ownership is classified for each survey location is the NRI). NLCD is strictly a source of land-cover information, however, and does not provide the necessary site conditions, crop types, and management information from which to estimate C stock changes on those lands. The sources of these additional data are discussed in subsequent sections of the NIR.

Managed Land Designation

Lands are designated as managed in the United States based on the definition provided earlier in this section. In order to apply the definition in an analysis of managed land, the following criteria are used:

- All Croplands and Settlements are designated as managed so only Grassland, Forest Land or Other Lands may be designated as unmanaged land;
- All Forest Lands with active fire protection are considered managed;
- All Grassland is considered managed at a county scale if there are livestock in the county;²³
- Other areas are considered managed if accessible based on the proximity to roads and other transportation corridors, and/or infrastructure;
- Protected lands maintained for recreational and conservation purposes are considered managed (i.e., managed by public and private organizations);
- Lands with active and/or past resource extraction are considered managed; and

²¹ FIA does collect some data on non-forest land use, but these are held in regional databases versus the national database. The status of these data is being investigated.

²² The FIA and NRI survey programs also do not include U.S. Territories with the exception of non-federal lands in Puerto Rico, which are included in the NRI survey. Furthermore, NLCD does not include coverage for all U.S. Territories.

²³ Assuming all Grasslands are grazed in a county with even very small livestock populations is a conservative assumption about human impacts on Grasslands. Currently, detailed information on grazing at sub-county scales is not available for the United States to make a finer delineation of managed land.

- Lands that were previously managed but subsequently classified as unmanaged remain in the managed land base for 20 years following the conversion to account for legacy effects of management on C stocks.

The analysis of managed lands is conducted using a geographic information system. Lands that are used for crop production or settlements are determined from the NLCD (Fry et al. 2011; Homer et al. 2007; Jin et al. 2013). Forest Lands with active fire management are determined from maps of federal and state management plans from the National Atlas (U.S. Department of Interior 2005) and Alaska Interagency Fire Management Council (1998). It is noteworthy that all forest lands in the conterminous United States have active fire protection, and are therefore designated as managed regardless of accessibility or other criteria. The designation of grasslands as managed is based on livestock population data at the county scale from the USDA National Agricultural Statistics Service (U.S. Department of Agriculture 2014). Accessibility is evaluated based on a 10-km buffer surrounding road and train transportation networks using the ESRI Data and Maps product (ESRI 2008), and a 10-km buffer surrounding settlements using NLCD. Lands maintained for recreational purposes are determined from analysis of the Protected Areas Database (U.S. Geological Survey 2012). The Protected Areas Database includes lands protected from conversion of natural habitats to anthropogenic uses and describes the protection status of these lands. Lands are considered managed that are protected from development if the regulations permit extractive or recreational uses or suppression of natural disturbance. Lands that are protected from development and not accessible to human intervention, including no suppression of disturbances or extraction of resources, are not included in the managed land base. Multiple data sources are used to determine lands with active resource extraction: Alaska Oil and Gas Information System (Alaska Oil and Gas Conservation Commission 2009), Alaska Resource Data File (U.S. Geological Survey 2012), Active Mines and Mineral Processing Plants (U.S. Geological Survey 2005), and Coal Production and Preparation Report (U.S. Energy Information Administration 2011). A buffer of 3,300 and 4,000 meters is established around petroleum extraction and mine locations, respectively, to account for the footprint of operation and impacts of activities on the surrounding landscape. The buffer size is based on visual analysis of approximately 130 petroleum extraction sites and 223 mines. The resulting managed land area is overlaid on the NLCD to estimate the area of managed land by land use for both federal and non-federal lands. The remaining land represents the unmanaged land base. The resulting spatial product is used to identify NRI survey locations that are considered managed and unmanaged for the conterminous United States and Hawaii, in addition to determining which areas in the NLCD for Alaska are included in the managed land base.

Approach for Combining Data Sources

The managed land base in the United States has been classified into the thirty-six IPCC land-use/land-use conversion categories using definitions developed to meet national circumstances, while adhering to IPCC (2006).²⁴ In practice, the land was initially classified into a variety of land-use categories within the NRI, FIA, and NLCD datasets, and then aggregated into the thirty-six broad land use and land-use change categories identified in IPCC (2006). All three datasets provide information on forest land areas in the conterminous United States, but the area data from FIA serve as the official dataset for estimating Forest Land in the conterminous United States.

Therefore, another step in the analysis is to address the inconsistencies in the representation of the Forest Land among the three databases. NRI and FIA have different criteria for classifying Forest Land in addition to different sampling designs, leading to discrepancies in the resulting estimates of Forest Land area on non-federal land in the conterminous United States. Similarly, there are discrepancies between the NLCD and FIA data for defining and classifying Forest Land on federal lands. Any change in Forest Land Area in the NRI and NLCD also requires a corresponding change in other land use areas because of the dependence between the Forest Land area and the amount of land designated as other land uses, such as the amount of Grassland, Cropland, and Wetlands (i.e., areas for the individual land uses must sum to the total area of the country).

FIA is the main database for forest statistics, and consequently, the NRI and NLCD are adjusted to achieve consistency with FIA estimates of Forest Land in the conterminous United States. Adjustments are made in the *Forest Land Remaining Forest Land*, *Land Converted to Forest Land*, and *Forest Land converted to other uses* (i.e., Grassland, Cropland and Wetlands). All adjustments are made at the state scale to address the differences in Forest Land definitions and the resulting discrepancies in areas among the land use and land-use change categories. There

²⁴ Definitions are provided in the previous section.

are three steps in this process. The first step involves adjustments for *Land Converted to Forest Land* (Grassland, Cropland and Wetlands), followed by adjustments in Forest Land converted to another land use (i.e., Grassland, Cropland and Wetlands), and finally adjustments to *Forest Land Remaining Forest Land*.

In the first step, *Land Converted to Forest Land* in the NRI and NLCD are adjusted to match the state-level estimates in the FIA data for non-federal and federal *Land Converted to Forest Land*, respectively. FIA data do not provide specific land-use categories that are converted to Forest Land, but rather a sum of all *Land Converted to Forest Land*. The NRI and NLCD provide information on specific land use conversions, however, such as *Grassland Converted to Forest Land*. Therefore, adjustments at the state level to NRI and NLCD are made proportional to the amount of land use change into Forest Land for the state, prior to any adjustments. For example, if 50 percent of land use change to Forest Land is associated with *Grassland Converted to Forest Land* in a state according to NRI or NLCD, then half of the discrepancy with FIA data in the area of *Land Converted to Forest Land* is addressed by increasing or decreasing the area in *Grassland Converted to Forest Land*. Moreover, any increase or decrease in *Grassland Converted to Forest Land* in NRI or NLCD is addressed by a corresponding change in the area of *Grassland Remaining Grassland*, so that the total amount of managed area is not changed within an individual state.

In the second step, state-level areas are adjusted in the NRI and NLCD to address discrepancies with FIA data for Forest Land converted to other uses. Similar to *Land Converted to Forest Land*, FIA does not provide information on the specific land-use changes, and so areas associated with Forest Land conversion to other land uses in NRI and NLCD are adjusted proportional to the amount area in each conversion class in these datasets.

In the final step, the area of *Forest Land Remaining Forest Land* in a given state according to the NRI and NLCD is adjusted to match the FIA estimates for non-federal and federal land, respectively. It is assumed that the majority of the discrepancy in *Forest Land Remaining Forest Land* is associated with an under- or over-prediction of *Grassland Remaining Grassland* and *Wetland Remaining Wetland* in the NRI and NLCD. This step also assumes that there are no changes in the land use conversion categories. Therefore, corresponding increases or decreases are made in the area estimates of *Grasslands Remaining Grasslands* and *Wetlands Remaining Wetlands* from the NRI and NLCD, in order to balance the change in *Forest Land Remaining Forest Land* area, and ensure no change in the overall amount of managed land within an individual state. The adjustments are based on the proportion of land within each of these land-use categories at the state level. (i.e., a higher proportion of Grassland led to a larger adjustment in Grassland area).

The modified NRI data are then aggregated to provide the land-use and land-use change data for non-federal lands in the conterminous United States, and the modified NLCD data are aggregated to provide the land use and land-use change data for federal lands. Data for all land uses in Hawaii are based on NRI for non-federal lands and on NLCD for federal lands. Land use data in Alaska are based solely on the NLCD data (Table 6-8). The result is land use and land-use change data for the conterminous United States, Hawaii, and Alaska.²⁵

A summary of the details on the approach used to combine data sources for each land use are described below.

- *Forest Land*: Both non-federal and federal forest lands in the conterminous United States and coastal Alaska are covered by FIA. FIA is used as the basis for both Forest Land area data as well as to estimate C stocks and fluxes on Forest Land in the conterminous United States. FIA does have survey plots in coastal Alaska that are used to determine the C stock changes, but the area data for this region are based on the 2001 NLCD. In addition, interior Alaska is not currently surveyed by FIA so forest land in this region are also based on the 2001 NLCD. NRI is being used in the current report to provide Forest Land areas on non-federal lands in Hawaii and NLCD is used for federal lands. FIA data will be collected in Hawaii in the future.
- *Cropland*: Cropland is classified using the NRI, which covers all non-federal lands within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Cropland area data as well as to estimate soil C stocks and fluxes on Cropland. NLCD is used to determine Cropland area and soil C stock changes on federal lands in the conterminous United

²⁵ Only one year of data are currently available for Alaska so there is no information on land-use change for this state.

States and Hawaii. NLCD is also used to determine croplands in Alaska, but C stock changes are not estimated for this region in the current Inventory.

- *Grassland*: Grassland on non-federal lands is classified using the NRI within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Grassland area data as well as to estimate soil C stocks and fluxes on Grassland. Grassland area and soil C stock changes are determined using the classification provided in the NLCD for federal land within the conterminous United States. NLCD is also used to estimate the areas of federal and non-federal grasslands in Alaska, and the federal lands in Hawaii, but the current Inventory does not include C stock changes in these areas.
- *Wetlands*: NRI captures wetlands on non-federal lands within 49 states (excluding Alaska), while federal wetlands and wetlands in Alaska are covered by the NLCD.²⁶
- *Settlements*: NRI captures non-federal settlement area in 49 states (excluding Alaska). If areas of Forest Land or Grassland under 10 acres (4.05 ha) are contained within settlements or urban areas, they are classified as Settlements (urban) in the NRI database. If these parcels exceed the 10 acre (4.05 ha) threshold and are Grassland, they will be classified as such by NRI. Regardless of size, a forested area is classified as non-forest by FIA if it is located within an urban area. Settlements on federal lands and in Alaska are covered by NLCD.
- *Other Land*: Any land that is not classified into one of the previous five land-use categories, is categorized as Other Land using the NRI for non-federal areas in the conterminous United States and Hawaii and using the NLCD for the federal lands in all regions of the United States and for non-federal lands in Alaska.

Some lands can be classified into one or more categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assignment priority in these cases. The ranking process is from highest to lowest priority, in the following manner:

Settlements > Cropland > Forest Land > Grassland > Wetlands > Other Land

Settlements are given the highest assignment priority because they are extremely heterogeneous with a mosaic of patches that include buildings, infrastructure, and travel corridors, but also open grass areas, forest patches, riparian areas, and gardens. The latter examples could be classified as Grassland, Forest Land, Wetlands, and Cropland, respectively, but when located in close proximity to settlement areas they tend to be managed in a unique manner compared to non-settlement areas. Consequently, these areas are assigned to the Settlements land-use category. Cropland is given the second assignment priority, because cropping practices tend to dominate management activities on areas used to produce food, forage, or fiber. The consequence of this ranking is that crops in rotation with pasture will be classified as Cropland, and land with woody plant cover that is used to produce crops (e.g., orchards) is classified as Cropland, even though these areas may meet the definitions of Grassland or Forest Land, respectively. Similarly, Wetlands are considered Croplands if they are used for crop production, such as rice or cranberries. Forest Land occurs next in the priority assignment because traditional forestry practices tend to be the focus of the management activity in areas with woody plant cover that are not croplands (e.g., orchards) or settlements (e.g., housing subdivisions with significant tree cover). Grassland occurs next in the ranking, while Wetlands then Other Land complete the list.

The assignment priority does not reflect the level of importance for reporting greenhouse gas emissions and removals on managed land, but is intended to classify all areas into a discrete land use. Currently, the IPCC does not make provisions in the guidelines for assigning land to multiple uses. For example, a wetland is classified as Forest Land if the area has sufficient tree cover to meet the stocking and stand size requirements. Similarly, wetlands are classified as Cropland if they are used for crop production, such as rice or cranberries, or as Grassland if they are composed principally of grasses, grass-like plants (i.e., sedges and rushes), forbs, or shrubs suitable for grazing and browsing. Regardless of the classification, emissions from these areas are included in the Inventory if the land is considered managed and presumably impacted by anthropogenic activity in accordance with the guidance provided in IPCC (2006).

²⁶ This analysis does not distinguish between managed and unmanaged wetlands, which is a planned improvement for the Inventory.

QA/QC and Verification

The land base derived from the NRI, FIA, and NLCD was compared to the Topologically Integrated Geographic Encoding and Referencing (TIGER) survey (U.S. Census Bureau 2010). The U.S. Census Bureau gathers data on the U.S. population and economy, and has a database of land areas for the country. The land area estimates from the U.S. Census Bureau differ from those provided by the land-use surveys used in the Inventory because of discrepancies in the reporting approach for the Census and the methods used in the NRI, FIA, and NLCD. The area estimates of land-use categories, based on NRI, FIA, and NLCD, are derived from remote sensing data instead of the land survey approach used by the U.S. Census Survey. More importantly, the U.S. Census Survey does not provide a time series of land-use change data or land management information. Consequently, the U.S. Census Survey was not adopted as the official land area estimate for the Inventory. Rather, the NRI, FIA, and NLCD datasets were adopted because these databases provide full coverage of land area and land use for the conterminous United States, Alaska, and Hawaii, in addition to management and other data relevant for the Inventory. Regardless, the total difference between the U.S. Census Survey and the combined NRI, FIA, and NLCD data is about 46 million hectares for the total U.S. land base of about 936 million hectares currently included in the Inventory, or a 5 percent difference. Much of this difference is associated with open waters in coastal regions and the Great Lakes, which is included in the TIGER Survey of the U.S. Census, but not included in the land representation using the NRI, FIA and NLCD. There is only a 0.4 percent difference when open water in coastal regions is removed from the TIGER data.

Recalculations Discussion

In previous years, FIA did not separate Forest Land into land use and land use change categories, reporting all areas as *Forest Land Remaining Forest Land* for the purpose of estimating forest carbon stock changes. In this Inventory, forest carbon stock changes are reported for *Land Converted to Forest*, *Forest Converted to other Land Uses*, in addition to *Forest Land Remaining Forest Land*. As such, adjustments to NRI and NLCD accounted for land use changes associated with Forest Land, which led to minor adjustments to the time series. Other small changes occurred in the areas of Grassland, Wetland, and Cropland due to the modifications to the Forest Land data in FIA and the process of combining the NRI, NLCD and FIA products into a harmonized dataset.

In addition to the changes in the FIA data, a new NRI dataset was incorporated into the current Inventory extending the time series from 2007 to 2010. The NRI program also recalculated the previous time series based on changes to the classification and imputation procedures for filling gaps.

The definition of Grassland also changed so that a land use history that includes three or fewer years within a sequence of grass pasture or rangeland is considered Grassland, rather than converting these areas into Cropland. Land use remains virtually unchanged in these cases with harvesting of the existing grass vegetation, with no impact on carbon stocks. In contrast, longer term adoption of continuous hay tends to change the management to a more intensive set of practices that influences the carbon stocks. This exception is only applied to hay. Any change in land management that involves cultivation of other crops, such as corn, wheat, or soybeans, is still considered a land use change.

The revisions in land representation led to the following changes in land use areas for the managed land base: on average over the time series, Forest Land area decreased by 0.2 percent, Cropland area increased by 3.1 percent, Grassland area increased by 0.7 percent, Wetland area decreased by 0.8 percent, Settlements decreased by 16.6 percent, and Other Lands increased by 5.8 percent.

Planned Improvements

A key planned improvement is to fully incorporate area data by land-use type for U.S. Territories into the Inventory. Fortunately, most of the managed land in the United States is included in the current land-use statistics, but a complete accounting is a key goal for the near future. Preliminary land-use area data for U.S. Territories by land-use category are provided in Box 6-2: Preliminary Estimates of Land Use in U.S. Territories.

Box 6-2: Preliminary Estimates of Land Use in U.S. Territories

Several programs have developed land cover maps for U.S. Territories using remote sensing imagery, including the Gap Analysis Program, Caribbean Land Cover project, National Land Cover Dataset, USFS Pacific Islands Imagery Project, and the National Oceanic and Atmospheric Administration (NOAA) Coastal Change Analysis Program (C-CAP). Land-cover data can be used to inform a land-use classification if there is a time series to evaluate the dominate practices. For example, land that is principally used for timber production with tree cover over most of the time series is classified as forest land even if there are a few years of grass dominance following timber harvest. These products were reviewed and evaluated for use in the national Inventory as a step towards implementing a planned improvement to include U.S. Territories in the land representation for the Inventory. Recommendations are to use the NOAA C-CAP Regional Land Cover Database for the smaller island Territories (U.S. Virgin Islands, Guam, Northern Marianas Islands, and American Samoa) because this program is ongoing and therefore will be continually updated. The C-CAP product does not cover the entire territory of Puerto Rico so the NLCD was used for this area. The final selection of a land-cover product for these territories is still under discussion. Results are presented below (in hectares). The total land area of all U.S. Territories is 1.05 million hectares, representing 0.1 percent of the total land base for the United States.

Table 6-9: Total Land Area (Hectares) by Land-Use Category for U.S. Territories

| | Puerto Rico | U.S. Virgin Islands | Guam | Northern Marianas Islands | American Samoa | Total |
|--------------|----------------|---------------------|---------------|---------------------------|----------------|------------------|
| Cropland | 19,712 | 138 | 236 | 289 | 389 | 20,764 |
| Forest Land | 404,004 | 13,107 | 24,650 | 25,761 | 15,440 | 482,962 |
| Grasslands | 299,714 | 12,148 | 15,449 | 13,636 | 1,830 | 342,777 |
| Other Land | 5,502 | 1,006 | 1,141 | 5,186 | 298 | 13,133 |
| Settlements | 130,330 | 7,650 | 11,146 | 3,637 | 1,734 | 154,496 |
| Wetlands | 24,525 | 4,748 | 1,633 | 260 | 87 | 31,252 |
| Total | 883,788 | 38,796 | 54,255 | 48,769 | 19,777 | 1,045,385 |

Additional work will be conducted to reconcile differences in Forest Land estimates between the NRI and FIA. This improvement will include an analysis designed to develop finer scale adjustments at the survey locations. Harmonization is planned at the survey location scale using ancillary data, such as the NLCD, which is expected to better capture the differences in Forest Land classification between the two surveys, as well as the conversions of land to other uses that involve Forest Land.

NLCD data for Alaska were recently released for 2011, and will be used to analyze land use change for this state in the next Inventory. There are also other databases that may need to be reconciled with the NRI and NLCD datasets, particularly for Settlements. Urban area estimates, used to produce C stock and flux estimates from urban trees, are currently based on population data (1990, 2000, and 2010 U.S. Census data). Using the population statistics, “urban clusters” are defined as areas with more than 500 people per square mile. The USFS is currently moving ahead with an Urban Forest Inventory program so that urban forest area estimates will be consistent with FIA forest area estimates outside of urban areas, which would be expected to reduce omissions and overlap of forest area estimates along urban boundary areas.

As adopted by the UNFCCC, new guidance in the *2013 Supplement to the 2006 Guidelines for National Greenhouse Gas Inventories: Wetlands* will be implemented in the Inventory. This will likely have implications for the classification of managed and unmanaged wetlands in the Inventory report. More detailed wetlands datasets will also be evaluated and integrated into the analysis in order to implement the new guidance.

6.2 Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks (IPCC Source Category 4A1)

Delineation of Carbon Pools

For estimating carbon (C) stocks or stock change (flux), C in forest ecosystems can be divided into the following five storage pools (IPCC 2006):

- Aboveground biomass, which includes all living biomass above the soil including stem, stump, branches, bark, seeds, and foliage. This category includes live understory.
- Belowground biomass, which includes all living biomass of coarse living roots greater than 2 millimeters (mm) diameter.
- Dead wood, which includes all non-living woody biomass either standing, lying on the ground (but not including litter), or in the soil.
- Litter, which includes the litter, fomic, and humic layers, and all non-living biomass with a diameter less than 7.5 centimeters (cm) at transect intersection, lying on the ground.
- Soil organic C (SOC), including all organic material in soil to a depth of 1 meter but excluding the coarse roots of the belowground pools.

In addition, there are two harvested wood pools to account for when estimating C flux:

- Harvested wood products (HWP) in use.
- HWP in solid waste disposal sites (SWDS).

Forest Carbon Cycle

Carbon is continuously cycled among the previously defined C storage pools and the atmosphere as a result of biogeochemical processes in forests (e.g., photosynthesis, respiration, decomposition, and disturbances such as fires or pest outbreaks) and anthropogenic activities (e.g., harvesting, thinning, and replanting). As trees photosynthesize and grow, C is removed from the atmosphere and stored in living tree biomass. As trees die and otherwise deposit litter and debris on the forest floor, C is released to the atmosphere and is also transferred to the litter, dead wood and soil pools by organisms that facilitate decomposition.

The net change in forest C is not equivalent to the net flux between forests and the atmosphere because timber harvests do not cause an immediate flux of all harvested biomass C to the atmosphere. Instead, harvesting transfers a portion of the C stored in wood to a "product pool." Once in a product pool, the C is emitted over time as CO₂ in the case of decomposition and as CO₂, CH₄, N₂O, CO, NO_x when the wood product combusts. The rate of emission varies considerably among different product pools. For example, if timber is harvested to produce energy, combustion releases C immediately, and these emissions are reported for information purposes in the Energy sector while the harvest (i.e., the associated reduction in forest C stocks) and subsequent combustion are implicitly accounted for under the Land Use, Land-Use Change, and Forestry (LULUCF) sector (i.e., the harvested timber does not enter the HWP pools). Conversely, if timber is harvested and used as lumber in a house, it may be many decades or even centuries before the lumber decays and C is released to the atmosphere. If wood products are disposed of in SWDS, the C contained in the wood may be released many years or decades later, or may be stored almost permanently in the SWDS. These latter fluxes, with the exception of CH₄ from wood in SWDS which is included in the Waste sector, are also accounted for under the LULUCF sector.

Net Change in Carbon Stocks within Forest Land of the United States

This section describes the general method for quantifying the net changes in C stocks in the five forest C pools and two harvested wood pools. The underlying methodology for determining C stock and stock-change relies on data

from the Forest Inventory and Analysis (FIA) program within the USDA Forest Service. The annual forest inventory system is implemented across all U.S. forest lands within the conterminous 48 states but excluding interior Alaska, Hawaii, and U.S. Territories at this time. The methods for estimation and monitoring are continuously improved and these improvements are reflected in the C estimates (Woodall et al. 2015a). The net change in C stocks for each pool is estimated, and then the changes in stocks are summed for all pools to estimate total net flux. The focus on C implies that all C-based greenhouse gases are included, and the focus on stock change suggests that specific ecosystem fluxes do not need to be separately itemized in this report. Changes in C stocks from disturbances, such as forest fires or harvesting, are included in the net changes. For instance, an inventory conducted after fire counts only the trees that are left. Therefore, changes in C stocks from natural disturbances, such as wildfires, pest outbreaks, and storms, are accounted for in the forest inventory approach; however, they are highly variable from year to year. The IPCC (2006) recommends estimating changes in C stocks from forest lands according to several land-use types and conversions, specifically *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, with the former being forest lands that have been forest lands for 20 years or longer and the latter being lands that have been classified as forest lands for less than 20 years. This is the first report to delineate forest C stock changes by these two categories and in order to facilitate this delineation, a different approach to forest C accounting was used this year in the United States (Woodall et al. 2015a).

Forest Area in the United States

Approximately 34 percent of the U.S. land area is estimated to be forested based on the U.S. definition of forest land as provided in the Section 6.1 Representation of the U.S. Land Base. The most recent forest inventories from each of the conterminous 48 states (USDA Forest Service 2014a, 2014b) comprise an estimated 266 million hectares of forest land that are considered managed and are included in this Inventory. An additional 6.2 million hectares of forest land in southeast and south central coastal Alaska are inventoried and are also included here. Some differences exist in forest land defined in Oswald et al. (2014) and the forest land included in this report, which is based on the USDA Forest Service (2015b) forest inventory. Annual inventory data are not yet available for Hawaii and interior Alaska, but estimates of these areas are included in Oswald et al. (2014). Updated survey data for central and western forest land in both Oklahoma and Texas have only recently become available, and these forests contribute to overall C stocks reported below. While Hawaii and U.S. Territories have relatively small areas of forest land and thus may not substantially influence the overall C budget, these regions will be added to the forest C estimates as sufficient data become available. Agroforestry systems that meet the definition of forest land are also not currently accounted for in the Inventory since they are not explicitly inventoried by either the FIA program or the Natural Resources Inventory (NRI)²⁷ of the USDA Natural Resources Conservation Service (Perry et al. 2005).

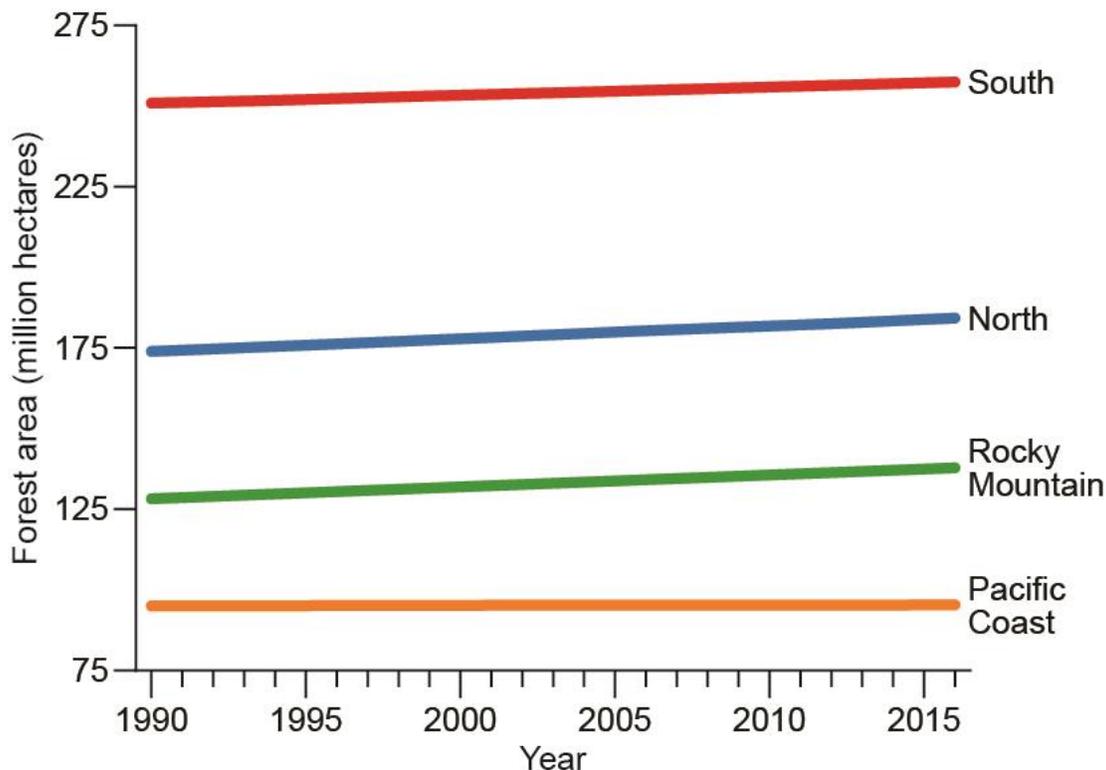
An estimated 77 percent (211 million hectares) of U.S. forests in southeast and southcentral coastal Alaska and the conterminous United States are classified as timberland, meaning they meet minimum levels of productivity and have not been removed from production. Ten percent of southeast and southcentral coastal Alaska forest land and 80 percent of forest land in the conterminous United States are classified as timberland. Of the remaining non-timberland, 30 million hectares are reserved forest lands (withdrawn by law from management for production of wood products) and 69 million hectares are lower productivity forest lands (Oswald et al. 2014). Historically, the timberlands in the conterminous 48 states have been more frequently or intensively surveyed than forest land not meeting the minimum level of productivity and removed from production.

Since the late 1980s, forest land area in southeast and southcentral coastal Alaska and the conterminous United States has increased by about 14 million hectares (Oswald et al. 2014) with the southern region of the United States containing the most forest land (Figure 6-2). A substantial portion of this accrued forest land is from the conversion of abandoned croplands to forest (e.g., Woodall et al. 2015b). Current trends in the forest land area in the conterminous U.S. and southeast and south central coastal Alaska represented here show an average annual rate of increase of 0.1 percent. In addition to the increase in forest area, the major influences to the net C flux from forest land across the 1990 to 2014 time series are management activities and the ongoing impacts of previous land-use conversions. These activities affect the net flux of C by altering the amount of C stored in forest ecosystems and also the area converted to forest land. For example, intensified management of forests that leads to an increased rate of

²⁷ The Natural Resources Inventory of the USDA Natural Resources Conservation Service is described in the Section 6.1—Representation of the U.S. Land Base.

growth of aboveground biomass (and possible changes to the other C pools) may increase the eventual biomass density of the forest, thereby increasing the uptake and storage of C in the aboveground biomass pool.²⁸ Though harvesting forests removes much of the C in aboveground biomass (and possibly changes C density in other pools), on average, the estimated volume of annual net growth in the conterminous U.S. states is about double the volume of annual removals on timberlands (Oswalt et al. 2014). The net effects of forest management and changes in *Forest Land Remaining Forest Land* are captured in the estimates of C stocks and fluxes presented in this section.

Figure 6-2: Changes in Forest Area by Region for *Forest Land Remaining Forest Land* in the conterminous United States and coastal Alaska (1990-2014, Million Hectares)



Forest Carbon Stocks and Stock Change

In the United States, improved forest management practices, the regeneration of forest areas cleared more than 20 years prior to the reporting year, and timber harvesting and use have resulted in net uptake (i.e., net sequestration) of C each year from 1990 through 2014. The rate of forest clearing in the 17th century following European settlement

²⁸ The term “biomass density” refers to the mass of live vegetation per unit area. It is usually measured on a dry-weight basis. Dry biomass is assumed to be 50 percent C by weight.

had slowed by the late 19th century. Through the later part of the 20th century many areas of previously forested in the United States were allowed to revert to forests or were actively reforested. The impacts of these land-use changes still influence C fluxes from these forest lands. More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. In addition to forest regeneration and management, forest harvests have also affected net C fluxes. Because most of the timber harvested from U.S. forest land is used in wood products, and many discarded wood products are disposed of in SWDS rather than by incineration, significant quantities of C in harvested wood are transferred to these long-term storage pools rather than being released rapidly to the atmosphere (Skog 2008). The size of the stocks in these long-term C storage pools has increased during the last century with the question arising as to how long U.S. forest land can remain a net C sink (Coulston et al. 2015; Wear and Coulston 2015). Changes in C stocks in the forest and harvested wood pools associated with *Forest Land Remaining Forest Land* were estimated to account for net sequestration of 742.3 MMT CO₂ Eq. (202.5 MMT C) in 2014 (Table 6-10 and Table 6-11). Overall, estimates of average C density in forest ecosystems (including all pools) remained stable at approximately 0.0003 MMT C ha⁻¹ from 1990 to 2014 (Table 6-11 and Table 6-12). The stable forest ecosystem C density when combined with increasing forest area results in net C accumulation over time. Management practices that increase C stocks on forest land, as well as legacy effects of afforestation and reforestation efforts, influence the trends of increased C densities in forests and increased forest land area in the United States (Woodall et al. 2015b). These increases may be influenced in some regions by reductions in C density or forest land area due to natural disturbances (e.g., wildfire, weather, insects/disease). Aboveground live biomass accounted for the majority of net sequestration among all forest ecosystem pools (Figure 6-4).

The estimated net sequestration of C in HWP was 112.3 MMT CO₂ Eq. (30.6 MMT C) in 2014 (Table 6-10 and Table 6-11). The majority of this sequestration, 69.5 MMT CO₂ Eq. (19.0 MMT C) was from wood and paper in SWDS. Products in use accounted for an estimated 42.7 MMT CO₂ Eq. (11.7 MMT C) in 2014.

Table 6-10: Net CO₂ Flux from Forest Pools in *Forest Land Remaining Forest Land* and Harvested Wood Pools. (MMT CO₂ Eq.)

| Carbon Pool | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Forest | (598.8) | (584.3) | (647.2) | (637.8) | (632.4) | (631.2) | (630.1) |
| Aboveground | (312.4) | (310.3) | (331.2) | (329.4) | (324.6) | (323.5) | (322.5) |
| Belowground | (66.6) | (65.7) | (69.6) | (69.3) | (68.2) | (67.9) | (67.6) |
| Dead Wood | (34.8) | (44.0) | (50.2) | (52.9) | (53.7) | (53.9) | (54.2) |
| Litter | (35.9) | (28.5) | (34.5) | (33.9) | (33.1) | (32.9) | (32.7) |
| Soil Organic C | (149.2) | (135.8) | (161.7) | (152.4) | (152.8) | (152.9) | (153.1) |
| Harvested Wood | (124.7) | (107.6) | (94.8) | (98.9) | (103.4) | (107.9) | (112.3) |
| Products in Use | (55.6) | (44.2) | (30.4) | (33.1) | (36.4) | (39.6) | (42.7) |
| SWDS | (69.1) | (63.4) | (64.5) | (65.8) | (67.1) | (68.3) | (69.5) |
| Total Net Flux | (723.5) | (691.9) | (742.0) | (736.7) | (735.8) | (739.1) | (742.3) |

Note: Forest C stocks do not include forest stocks in U.S. Territories, Hawaii, a portion of managed forests in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Table 6-11: Net C Flux from Forest Pools in *Forest Land Remaining Forest Land* and Harvested Wood Pools (MMT C)

| Carbon Pool | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Forest | (163.3) | (159.3) | (176.5) | (173.9) | (172.5) | (172.2) | (171.8) |
| Aboveground Biomass | (85.2) | (84.6) | (90.3) | (89.8) | (88.5) | (88.2) | (88.0) |
| Belowground Biomass | (18.2) | (17.9) | (19.0) | (18.9) | (18.6) | (18.5) | (18.4) |
| Dead Wood | (9.5) | (12.0) | (13.7) | (14.4) | (14.6) | (14.7) | (14.8) |
| Litter | (9.8) | (7.8) | (9.4) | (9.3) | (9.0) | (9.0) | (8.9) |
| Soil Organic C | (40.7) | (37.0) | (44.1) | (41.6) | (41.7) | (41.7) | (41.7) |

| | | | | | | | |
|-----------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Harvested Wood | (34.0) | (29.3) | (25.9) | (27.0) | (28.2) | (29.4) | (30.6) |
| Products in Use | (15.2) | (12.1) | (8.3) | (9.0) | (9.9) | (10.8) | (11.7) |
| SWDS | (18.8) | (17.3) | (17.6) | (17.9) | (18.3) | (18.6) | (19.0) |
| Total Net Flux | (197.3) | (188.7) | (202.4) | (200.9) | (200.7) | (201.6) | (202.5) |

Note: Forest C stocks do not include forest stocks in U.S. Territories, Hawaii, a portion of managed lands in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

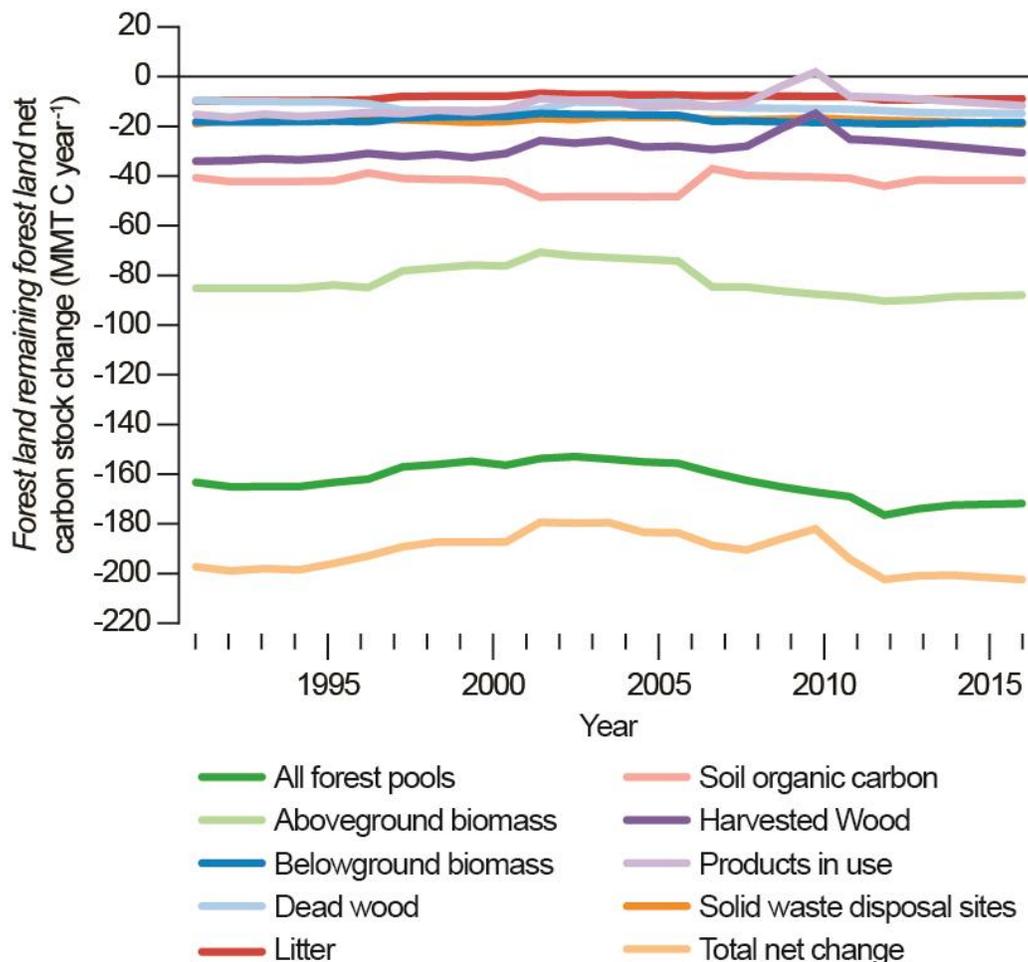
Stock estimates for forest and harvested wood C storage pools are presented in Table 6-12. Together, the estimated aboveground biomass and soil C pools account for a large proportion of total forest C stocks. Note that the forest land area estimates in Table 6-12 do not precisely match those in Section 6.1 Representation of the U.S. Land Base for *Forest Land Remaining Forest Land*. This is because the forest land area estimates in Table 6-12 only include managed forest land in the conterminous 48 states and southeast and south central coastal Alaska (which is the current area encompassed by FIA survey data, approximately 6.2 million ha) while the estimates in Section 6.1 include all managed forest land in Alaska (approximately 28.0 million ha as part of interior Alaska).

Table 6-12: Forest Area (1,000 ha) and C Stocks in *Forest Land Remaining Forest Land* and Harvested Wood Pools (MMT C)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Forest Area (1000 ha) | 261,796 | 268,029 | 270,065 | 270,462 | 270,871 | 271,871 | 271,719 | 272,158 |
| Carbon Pools (MMT C) | | | | | | | | |
| Forest | 84,891 | 87,271 | 88,094 | 88,271 | 88,445 | 88,617 | 88,789 | 88,961 |
| Aboveground Biomass | 11,896 | 13,076 | 13,508 | 13,598 | 13,688 | 13,777 | 13,865 | 13,953 |
| Belowground Biomass | 2,442 | 2,691 | 2,782 | 2,801 | 2,820 | 2,839 | 2,857 | 2,876 |
| Dead Wood | 2,404 | 2,574 | 2,637 | 2,651 | 2,665 | 2,680 | 2,695 | 2,710 |
| Litter | 5,833 | 5,958 | 5,997 | 6,006 | 6,016 | 6,025 | 6,034 | 6,042 |
| Soil Organic C | 62,316 | 62,972 | 63,170 | 63,214 | 63,255 | 63,297 | 63,339 | 63,381 |
| Harvested Wood | 1,897 | 2,356 | 2,474 | 2,500 | 2,527 | 2,555 | 2,584 | 2,615 |
| Products in Use | 1,250 | 1,449 | 1,482 | 1,490 | 1,499 | 1,509 | 1,520 | 1,531 |
| SWDS | 647 | 906 | 992 | 1,010 | 1,028 | 1,046 | 1,065 | 1,084 |
| Total C Stock | 86,788 | 89,627 | 90,568 | 90,771 | 90,972 | 91,172 | 91,374 | 91,576 |

Note: Forest area and C stock estimates include all *Forest Land Remaining Forest Land* in the conterminous 48 states and southeast and south central coastal Alaska (6.2 million ha), which is the current area encompassed by FIA survey data. Forest C stocks do not include forest stocks in U.S. Territories, Hawaii, a large portion of interior Alaska (28.0 million ha), or trees on non-forest land (e.g., urban trees, agroforestry systems). The forest area estimates in this table do not match those Section 6.1 Representation of the U.S. Land Base, which includes all managed forest land in Alaska. Harvested wood product stocks include exports, even if the logs are processed in other countries, and exclude imports. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding. Inventories are assumed to represent stocks as of January 1 of the Inventory year. Flux is the net annual change in stock. Thus, an estimate of flux for 2014 requires estimates of C stocks for 2014 and 2015.

Figure 6-3: Estimated Net Annual Changes in C Stocks for Major C Pools in Forest Land Remaining Forest Land in the Conterminous U.S. and Coastal Alaska (MMT C year⁻¹)



Box 6-3: CO₂ Emissions from Forest Fires

As stated previously, the forest inventory approach implicitly accounts for all C losses due to disturbances such as forest fires, because only C remaining in the forest is estimated. Net C stock change is estimated by subtracting consecutive C stock estimates. A forest fire disturbance removes C from the forest. The inventory data on which net C stock estimates are based already reflect this C loss. Therefore, estimates of net annual changes in C stocks for U.S. forest land already account for CO₂ emissions from forest fires occurring in the conterminous states as well as the portion of managed forest lands in Alaska that are captured in this Inventory. Because it is of interest to quantify the magnitude of CO₂ emissions from fire disturbance, these separate estimates are highlighted here. Note that these CO₂ estimates are based on the same methodology as applied for the non-CO₂ greenhouse gas emissions from forest fires that are also quantified in a separate section below as required by IPCC Guidance and UNFCCC Reporting Requirements.

The IPCC (2006) methodology and a combination of U.S.-specific data on annual area burned and potential fuel availability together with default combustion factors were employed to estimate CO₂ emissions from forest fires. CO₂ emissions for wildfires in the conterminous 48 states and in Alaska as well as prescribed fires in 2014 were estimated to be 92.3 MMT CO₂ year⁻¹ (Table 6-13). Most of this quantity is an embedded component of the net annual forest C stock change estimates provided previously (e.g., Table 6-11), but this separate approach to estimate emissions is necessary in order to associate a portion of emissions, including estimates of CH₄ and N₂O, with fire. See the discussion in Annex 3.13 for more details on this methodology. Note that the estimates for Alaska provided

in Table 6-13 include all managed forest land in the state and are not limited to the subset with permanent inventory plots on managed lands as specified elsewhere in this chapter (e.g., Table 6-11).

Table 6-13: Estimates of CO₂ (MMT year⁻¹) Emissions from Forest Fires in the Conterminous 48 States and Alaska^a

| Year | CO ₂ emitted from Wildfires in the Conterminous 48 States (MMT yr ⁻¹) | CO ₂ emitted from Wildfires in Alaska (MMTyr ⁻¹) | CO ₂ emitted from Prescribed Fires (MMTyr ⁻¹) | Total CO ₂ emitted (MMTyr ⁻¹) |
|-------------------|--|---|--|--|
| 1990 | 21.3 | 19.5 | 0.2 | 40.9 |
| 2005 | 42.9 | 80.7 | 1.3 | 124.9 |
| 2010 | 12.2 | 11.2 | 18.4 | 41.7 |
| 2011 | 73.9 | 3.5 | 5.9 | 83.3 |
| 2012 | 133.7 | 2.7 | 2.9 | 139.3 |
| 2013 | 64.7 | 22.3 | 5.3 | 92.3 |
| 2014 ^b | 64.7 | 22.3 | 5.3 | 92.3 |

^a These emissions have already been accounted for in the estimates of net annual changes in C stocks, which account for the amount sequestered minus any emissions, including the assumption that combusted wood may continue to decay through time.

^b The data for 2014 were incomplete when these estimates were summarized; therefore 2013, the most recent available estimate, is applied to 2014.

Methodology and Data Sources

The methodology described herein is consistent with IPCC (2006). Forest ecosystem C stocks and net annual C stock change were determined according to the stock-difference method, which involved applying C estimation factors to annual forest inventories across time to obtain C stocks and then subtracting between the years to obtain the stock change. Harvested wood C estimates were based on factors such as the allocation of wood to various primary and end-use products as well as half-life (the time at which half of the amount placed in use will have been discarded from use) and expected disposition (e.g., product pool, SWDS, combustion). An overview of the different methodologies and data sources used to estimate the C in forest ecosystems or harvested wood products is provided here. See Annex 3.13 for details and additional information related to the methods and data.

Forest Ecosystem Carbon from Forest Inventory

The U.S. used a different accounting approach (Woodall et al. 2015a) for this Inventory than what was used in previous submissions that removes the older, often inconsistent inventory information from the accounting procedures and enables the delineation of forest C accumulation by forest growth, land use change, and natural disturbances such as fire. Development will continue on a system that attributes changes in forest C to disturbances and delineates *Land Converted to Forest Land* from *Forest Land Remaining Forest Land*. As part of this development, C pool science will continue and will be expanded to include C stock transfers from forest land to other land uses, and include techniques to better identify land use change (see the Planned Improvements section below).

Unfortunately, the annual inventory system does not extend into the 1990s, necessitating the adoption of a system to “backcast” the annual C estimates. To facilitate the backcasting of the U.S. annual forest inventory C estimates, the accounting framework used in this Inventory is comprised of a forest dynamics module (age transition matrices) and a land use dynamics module (land area transition matrices). The forest dynamics module assesses forest sequestration, forest aging, and disturbance effects (i.e., disturbances such as wind, fire, and floods identified by foresters on inventory plots). The land use dynamics module assesses C stock transfers associated with afforestation and deforestation (e.g., Woodall et al. 2015b). Both modules are developed from land use area statistics and C stock change or C stock transfer by age class. The required inputs are estimated from more than 625,000 forest and nonforest observations in the FIA national database (U.S. Forest Service 2015a, b, c). Model predictions for before

the annual inventory period are constructed from the accounting framework using the annual observations. The accounting approach used this year is fundamentally driven by the annual forest inventory system conducted by the FIA program (Frayer and Furnival 1999; Bechtold and Patterson 2005; USDA Forest Service 2015d, 2015a). The FIA program relies on a rotating panel statistical design with a sampling intensity of one 674.5 m² ground plot per 2,403 ha of land and water area. A five-panel design, with 20 percent of the field plots typically measured each year within a state, is used in the eastern United States and a ten-panel design, with 10 percent of the field plots measured each year within a state, is used in the western United States. The interpenetrating hexagonal design across the U.S. landscape enables the sampling of plots at various intensities in a spatially and temporally unbiased manner. Typically, tree and site attributes are measured with higher sample intensity while other ecosystem attributes such as downed dead wood are sampled during summer months at lower intensities. The first step in incorporating FIA data into the framework was to identify annual inventory datasets by state. Inventories include data collected on permanent inventory plots on forest lands and were organized as separate datasets, each representing a complete inventory, or survey, of an individual state at a specified time. Many of the annual inventories reported for states are represented as “moving window” averages, which mean that a portion—but not all—of the previous year’s inventory is updated each year (USDA Forest Service 2015d). Forest C calculations are organized according to these state surveys, and the frequency of surveys varies by state.

Using this FIA data, separate estimates were prepared for the five C storage pools identified by IPCC (2006) and described above. All estimates were based on data collected from the extensive array of permanent, annual forest inventory plots and associated models (e.g., live tree belowground biomass) in the U.S. (USDA Forest Service 2015b, 2015c). Carbon conversion factors were applied at the disaggregated level of each inventory plot and then appropriately expanded to population estimates. Tier 3 methods, as outlined by IPCC (2006), were used for the five reporting pools.

Carbon in Biomass

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at breast height (dbh) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates were made for above- and belowground biomass components. If inventory plots included data on individual trees, tree C was based on Woodall et al. (2011a), which is also known as the component ratio method (CRM), and is a function of volume, species, and diameter. An additional component of foliage, which was not explicitly included in Woodall et al. (2011a), was added to each tree following the same CRM method.

Understory vegetation is a minor component of biomass, which is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than 2.54 cm dbh. For this Inventory, it was assumed that 10 percent of total understory C mass is belowground (Smith et al. 2006). Estimates of C density were based on information in Birdsey (1996) and biomass estimates from Jenkins et al. (2003). Understory biomass represented over one percent of C in biomass, but its contribution rarely exceeded 2 percent of the total.

Carbon in Dead Organic Matter

Dead organic matter was initially calculated as three separate pools—standing dead trees, downed dead wood, and litter—with C stocks estimated from sample data or from models. The standing dead tree C pool includes aboveground and belowground (coarse root) biomass for trees of at least 12.7 cm dbh. Calculations followed the basic method applied to live trees (Woodall et al. 2011a) with additional modifications to account for decay and structural loss (Domke et al. 2011; Harmon et al. 2011). Downed dead wood estimates are based on measurement of a subset of FIA plots for downed dead wood (Domke et al. 2013; Woodall and Monleon 2008; Woodall et al. 2013). Downed dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. This includes stumps and roots of harvested trees. To facilitate the downscaling of downed dead wood C estimates from the state-wide population estimates to individual plots, downed dead wood models specific to regions and forest types within each region are used. Litter C is the pool of organic C (also known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. A subset of FIA plots are measured for litter C. A modeling approach, using litter C measurements from FIA plots (Domke et al. 2016) was used to estimate litter C for every FIA plot used in the accounting framework.

Carbon in Forest Soil

Soil organic carbon (SOC) is the largest terrestrial C sink, and management of this pool is a critical component of efforts to mitigate atmospheric C concentrations. SOC also affects essential biological, chemical, and physical soil functions such as nutrient cycling, water retention, and soil structure (Jandl et al. 2014). Much of the SOC on earth is found in forest ecosystems and is thought to be relatively stable. However, there is growing evidence that SOC is sensitive to global change effects, particularly land use histories, resource management, and climate. In the U.S., SOC in forests is monitored the FIA program (O’Neill et al. 2005). In previous C inventory submissions, SOC predictions were based, in part, on a model using the State Soil Geographic (STATSGO) database compiled by the Natural Resources Conservation Service (NRCS) (Amichev and Glabraith 2004). Estimates of forest SOC found in the STATSGO database may be based on expert opinion rather than actual measurements. The FIA program has been consistently measuring soil attributes as part of the annual inventory since 2001 and has amassed an extensive inventory of SOC measurement data on forest land in the conterminous U.S. and coastal Alaska (O’Neill et al. 2005). More than 5,000 profile observations of SOC on forest land from FIA and the International Soil Carbon Monitoring Network were used to develop and implement an approach that enabled the prediction of soil C to a depth of 100 cm from empirical measurements to a depth of 20 cm and included site-, stand-, and climate-specific variables that yield predictions of SOC stocks and stock changes specific to forest land in the United States (Domke et al. In prep). Note that SOC is reported to a depth of 100 cm for Forest Land Remaining Forest Land to remain consistent with past reporting, however for consistency across land-use categories it is reported to a depth of 30 cm in Section 6.3 *Land Converted to Forest Land*.

Harvested Wood Carbon

Estimates of the HWP contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) were based on methods described in Skog (2008) using the WOODCARB II model and the U.S. forest products module (Ince et al. 2011). These methods are based on IPCC (2006) guidance for estimating the HWP contribution. IPCC (2006) provides methods that allow for reporting of HWP contribution using one of several different accounting approaches: Production, stock change and atmospheric flow, as well as a default method that assumes there is no change in HWP C stocks (see Annex 3.13 for more details about each approach). The U.S. used the production accounting approach to report HWP Contribution. Under the production approach, C in exported wood was estimated as if it remains in the United States, and C in imported wood was not included in the estimates. Annual estimates of change were calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in SWDS. Emissions from HWP associated with wood biomass energy are not included in this accounting—a net of zero sequestration and emissions as they are a part of energy accounting (see Chapter 3).

Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end-uses. There is one product category and one end-use category for paper. Additions to and removals from pools were tracked beginning in 1900, with the exception that additions of softwood lumber to housing began in 1800. Solidwood and paper product production and trade data were taken from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census 1976; Ulrich 1985, 1989; Steer 1948; AF&PA 2006a, 2006b; Howard 2003, 2007, forthcoming). Estimates for disposal of products reflected the change over time in the fraction of products discarded to SWDS (as opposed to burning or recycling) and the fraction of SWDS that were in sanitary landfills versus dumps.

The annual HWP variables that were used to estimate HWP contribution using the production approach are:

- (1) annual change of C in wood and paper products in use in the U.S. and other countries where the wood came from trees harvested in the United States, and
- (2) annual change of C in wood and paper products in SWDS in the U.S. and other countries where the wood came from trees harvested in the United States

The sum of these variables yield estimates for HWP contribution under the production accounting approach.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems through a combination of sample-based and model-based approaches to uncertainty for forest ecosystem CO₂ flux (IPCC Approach 1). A

Monte Carlo Stochastic Simulation of the Methods described above and probabilistic sampling of C conversion factors were used to determine the HWP uncertainty (IPCC Approach 2). See Annex 3.13 for additional information. The 2014 net annual change for forest C stocks was estimated to be between -1,018.4 and -465.7 MMT CO₂ Eq. around a central estimate of -742.3 MMT CO₂ Eq. at a 95 percent confidence level. This includes a range of -905.0 to -355.1 MMT CO₂ Eq. around a central estimate of -630.1 MMT CO₂ Eq. for forest ecosystems and -136.8 to -82.2 MMT CO₂ Eq. around a central estimate of -112.3 for HWP.

Table 6-14: Quantitative Uncertainty Estimates for Net CO₂ Flux from *Forest Land Remaining Forest Land*: Changes in Forest C Stocks (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate | | | |
|--------------------------------------|-----------------------|---|---|----------------|---------------|--------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Forest C Pools ^a | CO ₂ | (630.1) | (905.0) | (355.1) | -43.6% | 43.6% |
| Harvested Wood Products ^b | CO ₂ | (112.3) | (136.8) | (82.2) | -21.9% | 26.8% |
| Total Forest | CO₂ | (742.3) | (1,018.4) | (465.7) | -37.2% | 37.3% |

^aRange of flux estimates predicted through a combination of sample based and model based uncertainty for a 95 percent confidence interval, IPCC Approach 1.

^bRange of flux estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval, IPCC Approach 2.

Note: Parentheses indicate negative values or net sequestration.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

As discussed above, the FIA program has conducted consistent forest surveys based on extensive statistically-based sampling of most of the forest land in the conterminous United States, dating back to 1952. The FIA program includes numerous quality assurance and quality control (QA/QC) procedures, including calibration among field crews, duplicate surveys of some plots, and systematic checking of recorded data. Because of the statistically-based sampling, the large number of survey plots, and the quality of the data, the survey databases developed by the FIA program form a strong foundation for C stock estimates. Field sampling protocols, summary data, and detailed inventory databases are archived and are publicly available on the Internet (USDA Forest Service 2015d).

General quality control procedures were used in performing calculations to estimate C stocks based on survey data. For example, the C datasets, which include inventory variables such as areas and volumes, were compared to standard inventory summaries such as the forest resource statistics of Oswalt et al. (2014) or selected population estimates generated from FIADB 6.0, which are available at an FIA internet site (USDA Forest Service 2015b). Agreement between the C datasets and the original inventories is important to verify accuracy of the data used. Finally, C stock estimates were compared with previous Inventory report estimates to ensure that any differences could be explained by either new data or revised calculation methods (see the Recalculations discussion, below).

Estimates of the HWP variables and the HWP contribution under the production accounting approach use data from U.S. Census and USDA Forest Service surveys of production and trade. Factors to convert wood and paper to units of C are based on estimates by industry and Forest Service published sources. The WOODCARB II model uses estimation methods suggested by IPCC (2006). Estimates of annual C change in solidwood and paper products in use were calibrated to meet two independent criteria. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needs to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. Meeting the first criterion resulted in an estimated half-life of about 80 years for single family housing built in the 1920s, which is confirmed by other U.S. Census data on housing. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needs to match EPA estimates of discards used in the Waste sector each year over the period 1990 to 2000 (EPA 2006). These criteria help reduce uncertainty in estimates of annual change in C in products in use in the United States and, to a lesser degree, reduce uncertainty in estimates of annual change in C in products made from wood harvested in the United States. In addition, WOODCARB II landfill decay rates have been validated by ensuring that estimates of

CH₄ emissions from landfills based on EPA (2006) data are reasonable in comparison to CH₄ estimates based on WOODCARB II landfill decay rates.

Recalculations Discussion

Forest ecosystem stock and stock-change estimates differ from the previous Inventory report principally due to the adoption of a new accounting framework (Woodall et al. 2015a). The major differences between the framework used this year and past accounting approaches is the sole use of annual FIA data and the back-casting of forest C stocks across the 1990s based on forest C stock density and land use change information obtained from the nationally consistent annual forest inventory coupled with in situ observations of non-tree C pools such as soils, dead wood, and litter. The use of this accounting framework has enabled the creation of the two land use sections for forest C stocks: *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. In prior submissions (e.g., the 1990 through 2013 Inventory submission), the C stock changes from *Land Converted to Forest Land* were a part of the *Forest Land Remaining Forest Land* section and it was not possible to disaggregate the estimates. A second major change was the adoption of a new approach to estimate forest soil C, the largest C stock in the U.S. For detailed discussion of these new approaches please refer to the Methodology section, Annex 3.13, Domke et al. (In prep), and Woodall et al. (2015a). In addition to these major changes, the refined land representation analysis described in Section 6.1 Representation of the U.S. Land Base which identifies some of the forest land in south central and southeastern coastal Alaska as unmanaged; this is in contrast to past assumptions of “managed” land for these forest lands included in the FIA database. Therefore, the C stock and flux estimates for southeast and south central coastal Alaska, as included here, reflect that adjustment, which effectively reduces the managed forest area by approximately 5 percent.

In addition to the creation of explicit estimates of removals and emissions by *Forest Land Remaining Forest Land* versus *Land Converted to Forest Land*, the accounting framework used this year eliminated the use of periodic data (which may be inconsistent with annual inventory data) which contributed to a data artifact in prior estimates of emissions/removals from 1990 to the present. In the previous Inventory report, there was a reduction in net sequestration from 1995 to 2000 followed by an increase in net sequestration from 2000 to 2004. This artifact of comparing inconsistent inventories of the 1980s through 1990s to the nationally consistent inventories of the 2000s has been removed in this Inventory.

Estimated annual net additions to HWP C stocks increased slightly between 2014 and 2015. Estimated net additions to solidwood products in use slightly increased due to a further recovery of the housing market. Estimated net additions to products in use for 2014 are about 20 percent of the level of net additions to products in use in 2006, i.e., prior to the recession. The decline in net additions to HWP C stocks continued through 2008 from the recent high point in 2005. This is due to sharp declines in U.S. production of solidwood and paper products in 2007 and 2008 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2007 and 2008 were exceeded by discards from uses. The result is a net reduction in the amount of HWP C that is held in products in use during this time period. For 2008, emissions from landfills exceeded additions to landfills. That said, following the recent recession the net additions to landfills have returned to normal levels. Overall, there were net C additions to HWP in use and in SWDS combined due, in large part, to updated data on products in use from 2010 to the present.

Planned Improvements

Reliable estimates of forest C across the diverse ecosystems of the U.S. require a high level of investment in both annual monitoring and associated analytical techniques. Development of improved monitoring/reporting techniques is a continuous process that occurs simultaneously with annual Inventory submissions. Planned improvements can be broadly assigned to the following categories: development of a robust accounting system, individual C pool estimation, coordination with other land-use categories, and annual inventory data incorporation.

As this is the first report to delineate C change by *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, there are many improvements necessary. Since the accounting approach used this year operates at the regional scale for the United States, research will occur to leverage auxiliary information (i.e., remotely sensed information) to operate at finer scales in future accounting approaches. As in past submissions, deforestation is implicitly included in the report given the annual forest inventory system but not explicitly estimated. Carbon dioxide, CH₄ and N₂O emissions from forest lands with drained organic soils were not included in this Inventory.

We will apply the latest guidance in the Wetlands Supplement (IPCC 2014) by including CO₂, CH₄ and N₂O emissions from forest lands with drained organic soils in future submissions. The transparency and repeatability of accounting systems will be increased through the dissemination of open source code (e.g., R programming language) in concert with the public availability of the annual forest inventory data (USDA 2015b). Also, several FIA database processes will be institutionalized to increase efficiency and QA/QC in reporting and further improve transparency, consistency, and availability of data used in reporting. Finally, a Tier 1 approach was used to estimate uncertainty associated with C stock changes in the *Forest Land Remaining Forest Land* category in this report. There is research underway investigating more robust approaches to total uncertainty (Woodall et al. 2015a) which will be considered in future Inventory reports.

In the current Inventory, the approach to estimating the soil C pool was refined by incorporating a national inventory of SOC (O’Neil et al. 2005) in combination with auxiliary soil, site, and climate information (Domke et al. In prep). The modeling framework used to estimate downed dead wood within the dead wood C pool will be updated similar to the litter (Domke et al. 2016) and soil C pools (Domke et al. In prep). Finally, components of other pools, such as C in belowground biomass (Russell et al. 2015) and understory vegetation (Russell et al. 2014), are being explored but may require additional investment in field inventories before improvements can be realized with Inventory submissions.

The foundation of forest C accounting is the annual forest inventory system. The ongoing annual surveys by the FIA program are expected to improve the accuracy and precision of forest C estimates as new state surveys become available (USDA Forest Service 2015b), particularly in western states. Hawaii and U.S. Territories will be included when appropriate forest C data are available (as of July 21, 2015, Hawaii is not yet reporting any data from the annualized sampling design). Forest lands in interior Alaska (AK) are not yet included in this report as an annual inventory has never been conducted in this remote region. A pilot study of an efficient method for inventorying forest C stocks in interior AK (Woodall et al. 2015) has been conducted with results still being evaluated. Although an annual forest inventory of interior AK may be implemented in the 2016 field season, alternative methods of estimating C stock change will need to be explored as it may take over a decade to re-measure newly established plots in the 2016 field season. To that end, research is underway to incorporate all FIA plot information (both annual and periodic data) and the Landsat and MODIS time-series (along with other remotely sensed data) in a design-based, model-assisted format for estimating GHG emissions and removals as well as change detection across the entire reporting period and all managed forest land in the United States. Leveraging this auxiliary information will aid not only the interior AK effort but the entire inventory system. In addition to fully inventorying all managed forest land in the United States, the more intensive sampling of fine woody debris, litter, and SOC on a subset of FIA plots continues and will substantially improve resolution of C pools (i.e., greater sample intensity; Westfall et al. 2013) as this information becomes available (Woodall et al. 2011b). Increased sample intensity of some C pools and using annualized sampling data as it becomes available for those states currently not reporting are planned for future submissions. The FIA sampling frame extends beyond the forest land use category (e.g., woodlands and urban areas) with inventory-relevant information for these lands which will likely become increasingly available in coming years.

Non-CO₂ Emissions from Forest Fires

Emissions of non-CO₂ gases from forest fires were estimated using U.S.-specific data for annual area of forest burned and potential fuel availability as well as the default IPCC (2006) emissions and combustion factors applied to the IPCC methodology. Emissions from this source in 2014 were estimated to be 7.3 MMT CO₂ Eq. of CH₄ and 4.8 MMT CO₂ Eq. of N₂O (Table 6-15, kt units available in Table 6-16). The estimates of non-CO₂ emissions from forest fires account for wildfires in the conterminous 48 states and Alaska as well as prescribed fires.

Table 6-15: Estimated Non-CO₂ Emissions from Forest Fires (MMT CO₂ Eq.) for U.S. Forests

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 ^a |
|------------------|------------|-------------|------------|-------------|-------------|-------------|-------------------|
| CH ₄ | 3.3 | 9.9 | 3.3 | 6.6 | 11.1 | 7.3 | 7.3 |
| N ₂ O | 2.2 | 6.5 | 2.2 | 4.4 | 7.3 | 4.8 | 4.8 |
| Total | 5.4 | 16.5 | 5.4 | 11.0 | 18.3 | 12.2 | 12.2 |

^a The data for 2014 were incomplete when these estimates were summarized; therefore 2013, the most recent available estimate, is applied to 2014.

Table 6-16: Estimated Non-CO₂ Emissions from Forest Fires (kt) for U.S. Forests

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 ^a |
|------------------|-------|-------|-------|-------|-------|-------|-------------------|
| CH ₄ | 131 | 397 | 131 | 265 | 443 | 294 | 294 |
| N ₂ O | 7 | 22 | 7 | 15 | 24 | 16 | 16 |
| CO | 2,792 | 8,515 | 2,845 | 5,683 | 9,499 | 6,298 | 6,298 |
| NO _x | 78 | 239 | 80 | 159 | 266 | 177 | 177 |

^a The data for 2014 were incomplete when these estimates were summarized; therefore 2013, the most recent available estimate, is applied to 2014.

Methodology

Non-CO₂ emissions from forest fires—specifically for CH₄ and N₂O emissions—were calculated following IPCC (2006) methodology, which included a combination of U.S. specific data on area burned and potential fuel available for combustion along with IPCC default combustion and emission factors. The estimates were calculated according to model 2.27 of IPCC (2006, Volume 4, Chapter 2), which in general terms is:

$$\text{Emissions} = \text{Area burned} \times \text{Fuel available} \times \text{Combustion factor} \times \text{Emission factor} \times 10^{-3}$$

where area burned is based on Monitoring Trends in Burn Severity (MTBS) data summaries (MTBS 2015), fuel estimates are based on current carbon density estimates obtained from the latest FIA data for each state, and combustion and emission factors are from IPCC (2006, Volume 4, Chapter 2). See Annex 3.13 for further details.

Uncertainty and Time-Series Consistency

In order to quantify the uncertainties for non-CO₂ emissions from forest fires calculated as described above, a Monte Carlo (IPCC Approach 2) sampling approach was employed to propagate uncertainty in the model as it was applied for U.S. forest land. See IPCC (2006) and Annex 3.13 for the quantities and assumptions employed to define and propagate uncertainty. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 6-17.

Table 6-17: Quantitative Uncertainty Estimates of Non-CO₂ Emissions from Forest Fires in Forest Land Remaining Forest Land (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|---|------------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Non-CO ₂ Emissions from Forest Fires | CH ₄ | 7.3 | 1.0 | 20.1 | -86% | +174% |
| Non-CO ₂ Emissions from Forest Fires | N ₂ O | 4.8 | 1.2 | 12.4 | -76% | +157% |

^a Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for forest fires included checking input data, documentation, and calculations to ensure data were properly handled through the Inventory process. Further, the set of fire emissions estimates using MODIS imagery and post-fire observations developed for Alaska by Veraverbeke et al. (2015) (Table A-16) were used to compare with the estimates of CO₂ and C emissions from forest fires in Alaska (Table 6-13 and A-14). The alternate sources of data for annual areas burned and possible fuel availability were found to be similar to the data in use here. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current non-CO₂ emissions estimates are based on the calculation described above and in IPCC (2006), which is a very similar approach to the basic calculation of previous Inventory reports. However, some of the data summarized and applied to the calculation are very different for the current Inventory. The use of the MTBS data summaries is the most prominent example. Annual burned areas on managed forest lands were identified according to Ruefenacht et al. (2008) and Ogle et al. (In preparation). The other change with the current Inventory estimates is in the use of the underlying plot level carbon densities based on forest inventory plots. Although the base data are similar to past years, the current uncertainty estimates are based on an assumption that plot-to-plot variability is a greater influence on uncertainty than the uncertainty in the forest-inventory to C conversion factors (as employed for uncertainty in the past). See Annex 3.13 for additional details.

Planned Improvements

Possible future improvements within the context of this same IPCC (2006) methodology are most likely to involve greater specificity by fire or groups of fires and less reliance on wide regional values or IPCC defaults. Spatially relating potential fuel to more localized forest structure is the best example of this. An additional improvement would be combustion factors more locally appropriate for the type, location, and intensity of fire, which are currently unused information provided with the MTBS data summaries. All planned improvements depend on future availability of appropriate U.S.-specific data.

N₂O Fluxes from Forest Soils (IPCC Source Category 4A1)

Of the synthetic nitrogen (N) fertilizers applied to soils in the United States, no more than one percent is applied to forest soils. Application rates are similar to those occurring on cropland soils, but in any given year, only a small proportion of total forested land receives N fertilizer. This is because forests are typically fertilized only twice during their approximately 40-year growth cycle (once at planting and once midway through their life cycle). While the rate of N fertilizer application for the area of forests that receives N fertilizer in any given year is relatively high, the annual application rate is quite low over the entire forestland area.

N additions to soils result in direct and indirect N₂O emissions. Direct emissions occur on-site due to the N additions. Indirect emissions result from fertilizer N that is transformed and transported to another location in a form other than N₂O (ammonia [NH₃] and nitrogen oxide [NO_x] volatilization, nitrogen trioxide [NO₃] leaching and runoff), and later converted into N₂O at the off-site location. The indirect emissions are assigned to forest land because the management activity leading to the emissions occurred in forest land.

Direct N₂O emissions from forest soils in 2014 were 0.3 MMT CO₂ Eq. (1 kt), and the indirect emissions were 0.1 MMT CO₂ Eq. (0.4 kt). Total emissions for 2014 were 0.5 MMT CO₂ Eq. (2 kt) and have increased by 455 percent from 1990 to 2014. Increasing emissions over the time series is a result of greater area of N fertilized pine plantations in the southeastern United States and Douglas-fir timberland in western Washington and Oregon. Total forest soil N₂O emissions are summarized in Table 6-18.

Table 6-18: N₂O Fluxes from Soils in *Forest Land Remaining Forest Land* (MMT CO₂ Eq. and kt N₂O)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|------------|------------|------------|------------|------------|------------|------------|
| Direct N₂O Fluxes from Soils | | | | | | | |
| MMT CO ₂ Eq. | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| kt N ₂ O | + | 1 | 1 | 1 | 1 | 1 | 1 |
| Indirect N₂O Fluxes from Soils | | | | | | | |
| MMT CO ₂ Eq. | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| kt N ₂ O | + | + | + | + | + | + | + |
| Total | | | | | | | |
| MMT CO ₂ Eq. | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| kt N ₂ O | + | 2 | 2 | 2 | 2 | 2 | 2 |

+ Does not exceed 0.05 MMT CO₂ Eq. or 0.5 kt.

Note: Totals may not sum due to independent rounding.

Methodology

The IPCC Tier 1 approach is used to estimate N₂O from soils within *Forest Land Remaining Forest Land*. According to U.S. Forest Service statistics for 1996 (USDA Forest Service 2001), approximately 75 percent of trees planted are for timber, and about 60 percent of national total harvested forest area is in the southeastern United States. Although southeastern pine plantations represent the majority of fertilized forests in the United States, this Inventory also accounted for N fertilizer application to commercial Douglas-fir stands in western Oregon and Washington. For the Southeast, estimates of direct N₂O emissions from fertilizer applications to forests are based on the area of pine plantations receiving fertilizer in the southeastern United States and estimated application rates (Albaugh et al. 2007; Fox et al. 2007). Not accounting for fertilizer applied to non-pine plantations is justified because fertilization is routine for pine forests but rare for hardwoods (Binkley et al. 1995). For each year, the area of pine receiving N fertilizer is multiplied by the weighted average of the reported range of N fertilization rates (121 lbs. N per acre). Area data for pine plantations receiving fertilizer in the Southeast are not available for 2005 through 2014, so data from 2004 are used for these years. For commercial forests in Oregon and Washington, only fertilizer applied to Douglas-fir is addressed in the inventory because the vast majority (approximately 95 percent) of the total fertilizer applied to forests in this region is applied to Douglas-fir (Briggs 2007). Estimates of total Douglas-fir area and the portion of fertilized area are multiplied to obtain annual area estimates of fertilized Douglas-fir stands. Similar to the Southeast, data are not available for 2005 through 2014, so data from 2004 are used for these years. The annual area estimates are multiplied by the typical rate used in this region (200 lbs. N per acre) to estimate total N applied (Briggs 2007), and the total N applied to forests is multiplied by the IPCC (2006) default emission factor of one percent to estimate direct N₂O emissions.

For indirect emissions, the volatilization and leaching/runoff N fractions for forest land are calculated using the IPCC default factors of 10 percent and 30 percent, respectively. The amount of N volatilized is multiplied by the IPCC default factor of one percent for the portion of volatilized N that is converted to N₂O off-site. The amount of N leached/runoff is multiplied by the IPCC default factor of 0.075 percent for the portion of leached/runoff N that is converted to N₂O off-site. The resulting estimates are summed to obtain total indirect emissions.

Uncertainty and Time-Series Consistency

The amount of N₂O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N₂O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in Section 5.4 Agricultural Soil Management and Section 6.10 Settlements Remaining Settlements.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates are assigned a default level²⁹ of uncertainty at ±50 percent, and area receiving fertilizer is assigned a ±20 percent according to expert knowledge (Binkley 2004). The uncertainty ranges around the 2005 activity data and emission factor input variables are directly applied to the 2014 emission estimates. IPCC (2006) provided estimates for the uncertainty associated with direct and indirect N₂O emission factor for synthetic N fertilizer application to soils.

Uncertainty is quantified using simple error propagation methods (IPCC 2006). The results of the quantitative uncertainty analysis are summarized in Table 6-19. Direct N₂O fluxes from soils in 2014 are estimated to be between 0.1 and 1.1 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 59 percent below and 211 percent above the 2014 emission estimate of 0.3 MMT CO₂ Eq. Indirect N₂O emissions in 2014 are between 0.02 and 0.4 MMT CO₂ Eq., ranging from 86 percent below to 238 percent above the 2014 emission estimate of 0.1 MMT CO₂ Eq.

²⁹ Uncertainty is unknown for the fertilization rates so a conservative value of ±50 percent is used in the analysis.

Table 6-19: Quantitative Uncertainty Estimates of N₂O Fluxes from Soils in *Forest Land Remaining Forest Land* (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate (MMT CO ₂ Eq.) | | | |
|---|------------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Forest Land Remaining Forest Land | | | | | | |
| Direct N ₂ O Fluxes from Soils | N ₂ O | 0.3 | 0.1 | 1.1 | -59% | +211% |
| Indirect N ₂ O Fluxes from Soils | N ₂ O | 0.1 | + | 0.4 | -86% | +238% |

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: These estimates include direct and indirect N₂O emissions from N fertilizer additions to both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

The spreadsheet tab containing fertilizer applied to forests and calculations for N₂O and uncertainty ranges are checked and verified.

Planned Improvements

Additional data will be compiled to update estimates of forest areas receiving N fertilizer as new reports are made available. Another improvement is to further disaggregate emissions by state for southeastern pine plantations and northwestern Douglas-fir forests to estimate soil N₂O emission. This improvement is contingent on the availability of state-level N fertilization data for forest land.

6.3 Land Converted to Forest Land (IPCC Source Category 4A2)

The C stock change estimates for *Land Converted to Forest Land* that are provided in this section include all forest land in an inventory year that had been in another land use(s) during the previous 20 years³⁰ (USDA NRCS 2009). For example, cropland or grassland converted to forest land during the past 20 years would be reported in this category. Recently-converted lands are in this category for 20 years as recommended in the *2006 IPCC Guidelines* (IPCC 2006). It is also important to note that the accounting framework used this year to develop estimates of C stock change for *Forest Land Remaining Forest Land* and intended to be used for *Land Converted to Forest Land* was not fully developed for this Inventory and therefore only estimates of C stock changes from mineral soils are included in *Land Converted to Forest Land* following Ogle et al (2003, 2006) and IPCC (2006). Carbon stock changes for the other pools (i.e., aboveground and belowground biomass, dead wood, and litter), as recommended for inclusion by IPCC (2006) are not included for the *Land Converted to Forest Land* category in this Inventory, but research is underway to include these IPCC pools in subsequent submissions of the Inventory. This was due, in part, for a need to more thoroughly quantify the length of time that land remains in a conversion category after a change in land use and also because the accounting framework was not fully developed in time to estimate C stocks and

³⁰ The 2009 USDA National Resources Inventory (NRI) land-use survey points were classified according to land-use history records starting in 1982 when the NRI survey began. Consequently the classifications from 1990 to 2001 were based on less than 20 years.

stock changes for the IPCC pools over the default 20-year conversion period in the *Land Converted to Forest Land* category.

Area of Land Converted to Forest in the United States

The annual conversion of land from other land-use categories (i.e., Cropland, Grassland, Wetlands, Settlements, and Other Lands) to forest land resulted in a fairly continuous net annual accretion of forest land area from 1990 to the present at an approximate rate of 1 million ha year⁻¹. The rate of forest clearing in the 17th century following European settlement had slowed by the late 19th century. Through the later part of the 20th century, many areas of previously converted forested land in the United States were allowed to revert to forests or were actively reforested (Birdsey et al. 2006). The impacts of these land-use changes still influence C fluxes from these forest lands (land-use change legacy effects, Woodall et al. 2015b). More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. Recent analyses suggest that net accumulation of forest area continues in areas of the United States, in particular the northeastern United States (Woodall et al. 2015b).

The conversion of grassland to forest land resulted in the largest source of soil C sequestration (accounting for approximately 68 percent of the sequestration in the category in 2014), though gains have decreased over the time series which is the result of less conversion into the forest land category in recent years (see Table 6-20). The net flux of C from the mineral soil stock changes in 2014 was -0.3 MMT CO₂ Eq. (-0.1 MMT C) (Table 6-20 and Table 6-21). Note that soil carbon has historically been reported to a depth of 100 cm in the *Forest Land Remaining Forest Land* category (Domke et al. In preparation) while other land-use categories report soil carbon to a depth of 20 or 30 cm. To ensure consistency in the *Land Converted to Forest Land* category where C stock transfers occur between land-use categories, all soil estimates are based on methods from Ogle et al. (2003, 2006) and IPCC (2006).

Table 6-20: Net CO₂ Flux from Soil C Stock Changes in *Land Converted to Forest Land* by Land Use Change Category (MMT CO₂ Eq.)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Cropland Converted to Forest Land | | | | | | | |
| Mineral Soil | (0.2) | (0.2) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Grassland Converted to Forest Land | | | | | | | |
| Mineral Soil | (0.4) | (0.5) | (0.3) | (0.2) | (0.2) | (0.2) | (0.2) |
| Other Land Converted to Forest Land | | | | | | | |
| Mineral Soil | (0.1) | (0.1) | + | + | + | + | + |
| Settlements Converted to Forest Land | | | | | | | |
| Mineral Soil | + | + | + | + | + | + | + |
| Wetlands Converted to Forest Land | | | | | | | |
| Mineral Soil | + | + | + | + | + | + | + |
| Total Mineral Soil Flux | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |
| Total Soil Flux | (0.7) | (0.8) | (0.4) | (0.4) | (0.4) | (0.3) | (0.3) |

+ Absolute value does not exceed 0.05 MMT CO₂ Eq.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-21: Net C Flux from Soil C Stock Changes in Land Converted to Forest Land by Land Use Change Category (MMT C)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|-------|-------|-------|-------|-------|-------|-------|
| Cropland Converted to Forest Land | | | | | | | |
| Mineral Soil | + | (0.1) | + | + | + | + | + |
| Grassland Converted to Forest Land | | | | | | | |
| Mineral Soil | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Other Land Converted to Forest Land | | | | | | | |
| Mineral Soil | + | + | + | + | + | + | + |
| Settlements Converted to Forest Land | | | | | | | |

| | | | | | | | | | |
|--|--------------|--|--------------|--|--------------|--------------|--------------|--------------|--------------|
| Mineral Soil | + | | + | | + | + | + | + | + |
| Wetlands Converted to Forest Land | | | | | | | | | |
| Mineral Soil | + | | + | | + | + | + | + | + |
| Total Mineral Soil Flux | (0.2) | | (0.2) | | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Total Soil Flux | (0.2) | | (0.2) | | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |

+ Absolute value does not exceed 0.05 MMT C.

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Methodology

The following section includes a description of the methodology used to estimate changes in mineral soil C stocks for *Land Converted to Forest Land*. Carbon stock changes for the other pools (i.e., aboveground and belowground biomass, dead wood, and litter), as recommended for inclusion by IPCC (2006) for each land use and land use conversion category are not included in this Inventory. This was due, in part, for a need to more thoroughly quantify the length of time that land remains in a conversion category after a change in land use and also because the accounting framework was not developed in time to estimate C stocks and stock changes for the IPCC pools in the *Land Converted to Forest Land* category over the default 20-year conversion period. Improvements are underway to include all C pool estimates in future inventories.

Mineral Soil Carbon Stock Changes

A Tier 2 method is applied to estimate soil C stock changes for *Land Converted to Forest Land* (Ogle et al. 2003, 2006; IPCC 2006). For this method, land is stratified by climate, soil types, land use, and land management activity, and then assigned reference carbon levels and factors for the forest land and the previous land use. The difference between the stocks is reported as the stock change under the assumption that the change occurs over 20 years. Reference C stocks have been estimated from data in the National Soil Survey Characterization Database (USDA-NRCS 1997), and U.S.-specific stock change factors have been derived from published literature (Ogle et al. 2003, 2006). Land use and land use change patterns are determined from a combination of the Forest Inventory and Analysis Dataset (FIA), the 2010 National Resources Inventory (NRI) (USDA-NRCS 2013), and National Land Cover Dataset (NLCD) (Homer et al. 2007). See Annex 3.12 for more information about this method (Methodology for Estimating N₂O Emissions, CH₄ Emissions and Soil Organic C Stock Changes from Agricultural Soil Management).

Uncertainty and Time-Series Consistency

Uncertainty estimates for mineral soil C stock changes were developed using the same methodologies as described for the Tier 2 component of the mineral soils in *Cropland Remaining Cropland*.

Uncertainty estimates are presented in Table 6-22 for each land conversion category. Uncertainty estimates were obtained using a Monte Carlo approach. Uncertainty estimates were combined using the error propagation model in accordance with IPCC (2006). The combined uncertainty for soil C stocks in *Land Converted to Forest Land* ranged from 70 percent below to 67 percent above the 2014 stock change estimate of -0.3 MMT CO₂ Eq.

Table 6-22: Quantitative Uncertainty Estimates for Mineral Soil C Stock Changes (MMT CO₂ Eq. per yr) in 2014 Occurring Within *Land Converted to Forest Land*

| Source | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Range ^a | | | |
|---|---|---|-------------|-----------------|-----------------|
| | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Cropland Converted to Forest Land | | | | | |
| Mineral Soils Tier 2 | (0.1) | (0.1) | + | -99% | 94% |
| Grassland Converted to Forest Land | | | | | |
| Mineral Soils Tier 2 | (0.2) | (0.5) | + | -99% | 94% |
| Other Lands Converted to Forest Land | | | | | |
| Mineral Soils Tier 2 | + | (0.1) | + | -99% | 94% |

| | | | | | |
|---|--------------|--------------|--------------|-------------|------------|
| Settlements Converted to Forest Land | | | | | |
| Mineral Soils Tier 2 | + | + | + | -99% | 94% |
| Wetlands Converted to Forest Land | | | | | |
| Mineral Soils Tier 2 | + | + | + | -99% | 94% |
| Total: Lands Converted to Forest Lands | (0.3) | (0.6) | (0.1) | -70% | 67% |

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Range of flux estimate for 95 percent confidence interval

Note: Parentheses indicate net sequestration.

Uncertainty is also associated with lack of reporting of biomass, litter and dead wood C stock changes in this category. The accumulation of biomass, litter and dead wood in this category may have led to substantial changes in the biomass, litter and dead wood C stocks in some regions of the U.S. These stock changes will be included in future submissions (see Planned Improvements below).

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See QA/QC and Verification section under *Cropland Remaining Cropland*.

Recalculations Discussion

This is the first U.S. submission to include a *Land Converted to Forest Land* section containing specific soil C stock change estimates. In prior submissions (e.g., EPA 2015), the C stock changes from *Land Converted to Forest Land* were a part of the *Forest Land Remaining Forest Land* estimates. As such, no recalculations were conducted for this chapter in this year's submission. See the Recalculations section in *Forest Land Remaining Forest Land* for a detailed explanation on overall changes resulting from implementing a different accounting approach in the current Inventory report.

Planned Improvements

A different accounting framework (Woodall et al. 2015a) was used for the forest land category in this report with the specific intent of separating *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. While this new approach led to improvements (e.g., disaggregation of forest land area between the land-use categories), there are many improvements still necessary to fully incorporate all C pool estimates and all land-use categories over the entire time series. First, research, in coordination with the other land-use categories, into the length of time that forest land remains in the *Land Converted to Forest Land* category will be undertaken and a mechanism to account for emissions and removals for all IPCC pools in this conversion category will be developed. Second, soil carbon has historically been reported to a depth of 100 cm in the *Forest Land Remaining Forest Land* category (Domke et al. In preparation) while other land-use categories (e.g., Grasslands and Croplands) report soil carbon to a depth of 20 or 30 cm. To ensure consistency in the *Land Converted to Forest Land* category where C stock transfers occur between land-use categories, all mineral soil estimates in the *Land Converted to Forest Land* category in this Inventory are based on methods from Ogle et al. (2003, 2006) and IPCC (2006). Methods have recently been developed (Domke et al. In prep) to estimate soil carbon to depths of 20, 30, and 100 cm the in Forest Land category using in situ measurements from the Forest Inventory and Analysis program within the USDA Forest Service and the International Soil Carbon Network. In subsequent Inventories, a common reporting depth will be defined for all land conversion categories and Domke et al. (In preparation) will be used in the *Forest Land Remaining Forest Land* and *Land Converted to Forest Land* categories to ensure consistent accounting across all forest land. Third, only estimates of mineral soil C are included in the *Land Converted to Forest Land* category this year. This led to an incomplete Inventory since the other IPCC pools were not included. In subsequent reports, all IPCC pools will be included in the *Land Converted to Forest Land* category. This will require coordination between land-use categories to ensure incorporation of country-specific or IPCC Tier 1 estimates for all IPCC C pools to ensure complete and consistent accounting between land-use categories.

6.4 Cropland Remaining Cropland (IPCC Source Category 4B1)

Mineral and Organic Soil Carbon Stock Changes

Carbon (C) in cropland ecosystems occurs in biomass, dead organic matter, and soils. However, C storage in cropland biomass and dead organic matter is relatively ephemeral, with the exception of C stored in perennial woody crop biomass, such as citrus groves and apple orchards. Within soils, C is found in organic and inorganic forms of C, but soil organic C (SOC) is the main source and sink for atmospheric CO₂ in most soils. IPCC (2006) recommends reporting changes in SOC stocks due to agricultural land-use and management activities on both mineral and organic soils.³¹

Well-drained mineral soils typically contain from 1 to 6 percent organic C by weight, whereas mineral soils with high water tables for substantial periods during the year may contain significantly more C (NRCS 1999). Conversion of mineral soils from their native state to agricultural land uses can cause up to half of the SOC to be lost to the atmosphere due to enhanced microbial decomposition. The rate and ultimate magnitude of C loss depends on subsequent management practices, climate and soil type (Ogle et al. 2005). Agricultural practices, such as clearing, drainage, tillage, planting, grazing, crop residue management, fertilization, and flooding, can modify both organic matter inputs and decomposition, and thereby result in a net C stock change (Parton et al. 1987; Paustian et al. 1997a; Conant et al. 2001; Ogle et al. 2005). Eventually, the soil can reach a new equilibrium that reflects a balance between C inputs (e.g., decayed plant matter, roots, and organic amendments such as manure and crop residues) and C loss through microbial decomposition of organic matter (Paustian et al. 1997b).

Organic soils, also referred to as *Histosols*, include all soils with more than 12 to 20 percent organic C by weight, depending on clay content (NRCS 1999; Brady and Weil 1999). The organic layer of these soils can be very deep (i.e., several meters), and form under inundated conditions that results in minimal decomposition of plant residues. When organic soils are prepared for crop production, they are drained and tilled, leading to aeration of the soil that accelerates both the decomposition rate and CO₂ emissions.³² Due to the depth and richness of the organic layers, C loss from drained organic soils can continue over long periods of time, which varies depending on climate and composition (i.e., decomposability) of the organic matter (Armentano and Menges 1986). Due to deeper drainage and more intensive management practices, the use of organic soils for annual crop production (and also settlements) leads to higher C loss rates than drainage of organic soils in grassland or forests (IPCC 2006).

Cropland Remaining Cropland includes all cropland in an Inventory year that has been used as cropland for the previous 20 years according to the 2010 United States Department of Agriculture (USDA) National Resources Inventory (NRI) land-use survey for non-federal lands (USDA-NRCS 2013) and according to the National Land Cover Dataset for federal lands (Homer et al. 2007; Fry et al. 2011; Homer et al. 2015). Cropland includes all land used to produce food and fiber, in addition to forage that is harvested and used as feed (e.g., hay and silage), and cropland that has been enrolled in the Conservation Reserve Program (CRP) (i.e., considered reserve cropland). Cropland in Alaska is not included in the Inventory, but is a relatively small amount of U.S. cropland area (approximately 28,700 hectares). Some miscellaneous croplands are also not included in the Inventory due to limited understanding of greenhouse gas emissions from these management systems (e.g., aquaculture). This leads to a small discrepancy between the total amount of managed area in *Cropland Remaining Cropland* (see Section 6.1 Representation of the U.S. Land Base) and the cropland area included in the Inventory analysis (0.5 to 0.7 million hectares or 0.02 percent of the total cropland areas in the United States between 1990 and 2014). Improvements are underway to include croplands in Alaska and other miscellaneous cropland areas as part of future C inventories.

³¹ Carbon dioxide emissions associated with liming are also estimated but are included in a separate section of the report.

³² Note: N₂O emissions from soils are included in the Agricultural Soil Management section.

Carbon dioxide emissions and removals³³ due to changes in mineral soil C stocks are estimated using a Tier 3 Approach for the majority of annual crops (Ogle et al. 2010). A Tier 2 IPCC method is used for the remaining crops not included in the Tier 3 method (see Methodology section for a list of crops in the Tier 2 and 3 methods) (Ogle et al. 2003, 2006). In addition, a Tier 2 method is used for very gravelly, cobbly, or shaley soils (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale) regardless of crop, and for additional changes in mineral soil C stocks that are not addressed with the Tier 3 approach (i.e., change in C stocks after 2010 due to CRP enrollment). Emissions from organic soils are estimated using a Tier 2 IPCC method.

Land-use and land management of mineral soils are the largest contributor to total net C stock change, especially in the early part of the time series (see Table 6-23 and Table 6-24). (Note: Estimates after 2010 are based on NRI data from 2010 and therefore do not fully reflect changes occurring in the latter part of the time series). In 2014, mineral soils are estimated to sequester 36.2 MMT CO₂ Eq. from the atmosphere (9.9 MMT C). This rate of C storage in mineral soils represents about a 42 percent decrease in the rate since the initial reporting year of 1990. CO₂ emissions from organic soils are 27.8 MMT CO₂ Eq. (7.6 MMT C) in 2014, which is a 0.8 percent decrease compared to 1990. In total, United States agricultural soils in *Cropland Remaining Cropland* sequestered approximately 8.4 MMT CO₂ Eq. (2.3 MMT C) in 2014.

Table 6-23: Net CO₂ Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (MMT CO₂ Eq.)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|---------------|---------------|------------|---------------|---------------|--------------|--------------|
| Mineral Soils | (62.3) | (42.8) | (26.0) | (40.3) | (38.9) | (37.0) | (36.2) |
| Organic Soils | 28.0 | 28.7 | 27.8 | 27.8 | 27.8 | 27.8 | 27.8 |
| Total Net Flux | (34.3) | (14.1) | 1.8 | (12.5) | (11.2) | (9.3) | (8.4) |

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-24: Net CO₂ Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (MMT C)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|------------|--------------|--------------|--------------|--------------|
| Mineral Soils | (17.0) | (11.7) | (7.1) | (11.0) | (10.6) | (10.1) | (9.9) |
| Organic Soils | 7.6 | 7.8 | 7.6 | 7.6 | 7.6 | 7.6 | 7.6 |
| Total Net Flux | (9.4) | (3.8) | 0.5 | (3.4) | (3.0) | (2.5) | (2.3) |

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

The major cause of the reduction in soil C accumulation over the time series (i.e., 2014 is 75 percent less than 1990) is the decline in annual cropland enrolled in the CRP³⁴ which was initiated in 1985. For example, over 2 million hectares that had been enrolled in the CRP were returned to agricultural production during the last 5 years resulting in a loss of soil C. However, positive increases in C stocks continue on the nearly 10 million hectares of land currently enrolled in the CRP, as well as from intensification of crop production by limiting the use of bare-summer fallow in semi-arid regions, increased hay production, and adoption of conservation tillage (i.e., reduced- and no-till practices).

³³ Note that removals occur through uptake of CO₂ into crop and forage biomass that is later incorporated into soil C pools.

³⁴ The Conservation Reserve Program (CRP) is a land conservation program administered by the Farm Service Agency (FSA). In exchange for a yearly rental payment, farmers enrolled in the program agree to remove environmentally sensitive land from agricultural production and plant species that will improve environmental health and quality. Contracts for land enrolled in CRP are 10 to 15 years in length. The long-term goal of the program is to re-establish valuable land cover to help improve water quality, prevent soil erosion, and reduce loss of wildlife habitat.

The spatial variability in the 2014 annual C stock changes are displayed in Figure 6-4 and Figure 6-5 for mineral and organic soils, respectively. The highest rates of net C accumulation in mineral soils occurred in the Midwest, which is the region with the largest amounts of conservation tillage, and the next highest rates of C accumulation occur in the South-central and Northwest regions of the United States. The regions with the highest rates of emissions from organic soils occur in the Southeastern Coastal Region (particularly Florida), upper Midwest and Northeast surrounding the Great Lakes, and the Pacific Coast (particularly California), which coincides with the largest concentrations of organic soils in the United States that are used for agricultural production.

Figure 6-4: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2014, Cropland Remaining Cropland

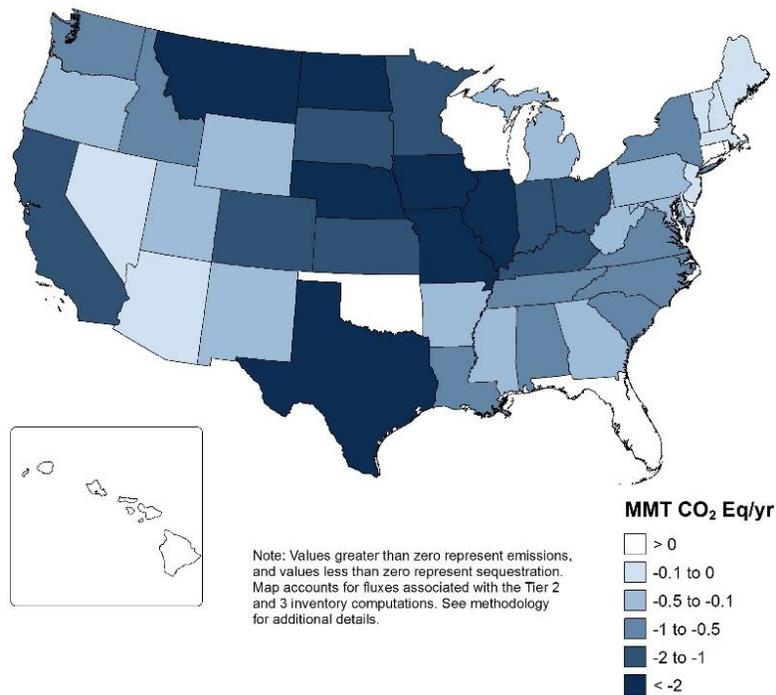
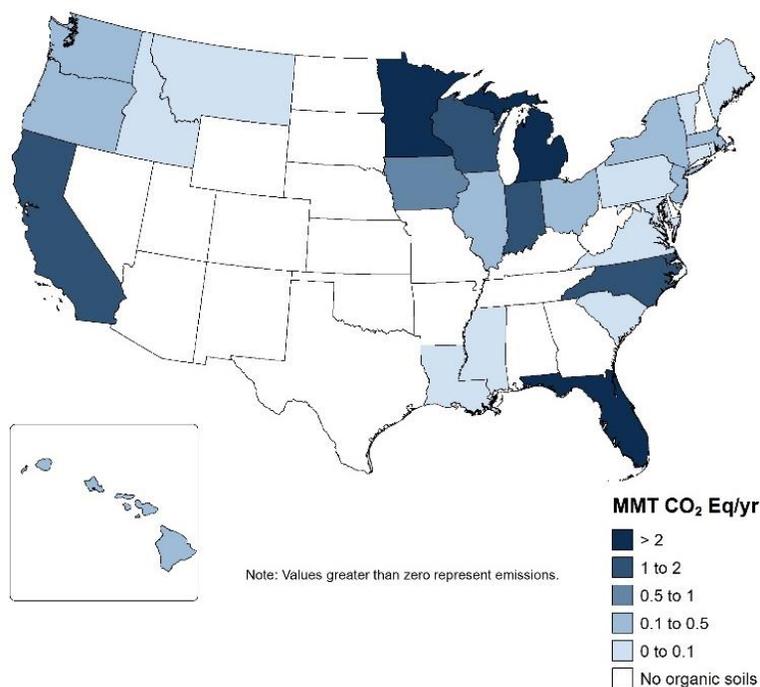


Figure 6-5: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2014, *Cropland Remaining Cropland*



Methodology

The following section includes a description of the methodology used to estimate changes in soil C stocks for *Cropland Remaining Cropland*, including (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils.

Soil C stock changes are estimated for *Cropland Remaining Cropland* (as well as agricultural land falling into the IPCC categories *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*) according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2013). The NRI is a statistically-based sample of all non-federal land, and includes approximately 596,787 survey locations in agricultural land for the conterminous United States and Hawaii.³⁵ Each survey location is associated with an “expansion factor” that allows scaling of C stock changes from NRI survey locations to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were collected for each NRI point on a 5-year cycle beginning from 1982 through 1997. For cropland, data had been collected for 4 out of 5 years during each survey cycle (i.e., 1979 through 1982, 1984 through 1987, 1989 through 1992, and 1994 through 1997). In 1998, the NRI program began collecting annual data, and the annual data are currently available through 2012 (USDA-NRCS 2015). However, this Inventory only uses NRI data through 2010 because newer data were not available in time to incorporate the additional years. NRI survey locations are classified as *Cropland Remaining Cropland* in a given year between 1990 and 2010 if the land use had been cropland for a continuous time period of at least 20 years. NRI survey locations are classified according to land-use histories starting in 1979, and consequently the classifications are based on less than 20 years from 1990 to 1998. This may have led to an overestimation of *Cropland Remaining Cropland* in the early part of the time series to the extent that some areas are converted to cropland prior to 1979.

³⁵ NRI survey locations are classified as agricultural if under grassland or cropland management between 1990 and 2010.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach (Ogle et al. 2010) is applied to estimate C stock changes for mineral soils on the majority of land that is used to produce annual crops in the United States. These crops include alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat. The model-based approach uses the DAYCENT biogeochemical model (Parton et al. 1998; Del Grosso et al. 2001, 2011) to estimate soil C stock changes and soil nitrous oxide emissions from agricultural soil management. Carbon and N dynamics are linked in plant-soil systems through the biogeochemical processes of microbial decomposition and plant production (McGill and Cole 1981). Coupling the two source categories (i.e., agricultural soil C and N₂O) in a single inventory analysis ensures that there is a consistent treatment of the processes and interactions between C and N cycling in soils.

The remaining crops on mineral soils are estimated using an IPCC Tier 2 method (Ogle et al. 2003), including some vegetables, tobacco, perennial/horticultural crops, and crops that are rotated with these crops. The Tier 2 method is also used for very gravelly, cobbly, or shaley soils (greater than 35 percent by volume), and stock changes on federal croplands are estimated with the Tier 2 method. Mineral SOC stocks are estimated using a Tier 2 method for these areas because the DAYCENT model, which is used for the Tier 3 method, has not been fully tested for estimating C stock changes associated with these crops and rotations, as well as cobbly, gravelly, or shaley soils. In addition, there is insufficient information to simulate croplands on federal lands. The Tier 2 methods is also used to estimate additional stock changes on lands enrolled in CRP after 2010, which is the last year of data in the NRI time series, using aggregated data on CRP enrollment compiled by the USDA Farm Services Agency.

Further elaboration on the methodology and data used to estimate stock changes from mineral soils are described below and in Annex 3.12.

Tier 3 Approach

Mineral SOC stocks and stock changes are estimated using the DAYCENT biogeochemical³⁶ model (Parton et al. 1998; Del Grosso et al. 2001, 2011), which simulates cycling of C, N and other nutrients in cropland, grassland, forest, and savanna ecosystems. The DAYCENT model utilizes the soil C modeling framework developed in the Century model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), but has been refined to simulate dynamics at a daily time-step. The modeling approach uses daily weather data as an input, along with information about soil physical properties. Input data on land use and management are specified at a daily resolution and include land-use type, crop/forage type, and management activities (e.g., planting, harvesting, fertilization, manure amendments, tillage, irrigation, residue removal, grazing, and fire). The model simulates net primary productivity (NPP) using the NASA-CASA production algorithm MODIS Enhanced Vegetation Index (EVI) products, MOD13Q1 and MYD13Q1, for most croplands³⁷ (Potter et al. 1993, 2007). The model also simulates soil temperature, and water dynamics, in addition to turnover, stabilization, and mineralization of soil organic matter C and nutrients (N, P, K, S). This method is more accurate than the Tier 1 and 2 approaches provided by the IPCC (2006) because the simulation model treats changes as continuous over time as opposed to the simplified discrete changes represented in the default method (see Box 6-4 for additional information).

Box 6-4: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches

A Tier 3 model-based approach is used to estimate soil C stock changes on the majority of agricultural land on mineral soils. This approach results in a more complete and accurate accounting of soil C stock changes and entails several fundamental differences from the IPCC Tier 1 or 2 methods, as described below.

- (1) The IPCC Tier 1 and 2 methods are simplified and classify land areas into discrete categories based on highly aggregated information about climate (six regions), soil (seven types), and management (eleven

³⁶ Biogeochemical cycles are the flow of chemical elements and compounds between living organisms and the physical environment.

³⁷ NPP is estimated with the NASA-CASA algorithm for most of the cropland that is used to produce major commodity crops in the central United States from 2000 to 2010. Other regions and years prior to 2000 are simulated with a method that incorporates water, temperature and moisture stress on crop production (see Metherell et al. 1993), but does not incorporate the additional information about crop condition provided with remote sensing data.

management systems) in the United States. In contrast, the Tier 3 model incorporates the same variables (i.e., climate, soils, and management systems) with considerably more detail both temporally and spatially, and captures multi-dimensional interactions through the more complex model structure.

- (2) The IPCC Tier 1 and 2 methods have a simplified spatial resolution in which data are aggregated to soil types in climate regions, of which there are about 30 combinations in the United States. In contrast, the Tier 3 model simulates soil C dynamics at more than 300,000 individual NRI survey locations in individual fields.
 - (3) The IPCC Tier 1 and 2 methods use simplified equilibrium step changes for changes in C emissions. In contrast, the Tier 3 approach simulates a continuous time period. More specifically, the DAYCENT model (i.e., daily time-step version of the Century model) simulates soil C dynamics (and CO₂ emissions and uptake) on a daily time step based on C emissions and removals from plant production and decomposition processes. These changes in soil C stocks are influenced by multiple sources that affect primary production and decomposition, including changes in land use and management, weather variability and secondary feedbacks between management activities, climate, and soils.
-

Historical land-use patterns and irrigation histories are simulated with DAYCENT based on the 2010 USDA NRI survey (USDA-NRCS 2013). Additional sources of activity data are used to supplement the land-use information from the NRI. The Conservation Technology Information Center (CTIC 2004) provided annual data on tillage activity at the county level for the conterminous United States between 1989 and 2004, and these data are adjusted for long-term adoption of no-till agriculture (Towery 2001). Information on fertilizer use and rates by crop type for different regions of the United States are obtained primarily from the USDA Economic Research Service. The data collection program was known as the Cropping Practices Surveys through 1995 (USDA-ERS 1997), and then became the Agricultural Resource Management Surveys (ARMS) (USDA-ERS 2011).³⁸ Additional data are compiled through other sources particularly the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to cropland during 1997 are estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 are used to adjust the area amended with manure (see Annex 3.12 for further details). Greater availability of managed manure N relative to 1997 is assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 is assumed to reduce the amended area. Data on the county-level N available for application are estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and include the addition of N from bedding materials. Nitrogen losses include direct N₂O emissions, volatilization of ammonia and NO_x, N runoff and leaching, and the N in poultry manure used as a feed supplement. More information on livestock manure production is available in Section 5.2 - Manure Management and Annex 3.11.

Daily weather data are another input to the model simulations, and these data are based on a 4 kilometer gridded product from the PRISM Climate Group (2015). Soil attributes are obtained from the Soil Survey Geographic Database (SSURGO) (Soil Survey Staff 2015). The C dynamics at each NRI point are simulated 100 times as part of the uncertainty analysis, yielding a total of over 18 million simulation runs for the analysis. Uncertainty in the C stock estimates from DAYCENT associated with parameterization and model algorithms are adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Ogle et al. 2007, 2010). Carbon stocks and 95 percent confidence intervals are estimated for each year between 1990 and 2010. C stock changes from 2011 to 2014 are assumed to be similar to 2010 for this Inventory. Future Inventories will be updated with new activity data when the data are made available, and the time series will be recalculated (see Planned Improvements section).

Tier 2 Approach

In the IPCC Tier 2 method, data on climate, soil types, land-use, and land management activity are used to classify land area and apply appropriate stock change factors (Ogle et al. 2003, 2006). Reference C stocks are estimated using the National Soil Survey Characterization Database (NRCS 1997) with cultivated cropland as the reference

³⁸ See <<http://www.ers.usda.gov/data-products/arms-farm-financial-and-crop-production-practices/arms-data.aspx>>.

condition, rather than native vegetation as used in IPCC (2006). Soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997) than are soils under a native condition, and therefore cultivated cropland provided a more robust sample for estimating the reference condition. U.S.-specific C stock change factors are derived from published literature to determine the impact of management practices on SOC storage (Ogle et al. 2003, Ogle et al. 2006). The factors include changes in tillage, cropping rotations, intensification, and land-use change between cultivated and uncultivated conditions. U.S. factors associated with organic matter amendments are not estimated due to an insufficient number of studies in the United States to analyze the impacts. Instead, factors from IPCC (2006) are used to estimate the effect of those activities.

Climate zones in the United States are classified using mean precipitation and temperature (1950 to 2000) variables from the WorldClim data set (Hijmans et al. 2005) and potential evapotranspiration data from the Consortium for Spatial Information (CGIAR-CSI) (Zomer et al. 2008, 2007) (Figure A-14). IPCC climate zones are then assigned to NRI point locations.

Activity data are primarily based on the historical land-use/management patterns recorded in the 2010 NRI (USDA-NRCS 2013). Each NRI point is classified by land use, soil type, climate region, and management condition. Survey locations on federal lands are included in the NRI, but land use and cropping history are not compiled at these locations in the survey program (i.e., NRI is restricted to data collection on non-federal lands). Land-use patterns at the NRI survey locations on federal lands are based on the National Land Cover Database (NLCD) (Fry et al. 2011; Homer et al. 2007; Homer et al. 2015). Classification of cropland area by tillage practice is based on data from the Conservation Technology Information Center (CTIC 2004; Towery 2001) as described above. Activity data on wetland restoration of Conservation Reserve Program land are obtained from Euliss and Gleason (2002). Manure N amendments over the inventory time period are based on application rates and areas amended with manure N from Edmonds et al. (2003), in addition to the managed manure production data discussed in the methodology subsection for the Tier 3 analysis.

Combining information from these data sources, SOC stocks for mineral soils are estimated 50,000 times for each year in the time series, using a Monte Carlo stochastic simulation approach and probability distribution functions for U.S.-specific stock change factors, reference C stocks, and land-use activity data (Ogle et al. 2002; Ogle et al. 2003; Ogle et al. 2006). The annual C stock changes from 2011 through 2014 for the Tier 2 method is assumed to be similar to 2010 because no additional activity data are available from NRI for these latter years. As with the Tier 3 method, future Inventories will be updated with new activity data when the data are made available, and the time series will be recalculated (see Planned Improvements section).

Additional Mineral C Stock Change

Annual C stock change estimates for mineral soils between 2011 and 2014 are adjusted to account for additional C stock changes associated with gains or losses in soil C after 2010 due to changes in CRP enrollment (USDA-FSA 2014). The change in enrollment relative to 2010 is based on data from USDA-FSA (2014) for 2011 through 2014. The differences in mineral soil areas are multiplied by 0.5 metric tons C per hectare per year to estimate the net effect on soil C stocks. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.12 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Cropland Remaining Cropland* are estimated using the Tier 2 method provided in IPCC (2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo Stochastic Simulation with 50,000 iterations. Emissions are based on the annual data for drained organic soils from 1990 to 2010 for *Cropland Remaining Cropland* areas in the 2010 NRI (USDA-NRCS 2013). The annual emissions estimated for 2010 are applied to 2011 through 2014. Future Inventories will be updated with new activity data when the data are made available, and the time series will be recalculated (see Planned Improvements section).

Uncertainty and Time-Series Consistency

Uncertainty associated with the *Cropland Remaining Cropland* land-use category is addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table

6-25 for each subsource (mineral soil C stocks and organic soil C stocks) and the method that is used in the Inventory analysis (i.e., Tier 2 and Tier 3). Uncertainty for the Tier 2 and 3 Approaches is derived using a Monte Carlo approach (see Annex 3.12 for further discussion), but the C stock changes from the individual Tier 2 and 3 approaches are combined using the simple error propagation method provided by the IPCC (2006). The combined uncertainty is calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Cropland Remaining Cropland* ranged from 401 percent below to 414 percent above the 2014 stock change estimate of -8.4 MMT CO₂ Eq.

Table 6-25: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Cropland Remaining Cropland* (MMT CO₂ Eq. and Percent)

| Source | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a | | | |
|---|---|--|----------------|---|----------------|
| | | Uncertainty Range (MMT CO ₂ Eq.) | | Relative to Flux Estimate ^a (%) | |
| | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 3 Inventory Methodology | (36.7) | (69.0) | (4.5) | -88% | +88% |
| Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology | (3.2) | (5.2) | (1.5) | -64% | +54% |
| Mineral Soil C Stocks: Cropland Remaining Cropland (Change in CRP enrollment relative to 2003) | 3.7 | 1.9 | 5.6 | -50% | +50% |
| Organic Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology | 27.8 | 17.8 | 41.0 | -36% | +48% |
| Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stock Change in Cropland Remaining Cropland | (8.4) | (42.3) | 26.5 | -401% | +414% |

^a Range of C stock change estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval. Notes: Parentheses indicate net sequestration.

Uncertainty is also associated with lack of reporting of agricultural biomass and dead organic matter C stock changes. Biomass C stock changes are likely minor in perennial crops, such as orchards and nut plantations, given the small amount of change in land that is used to produce these commodities in the U.S. In contrast, agroforestry practices, such as shelterbelts, riparian forests and intercropping with trees, may be significantly changing biomass C stocks over the Inventory times series, at least in some regions of the United States, but there are currently no datasets to evaluate the trends. Changes in litter C stocks are also assumed to be negligible in croplands over annual time frames, although there are certainly significant changes at sub-annual time scales across seasons. However, this trend may change in the future, particularly if crop residue becomes a viable feedstock for bioenergy production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data are properly handled throughout the inventory process. Inventory reporting forms and text are reviewed and revised as needed to correct transcription errors. Results from the DAYCENT model are compared to field measurements, and a statistical relationship has been developed to assess uncertainties in the predictive capability of the model. The comparisons included over 80 long-term experiments, representing about 908 combinations of management treatments across all of the sites (see Ogle et al. 2007 and Annex 3.12 for more information). Quality control identified problems with simulation of hydric soils in the equilibrium and base histories, which proceed the simulation of the NRI histories from 1979 to 2010. Hydric soils were draining more quickly than expected in the simulations, and resulted in low values for the carbon stocks at the beginning of the history in 1979. Corrective actions were taken by adjusting the parameters to reduce the drainage rate on hydric soils during the equilibrium and simulate slower decomposition rates with a high water table.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements: 1) incorporation of updated NRI data for 1990 through 2010; 2) inclusion of federal croplands; and 3) improving the simulation of hydric soil. As a result of these improvements, the change in SOC stocks declined by an average of 16.5 MMT CO₂ Eq., which is a 48 percent change in the reported soil C stock changes compared to the previous Inventory. The largest driver of this change is associated with corrective actions taken to more accurately represent the hydric soil condition.

Planned Improvements

Two major planned improvements are underway. The first is to update the time series of land use and management data from the USDA NRI so that it is extended from 2010 through 2012 for both the Tier 2 and 3 methods (USDA-NRCS 2015). Fertilization and tillage activity data will also be updated as part of this improvement. The remote-sensing based data on the Enhanced Vegetation Index will be extended through 2012 in order to use the EVI data to drive crop production in DAYCENT. Overall, this improvement will extend the time series of activity data for the Tier 2 and 3 analyses through 2012.

The second major planned improvement is to analyze C stock changes in Alaska for cropland and managed grassland, using the Tier 2 method for mineral and organic soils that is described earlier in this section. This analysis will initially focus on land use change, which typically has a larger impact on soil C stock changes, but will be further refined over time to incorporate more of the management data.

An improvement is also underway to simulate crop residue burning in the DAYCENT based on the amount of crop residues burned according to the data that is used in the Field Burning of Agricultural Residues source category (Section 5.5). This improvement will more accurately represent the C inputs to the soil that are associated with residue burning. Other improvements are underway to refine the production part of the DAYCENT biogeochemical model. For example, senescence events following grain filling in crops, such as wheat, have been refined based on recent model algorithm development, and will be incorporated into next year's Inventory.

All of these improvements are expected to be completed for the 1990 through 2015 Inventory. However, the time line may be extended if there are insufficient resources to fund all or part of these planned improvements.

CO₂ Emissions from Liming

IPCC (2006) recommends reporting CO₂ emissions from lime additions (in the form of crushed limestone (CaCO₃) and dolomite (CaMg(CO₃)₂) to soils. Limestone and dolomite are added by land managers to increase soil pH (i.e., to reduce acidification). Carbon dioxide emissions occur as these compounds react with hydrogen ions in soils. The rate and ultimate magnitude of degradation of applied limestone and dolomite depends on the soil conditions, soil type, climate regime, and whether limestone or dolomite is applied. Emissions from liming of soils have fluctuated over the past 24 years, ranging from 3.7 MMT CO₂ Eq. to 6.0 MMT CO₂ Eq. In 2014, liming of soils in the United States resulted in emissions of 4.1 MMT CO₂ Eq. (1.1 MMT C), representing an 11 percent decrease in emissions since 1990 (see Table 6-26 and Table 6-27). The trend is driven by the amount of limestone and dolomite applied to soils over the time period.

Table 6-26: Emissions from Liming (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|------------|------------|
| Limestone | 4.1 | 3.9 | 4.3 | 3.4 | 4.5 | 3.6 | 3.8 |
| Dolomite | 0.6 | 0.4 | 0.5 | 0.4 | 1.5 | 0.3 | 0.3 |
| Total^a | 4.7 | 4.3 | 4.8 | 3.9 | 6.0 | 3.9 | 4.1 |

^a Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Note: Totals may not sum due to independent rounding.

Table 6-27: Emissions from Liming (MMT C)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|------------|------------|------------|------------|------------|------------|------------|
| Limestone | 1.1 | 1.1 | 1.2 | 0.9 | 1.2 | 1.0 | 1.0 |
| Dolomite | 0.2 | 0.1 | 0.1 | 0.1 | 0.4 | 0.1 | 0.1 |
| Total^a | 1.3 | 1.2 | 1.3 | 1.1 | 1.6 | 1.1 | 1.1 |

^a Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, and Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Note: Totals may not sum due to independent rounding.

Methodology

Carbon dioxide emissions from application of limestone and dolomite to soils were estimated using a Tier 2 methodology consistent with IPCC (2006). The annual amounts of limestone and dolomite applied (see Table 6-28) were multiplied by CO₂ emission factors from West and McBride (2005). These emission factors (0.059 metric ton C/metric ton limestone, 0.064 metric ton C/metric ton dolomite) are lower than the IPCC default emission factors because they account for the portion of carbonates that are transported from soils through hydrological processes and eventually deposited in ocean basins (West and McBride 2005). This analysis of lime dissolution is based on studies in the Mississippi River basin, where the vast majority of lime application occurs in the United States (West 2008). Moreover, much of the remaining lime application is occurring under similar precipitation regimes, and so the emission factors are considered a reasonable approximation for all lime application in the United States (West 2008).

The annual application rates of limestone and dolomite were derived from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Industry Surveys* (Tepordei 1993 through 2006; Willett 2007a, 2007b, 2009, 2010, 2011a, 2011b, 2013a, 2014 and 2015; USGS 2008 through 2015). The U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) compiled production and use information through surveys of crushed stone manufacturers. However, manufacturers provided different levels of detail in survey responses so the estimates of total crushed limestone and dolomite production and use were divided into three components: (1) production by end-use, as reported by manufacturers (i.e., “specified” production); (2) production reported by manufacturers without end-uses specified (i.e., “unspecified” production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e., “estimated” production).

Box 6-5: Comparison of the Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

Emissions from liming of soils were estimated using a Tier 2 methodology based on emission factors specific to the United States that are lower than the IPCC (2006) emission default factors. Most lime application in the United States occurs in the Mississippi River basin, or in areas that have similar soil and rainfall regimes as the Mississippi River basin. Under these conditions, a significant portion of dissolved agricultural lime leaches through the soil into groundwater. Groundwater moves into channels and is transported to larger rivers and eventually the ocean where

CaCO₃ precipitates to the ocean floor (West and McBride 2005). The U.S. specific emission factors (0.059 metric ton C/metric ton limestone and 0.064 metric ton C/metric ton dolomite) are about half of the IPCC (2006) emission factors (0.12 metric ton C/metric ton limestone and 0.13 metric ton C/metric ton dolomite). For comparison, the 2014 U.S. emission estimate from liming of soils is 4.1 MMT CO₂ Eq. using the U.S.-specific factors. In contrast, emissions would be estimated at 8.4 MMT CO₂ Eq. using the IPCC (2006) default emission factors.

Data on “specified” limestone and dolomite amounts were used directly in the emission calculation because the end use is provided by the manufactures and can be used to directly determine the amount applied to soils. However, it is not possible to determine directly how much of the limestone and dolomite is applied to soils for manufacturer surveys in the “unspecified” and “estimated” categories. For these categories, the amounts of crushed limestone and dolomite applied to soils were determined by multiplying the percentage of total “specified” limestone and dolomite production applied to soils by the total amounts of “unspecified” and “estimated” limestone and dolomite production. In other words, the proportion of total “unspecified” and “estimated” crushed limestone and dolomite that was applied to soils is proportional to the amount of total “specified” crushed limestone and dolomite that was applied to soils.

In addition, data were not available for 1990, 1992, and 2013 on the fractions of total crushed stone production that were limestone and dolomite, and on the fractions of limestone and dolomite production that were applied to soils. To estimate the 1990 and 1992 data, a set of average fractions were calculated using the 1991 and 1993 data. These average fractions were applied to the quantity of "total crushed stone produced or used" reported for 1990 and 1992 in the 1994 *Minerals Yearbook* (Tepordei 1996). To estimate 2014 data, 2013 fractions were applied to a 2014 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2015* (USGS 2015).

The primary source for limestone and dolomite activity data is the *Minerals Yearbook*, published by the Bureau of Mines through 1994 and by the USGS from 1995 to the present. In 1994, the “Crushed Stone” chapter in the *Minerals Yearbook* began rounding (to the nearest thousand metric tons) quantities for total crushed stone produced or used. It then reported revised (rounded) quantities for each of the years from 1990 to 1993. In order to minimize the inconsistencies in the activity data, these revised production numbers have been used in all of the subsequent calculations.

Emissions from limestone and dolomite are estimated at the state level and summed to obtain the national estimate. The state-level estimates are not reported here, but are available upon request. Also, it is important to note that all emissions from liming are reported in *Cropland Remaining Cropland* because it is not possible to subdivide the data to each land-use category (i.e., *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*).

Table 6-28: Applied Minerals (MMT)

| Mineral | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------|------|------|------|------|------|------|------|
| Limestone ^a | 19.0 | 18.1 | 20.0 | 15.9 | 20.8 | 16.6 | 17.5 |
| Dolomite ^a | 2.4 | 1.9 | 1.9 | 1.9 | 6.3 | 1.4 | 1.5 |

^a Data represent amounts applied to *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Uncertainty and Time-Series Consistency

Uncertainty regarding the amount of limestone and dolomite applied to soils was estimated at ±15 percent with normal densities (Tepordei 2003; Willett 2013b). Analysis of the uncertainty associated with the emission factors included the fraction of lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not addressed in this analysis, but is assumed to be a relatively small contributor to the overall uncertainty (West 2005). The probability distribution functions for the fraction of lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were represented as smoothed

triangular distributions between ranges of zero and 100 percent of the estimates. The uncertainty surrounding these two components largely drives the overall uncertainty. More information on the uncertainty estimates for CO₂ Emissions from Liming is contained within the Uncertainty Annex 7.

A Monte Carlo (Approach 2) uncertainty analysis was applied to estimate the uncertainty in CO₂ emissions from liming. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 6-29. CO₂ emissions from Liming in 2014 were estimated to be between -0.5 and 7.8 MMT CO₂ Eq. at the 95 percent confidence level. This confidence interval represents a range of 111 percent below to 88 percent above the 2014 emission estimate of 4.1 MMT CO₂ Eq.

Table 6-29: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Liming (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|---------------------|-----------------|---|--|-------------|-------------|-------------|
| | | | (MMT CO ₂ Eq.) | | (%) | |
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Liming ^b | CO ₂ | 4.1 | (0.5) | 7.8 | -111% | +88% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

^b Includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land and Land Converted to Forest Land*, as it is not possible to subdivide the data by land-use category.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for liming has been developed and implemented, and the quality control effort focused on the Tier 1 procedures for this Inventory. Quality control procedures did uncover a transcription error in the spreadsheets that was corrected.

Recalculations Discussion

Adjustments were made in the current Inventory to improve the results. First, limestone and dolomite application data for 2013 were approximated in the previous Inventory using a ratio of total crushed stone for 2013 relative to 2012 (similar to 2014 in the current Inventory). The estimates for 2013 were updated with the recently published data from USGS (2015). Second, quality control measures uncovered a transcription error in the 2012 activity data that increased the emission estimate by 0.2 MMT CO₂ Eq. related to the previous Inventory. With these revisions in the activity data, the emissions increased by 3.5 percent in 2012 and decreased by 34 percent in 2013 relative to the previous Inventory.

CO₂ Emissions from Urea Fertilization

The use of urea (CO(NH₂)₂) as a fertilizer leads to CO₂ emissions through the release of CO₂ that was fixed during the industrial production process. In the presence of water and urease enzymes, urea is converted into ammonium (NH₄⁺), hydroxyl ion (OH), and bicarbonate (HCO₃⁻). The bicarbonate then evolves into CO₂ and water. Emissions from urea fertilization in the United States totaled 4.5 MMT CO₂ Eq. (1.2 MMT C) in 2014 (Table 6-30 and Table 6-31). Due to an increase in application of urea fertilizers between 1990 and 2014, CO₂ emissions have increased by 87 percent from this management activity.

Table 6-30: CO₂ Emissions from Urea Fertilization (MMT CO₂ Eq.)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------------|------|------|------|------|------|------|------|
| Urea Fertilization ^a | 2.4 | 3.5 | 3.8 | 4.1 | 4.2 | 4.3 | 4.5 |

^a Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Table 6-31: CO₂ Emissions from Urea Fertilization (MMT C)

| Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---------------------------------|------|------|------|------|------|------|------|
| Urea Fertilization ^a | 0.7 | 1.0 | 1.0 | 1.1 | 1.2 | 1.2 | 1.2 |

^a Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Methodology

Carbon dioxide emissions from the application of urea to agricultural soils were estimated using the IPCC (2006) Tier 1 methodology. The method assumes that all CO₂ fixed during the industrial production process of urea are released after application. The annual amounts of urea applied to croplands (see Table 6-32) were derived from the state-level fertilizer sales data provided in *Commercial Fertilizers* (TVA 1991, 1992, 1993, 1994; AAPFCO 1995 through 2014). These amounts were multiplied by the default IPCC (2006) emission factor (0.20 metric tons of C per metric ton of urea), which is equal to the C content of urea on an atomic weight basis. Because fertilizer sales data are reported in fertilizer years (July previous year through June current year), a calculation was performed to convert the data to calendar years (January through December). According to monthly fertilizer use data (TVA 1992b), 35 percent of total fertilizer used in any fertilizer year is applied between July and December of the previous calendar year, and 65 percent is applied between January and June of the current calendar year. For example, for the 2000 fertilizer year, 35 percent of the fertilizer was applied in July through December 1999, and 65 percent was applied in January through June 2000.

Fertilizer sales data for the 2013 and 2014 fertilizer years (i.e., July 2012 through June 2013 and July 2013 through June 2014) were not available for this Inventory. Therefore, urea application in the 2013 and 2014 fertilizer years were estimated using a linear, least squares trend of consumption over the data from the previous five years (2008 through 2012) at the state level. A trend of five years was chosen as opposed to a longer trend as it best captures the current inter-state and inter-annual variability in consumption. State-level estimates of CO₂ emissions from the application of urea to agricultural soils were summed to estimate total emissions for the entire United States. The fertilizer year data is then converted into calendar year data using the method described above.

Emissions are estimated at the state level and summed to obtain the national estimate. The state-level estimates are not reported here, but are available upon request. Also, it is important to note that all emissions from urea fertilization are reported in *Cropland Remaining Cropland* because it is not currently possible to apportion the emissions to each land-use category (i.e., *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*), however, the majority of urea fertilization is likely to have occurred on *Cropland Remaining Cropland*.

Table 6-32: Applied Urea (MMT)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------------------|------|------|------|------|------|------|------|
| Urea Fertilizer ^a | 3.3 | 4.8 | 5.2 | 5.6 | 5.8 | 5.9 | 6.2 |

^a These numbers represent amounts applied to all agricultural land, including *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements, Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, as it is not currently possible to apportion the data by land-use category.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 6-33 for *Urea Fertilization*. An Approach 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C in CO(NH₂)₂ applied to soils is ultimately emitted into the environment as CO₂. This factor does not incorporate the possibility that some of the C may be retained in the soil, and therefore the uncertainty range was set from 0 percent emissions to the maximum emission value of 100 percent using a triangular distribution. In addition, each urea consumption data point has an associated uncertainty. Carbon dioxide emissions from urea fertilization of agricultural soils in 2014 were estimated to be between 2.6 and 4.5 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of 42 percent below to 0 percent above the 2014 emission estimate of 4.5 MMT CO₂ Eq.

Table 6-33: Quantitative Uncertainty Estimates for CO₂ Emissions from Urea Fertilization (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) | | | |
|--------------------|-----------------|---|---|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Urea Fertilization | CO ₂ | 4.5 | 2.6 | 4.5 | -42% | 0% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

There are additional uncertainties that are not quantified in this analysis. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals, but the amount is likely very small. For example, research on aircraft deicing practices is consistent with this assumption based on a 1992 survey that found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 metric tons per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). In addition, there is uncertainty surrounding the underlying assumptions behind the calculation that converts fertilizer years to calendar years. These uncertainties are negligible over multiple years, however, because an over- or under-estimated value in one calendar year is addressed with corresponding increase or decrease in the value for the subsequent year.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for Urea Fertilization has been developed and implemented. For this year, the Tier 1 analysis was performed and an error was found in a formula reference to an incorrect cell in the spreadsheets.

Recalculations Discussion

In the current Inventory, the 2013 emission estimate was updated to reflect a correction to the calculations made in the previous Inventory report. Quality control checks uncovered an incorrect spreadsheet cell reference influencing

the state-level emission calculations. The 2013 emission estimate increased by 8.3 percent, relative to the previous report, due to this correction.

Planned Improvements

No improvements are planned for this source.

6.5 Land Converted to Cropland (IPCC Source Category 4B2)

Land Converted to Cropland includes all cropland in an Inventory year that had been in another land use(s) during the previous 20 years (USDA-NRCS 2013), and used to produce food or fiber, or forage that is harvested and used as feed (e.g., hay and silage). For example, grassland or forestland converted to cropland during the past 20 years would be reported in this category. Recently-converted lands are retained in this category for 20 years as recommended in the IPCC guidelines (IPCC 2006). This Inventory includes all croplands in the conterminous United States and Hawaii, but does not include a minor amount of *Land Converted to Cropland* in Alaska. Some miscellaneous croplands are also not included in the Inventory due to limited understanding of greenhouse gas dynamics in management systems (e.g., aquaculture) or climate zones (e.g., boreal climates). Consequently there is a discrepancy between the total amount of managed area in *Land Converted to Cropland* (see Section 6.1 Representation of the U.S. Land Base) and the cropland area included in the Inventory. Improvements are underway to include croplands in Alaska and miscellaneous crops in future C inventories.

Land use change can lead to large losses of C to the atmosphere, particularly conversions from forest land (Houghton et al. 1983). Moreover, conversion of forest to another land use (i.e., deforestation) is one of the largest anthropogenic sources of emissions to the atmosphere globally (Schimel 1995), although this source may be declining according to a recent assessment (Tubiello et al. 2015).

The 2006 IPCC Guidelines recommend reporting changes in biomass, dead organic matter and soil organic carbon (SOC)³⁹ stocks with land use change. All soil C stock changes are estimated and reported for *Land Converted to Cropland*, but there is limited reporting of other pools in this Inventory. Loss of aboveground biomass C from *Forest Converted to Cropland* is reported but losses from belowground biomass, dead wood and litter pools with forest conversion are not included in this Inventory.⁴⁰ In addition, biomass C stock changes are not estimated for other land use conversions (other than Forest Land) to Cropland.⁴¹

Loss of aboveground woody biomass C from *Forest Converted to Cropland* is the largest contributor to C loss throughout the time series, accounting for approximately 64 percent of the total emissions (Table 6-34 and Table 6-35). *Grassland Converted to Cropland* is the largest source of emissions associated with soil C pools across the time series (accounting for approximately 91 percent of the average loss of soil C), largely because the area of *Grassland Converted to Cropland* is significantly higher than for other land use conversions to cropland, though losses declined over the time series. The net change in total C stocks for 2014 led to CO₂ emissions to the atmosphere of 22.1 MMT CO₂ Eq. (6.0 MMT C), including 11.5 MMT CO₂ Eq. (3.1 MMT C) from biomass C losses, 6.3 MMT CO₂ Eq. (1.7 MMT C) from mineral soils and 4.3 MMT CO₂ Eq. (1.2 MMT C) from drainage and cultivation of organic soils. Emissions in 2014 are 66 percent lower than the emissions in the initial reporting year of 1990, largely due to less conversion of *Forest Land to Cropland*.

³⁹ CO₂ emissions associated with liming and urea fertilization are also estimated but included in Section 6.4 *Cropland Remaining Cropland* as it was not possible to separate additions of lime and urea by land use.

⁴⁰ A planned improvement is to estimate the losses of carbon from belowground biomass, dead wood and litter with *Forest Converted to Cropland*.

⁴¹ Changes in biomass C stocks are not currently reported for other land use conversions (other than forest land) to cropland, but this is a planned improvement for a future inventory. Note: changes in dead organic matter are assumed to negligible for other land use conversions (i.e., other than forest land) to cropland based on the Tier 1 method in IPCC (2006).

Table 6-34: Net CO₂ Flux from Soil C Stock Changes in *Land Converted to Cropland* by Land Use Change Category (MMT CO₂ Eq.)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Grassland Converted to Cropland | | | | | | | |
| Mineral Soils | 14.2 | 9.1 | 7.9 | 5.8 | 5.8 | 5.9 | 5.9 |
| Organic Soils | 3.2 | 4.2 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 |
| Forest Converted to Cropland | | | | | | | |
| Biomass | 46.9 | 17.9 | 11.0 | 11.0 | 11.5 | 11.5 | 11.5 |
| Mineral Soils | 0.2 | 0.1 | + | + | + | + | + |
| Organic Soils | 0.1 | + | + | + | + | + | + |
| Other Lands Converted Cropland | | | | | | | |
| Mineral Soils | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Organic Soils | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Settlements Converted Cropland | | | | | | | |
| Mineral Soils | 0.1 | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Organic Soils | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Wetlands Converted Cropland | | | | | | | |
| Mineral Soils | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Organic Soils | 0.6 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Total Biomass Flux | 46.9 | 17.9 | 11.0 | 11.0 | 11.5 | 11.5 | 11.5 |
| Total Mineral Soil Flux | 14.7 | 9.5 | 8.4 | 6.3 | 6.3 | 6.3 | 6.3 |
| Total Organic Soil Flux | 4.0 | 4.8 | 4.3 | 4.3 | 4.3 | 4.3 | 4.3 |
| Total Net Flux | 65.7 | 32.2 | 23.7 | 21.6 | 22.0 | 22.1 | 22.1 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding.

Table 6-35: Net CO₂ Flux from Soil C Stock Changes in *Land Converted to Cropland* (MMT C)

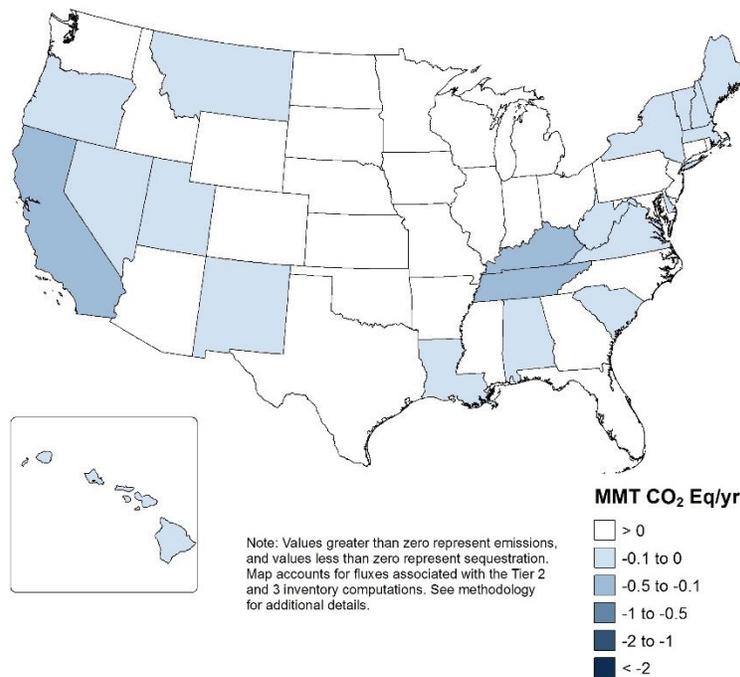
| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|-------------|------------|------------|------------|------------|------------|------------|
| Grassland Converted to Cropland | | | | | | | |
| Mineral Soils | 3.9 | 2.5 | 2.2 | 1.6 | 1.6 | 1.6 | 1.6 |
| Organic Soils | 0.9 | 1.1 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Forest Converted to Cropland | | | | | | | |
| Biomass | 12.8 | 4.9 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 |
| Mineral Soils | 0.1 | + | + | + | + | + | + |
| Organic Soils | + | + | + | + | + | + | + |
| Other Lands Converted Cropland | | | | | | | |
| Mineral Soils | + | + | + | 0.1 | 0.1 | 0.1 | 0.1 |
| Organic Soils | + | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Settlements Converted Cropland | | | | | | | |
| Mineral Soils | + | + | + | + | + | + | + |
| Organic Soils | + | + | + | + | + | + | + |
| Wetlands Converted Cropland | | | | | | | |
| Mineral Soils | + | + | + | + | + | + | + |
| Organic Soils | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Biomass Flux | 12.8 | 4.9 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 |
| Total Mineral Soil Flux | 4.0 | 2.6 | 2.3 | 1.7 | 1.7 | 1.7 | 1.7 |
| Total Organic Soil Flux | 1.1 | 1.3 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| Total Net Flux | 17.9 | 8.8 | 6.5 | 5.9 | 6.0 | 6.0 | 6.0 |

+ Does not exceed 0.05 MMT C

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding.

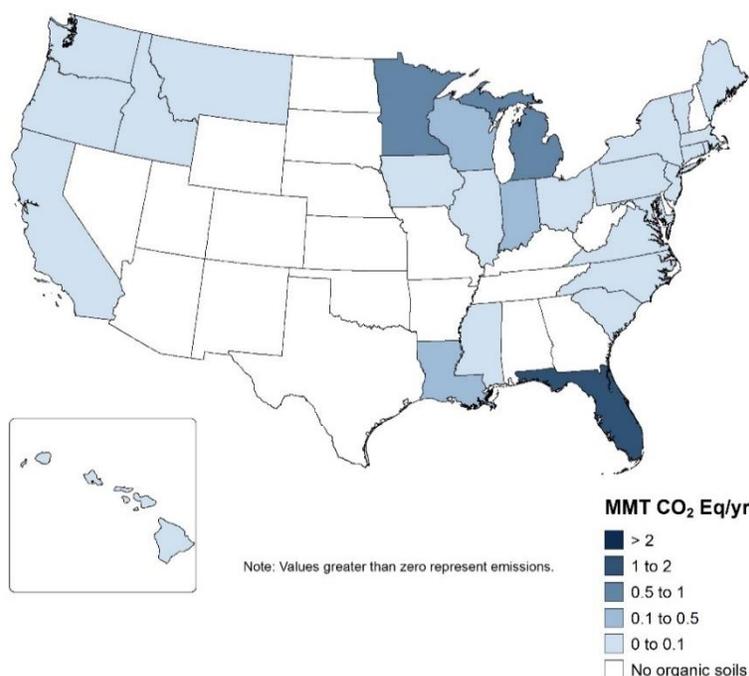
The spatial variability in the 2014 annual C stock changes⁴² for mineral soils is displayed in Figure 6-6 and for organic soils in Figure 6-7. In most states, soil C stocks declined for *Land Converted to Cropland*. This is because conversion of grassland and forestland to cropland led to enhanced decomposition of soil organic matter and a net loss of C from the soil pool. There were some exceptions to this generality, with gains in soil C in regions where the cropland is irrigated or land is converted from a grassland into hay production. These types of conversions generally lead to more inputs of fertilizer and/or water, which enhances production and carbon input to the soil. The regions with the highest rates of emissions from organic soils coincide with the largest concentrations of organic soils used for agricultural production, including the Southeastern Coastal Region (particularly Florida), upper Midwest and Northeast surrounding the Great Lakes, and the Pacific Coast.

Figure 6-6: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2014, Land Converted to Cropland



⁴² A planned improvement is to include biomass C stock changes in the figures; currently the maps only include the spatial patterns associated with soil C stock changes.

Figure 6-7: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2014, Land Converted to Cropland



Methodology

The following section includes a description of the methodology used to estimate changes in C stocks for *Land Converted to Cropland*, including: (1) aboveground biomass from conversion of forest land to cropland; (2) agricultural land-use and management activities on mineral soils; and (3) agricultural land-use and management activities on organic soils. Belowground live biomass and dead organic matter C stock changes are not estimated in the current Inventory for *Land Converted to Cropland*. Further elaboration on the methodologies and data used to estimate stock changes for mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.12.

Biomass Carbon Stock Changes

A Tier 2 method is applied to estimate aboveground biomass C stock changes⁴³ for *Forest Land Converted to Cropland*. For this method, land is stratified by region, forest type, and site productivity and then assigned reference C density estimates for aboveground biomass for the cropland (assumed to be zero since no reference aboveground biomass C density estimates exist) and forest land use. The difference between the stocks is reported as the stock change under the assumption that the change occurred in the year of the conversion. Reference C density estimates for aboveground biomass for the forest land use have been estimated from data in the Forest Inventory and Analysis (FIA) program within the USDA Forest Service (USDA Forest Service 2015). If FIA plots include data on individual trees, aboveground C density estimates are based on Woodall et al. (2011), which is also known as the component ratio method, and is a function of tree volume, species, diameter, and, in some regions, height and site quality. See Annex 3.13 for more information about reference C density estimates for forest land.

⁴³ A planned improvement is to estimate the losses of C from belowground biomass, dead wood and litter with *Forest Converted to Cropland*.

Soil Carbon Stock Changes

Soil C stock changes are estimated for *Land Converted to Cropland* according to land-use histories recorded in the 2010 USDA NRI survey for non-federal lands (USDA-NRCS 2013). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) had been collected for each NRI point on a 5-year cycle beginning in 1982. In 1998, the NRI program began collecting annual data, which are currently available through 2012 (USDA-NRCS 2015). However, this Inventory only uses NRI data through 2010 because newer data were not available in time to incorporate the additional years. NRI survey locations are classified as *Land Converted to Cropland* in a given year between 1990 and 2010 if the land use is cropland but had been another use during the previous 20 years. NRI survey locations are classified according to land-use histories starting in 1979, and consequently the classifications are based on less than 20 years from 1990 to 1998, which may have led to an underestimation of *Land Converted to Cropland* in the early part of the time series to the extent that some areas are converted to cropland prior to 1979. For federal lands, the land use history is derived from land cover changes in the National Land Cover Dataset (Homer et al. 2007; Fry et al. 2011; Homer et al. 2015).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach (Ogle et al. 2010) is applied to estimate C stock changes for mineral soils on the majority of land that is used to produce annual crops in the United States. These crops include alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat. Soil C stock changes on the remaining soils are estimated with the IPCC Tier 2 method (Ogle et al. 2003), including land used to produce some vegetables, tobacco, perennial/horticultural crops and crops rotated with these crops; land on very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from another land use or federal ownership.⁴⁴

Tier 3 Approach. For the Tier 3 method, mineral SOC stocks and stock changes are estimated using the DAYCENT biogeochemical⁴⁵ model (Parton et al. 1998; Del Grosso et al. 2001, 2011). The DAYCENT model utilizes the soil C modeling framework developed in the Century model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), but has been refined to simulate dynamics at a daily time-step. National estimates are obtained by using the model to simulate historical land-use change patterns as recorded in the USDA NRI (USDA-NRCS 2013). Carbon stocks and 95 percent confidence intervals are estimated for each year between 1990 and 2010, but C stock changes from 2010 to 2014 are assumed to be similar to 2010. Future inventories will be updated with new activity data when the data are made available, and the time series will be recalculated (See Planned Improvements section in *Cropland Remaining Cropland*). See the *Cropland Remaining Cropland* section for additional discussion of the Tier 3 methodology for mineral soils.

Tier 2 Approach. For the mineral soils not included in the Tier 3 analysis, SOC stock changes are estimated using a Tier 2 Approach for *Land Converted to Cropland* as described in the Tier 2 Approach for mineral soils in the *Cropland Remaining Cropland* section.

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Cropland* are estimated using the Tier 2 method provided in IPCC (2006), with U.S.-specific C loss rates (Ogle et al. 2003) as described in the *Cropland Remaining Cropland* section for organic soils.

Uncertainty and Time-Series Consistency

The uncertainty analysis for aboveground biomass C losses with *Forest Converted to Cropland* is conducted in the same way as the uncertainty assessment for forest ecosystem C flux in the *Forest Land Remaining Forest Land*

⁴⁴ Federal land is not a land use, but rather an ownership designation that is treated as grassland for purposes of these calculations. The specific land use on federal lands is not identified in the NRI survey (USDA-NRCS 2013).

⁴⁵ Biogeochemical cycles are the flow of chemical elements and compounds between living organisms and the physical environment.

category. Sample and model-based error are combined using simple error propagation methods provided by the IPCC (2006). For additional details see the Uncertainty Analysis in Annex 3.13. Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 methodologies are based on a Monte Carlo approach that is described for *Cropland Remaining Cropland*. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* is estimated using a Monte Carlo approach, which is also described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 6-36 for each subsource (i.e., biomass C stocks, mineral soil C stocks and organic soil C stocks) and the method applied in the Inventory analysis (i.e., Tier 2 and Tier 3). Uncertainty estimates from the Tier 2 and 3 approaches are combined using the simple error propagation methods provided by the IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for total C stocks in *Land Converted to Cropland* ranged from 54 percent below to 52 percent above the 2014 stock change estimate of 22.1 MMT CO₂ Eq.

Table 6-36: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Cropland* (MMT CO₂ Eq. and Percent)

| Source | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a | | | |
|--|---|--|-------------|-----------------|-----------------|
| | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Grassland Converted to Cropland | 9.7 | (2.2) | 20.3 | -123% | 110% |
| Mineral Soil C Stocks: Tier 3 | 4.5 | (5.3) | 14.4 | -218% | 218% |
| Mineral Soil C Stocks: Tier 2 | 1.3 | (0.1) | 2.2 | -108% | 69% |
| Organic Soil C Stocks: Tier 2 | 3.8 | 10.2 | + | -168% | 99% |
| Forests Converted to Cropland | 11.5 | 9.2 | 13.9 | -21% | 21% |
| Biomass C Stocks | 11.5 | 10.0 | 12.9 | -13% | 13% |
| Mineral Soil C Stocks: Tier 2 | + | + | 0.1 | -111% | 71% |
| Organic Soil C Stocks: Tier 2 | + | 0.1 | 0.0 | -154% | 100% |
| Other Lands Converted to Cropland | 0.2 | (+) | 0.3 | -112% | 83% |
| Mineral Soil C Stocks: Tier 2 | 0.2 | (+) | 0.3 | -112% | 72% |
| Organic Soil C Stocks: Tier 2 | 0.0 | 0.0 | 0.1 | 0% | 0% |
| Settlements Converted to Cropland | 0.1 | + | 0.5 | -71% | 255% |
| Mineral Soil C Stocks: Tier 2 | 0.1 | (+) | 0.1 | -112% | 72% |
| Organic Soil C Stocks: Tier 2 | 0.1 | 0.1 | 0.4 | -91% | 454% |
| Wetlands Converted to Croplands | 0.6 | 0.3 | 4.5 | -53% | 694% |
| Mineral Soil C Stocks: Tier 2 | 0.1 | + | 0.2 | -75% | 50% |
| Organic Soil C Stocks: Tier 2 | 0.4 | 0.7 | 4.3 | -65% | 908% |
| Total: Land Converted to Cropland | 22.1 | 10.1 | 33.5 | -54% | 52% |
| Biomass C Stocks | 11.5 | 10.0 | 12.9 | -13% | 13% |
| Mineral Soil C Stocks: Tier 3 | 4.5 | (5.3) | 14.4 | -218% | 218% |
| Mineral Soil C Stocks: Tier 2 | 1.7 | 0.3 | 2.7 | -83% | 53% |
| Organic Soil C Stocks: Tier 2 | 4.3 | (2.1) | 9.8 | -148% | 126% |

+ Absolute value does not exceed 0.05 MMT CO₂ Eq.

^a Range of C stock change estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values or net sequestration.

Uncertainty is also associated with lack of reporting of agricultural biomass and litter C stock changes. Biomass C stock changes are likely minor in perennial crops, such as orchards and nut plantations, given the small amount of change in land used to produce these commodities in the United States. In contrast, agroforestry practices, such as shelterbelts, riparian forests and intercropping with trees, may have led to significant changes in biomass C stocks, at least in some regions of the United States. However, there are currently no datasets to evaluate the trends. Changes in dead organic matter C stocks are also assumed to be negligible in croplands over annual time frames, although there are certainly significant changes at sub-annual time scales across seasons. However, this trend may change in the future, particularly if crop residue becomes a viable feedstock for bioenergy production.

Methodological recalculations are applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See the QA/QC and Verification section in *Cropland Remaining Cropland*.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements: 1) incorporation of updated NRI data for 1990 through 2010; 2) inclusion of federal croplands; 3) improving the simulation of hydric soils in DAYCENT, and 4) incorporating the aboveground biomass C stock losses with *Forest Land Converted to Cropland*. As a result of these improvements to the Inventory, *Land Converted to Cropland* have a larger reported loss of C, estimated at 21.0 MMT CO₂ Eq. over the time series. This represents a 100 percent increase in the losses of carbon with *Land Converted to Cropland* compared to the previous Inventory, and is largely driven by reporting aboveground biomass C loss from *Forest Converted to Croplands* in this category instead of *Forest Land Remaining Forest Land* where it was included in the previous Inventory submissions.

Planned Improvements

Soil C stock changes with land use conversion from forest land to cropland are undergoing further evaluation to ensure consistency in the time series. Different methods are used to estimate soil C stock changes in forest land and croplands, and while the areas have been reconciled between these land uses, there has been limited evaluation of the consistency in C stock changes with conversion from forest land to cropland. This planned improvement may not be fully implemented for another year, depending on resource availability.

The impact of *Forest Land Converted to Cropland* on belowground biomass and dead organic matter pools are not estimated in the current Inventory, and so another planned improvement is to estimate changes in C stocks for these pools in the next Inventory. In addition, biomass C stock changes will be estimated for *Grassland Converted to Cropland*, as well as other land use conversions to cropland to the extent that data are available. Additional planned improvements are discussed in the *Cropland Remaining Cropland* section.

6.6 Grassland Remaining Grassland (IPCC Source Category 4C1)

Grassland Remaining Grassland includes all grassland in an Inventory year that had been classified as grassland for the previous 20 years (USDA-NRCS 2013). Grassland includes pasture and rangeland that are primarily, but not exclusively used for livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are typically seeded grassland (possibly following tree removal) that may also have additional management, such as irrigation or interseeding of legumes. This Inventory includes all privately-owned and federal grasslands in the conterminous United States and Hawaii, but does not include approximately 50 million hectares of *Grassland Remaining Grassland* in Alaska. This leads to a discrepancy with the total amount of managed area in *Grassland Remaining Grassland* (see Section 6.1 Representation of the U.S. Land Base) and the grassland area included in the Inventory analysis (IPCC Source Category 4C1—Section 6.6).

Background on agricultural carbon (C) stock changes is provided in Section 6.4, *Cropland Remaining Cropland*, and will only be summarized here. Soils are the largest pool of C in agricultural land, and also have the greatest potential for longer-term storage or release of C. Biomass and dead organic matter C pools are relatively small and ephemeral compared to the soil C pool, with the exception of C stored in tree and shrub biomass that occurs in grasslands. The *2006 IPCC Guidelines* (IPCC 2006) recommend reporting changes in soil organic C (SOC) stocks

due to (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.⁴⁶

In *Grassland Remaining Grassland*, there has been considerable variation in soil C stocks between 1990 and 2014. These changes are driven by variability in weather patterns and associated interaction with land management activity. Moreover, changes remain small on a per hectare rate across the time series even in the years with a larger total change in stocks. Land use and management generally increased soil C in mineral soils for *Grassland Remaining Grassland* between 1990 and 2010, after which the trend is reversed to a small decline in soil C. In contrast, organic soils lose a relatively constant amount of C annually from 1990 through 2014. In 2014, soil C stocks decreased by 3.8 MMT CO₂ Eq. (1.0 MMT C), with an uptake of 0.6 MMT CO₂ Eq. (0.2 MMT C) in mineral soils but a loss of 4.3 MMT CO₂ Eq. (1.2 MMT C) from organic soils (Table 6-37 and Table 6-38). The overall trend represents a 129 percent increase in the flux relative to the flux in the initial reporting year of 1990.

Table 6-37: Net CO₂ Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (MMT CO₂ Eq.)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|---------------|--------------|--------------|------------|------------|------------|------------|
| Mineral Soils | (19.0) | (7.7) | (11.7) | (1.2) | (0.8) | (0.6) | (0.6) |
| Organic Soils | 6.1 | 4.5 | 4.4 | 4.4 | 4.3 | 4.3 | 4.3 |
| Total Net Flux | (12.9) | (3.3) | (7.3) | 3.1 | 3.6 | 3.8 | 3.8 |

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-38: Net CO₂ Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (MMT C)

| Soil Type | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|------------|------------|------------|------------|
| Mineral Soils | (5.2) | (2.1) | (3.2) | (0.3) | (0.2) | (0.2) | (0.2) |
| Organic Soils | 1.7 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| Total Net Flux | (3.5) | (0.9) | (2.0) | 0.8 | 1.0 | 1.0 | 1.0 |

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

The spatial variability in the 2014 annual CO₂ flux associate with mineral soils is displayed in Figure 6-8 and organic soils in Figure 6-9. Although relatively small on a per-hectare basis, grassland soils gained C in several regions during 2014, including most of the Eastern United States and Pacific Coastal Region. For organic soils, the regions with the highest rates of emissions coincide with the largest concentrations of organic soils used for managed grassland, including the Southeastern Coastal Region (particularly Florida), upper Midwest and Northeast, and the Pacific Coast.

⁴⁶ CO₂ emissions associated with liming and urea fertilization are also estimated but included in Section 6.4 *Cropland Remaining Cropland*.

Figure 6-8: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2014, *Grassland Remaining Grassland*

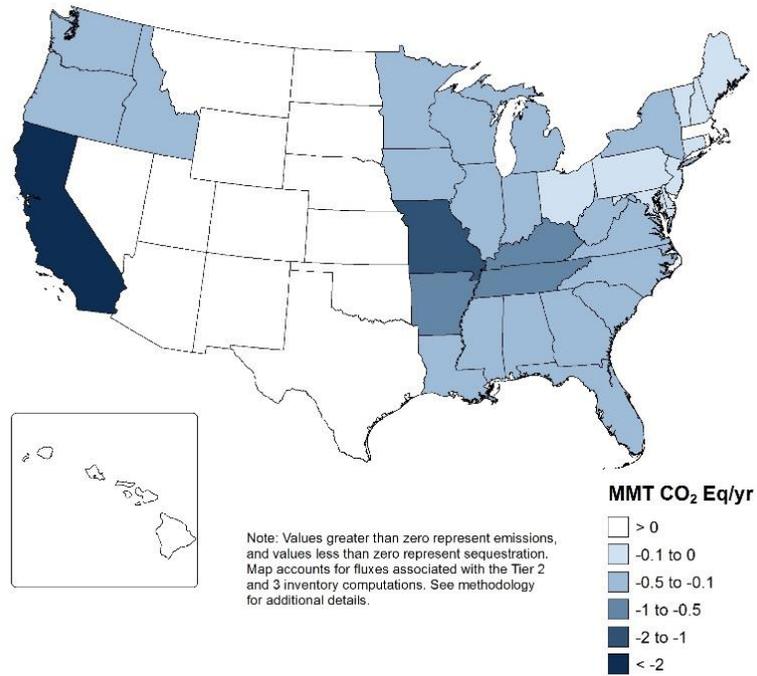
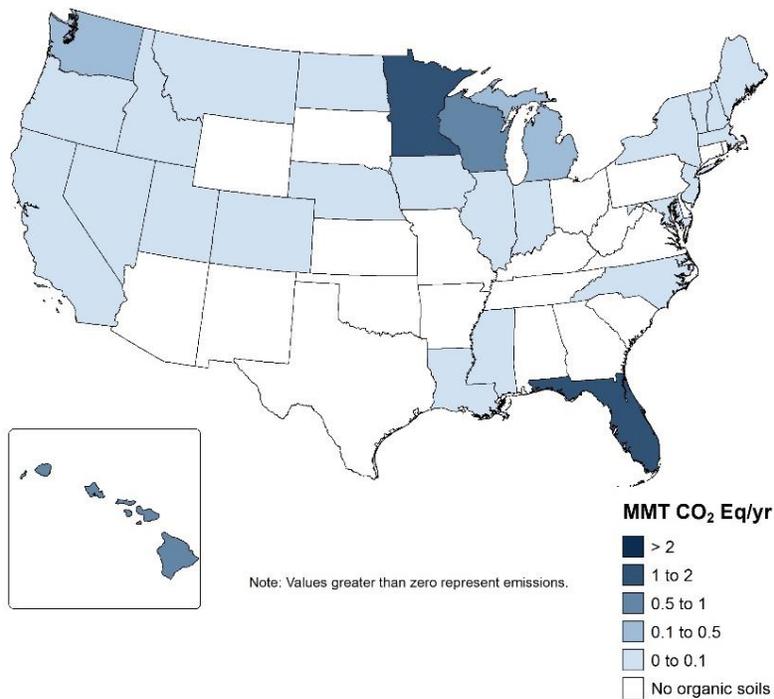


Figure 6-9: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2014, *Grassland Remaining Grassland*



Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks for *Grassland Remaining Grassland*, including: (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.12.

Soil C stock changes are estimated for *Grassland Remaining Grassland* on non-federal lands according to land use histories recorded in the 2010 USDA NRI survey (USDA-NRCS 2013). Land-use and some management information (e.g., grass type, soil attributes, and irrigation) were originally collected for each NRI survey location on a 5-year cycle beginning in 1982. In 1998, the NRI program began collecting annual data, and the annual data are currently available through 2012 (USDA-NRCS 2015). However, this Inventory only uses NRI data through 2010 because newer data were not available in time to incorporate the additional years. NRI survey locations are classified as *Grassland Remaining Grassland* in a given year between 1990 and 2010 if the land use had been grassland for 20 years. NRI survey locations are classified according to land-use histories starting in 1979, and consequently the classifications are based on less than 20 years from 1990 to 1998. This may have led to an overestimation of *Grassland Remaining Grassland* in the early part of the time series to the extent that some areas are converted to grassland prior to 1979. For federal lands, the land use history is derived from land cover changes in the National Land Cover Dataset (Homer et al. 2007; Fry et al. 2011; Homer et al. 2015).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach (Ogle et al. 2010) is applied to estimate C stock changes for most mineral soils in *Grassland Remaining Grassland*. The C stock changes for the remaining soils are estimated with an IPCC Tier 2 method (Ogle et al. 2003), including gravelly, cobbly, or shaley soils (greater than 35 percent by volume) and additional stock changes associated with sewage sludge amendments.

Tier 3 Approach

Mineral SOC stocks and stock changes for *Grassland Remaining Grassland* are estimated using the DAYCENT biogeochemical⁴⁷ model (Parton et al. 1998; Del Grosso et al. 2001, 2011), as described in *Cropland Remaining Cropland*. The DAYCENT model utilizes the soil C modeling framework developed in the Century model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), but has been refined to simulate dynamics at a daily time-step. Historical land-use patterns and irrigation histories are simulated with DAYCENT based on the 2010 USDA NRI survey (USDA-NRCS 2013). Frequency and rates of manure application to grassland during 1997 are estimated from data compiled by the USDA Natural Resources Conservation Service (NRCS) (Edmonds, et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 are used to adjust the area amended with manure (see *Cropland Remaining Cropland* section for further details). Greater availability of managed manure nitrogen (N) relative to 1997 is, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 is assumed to reduce the amended area.

The amount of manure produced by each livestock type is calculated for managed and unmanaged waste management systems based on methods described in Section 5.2 - Manure Management and Annex 3.11. Manure N deposition from grazing animals (i.e., PRP manure) is an input to the DAYCENT model (see Annex 3.11), and the remainder is deposited on federal lands (i.e., the amount that is not included in DAYCENT simulations is assumed to be applied on federal grasslands). Carbon stocks and 95 percent confidence intervals are estimated for each year between 1990 and 2010, but C stock changes from 2011 to 2014 are assumed to be similar to 2010 because activity data are not yet available for these years. Future inventories will be updated with new activity data when the data are made available, and the time series will be recalculated. See the *Cropland Remaining Cropland* section for additional discussion of the Tier 3 methodology for mineral soils.

⁴⁷ Biogeochemical cycles are the flow of chemical elements and compounds between living organisms and the physical environment.

Tier 2 Approach

The Tier 2 approach is based on the same methods described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils, with the exception of the land use and management data that are used in the Inventory for federal grasslands. The NRI (USDA-NRCS 2013) provides land use and management histories for all non-federal lands, and is the basis for the Tier 2 analysis for these areas. However, NRI does not provide land use information on federal lands. These data are based on the National Land Cover Database (NLCD) (Fry et al. 2011; Homer et al. 2007; Homer et al. 2015). In addition, the Bureau of Land Management (BLM) manages some of the federal grasslands, and has compiled information on grassland condition through the BLM Rangeland Inventory (BLM 2014). To estimate soil C stock changes from federal grasslands, rangeland conditions in the BLM data are aligned with IPCC grassland management categories of nominal, moderately degraded, and severely degraded in order to apply the appropriate emission factors. Further elaboration on the Tier 2 methodology and data used to estimate C stock changes from mineral soils are described in Annex 3.12.

Additional Mineral C Stock Change Calculations

A Tier 2 method is used to adjust annual C stock change estimates for mineral soils between 1990 and 2014 to account for additional C stock changes associated with sewage sludge amendments. Estimates of the amounts of sewage sludge N applied to agricultural land are derived from national data on sewage sludge generation, disposition, and N content. Although sewage sludge can be added to land managed for other land uses, it is assumed that agricultural amendments only occur in *Grassland Remaining Grassland*. Cropland is not likely to be amended with sewage sludge due to the high metal content and other pollutants in human waste. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, are obtained from EPA (1999) and estimates for 2004 are obtained from an independent national biosolids survey (NEBRA 2007). These values are linearly interpolated to estimate values for the intervening years, and linearly extrapolated to estimate values for years since 2004. N application rates from Kellogg et al. (2000) are used to determine the amount of area receiving sludge amendments. The soil C storage rate is estimated at 0.38 metric tons C per hectare per year for sewage sludge amendments to grassland as described above. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.12 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Grassland Remaining Grassland* are estimated using the Tier 2 method provided in IPCC (2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. For more information, see the *Cropland Remaining Cropland* section for organic soils.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 methodologies are based on a Monte Carlo approach that is described in the *Cropland Remaining Cropland* section. The uncertainty for annual C emission estimates from drained organic soils in *Grassland Remaining Grassland* is estimated using a Monte Carlo approach, which is also described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 6-39 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) and the method applied in the inventory analysis (i.e., Tier 2 and Tier 3). Uncertainty estimates from the Tier 2 and 3 approaches are combined using the simple error propagation methods provided by the IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Grassland Remaining Grassland* ranges from -1,006 percent below to 1,013 percent above the 2014 stock change estimate of 3.8 MMT CO₂ Eq. The large relative uncertainty is due to the almost zero level of change in soil C for 2014 even though the absolute amount of uncertainty is comparable to other land-use categories in this Inventory.

Table 6-39: Approach 2 Quantitative Uncertainty Estimates for C Stock Changes Occurring Within *Grassland Remaining Grassland* (MMT CO₂ Eq. and Percent)

| Source | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a | | | |
|---|---|--|-------------|-----------------|-----------------|
| | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Mineral Soil C Stocks Grassland Remaining Grassland, Tier 3 Methodology | 1.1 | (35.8) | 38.0 | -3,401% | +3,401% |
| Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology | (0.3) | (8.8) | 9.3 | -3,307% | +3,680% |
| Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology (Change in Soil C due to Sewage Sludge Amendments) | (1.4) | (2.1) | (0.7) | -50% | +50% |
| Organic Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology | 4.3 | 2.2 | 7.2 | -49% | +66% |
| Combined Uncertainty for Flux Associated with Agricultural Soil Carbon Stock Change in Grassland Remaining Grassland | 3.8 | (34.2) | 42.0 | -1,006% | +1,013% |

^a Range of C stock change estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Uncertainty is also associated with a lack of reporting on biomass and litter C stock changes and non-CO₂ greenhouse gas emissions from grassland fires. Biomass C stock changes may be significant for managed grasslands with woody encroachment despite not having attained enough tree cover to be considered forest lands. This Inventory does not currently include the non-CO₂ greenhouse gas emissions that occur with biomass burning. Grassland burning is not as common in the United States as in other regions of the world, but fires do occur through both natural ignition sources and prescribed burning. Changes in dead organic matter C stocks are assumed to be negligible in grasslands over annual time frames, although there are certainly significant changes at sub-annual time scales across seasons.

Methodological recalculations are applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See the QA/QC and Verification section in *Cropland Remaining Cropland*.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements, including 1) incorporation of updated NRI data for 1990 through 2010; 2) inclusion of federal grasslands in the Tier 2 analysis; and 3) improving the simulation of hydric soils in DAYCENT. As a result of these improvements to the Inventory, SOC stocks increased on average across the time series, equivalent to an uptake of 4.9 MMT CO₂ eq., which is a 20 percent increase in the reported soil C stock changes compared to the previous Inventory.

Planned Improvements

Grasslands in Alaska are not currently included in the Inventory. This is a significant planned improvement and estimates are expected to be available for the 1990 through 2015 Inventory. Another key planned improvement is to estimate biomass C stock changes for grasslands and non-CO₂ greenhouse gas emissions from burning of grasslands. For information about other improvements, see the Planned Improvements section in *Cropland Remaining Cropland*.

6.7 Land Converted to Grassland (IPCC Source Category 4C2)

Land Converted to Grassland includes all grassland in an Inventory year that had been in another land use(s) during the previous 20 years⁴⁸ (USDA-NRCS 2013). For example, cropland or forest land converted to grassland during the past 20 years would be reported in this category. Recently-converted lands are retained in this category for 20 years as recommended by IPCC (2006). Grassland includes pasture and rangeland that are used primarily but not exclusively for livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are typically seeded grassland (possibly following tree removal) that may also have additional management, such as irrigation or interseeding of legumes. This Inventory includes all grasslands in the conterminous United States and Hawaii, but does not include *Land Converted to Grassland* in Alaska. Consequently there is a discrepancy between the total amount of managed area for *Land Converted to Grassland* (see Section 6.1 Representation of the U.S. Land Base) and the grassland area included in the inventory analysis (IPCC Source Category 4C2—Section 6.7).

Land-use change can lead to large losses of C to the atmosphere, particularly conversions from forest land (Houghton et al. 1983). Moreover, conversion of forest to another land use (i.e., deforestation) is one of the largest anthropogenic sources of emissions to the atmosphere globally (Schimel 1995), although this source may be declining according to a recent assessment (Tubiello et al. 2015).

IPCC (2006) recommend reporting changes in biomass, dead organic matter, and soil organic C (SOC) stocks due to land use change.⁴⁹ All soil C stock changes are estimated and reported for *Land Converted to Grassland*, but there is limited reporting of other pools in this Inventory. Loss of aboveground biomass C from *Forest Converted to Grassland* is reported, but loss of C from belowground biomass, dead wood and litter pools with forest conversion are not included in this Inventory.⁵⁰ In addition, biomass C stock changes are not estimated for other land use conversions (other than forest land) to grassland.⁵¹

Land use and management of mineral soils in *Land Converted to Grassland* led to an increase in soil C stocks between 1990 and 2014 (see Table 6-40 and Table 6-41). The average soil C stock change for mineral soils between 1990 and 2014 sequestered 10.6 MMT CO₂ Eq. from the atmosphere (2.9 MMT C). In contrast, over the same period, drainage of organic soils for grassland management led to CO₂ emissions to the atmosphere of 1.5 MMT CO₂ Eq. (0.4 MMT C). In addition, aboveground woody biomass C losses from *Forest Land Converted to Grasslands* led to CO₂ emissions to the atmosphere of 49.5 MMT CO₂ Eq. (13.5 MMT C) in 2014. The total net C stock change in 2014 for *Land Converted to Grassland* is estimated as a loss of 40.4 MMT CO₂ Eq. (11.0 MMT C), which is a 3 percent increase in emissions compared to the emissions in the initial reporting year of 1990.

Table 6-40: Net CO₂ Flux from Soil and Biomass C Stock Changes for *Land Converted to Grassland* (MMT CO₂ Eq.)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|-------|-------|-------|-------|-------|-------|-------|
| Cropland Converted to Grassland | | | | | | | |
| Mineral Soils | (6.9) | (9.7) | (9.1) | (8.6) | (8.6) | (8.6) | (8.6) |

⁴⁸ NRI survey locations are classified according to land-use histories starting in 1979, and consequently the classifications are based on less than 20 years from 1990 to 2001. This may have led to an underestimation of *Land Converted to Grassland* in the early part of the time series to the extent that some areas are converted to grassland prior to 1979.

⁴⁹ CO₂ emissions associated with liming and urea fertilization are also estimated but included in Section 6.4 *Cropland Remaining Cropland*.

⁵⁰ A planned improvement is to estimate the losses of carbon from belowground biomass, dead wood and litter with *Forest Converted to Grassland*.

⁵¹ Changes in biomass C stocks are not currently reported for other conversions to grassland (other than forest land), but this is a planned improvement for a future inventory. Note: changes in dead organic matter are assumed to negligible for other land use conversions (i.e., other than forest land) to grassland based on the Tier 1 method in IPCC (2006).

| | | | | | | | |
|--|--------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Organic Soils | 0.5 | 1.0 | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 |
| Forest Converted to Grassland | | | | | | | |
| Biomass | 47.0 | 54.3 | 49.0 | 49.0 | 49.5 | 49.5 | 49.5 |
| Mineral Soils | (0.5) | (1.0) | (0.8) | (0.8) | (0.8) | (0.8) | (0.8) |
| Organic Soils | + | + | + | + | + | + | + |
| Other Lands Converted Grassland | | | | | | | |
| Mineral Soils | (0.6) | (1.1) | (0.8) | (0.8) | (0.8) | (0.8) | (0.8) |
| Organic Soils | + | 0.0 | + | + | + | + | + |
| Settlements Converted Grassland | | | | | | | |
| Mineral Soils | (0.1) | (0.2) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Organic Soils | + | + | + | + | + | + | + |
| Wetlands Converted Grassland | | | | | | | |
| Mineral Soils | (0.5) | (0.6) | (0.2) | (0.2) | (0.2) | (0.2) | (0.2) |
| Organic Soils | 0.1 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Total Biomass Flux | 47.0 | 54.3 | 49.0 | 49.0 | 49.5 | 49.5 | 49.5 |
| Total Mineral Soil Flux | (8.6) | (12.5) | (11.2) | (10.6) | (10.6) | (10.6) | (10.6) |
| Total Organic Soil Flux | 0.7 | 1.2 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Total Net Flux | 39.1 | 43.1 | 39.3 | 39.9 | 40.4 | 40.4 | 40.4 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-41: Net CO₂ Flux from Soil and Biomass C Stock Changes for *Land Converted to Grassland* (MMT C)

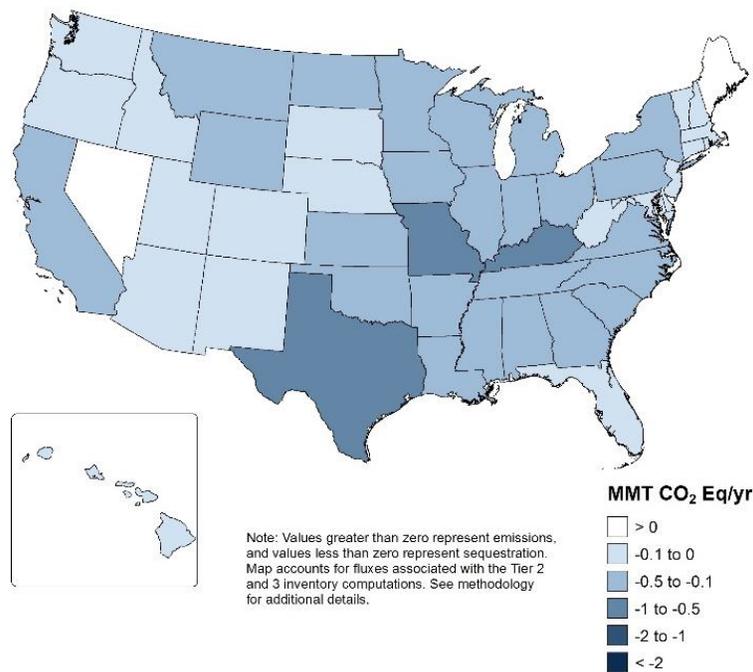
| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Cropland Converted to Grassland | | | | | | | |
| Mineral Soils | (1.9) | (2.6) | (2.5) | (2.3) | (2.3) | (2.3) | (2.3) |
| Organic Soils | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Forest Converted to Grassland | | | | | | | |
| Biomass | 12.8 | 14.8 | 13.4 | 13.4 | 13.5 | 13.5 | 13.5 |
| Mineral Soils | (0.1) | (0.3) | (0.2) | (0.2) | (0.2) | (0.2) | (0.2) |
| Organic Soils | + | + | + | + | + | + | + |
| Other Lands Converted Grassland | | | | | | | |
| Mineral Soils | (0.2) | (0.3) | (0.2) | (0.2) | (0.2) | (0.2) | (0.2) |
| Organic Soils | + | 0.0 | + | + | + | + | + |
| Settlements Converted Grassland | | | | | | | |
| Mineral Soils | (+) | (+) | (+) | (+) | (+) | (+) | (+) |
| Organic Soils | + | + | + | + | + | + | + |
| Wetlands Converted Grassland | | | | | | | |
| Mineral Soils | (0.1) | (0.2) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Organic Soils | + | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Biomass Flux | 12.8 | 14.8 | 13.4 | 13.4 | 13.5 | 13.5 | 13.5 |
| Total Mineral Soil Flux | (2.3) | (3.4) | (3.0) | (2.9) | (2.9) | (2.9) | (2.9) |
| Total Organic Soil Flux | 0.2 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Total Net Flux | 10.7 | 11.8 | 10.7 | 10.9 | 11.0 | 11.0 | 11.0 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Notes: Estimates after 2010 are based on NRI data from 2010 and therefore may not fully reflect changes occurring in the latter part of the time series. Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

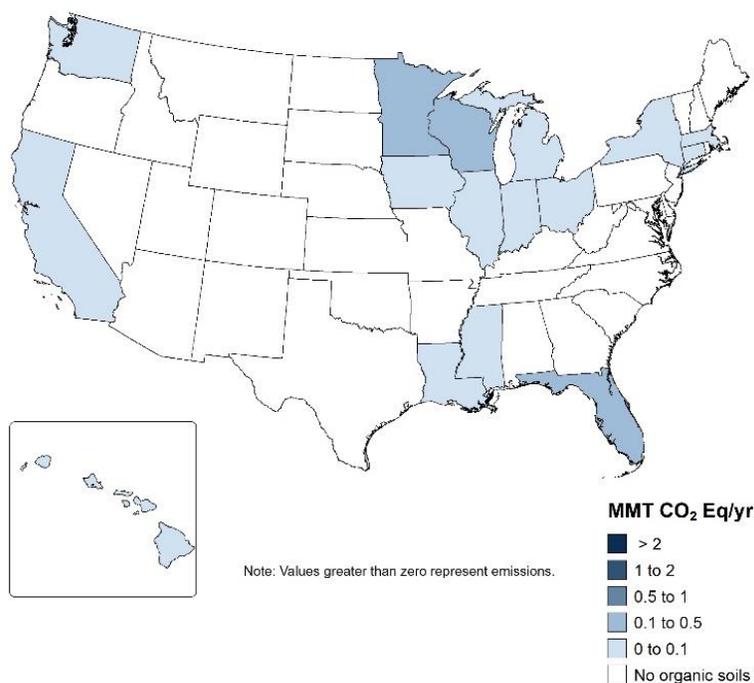
The spatial variability in the 2014 annual flux in CO₂ from mineral soils⁵² is displayed in Figure 6-10 and from organic soils in Figure 6-11. Soil C stocks increased in most states for *Land Converted to Grassland*, which is largely driven by conversion of annual cropland into continuous pasture. The largest gains are in Texas, Missouri and Kentucky. For organic soils, the regions with the highest rates of emissions coincide with the largest concentrations of organic soils used for managed grasslands, including Southeastern Coastal Region (particularly Florida), upper Midwest and Northeast surrounding the Great Lakes, and the Pacific Coast.

Figure 6-10: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2014, *Land Converted to Grassland*



⁵² A planned improvement is to include biomass C stock changes in the figures; currently the maps only include the spatial patterns associated with soil C stock changes.

Figure 6-11: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2014, Land Converted to Grassland



Methodology

The following section includes a description of the methodology used to estimate changes in biomass and soil C stocks for *Land Converted to Grassland*, including: (1) loss of aboveground biomass C with conversion of forest to grassland; (2) agricultural land-use and management activities on mineral soils; and (3) agricultural land-use and management activities on organic soils. Belowground live biomass and dead organic matter C stock changes associated with conversion of forest land to grassland are not estimated in the current Inventory for *Land Converted to Grassland*.

Biomass Carbon Stock Changes

A Tier 2 method is applied to estimate aboveground biomass C stock changes⁵³ for *Forest land Converted to Grassland*. For this method, land is stratified by region, forest type, and site productivity and then assigned reference C density estimates for aboveground biomass for the grassland (assumed to be zero since no reference aboveground biomass C density estimates exist) and forest land use. The difference between the stocks is reported as the stock change under the assumption that the change occurred in the year of the conversion. Reference C density estimates for aboveground biomass for the forest land use have been estimated from data in the Forest Inventory and Analysis (FIA) program within the USDA Forest Service (USDA Forest Service 2015). If FIA plots include data on individual trees, aboveground C density estimates are based on Woodall et al. (2011), which is also known as the component ratio method, and is a function of tree volume, species, diameter, and, in some regions, height and site quality. See Annex 3.13 for more information about reference C density estimates for forest land.

⁵³ A planned improvement is to estimate the losses of C from belowground biomass, dead wood and litter with *Forest Converted to Grassland*.

Soil Carbon Stock Changes

Soil C stock changes are estimated for *Land Converted to Grassland* according to land-use histories recorded in the 2010 USDA NRI survey for non-federal lands (USDA-NRCS 2013). Land use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI survey locations on a 5-year cycle beginning in 1982. In 1998, the NRI Program began collecting annual data, and the annual data are currently available through 2012 (USDA-NRCS 2015). However, this Inventory only uses NRI data through 2010 because newer data were not available in time to incorporate the additional years. NRI survey locations are classified as *Land Converted to Grassland* in a given year between 1990 and 2010 if the land use is grassland but had been classified as another use during the previous 20 years. NRI survey locations are classified according to land-use histories starting in 1979, and consequently the classifications are based on less than 20 years from 1990 to 1998. This may have led to an underestimation of *Land Converted to Grassland* in the early part of the time series to the extent that some areas are converted to grassland prior to 1979. For federal lands, the land use history is derived from land cover changes in the National Land Cover Dataset (Homer et al. 2007; Fry et al. 2011; Homer et al. 2015).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach (Ogle et al. 2010) is applied to estimate C stock changes for *Land Converted to Grassland* on most mineral soils. C stock changes on the remaining soils are estimated with an IPCC Tier 2 approach (Ogle et al. 2003), including prior cropland used to produce vegetables, tobacco, and perennial/horticultural crops; land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted to grassland from another land use other than cropland.

Tier 3 Approach. Mineral SOC stocks and stock changes are estimated using the DAYCENT biogeochemical⁵⁴ model (Parton et al. 1998; Del Grosso et al. 2001, 2011). The DAYCENT model utilizes the soil C modeling framework developed in the Century model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), but has been refined to simulate dynamics at a daily time-step. Historical land-use patterns and irrigation histories are simulated with DAYCENT based on the 2010 USDA NRI survey (USDA-NRCS 2013). C stocks and 95 percent confidence intervals are estimated for each year between 1990 and 2010, but C stock changes from 2010 to 2014 are assumed to be similar to 2010. Future inventories will be updated with new activity data when the data are made available, and the time series will be recalculated (See Planned Improvements section in *Cropland Remaining Cropland*). See the *Cropland Remaining Cropland* section and Annex 3.12 for additional discussion of the Tier 3 methodology for mineral soils.

Tier 2 Approach. For the mineral soils not included in the Tier 3 analysis, SOC stock changes are estimated using a Tier 2 Approach for *Land Converted to Grassland* as described in the Tier 2 Approach for mineral soils in the *Grassland Remaining Grassland* section.

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Grassland* are estimated using the Tier 2 method provided in IPCC (2006), with U.S.-specific C loss rates (Ogle et al. 2003) as described in the *Cropland Remaining Cropland* section for organic soils.

Uncertainty and Time-Series Consistency

The uncertainty analysis for aboveground biomass C losses with *Forest Converted to Grassland* is conducted in the same way as the uncertainty assessment for forest ecosystem C flux in the *Forest Land Remaining Forest Land* category. Sample and model-based error are combined using simple error propagation methods provided by the IPCC (2006). For additional details see the Uncertainty Analysis in Annex 3.13. Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 methodologies are based on a Monte Carlo approach that is described in the *Cropland Remaining Cropland* section. The uncertainty for annual C emission estimates from

⁵⁴ Biogeochemical cycles are the flow of chemical elements and compounds between living organisms and the physical environment.

drained organic soils in *Land Converted to Grassland* is estimated using a Monte Carlo approach, which is also described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 6-42 for each subsource (i.e., biomass C stocks, mineral soil C stocks and organic soil C stocks) and the method applied in the inventory analysis (i.e., Tier 2 and Tier 3). Uncertainty estimates from the Tier 2 and 3 approaches are combined using the simple error propagation methods provided by the IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for total C stocks in *Land Converted to Grassland* ranges from 26 percent below to 27 percent above the 2014 stock change estimate of 40.4 MMT CO₂ Eq.

Table 6-42: Approach 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Grassland* (MMT CO₂ Eq. and Percent)

| Source | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a (%) | | | |
|---|---|---|--------------|--------------|--------------|
| | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Cropland Converted to Grassland | (7.4) | (16.3) | 1.4 | -119% | +119% |
| Mineral Soil C Stocks: Tier 3 | (7.2) | (15.9) | 1.6 | -122% | +122% |
| Mineral Soil C Stocks: Tier 2 | (1.4) | (2.2) | (0.8) | -55% | +47% |
| Organic Soil C Stocks: Tier 2 | 1.2 | 0.4 | 2.3 | -63% | +96% |
| Forests Converted to Grassland | 48.7 | 42.8 | 54.9 | -12% | 13% |
| Biomass C Stocks | 49.5 | 43.7 | 55.6 | -12% | 12% |
| Mineral Soil C Stocks: Tier 2 | (0.8) | (1.8) | 0.1 | -120% | 112% |
| Organic Soil C Stocks: Tier 2 | + | + | + | -100% | 300% |
| Other Lands Converted to Grassland | (0.8) | (1.3) | (0.4) | -55% | +47% |
| Mineral Soil C Stocks: Tier 2 | (0.8) | (1.3) | (0.4) | -54% | +46% |
| Organic Soil C Stocks: Tier 2 | + | 0.0 | + | -100% | +179% |
| Settlements Converted to Grassland | (0.1) | (0.2) | (+) | -63% | +56% |
| Mineral Soil C Stocks: Tier 2 | (0.1) | (0.2) | (0.1) | -55% | +47% |
| Organic Soil C Stocks: Tier 2 | + | + | + | -79% | +125% |
| Wetlands Converted to Grasslands | 0.1 | (0.1) | 0.3 | -314% | +382% |
| Mineral Soil C Stocks: Tier 2 | (0.2) | (0.4) | (0.1) | -52% | +44% |
| Organic Soil C Stocks: Tier 2 | 0.3 | 0.1 | 0.5 | -51% | +71% |
| Total: Land Converted to Grassland | 40.4 | 29.8 | 51.2 | -26% | 27% |
| Biomass C Stocks | 49.5 | 43.7 | 55.6 | -12% | 12% |
| Mineral Soil C Stocks: Tier 3 | (7.2) | (15.9) | 1.6 | -122% | 122% |
| Mineral Soil C Stocks: Tier 2 | (3.4) | (4.7) | (2.2) | -39% | 35% |
| Organic Soil C Stocks: Tier 2 | 1.5 | 0.7 | 2.6 | -50% | 77% |

+ Absolute value does not exceed 0.05 MMT CO₂ Eq.

^a Range of C stock change estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Uncertainty is also associated with lack of reporting non-CO₂ greenhouse gas emissions that occur with biomass burning. Grassland burning is not as common in the United States as in other regions of the world, but fires do occur through both natural ignition sources and prescribed burning. Changes in dead organic matter C stocks are assumed to be negligible in grasslands over annual time frames, although there are likely significant changes at sub-annual time scales across seasons.

Methodological recalculations are applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the above Methodology section.

QA/QC and Verification

See the QA/QC and Verification section in *Cropland Remaining Cropland*.

Recalculations Discussion

Methodological recalculations in the current Inventory are associated with the following improvements, including: 1) incorporation of updated NRI data for 1990 through 2010; 2) inclusion of federal grasslands in the Tier 2 analysis; 3) improving the simulation of hydric soils in DAYCENT; and 4) incorporating the aboveground biomass C stock losses with *Forest Land Converted to Grassland*. As a result of these improvements to the Inventory, changes in stocks declined by an average of 49.0 MMT CO₂ Eq. annually over the time series. This represents a 565 percent increase in the losses of carbon with *Land Converted to Grassland* compared to the previous Inventory, and is largely driven by the inclusion of aboveground biomass C loss from *Forest Land Converted to Grasslands* in this category instead of *Forest Land Remaining Forest Land* where it was included in the previous Inventory submissions.

Planned Improvements

Soil C stock changes with land use conversion from forest land to grassland are undergoing further evaluation to ensure consistency in the time series. Different methods are used to estimate soil C stock changes in forest land and grasslands, and while the areas have been reconciled between these land uses, there has been limited evaluation of the consistency in C stock changes with conversion from forest land to grassland. This planned improvement may not be fully implemented for another year, depending on resource availability.

The impact of *Forest Land Converted to Grassland* on belowground biomass and dead organic matter pools are not estimated in the current Inventory, and so another planned improvement is to estimate changes in C stocks for these pools in the next Inventory. In addition, biomass C stock changes will be estimated for *Cropland Converted to Grassland*, and other land use conversions to grassland to the extent that data are available.

One additional planned improvement for the *Land Converted to Grassland* category is to develop an inventory of C stock changes for grasslands in Alaska. For information about other improvements, see the Planned Improvements section in *Cropland Remaining Cropland* and *Grassland Remaining Grassland*.

6.8 Wetlands Remaining Wetlands (IPCC Source Category 4D1)

Peatlands Remaining Peatlands

Emissions from Managed Peatlands

Managed peatlands are peatlands which have been cleared and drained for the production of peat. The production cycle of a managed peatland has three phases: land conversion in preparation for peat extraction (e.g., clearing surface biomass, draining), extraction, and abandonment, restoration, or conversion of the land to another use.

Carbon dioxide emissions from the removal of biomass and the decay of harvested peat constitute the major greenhouse gas flux from managed peatlands. Managed peatlands may also emit CH₄ and N₂O, however, this is a very small component of total emissions from this source category in the United States. The natural production of CH₄ is largely reduced but not entirely shut down when peatlands are drained in preparation for peat extraction (Strack et al. 2004 as cited in the *2006 IPCC Guidelines*). Drained land surface and ditch networks contribute to the CH₄ flux in peatlands managed for peat extraction. Methane emissions were considered insignificant under IPCC Tier 1 methodology (IPCC 2006), but are included in the emissions estimates for *Peatlands Remaining Peatlands* consistent with the *2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands* (IPCC 2013). Nitrous oxide emissions from managed peatlands depend on site fertility. In addition, abandoned and restored peatlands continue to release greenhouse gas emissions. This Inventory estimates CO₂, N₂O, and CH₄ emissions from peatlands managed for peat extraction in accordance with IPCC (2006 and 2013) guidelines.

CO₂, N₂O, and CH₄ Emissions from *Peatlands Remaining Peatlands*

IPCC (2013) recommends reporting CO₂, N₂O, and CH₄ emissions from lands undergoing active peat extraction (i.e., *Peatlands Remaining Peatlands*) as part of the estimate for emissions from managed wetlands. Peatlands occur where plant biomass has sunk to the bottom of water bodies and water-logged areas and exhausted the oxygen supply below the water surface during the course of decay. Due to these anaerobic conditions, much of the plant matter does not decompose but instead forms layers of peat over decades and centuries. In the United States, peat is extracted for horticulture and landscaping growing media, and for a wide variety of industrial, personal care, and other products. It has not been used for fuel in the United States for many decades. Peat is harvested from two types of peat deposits in the United States: sphagnum bogs in northern states (e.g., Minnesota) and wetlands in states further south (e.g., Florida). The peat from sphagnum bogs in northern states, which is nutrient poor, is generally corrected for acidity and mixed with fertilizer. Production from more southerly states is relatively coarse (i.e., fibrous) but nutrient rich.

IPCC (2006 and 2013) recommend considering both on-site and off-site emissions when estimating CO₂ emissions from *Peatlands Remaining Peatlands* using the Tier 1 approach. Current methodologies estimate only on-site N₂O and CH₄ emissions, since off-site N₂O estimates are complicated by the risk of double-counting emissions from nitrogen fertilizers added to horticultural peat, and off-site CH₄ emissions are not relevant given the non-energy uses of peat, so methodologies are not provided in IPCC (2013) guidelines. On-site emissions from managed peatlands occur as the land is cleared of vegetation and the underlying peat is exposed to sun and weather. As this occurs, some peat deposit is lost and CO₂ is emitted from the oxidation of the peat. Since N₂O emissions from saturated ecosystems tend to be low unless there is an exogenous source of nitrogen, N₂O emissions from drained peatlands are dependent on nitrogen mineralization and therefore on soil fertility. Peatlands located on highly fertile soils contain significant amounts of organic nitrogen in inactive form. Draining land in preparation for peat extraction allows bacteria to convert the nitrogen into nitrates which leach to the surface where they are reduced to N₂O, and contributes to the activity of methanogens, which produce CH₄, and methanotrophs which oxidize CH₄ into CO₂ (Blodau 2002; Treat et al. 2007 as cited in IPCC 2013). Ditch networks, which are constructed in order to drain the water off in preparation for peat extraction, also contribute to the flux of CH₄ through *in situ* production and lateral transfer of CH₄ from the organic soil matrix (IPCC 2013).

The two sources of off-site CO₂ emissions from managed peatlands are waterborne carbon losses and the horticultural and landscaping use of peat. Drainage waters in peatlands accumulate dissolved organic carbon which then reacts within aquatic ecosystems and is converted to CO₂ where it is then emitted to the atmosphere (Billet et al. 2004 as cited in IPCC 2013). Most (nearly 98 percent) of the CO₂ emissions from peat occur off-site, as the peat is processed and sold to firms which, in the United States, use it predominantly for horticultural and landscaping purposes. Nutrient-poor (but fertilizer-enriched) peat tends to be used in bedding plants and in greenhouse and plant nursery production, whereas nutrient-rich (but relatively coarse) peat is used directly in landscaping, athletic fields, golf courses, and plant nurseries.

Total emissions from *Peatlands Remaining Peatlands* were estimated to be 0.8 MMT CO₂ Eq. in 2014 (see Table 6-43) comprising 0.8 MMT CO₂ Eq. (842 kt) of CO₂, 0.001 MMT CO₂ Eq. (0.002 kt) of N₂O, and 0.004 MMT CO₂ Eq. (0.17 kt) of CH₄. Total emissions in 2014 were about 9 percent larger than total emissions in 2013. Peat production in Alaska in 2014 was not reported in *Alaska's Mineral Industry 2013* report. However, peat production reported in the lower 48 states in 2014 was 10 percent more than in 2013, and as a result, the emissions from *Peatlands Remaining Peatlands* in the lower 48 states and Alaska were greater in 2014 compared to 2013.

Total emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.8 and 1.3 MMT CO₂ Eq. across the time series with a decreasing trend from 1990 until 1993 followed by an increasing trend through 2000. After 2000, emissions generally decreased until 2006 and then increased until 2009, when the trend reversed until a slight increase from 2013 to 2014. Carbon dioxide emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.8 and 1.3 MMT CO₂ across the time series, and these emissions drive the trends in total emissions. CH₄ and N₂O emissions remained close to zero across the time series.

Table 6-43: Emissions from *Peatlands Remaining Peatlands* (MMT CO₂ Eq.)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|------|------|------|------|------|------|------|
| CO ₂ | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |
| Off-site | 1.0 | 1.0 | 1.0 | 0.9 | 0.8 | 0.7 | 0.8 |

| | | | | | | | |
|----------------------------|------------|------------|------------|------------|------------|------------|------------|
| On-site | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | + | 0.1 |
| N ₂ O (On-site) | + | + | + | + | + | + | + |
| CH ₄ (On-site) | + | + | + | + | + | + | + |
| Total | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 | 0.8 | 0.8 |

+ Does not exceed 0.05 MMT CO₂ Eq.

Notes: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports, and stockpiles (i.e., apparent consumption). Off-site N₂O emissions are not estimated to avoid double-counting N₂O emitted from the fertilizer that the peat is mixed with prior to horticultural use (see IPCC 2006). Totals may not sum due to independent rounding.

Table 6-44: Emissions from *Peatlands Remaining Peatlands* (kt)

| Gas | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------|-------|-------|-------|------|------|------|------|
| CO ₂ | 1,055 | 1,101 | 1,022 | 926 | 812 | 770 | 842 |
| Off-site | 985 | 1,030 | 956 | 866 | 760 | 720 | 787 |
| On-site | 70 | 71 | 66 | 60 | 53 | 50 | 55 |
| N ₂ O (On-site) | + | + | + | + | + | + | + |
| CH ₄ (On-site) | + | + | + | + | + | + | + |

+ Does not exceed 0.5 kt.

Notes: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports, and stockpiles (i.e., apparent consumption). Off-site N₂O emissions are not estimated to avoid double-counting N₂O emitted from the fertilizer that the peat is mixed with prior to horticultural use (see IPCC 2006). Totals may not sum due to independent rounding.

Methodology

Off-site CO₂ Emissions

Off-site CO₂ emissions from domestic peat production were estimated using a Tier 1 methodology consistent with IPCC (2006). The emissions were calculated by apportioning the annual weight of peat produced in the United States (Table 6-45) into peat extracted from nutrient-rich deposits and peat extracted from nutrient-poor deposits using annual percentage-by-weight figures. These nutrient-rich and nutrient-poor production values were then multiplied by the appropriate default C fraction conversion factor taken from IPCC (2006) in order to obtain off-site CO₂ emission estimates. For the lower 48 states, both annual percentages of peat type by weight and domestic peat production data were sourced from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Commodity Summaries* from the U.S. Geological Survey (USGS 1995–2015a; USGS 2015b). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying domestic peat producers. On average, about 75 percent of the peat operations respond to the survey; and USGS estimates data for non-respondents on the basis of prior-year production levels (Apodaca 2011).

The Alaska estimates rely on reported peat production from the annual *Alaska's Mineral Industry* reports (DGGS 1997–2014). Similar to the U.S. Geological Survey, the Alaska Department of Natural Resources, Division of Geological & Geophysical Surveys (DGGS) solicits voluntary reporting of peat production from producers for the *Alaska's Mineral Industry* report. However, the report does not estimate production for the non-reporting producers, resulting in larger inter-annual variation in reported peat production from Alaska depending on the number of producers who report in a given year (Szumigala 2011). In addition, in both the lower 48 states and Alaska, large variations in peat production can also result from variations in precipitation and the subsequent changes in moisture conditions, since unusually wet years can hamper peat production. The methodology estimates Alaska emissions separately from lower 48 emissions because the state conducts its own mineral survey and reports peat production by volume, rather than by weight (Table 6-46). However, volume production data were used to calculate off-site CO₂ emissions from Alaska applying the same methodology but with volume-specific C fraction conversion factors

from IPCC (2006).⁵⁵ Peat production was not reported for 2014 in *Alaska's Mineral Industry 2013* report (DGGS 2014); therefore Alaska's peat production in 2014 (reported in cubic yards) was assumed to be equal to its peat production in 2013.

Consistent with IPCC (2013) guidelines, off-site CO₂ emissions from dissolved organic carbon transported off-site were estimated based on the total area of peatlands managed for peat extraction, which is calculated from production data using the methodology described in the *On-Site CO₂ Emissions* section below. Carbon dioxide emissions from dissolved organic C were estimated by multiplying the area of peatlands by the default emission factor for dissolved organic C provided in IPCC (2013).

The *apparent consumption* of peat, which includes production plus imports minus exports plus the decrease in stockpiles, in the United States is over two-and-a-half times the amount of domestic peat production. However, consistent with the Tier 1 method whereby only domestic peat production is accounted for when estimating off-site emissions, off-site CO₂ emissions from the use of peat not produced within the United States are not included in the Inventory. The United States has largely imported peat from Canada for horticultural purposes; from 2010 to 2013, imports of sphagnum moss (nutrient-poor) peat from Canada represented 63 percent of total U.S. peat imports (USGS 2015c). Most peat produced in the United States is reed-sedge peat, generally from southern states, which is classified as nutrient rich by IPCC (2006). Higher-tier calculations of CO₂ emissions from apparent consumption would involve consideration of the percentages of peat types stockpiled (nutrient rich versus nutrient poor) as well as the percentages of peat types imported and exported.

Table 6-45: Peat Production of Lower 48 States (kt)

| Type of Deposit | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Nutrient-Rich | 595.1 | 657.6 | 558.9 | 511.2 | 409.9 | 418.5 | 459.0 |
| Nutrient-Poor | 55.4 | 27.4 | 69.1 | 56.8 | 78.1 | 46.5 | 51.0 |
| Total Production | 692.0 | 685.0 | 628.0 | 568.0 | 488.0 | 465.0 | 510.0 |

Sources: United States Geological Survey (USGS) (1991–2015a) *Minerals Yearbook: Peat* (1994–2014); United States Geological Survey (USGS) (2015b) *Mineral Commodity Summaries: Peat* (2014).

Table 6-46: Peat Production of Alaska (Thousand Cubic Meters)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|------|------|------|------|------|------|------|
| Total Production | 49.7 | 47.8 | 59.8 | 61.5 | 93.1 | 93.1 | 93.1 |

Sources: Division of Geological & Geophysical Surveys (DGGS), Alaska Department of Natural Resources (1997–2014) *Alaska's Mineral Industry Report (1997–2013)*.

On-site CO₂ Emissions

IPCC (2006) suggests basing the calculation of on-site emission estimates on the area of peatlands managed for peat extraction differentiated by the nutrient type of the deposit (rich versus poor). Information on the area of land managed for peat extraction is currently not available for the United States, but in accordance with IPCC (2006), an average production rate per area for the industry was applied to derive an area estimate. In a mature industrialized peat industry, such as exists in the United States and Canada, the vacuum method can extract up to 100 metric tons per hectare per year (Cleary et al. 2005 as cited in IPCC 2006).⁵⁶ In the lower 48 states, the area of land managed for peat extraction was estimated using nutrient-rich and nutrient-poor production data and the assumption that 100 metric tons of peat are extracted from a single hectare in a single year. The nutrient-rich and nutrient-poor annual land area estimates were then multiplied by the IPCC (2013) default emission factor in order to calculate on-site CO₂ emission estimates. Production data are not available by weight for Alaska. In order to calculate on-site

⁵⁵ Peat produced from Alaska was assumed to be nutrient poor; as is the case in Canada, “where deposits of high-quality [but nutrient poor] sphagnum moss are extensive” (USGS 2008).

⁵⁶ The vacuum method is one type of extraction that annually “mills” or breaks up the surface of the peat into particles, which then dry during the summer months. The air-dried peat particles are then collected by vacuum harvesters and transported from the area to stockpiles (IPCC 2006).

emissions resulting from *Peatlands Remaining Peatlands* in Alaska, the production data by volume were converted to weight using annual average bulk peat density values, and then converted to land area estimates using the same assumption that a single hectare yields 100 metric tons. The IPCC (2006) on-site emissions equation also includes a term which accounts for emissions resulting from the change in C stocks that occurs during the clearing of vegetation prior to peat extraction. Area data on land undergoing conversion to peatlands for peat extraction is also unavailable for the United States. However, USGS records show that the number of active operations in the United States has been declining since 1990; therefore, it seems reasonable to assume that no new areas are being cleared of vegetation for managed peat extraction. Other changes in C stocks in living biomass on managed peatlands are also assumed to be zero under the Tier 1 methodologies (IPCC 2006 and 2013).

On-site N₂O Emissions

IPCC (2006) suggests basing the calculation of on-site N₂O emission estimates on the area of nutrient-rich peatlands managed for peat extraction. These area data are not available directly for the United States, but the on-site CO₂ emissions methodology above details the calculation of area data from production data. In order to estimate N₂O emissions, the area of nutrient rich *Peatlands Remaining Peatlands* was multiplied by the appropriate default emission factor taken from IPCC (2013).

On-site CH₄ Emissions

IPCC (2013) also suggests basing the calculation of on-site CH₄ emission estimates on the total area of peatlands managed for peat extraction. Area data is derived using the calculation from production data described in the On-site CO₂ Emissions section above. In order to estimate CH₄ emissions from drained land surface, the area of *Peatlands Remaining Peatlands* was multiplied by the emission factor for direct CH₄ emissions taken from IPCC (2013). In order to estimate CH₄ emissions from drainage ditches, the total area of peatland was multiplied by the default fraction of peatland area that contains drainage ditches, and the appropriate emission factor taken from IPCC (2013).

Uncertainty and Time-Series Consistency

A Monte Carlo (Approach 2) uncertainty analysis was applied to estimate the uncertainty of CO₂, CH₄, and N₂O emissions from *Peatlands Remaining Peatlands*, using the following assumptions:

- The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed.
- The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. The peat type production percentages were assumed to have the same uncertainty values and distribution as the peat production data (i.e., ± 25 percent with a normal distribution).
- The uncertainty associated with the reported production data for Alaska was assumed to be the same as for the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the DGGS estimates that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008).
- The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008).
- IPCC (2006 and 2013) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emission factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed.
- The uncertainty values surrounding the C fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed.
- The uncertainty values associated with the fraction of peatland covered by ditches was assumed to be ± 100 percent with a normal distribution based on the assumption that greater than 10 percent coverage, the upper uncertainty bound, is not typical of drained organic soils outside of The Netherlands (IPCC 2013).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 6-47. Carbon dioxide emissions from *Peatlands Remaining Peatlands* in 2014 were estimated to be between 0.7 and 1.0 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of 14 percent below to 19 percent above the 2014 emission

estimate of 0.8 MMT CO₂ Eq. Methane emissions from *Peatlands Remaining Peatlands* in 2014 were estimated to be between 0.002 and 0.008 MMT CO₂ Eq. This indicates a range of 62 percent below to 61 percent above the 2014 emission estimate of 0.005 MMT CO₂ Eq. Nitrous oxide emissions from *Peatlands Remaining Peatlands* in 2014 were estimated to be between 0.0003 and 0.0010 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of 51 percent below to 61 percent above the 2014 emission estimate of 0.0006 MMT CO₂ Eq.

Table 6-47: Approach 2 Quantitative Uncertainty Estimates for CO₂, CH₄, and N₂O Emissions from *Peatlands Remaining Peatlands* (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (%) | | | |
|-------------------------------|------------------|--|--|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Peatlands Remaining Peatlands | CO ₂ | 0.8 | 0.7 | 1.0 | -14% | +19% |
| Peatlands Remaining Peatlands | CH ₄ | + | + | + | -62% | +61% |
| Peatlands Remaining Peatlands | N ₂ O | + | + | + | -51% | +61% |

+ Does not exceed 0.05 MMT CO₂ Eq.

^aRange of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation and no issues were identified.

Recalculations Discussion

The emission estimates for *Peatlands Remaining Peatlands* were updated for 2014 using the Peat section of the *Mineral Commodity Summaries 2015*. The new edition provided 2014 data for the lower 48 states, but data for Alaska were still unavailable. Because no peat production has been reported since *Alaska's Mineral Industry 2012* report, the 2013 and 2014 values were assumed to be equal to the 2012 value. If updated data are available for the next inventory cycle, this will result in a recalculation in the next Inventory report.

Planned Improvements

In order to further improve estimates of CO₂, N₂O, and CH₄ emissions from *Peatlands Remaining Peatlands*, future efforts will investigate if data sources exist for determining the quantity of peat harvested per hectare and the total area undergoing peat extraction.

The *2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands* describes inventory methodologies for various wetland source categories. In the 1990 through 2013 Inventory, updated methods for *Peatlands Remaining Peatlands* to align them with the *IPCC Supplement* were begun to be incorporated. For future inventories, the need for additional updates will be evaluated, in order to further address the IPCC Supplement for *Peatlands Remaining Peatlands*.

The *2006 IPCC Guidelines* do not cover all wetland types; they are restricted to peatlands drained and managed for peat extraction, conversion to flooded lands, and some guidance for drained organic soils. They also do not cover all of the significant activities occurring on wetlands (e.g., rewetting of peatlands). Since this Inventory only includes *Peatlands Remaining Peatlands*, additional wetland types and activities found in the *2013 IPCC Supplement* (IPCC 2013) will be reviewed to determine if they apply to the United States. For those that do, available data will be investigated to allow for the estimation of greenhouse gas fluxes in future Inventory reports.

Box 6-6: Progress on Inclusion of Managed Coastal Wetlands in the U.S. Greenhouse Gas Inventory

In 2014, the IPCC released the *2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands (Wetlands Supplement)*. The *Wetlands Supplement* provides methods for estimating anthropogenic emissions and removals of greenhouse gases from wetlands and drained soils. Specific consideration is given here to the inclusion of coastal wetlands as part of LULUCF reporting for anthropogenic emissions and removals of CO₂ and CH₄ and N₂O emissions.

In preparation for the next submission of the U.S. Inventory, the United States is exploring methodological approaches based on guidance in the *Wetlands Supplement*. The goal is to assemble all necessary activity data and emission factors, implement the methods described in the *Wetlands Supplement* and generate estimates at the Tier 1 or 2 level for managed coastal wetlands in the conterminous United States.

Fundamental considerations for inclusion of coastal wetlands as part of LULUCF reporting are: (1) how to apply the guidance in the *Wetlands Supplement* to specify what coastal wetlands are managed; (2) understanding what land-use categories coastal wetlands are in (i.e., Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land) and ensuring there is no overlap or missing lands within the U.S. land use matrix; and (3) understanding how the guidance can be applied when significant greenhouse gas emissions and removals occur in managed coastal wetlands outside of the U.S. land use matrix (i.e., seagrass meadows). These issues are under consideration and review by an interagency (U.S. Government) and academic team in anticipation of the next submission of the U.S. Inventory.

The availability of data and resources will be primary drivers in determining how the approaches in the *Wetlands Supplement* are applied. Specifically, the United States will work toward developing its inventory reporting of greenhouse gas emissions and removals from coastal wetlands by: (1) obtaining, collating and refining land use and land-use change data including (a) creating the coastal wetland boundary, (b) recognizing management activities and coastal wetland change resulting in land-use conversion (c) creating seamless integration where coastal wetlands may overlap with other land-use categories, (d) distinguishing salinity levels and soil types to apply appropriate C stocks and emission factors; and (2) developing the sector-specific inventory report for each new category and sub-category by: (a) increasing efforts toward reconciling land cover and land cover change spatial databases (i.e., Coastal Change Analysis Program) with vegetation, soil C stock and stock change data, and other levels of disaggregation that improve estimation accuracy, (b) developing Tier 1 (or Tier 2, if activity data and emission factors are available) emissions estimates for new source/sink categories under Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land, and (c) developing Tier 1 (or Tier 2, if activity data and emission factors are available) estimates of new source/sink categories that fall under new subcategories under Wetlands (*Other Wetlands Remaining Other Wetlands* and *Land Converted to Other Wetlands*) from the following activities: i) forest management in mangroves, ii) extraction in mangroves, tidal marshes and seagrass meadows (including excavation, aquaculture and salt production), iii) rewetting, revegetation and creation in mangroves, tidal marshes and seagrass meadows, iv) soil drainage in mangroves and tidal marshes (CO₂) and v) new categories of CH₄ emissions from rewetting of mangroves and tidal marshes and N₂O emissions from aquaculture, and (d) developing QA/QC procedures and protocols to be used in generating the estimates, and (e) refining uncertainty estimates.

6.9 Land Converted to Wetlands (IPCC Source Category 4D2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to wetlands each year, just as wetlands are converted to other uses. While the magnitude of these area changes is known (see Table 6-7), research is ongoing to track greenhouse gas fluxes across *Wetlands Remaining Wetlands* and *Land Converted to Wetlands*. Until such time that reliable and comprehensive estimates of greenhouse gas fluxes across these land-use and land-use change categories can be produced, it is not possible to separate CO₂, CH₄ or N₂O fluxes on *Land Converted to Wetlands* from fluxes on *Wetlands Remaining Wetlands* at this time.

6.10 Settlements Remaining Settlements

Changes in Carbon Stocks in Urban Trees (IPCC Source Category 4E1)

Urban forests constitute a significant portion of the total U.S. tree canopy cover (Dwyer et al. 2000). Urban areas (cities, towns, and villages) are estimated to cover over 3 percent of the United States (U.S. Census Bureau 2012). With an average tree canopy cover of 35 percent, urban areas account for approximately 5 percent of total tree cover in the continental United States (Nowak and Greenfield 2012). Trees in urban areas of the United States were estimated to account for an average annual net sequestration of 76.4 MMT CO₂ Eq. (20.8 MMT C) over the period from 1990 through 2014. Net C flux from urban trees in 2014 was estimated to be -90.6 MMT CO₂ Eq. (-24.7 MMT C). Annual estimates of CO₂ flux (Table 6-48) were developed based on periodic (1990, 2000, and 2010) U.S. Census data on urbanized area. The estimate of urbanized area is smaller than the area categorized as *Settlements* in the Representation of the U.S. Land Base section developed for this report: over the 1990 through 2014 time series the Census urban area totaled, on average, about 63 percent of the *Settlements* area.

In 2014, Census urban area totaled about 68 percent of the total area defined as *Settlements*. Census area data are preferentially used to develop C flux estimates for this source category since these data are more applicable for use with the available peer-reviewed data on urban tree canopy cover and urban tree C sequestration. Annual sequestration increased by 50 percent between 1990 and 2014 due to increases in urban land area. Data on C storage and urban tree coverage were collected since the early 1990s and have been applied to the entire time series in this report. As a result, the estimates presented in this chapter are not truly representative of changes in C stocks in urban trees for *Settlements* areas, but are representative of changes in C stocks in urban trees for Census urban area. The method used in this report does not attempt to scale these estimates to the *Settlements* area. Therefore, the estimates presented in this chapter are likely an underestimate of the true changes in C stocks in urban trees in all *Settlements* areas—i.e., the changes in C stocks in urban trees presented in this chapter are a subset of the changes in C stocks in urban trees in all *Settlements* areas.

Urban trees often grow faster than forest trees because of the relatively open structure of the urban forest (Nowak and Crane 2002). Because tree density in urban areas is typically much lower than in forested areas, the C storage per hectare of land is in fact smaller for urban areas than for forest areas. To quantify the C stored in urban trees, the methodology used here requires analysis per unit area of tree cover, rather than per unit of total land area (as is done for forests). Expressed in this way per unit of tree cover, areas covered by urban trees actually have a greater C density than do forested areas (Nowak and Crane 2002). Expressed per unit of land area, however, the situation is the opposite: because tree density is so much lower in urban areas, these areas have a smaller C density per unit land area than forest areas.

Table 6-48: Net C Flux from Urban Trees (MMT CO₂ Eq. and MMT C)

| Year | MMT CO ₂ Eq. | MMT C |
|------|-------------------------|--------|
| 1990 | (60.4) | (16.5) |
| 2005 | (80.5) | (22.0) |
| 2010 | (86.1) | (23.5) |
| 2011 | (87.3) | (23.8) |
| 2012 | (88.4) | (24.1) |
| 2013 | (89.5) | (24.4) |
| 2014 | (90.6) | (24.7) |

Note: Parentheses indicate net sequestration.

Methodology

Methods for quantifying urban tree biomass, C sequestration, and C emissions from tree mortality and decomposition were taken directly from Nowak et al. (2013), Nowak and Crane (2002), and Nowak (1994). In general, the methodology used by Nowak et al. (2013) to estimate net C sequestration in urban trees followed three steps, each of which is explained further in the paragraphs below. First, field data from cities and states were used to develop allometric equations that are then used to estimate C in urban tree biomass from data on measured tree dimensions. Second, estimates of annual tree growth and biomass increment were generated from published literature and adjusted for tree condition, land-use class, and growing season to generate estimates of gross C sequestration in urban trees for all 50 states and the District of Columbia. Third, estimates of C emissions due to mortality and decomposition were subtracted from gross C sequestration values to derive estimates of net C sequestration.

For this Inventory report, net C sequestration estimates for all 50 states and the District of Columbia, that were generated using the Nowak et al. (2013) methodology and expressed in units of C sequestered per unit area of tree cover, were then used to estimate urban tree C sequestration in the United States. To accomplish this, we used urban area estimates from U.S. Census data together with urban tree cover percentage estimates for each state and the District of Columbia from remote sensing data, an approach consistent with Nowak et al. (2013).

This approach is also consistent with the default IPCC Gain-Loss methodology in IPCC (2006), although sufficient field data are not yet available to separately determine interannual gains and losses in C stocks in the living biomass of urban trees. Instead, the methodology applied here uses estimates of net C sequestration based on modeled estimates of decomposition, as given by Nowak et al. (2013).

The first step in the methodology is to develop allometric equations that can be used to estimate C in urban tree biomass. In order to generate these allometric relationships between tree dimensions and tree biomass for cities and states, Nowak et al. (2013) and previously published research (Nowak and Crane 2002; Nowak 1994, 2007b, 2009) collected field measurements in a number of U.S. cities between 1989 and 2012. For a sample of trees in representative cities, data including tree measurements of stem diameter, tree height, crown height and crown width, and information on location, species, and canopy condition were collected. The data for each tree were converted into C storage by applying allometric equations to estimate aboveground biomass, a root-to-shoot ratio to convert aboveground biomass estimates to whole tree biomass, moisture content, a C content of 50 percent (dry weight basis), and an adjustment factor of 0.8 to account for urban trees having less aboveground biomass for a given stem diameter than predicted by allometric equations based on forest trees (Nowak 1994). Carbon storage estimates for deciduous trees include only C stored in wood. These calculations were then used to develop an allometric equation relating tree dimensions to C storage for each species of tree, encompassing a range of diameters.

The second step in the methodology is to estimate rates of tree growth for urban trees in the United States. Tree growth was estimated using annual height growth and diameter growth rates for specific land uses and diameter classes. In the Nowak et al. (2013) methodology that is applied here, growth calculations were adjusted by a factor to account for tree condition (fair to excellent, poor, critical, dying, or dead). For each tree, the difference in C storage estimates between year 1 and year ($x + 1$) represents the gross amount of C sequestered. These annual gross C sequestration rates for each species (or genus), diameter class, and land-use condition (e.g., parks, transportation, vacant, golf courses) were then scaled up to city estimates using tree population information. The area of assessment for each city or state was defined by its political boundaries; parks and other forested urban areas were thus included in sequestration estimates (Nowak 2011).

Most of the field data used to develop the methodology of Nowak et al. (2013) were analyzed using the U.S. Forest Service's Urban Forest Effects (UFORE) model. UFORE is a computer model that uses standardized field data from random plots in each city and local air pollution and meteorological data to quantify urban forest structure, values of the urban forest, and environmental effects, including total C stored and annual C sequestration. UFORE was used with field data from a stratified random sample of plots in each city to quantify the characteristics of the urban forest (Nowak et al. 2007).

Where gross C sequestration accounts for all carbon sequestered, net C sequestration for urban trees takes into account C emissions associated with tree death and removals. In the third step in the methodology developed by Nowak et al. (2013), estimates of net C emissions from urban trees were derived by applying estimates of annual mortality and condition, and assumptions about whether dead trees were removed from the site to the total C stock estimate for each city. Estimates of annual mortality rates by diameter class and condition class were derived from a

study of street-tree mortality (Nowak 1986). Different decomposition rates were applied to dead trees left standing compared with those removed from the site. For removed trees, different rates were applied to the removed/aboveground biomass in contrast to the belowground biomass. The estimated annual gross C emission rates for each species (or genus), diameter class, and condition class were then scaled up to city estimates using tree population information.

The data for all 50 states and the District of Columbia are described in Nowak et al. (2013) and reproduced in Table 6-49, which builds upon previous research, including: Nowak and Crane (2002), Nowak et al. (2007), Nowak and Greenfield (2012), and references cited therein. The full methodology development is described in the underlying literature, and key details and assumptions were made as follows. The allometric equations applied to the field data for the Nowak methodology for each tree were taken from the scientific literature (see Nowak 1994 and Nowak et al. 2002), but if no allometric equation could be found for the particular species, the average result for the genus was used. The adjustment (0.8) to account for less live tree biomass in urban trees was based on information in Nowak (1994). Measured tree growth rates for street (Frelich 1992; Fleming 1988; Nowak 1994), park (deVries 1987), and forest (Smith and Shifley 1984) trees were standardized to an average length of growing season (153 frost free days) and adjusted for site competition and tree condition. Standardized growth rates of trees of the same species or genus were then compared to determine the average difference between standardized street tree growth and standardized park and forest growth rates. Crown light exposure (CLE) measurements (number of sides and/or top of tree exposed to sunlight) were used to represent forest, park, and open (street) tree growth conditions. Local tree base growth rates (BG) were then calculated as the average standardized growth rate for open-grown trees multiplied by the number of frost free days divided by 153. Growth rates were then adjusted for CLE. The CLE adjusted growth rate was then adjusted based on tree health and tree condition to determine the final growth rate. Assumptions for which dead trees would be removed versus left standing were developed specific to each land use and were based on expert judgment of the authors. Decomposition rates were based on literature estimates (Nowak et al. 2013).

Estimates of gross and net sequestration rates for each of the 50 states and the District of Columbia (Table 6-49) were compiled in units of C sequestration per unit area of tree canopy cover. These rates were used in conjunction with estimates of state urban area and urban tree cover data to calculate each state's annual net C sequestration by urban trees. This method was described in Nowak et al. (2013) and has been modified here to incorporate U.S. Census data.

Specifically, urban area estimates were based on 1990, 2000, and 2010 U.S. Census data. The 1990 U.S. Census defined urban land as "urbanized areas," which included land with a population density greater than 1,000 people per square mile, and adjacent "urban places," which had predefined political boundaries and a population total greater than 2,500. In 2000, the U.S. Census replaced the "urban places" category with a new category of urban land called an "urban cluster," which included areas with more than 500 people per square mile. In 2010, the Census updated its definitions to have "urban areas" encompassing Census tract delineated cities with 50,000 or more people, and "urban clusters" containing Census tract delineated locations with between 2,500 and 50,000 people. Urban land area increased by approximately 23 percent from 1990 to 2000 and 14 percent from 2000 to 2010; Nowak et al. (2005) estimate that the changes in the definition of urban land are responsible for approximately 20 percent of the total reported increase in urban land area from 1990 to 2000. Under all Census (i.e., 1990, 2000, and 2010) definitions, the urban category encompasses most cities, towns, and villages (i.e., it includes both urban and suburban areas). *Settlements* area, as assessed in the Representation of the U.S. Land Base section developed for this report, encompassed all developed parcels greater than 0.1 hectares in size, including rural transportation corridors, and as previously mentioned represents a larger area than the Census-derived urban area estimates. However, the smaller, Census-derived urban area estimates were deemed to be more suitable for estimating national urban tree cover given the data available in the peer-reviewed literature (i.e., the data set available is consistent with Census urban rather than *Settlements* areas), and the recognized overlap in the changes in C stocks between urban forest and non-urban forest (see Planned Improvements below). U.S. Census urban area data is reported as a series of continuous blocks of urban area in each state. The blocks or urban area were summed to create each state's urban area estimate.

Net annual C sequestration estimates were derived for all 50 states and the District of Columbia by multiplying the gross annual emission estimates by 0.74, the standard ratio for net/gross sequestration set out in Table 3 of Nowak et al. (2013) (unless data existed for both gross and net sequestration for the state in Table 2 of Nowak et al. (2013), in which case they were divided to get a state-specific ratio). The gross and net annual C sequestration values for each state were multiplied by each state's area of tree cover, which was the product of the state's urban/community area as defined in the U.S. Census (2012) and the state's urban/community tree cover percentage. The urban/community

tree cover percentage estimates for all 50 states were obtained from Nowak and Greenfield (2012), which compiled ten years of research including Dwyer et al. (2000), Nowak et al. (2002), Nowak (2007a), and Nowak (2009). The urban/community tree cover percentage estimate for the District of Columbia was obtained from Nowak et al. (2013). The urban area estimates were taken from the 2010 U.S. Census (2012). The equation, used to calculate the summed carbon sequestration amounts, can be written as follows:

$$\text{Net annual C sequestration} = \text{Gross sequestration rate} \times \text{Net to Gross sequestration ratio} \times \text{Urban Area} \times \% \text{ Tree Cover}$$

Table 6-49: Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m²-yr) for 50 states plus the District of Columbia (2014)

| State | Gross Annual Sequestration | Net Annual Sequestration | Tree Cover | Gross Annual Sequestration per Area of Tree Cover | Net Annual Sequestration per Area of Tree Cover | Net: Gross Annual Sequestration Ratio |
|----------------|----------------------------|--------------------------|------------|---|---|---------------------------------------|
| Alabama | 1,165,574 | 862,524 | 55.2 | 0.343 | 0.254 | 0.74 |
| Alaska | 44,744 | 33,111 | 39.8 | 0.168 | 0.124 | 0.74 |
| Arizona | 385,644 | 285,376 | 17.6 | 0.354 | 0.262 | 0.74 |
| Arkansas | 424,922 | 314,443 | 42.3 | 0.331 | 0.245 | 0.74 |
| California | 2,106,024 | 1,558,458 | 25.1 | 0.389 | 0.288 | 0.74 |
| Colorado | 153,806 | 113,817 | 18.5 | 0.197 | 0.146 | 0.74 |
| Connecticut | 771,006 | 570,544 | 67.4 | 0.239 | 0.177 | 0.74 |
| Delaware | 136,070 | 100,692 | 35.0 | 0.335 | 0.248 | 0.74 |
| DC | 14,559 | 11,569 | 35.0 | 0.263 | 0.209 | 0.79 |
| Florida | 3,429,742 | 2,538,009 | 35.5 | 0.475 | 0.352 | 0.74 |
| Georgia | 2,580,659 | 1,909,688 | 54.1 | 0.353 | 0.261 | 0.74 |
| Hawaii | 246,168 | 182,164 | 39.9 | 0.581 | 0.430 | 0.74 |
| Idaho | 25,533 | 18,894 | 10.0 | 0.184 | 0.136 | 0.74 |
| Illinois | 760,263 | 562,594 | 25.4 | 0.283 | 0.209 | 0.74 |
| Indiana | 406,015 | 375,425 | 23.7 | 0.250 | 0.231 | 0.92 |
| Iowa | 119,006 | 88,064 | 19.0 | 0.240 | 0.178 | 0.74 |
| Kansas | 186,077 | 144,799 | 25.0 | 0.283 | 0.220 | 0.78 |
| Kentucky | 243,641 | 180,295 | 22.1 | 0.286 | 0.212 | 0.74 |
| Louisiana | 749,632 | 554,727 | 34.9 | 0.397 | 0.294 | 0.74 |
| Maine | 108,092 | 79,988 | 52.3 | 0.221 | 0.164 | 0.74 |
| Maryland | 597,897 | 442,444 | 34.3 | 0.323 | 0.239 | 0.74 |
| Massachusetts | 1,309,649 | 969,140 | 65.1 | 0.254 | 0.188 | 0.74 |
| Michigan | 740,048 | 547,635 | 35.0 | 0.220 | 0.163 | 0.74 |
| Minnesota | 354,139 | 262,063 | 34.0 | 0.229 | 0.169 | 0.74 |
| Mississippi | 494,558 | 365,973 | 47.3 | 0.344 | 0.255 | 0.74 |
| Missouri | 498,925 | 369,205 | 31.5 | 0.285 | 0.211 | 0.74 |
| Montana | 53,940 | 39,916 | 36.3 | 0.184 | 0.136 | 0.74 |
| Nebraska | 50,920 | 42,970 | 15.0 | 0.238 | 0.201 | 0.84 |
| Nevada | 44,096 | 32,631 | 9.6 | 0.207 | 0.153 | 0.74 |
| New Hampshire | 250,531 | 185,393 | 66.0 | 0.217 | 0.161 | 0.74 |
| New Jersey | 1,201,070 | 888,792 | 53.3 | 0.294 | 0.218 | 0.74 |
| New Mexico | 70,002 | 51,801 | 12.0 | 0.263 | 0.195 | 0.74 |
| New York | 1,096,654 | 811,524 | 42.6 | 0.240 | 0.178 | 0.74 |
| North Carolina | 2,076,636 | 1,536,711 | 51.1 | 0.312 | 0.231 | 0.74 |
| North Dakota | 14,946 | 7,102 | 13.0 | 0.223 | 0.106 | 0.48 |
| Ohio | 927,316 | 686,214 | 31.5 | 0.248 | 0.184 | 0.74 |
| Oklahoma | 366,160 | 270,959 | 31.2 | 0.332 | 0.246 | 0.74 |
| Oregon | 261,067 | 193,190 | 36.6 | 0.242 | 0.179 | 0.74 |
| Pennsylvania | 1,264,702 | 935,879 | 41.0 | 0.244 | 0.181 | 0.74 |
| Rhode Island | 137,147 | 101,489 | 51.0 | 0.258 | 0.191 | 0.74 |
| South Carolina | 1,107,882 | 819,832 | 48.9 | 0.338 | 0.250 | 0.74 |
| South Dakota | 21,348 | 18,513 | 14.0 | 0.236 | 0.205 | 0.87 |
| Tennessee | 1,063,362 | 950,771 | 43.8 | 0.303 | 0.271 | 0.89 |
| Texas | 2,808,539 | 2,078,319 | 31.4 | 0.368 | 0.272 | 0.74 |
| Utah | 91,713 | 67,868 | 16.4 | 0.215 | 0.159 | 0.74 |

| | | | | | | |
|---------------|-------------------|-------------------|------|-------|-------|------|
| Vermont | 46,571 | 34,462 | 53.0 | 0.213 | 0.158 | 0.74 |
| Virginia | 839,610 | 621,311 | 39.8 | 0.293 | 0.217 | 0.74 |
| Washington | 571,062 | 422,586 | 34.6 | 0.258 | 0.191 | 0.74 |
| West Virginia | 255,369 | 188,973 | 61.0 | 0.241 | 0.178 | 0.74 |
| Wisconsin | 364,611 | 269,812 | 31.8 | 0.225 | 0.167 | 0.74 |
| Wyoming | 19,203 | 14,210 | 19.9 | 0.182 | 0.135 | 0.74 |
| Total | 33,056,852 | 24,712,872 | | | | |

Uncertainty and Time-Series Consistency

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 50 states and the District of Columbia. A 10 percent uncertainty was associated with urban area estimates based on expert judgment.

Uncertainty associated with estimates of percent urban tree coverage for each of the 50 states was based on standard error estimates reported by Nowak and Greenfield (2012). Uncertainty associated with estimate of percent urban tree coverage for the District of Columbia was based on the standard error estimate reported by Nowak et al. (2013). Uncertainty associated with estimates of gross and net C sequestration for each of the 50 states and the District of Columbia was based on standard error estimates for each of the state-level sequestration estimates reported by Nowak et al. (2013). These estimates are based on field data collected in each of the 50 states and the District of Columbia, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

A Monte Carlo (Approach 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 6-50. The net C flux from changes in C stocks in urban trees in 2014 was estimated to be between -134.0 and -47.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 51 percent more sequestration to 46 percent less sequestration than the 2014 flux estimate of -90.6 MMT CO₂ Eq.

Table 6-50: Approach 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a (MMT CO ₂ Eq.) (%) | | | |
|------------------------------------|-----------------|---|---|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Changes in C Stocks in Urban Trees | CO ₂ | (90.6) | (134.0) | (47.4) | -51% | +46% |

^a Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Parentheses indicate negative values or net sequestration.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for urban trees included checking input data, documentation, and calculations to ensure data were properly handled through the Inventory process. Errors that were found during this process were corrected as necessary. One key edit in the current Inventory report is that Table 6-49 has been updated. For this Table, the values in the 1990 through 2012 Inventory and 1990 through 2013 Inventory reports were the same. The updated

values for the current (1990 through 2014) Inventory were inserted here, noting that they represent a two-year increment in urban tree C sequestration from what was presented in the previous Inventory.

Planned Improvements

A consistent representation of the managed land base in the United States is discussed in the Representation of the U.S. Land Base section, and discusses a planned improvement by the USDA Forest Service to reconcile the overlap between urban forest and non-urban forest greenhouse gas inventories. Because some plots defined as “forest” in the Forest Inventory and Analysis (FIA) program of the USDA Forest Service actually fall within the boundaries of the areas also defined as Census urban, there may be “double-counting” of these land areas in estimates of C stocks and fluxes for this report. Specifically, Nowak et al. (2013) estimates that 1.5 percent of forest plots measured by the FIA program fall within land designated as Census urban, suggesting that approximately 1.5 percent of the C reported in the Forest source category might also be counted in the Urban Trees source category.

Future research may also enable more complete coverage of changes in the C stock in urban trees for all *Settlements* land. To provide estimates for all *Settlements*, research would need to establish the extent of overlap between the areas of land included in the *Settlements* land use category and Census-defined urban areas, and would have to separately characterize sequestration on non-urban *Settlements* land.

N₂O Fluxes from Settlement Soils (IPCC Source Category 4E1)

Of the synthetic N fertilizers applied to soils in the United States, approximately 3.1 percent are currently applied to lawns, golf courses, and other landscaping occurring within settlement areas. Application rates are lower than those occurring on cropped soils, and, therefore, account for a smaller proportion of total U.S. soil N₂O emissions per unit area. In addition to synthetic N fertilizers, a portion of surface applied sewage sludge is applied to settlement areas.

N additions to soils result in direct and indirect N₂O emissions. Direct emissions occur on-site due to the N additions. Indirect emissions result from fertilizer and sludge N that is transformed and transported to another location in a form other than N₂O (ammonia [NH₃] and nitrogen oxide [NO_x] volatilization, nitrogen trioxide [NO₃] leaching and runoff), and later converted into N₂O at the off-site location. The indirect emissions are assigned to settlements because the management activity leading to the emissions occurred in settlements.

Total N₂O emissions from settlement soils were 2.4 MMT CO₂ Eq. (8 kt of N₂O) in 2014. There was an overall increase of 78 percent from 1990 to 2014 due to an expanding settlement area requiring more synthetic N fertilizer. Interannual variability in these emissions is directly attributable to interannual variability in total synthetic fertilizer consumption and sewage sludge applications in the United States. Emissions from this source are summarized in Table 6-51.

Table 6-51: N₂O Fluxes from Soils in *Settlements Remaining Settlements* (MMT CO₂ Eq. and kt N₂O)

| | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|------|------|------|------|------|------|------|
| Direct N₂O Fluxes from Soils | | | | | | | |
| MMT CO ₂ Eq. | 1.0 | 1.8 | 1.8 | 1.9 | 1.9 | 1.8 | 1.8 |
| kt N ₂ O | 3 | 6 | 6 | 6 | 6 | 6 | 6 |
| Indirect N₂O Fluxes from Soils | | | | | | | |
| MMT CO ₂ Eq. | 0.4 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| kt N ₂ O | 1 | 2 | 2 | 2 | 2 | 2 | 2 |
| Total | | | | | | | |
| MMT CO ₂ Eq. | 1.4 | 2.3 | 2.4 | 2.5 | 2.5 | 2.4 | 2.4 |
| kt N ₂ O | 5 | 8 | 8 | 8 | 9 | 8 | 8 |

Note: Totals may not sum due to independent rounding.

Methodology

For soils within *Settlements Remaining Settlements*, the IPCC Tier 1 approach is used to estimate soil N₂O emissions from synthetic N fertilizer and sewage sludge additions. Estimates of direct N₂O emissions from soils in settlements are based on the amount of N in synthetic commercial fertilizers applied to settlement soils, and the amount of N in

sewage sludge applied to non-agricultural land and surface disposal (see Annex 3.12 for a detailed discussion of the methodology for estimating sewage sludge application).

Nitrogen applications to settlement soils are estimated using data compiled by the USGS (Ruddy et al. 2006). The USGS estimated on-farm and non-farm fertilizer use is based on sales records at the county level from 1982 through 2001 (Ruddy et al. 2006). Non-farm N fertilizer is assumed to be applied to settlements and forest lands; values for 2002 through 2014 are based on 2001 values adjusted for annual total N fertilizer sales in the United States because there is no new activity data on application after 2001. Settlement application is calculated by subtracting forest application from total non-farm fertilizer use. Sewage sludge applications are derived from national data on sewage sludge generation, disposition, and N content (see Annex 3.12 for further detail). The total amount of N resulting from these sources is multiplied by the IPCC default emission factor for applied N (one percent) to estimate direct N₂O emissions (IPCC 2006).

For indirect emissions, the total N applied from fertilizer and sludge is multiplied by the IPCC default factors of 10 percent for volatilization and 30 percent for leaching/runoff to calculate the amount of N volatilized and the amount of N leached/runoff. The amount of N volatilized is multiplied by the IPCC default factor of one percent for the portion of volatilized N that is converted to N₂O off-site and the amount of N leached/runoff is multiplied by the IPCC default factor of 0.075 percent for the portion of leached/runoff N that is converted to N₂O off-site. The resulting estimates are summed to obtain total indirect emissions.

Uncertainty and Time-Series Consistency

The amount of N₂O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N₂O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application is assigned a default level of ±50 percent.⁵⁷ Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal is derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. In addition, the uncertainty ranges around 2005 activity data and emission factor input variables are directly applied to the 2014 emission estimates. Uncertainty in the direct and indirect emission factors is provided by IPCC (2006).

Uncertainty is quantified using simple error propagation methods (IPCC 2006), and the results are summarized in Table 6-52. Direct N₂O emissions from soils in *Settlements Remaining Settlements* in 2014 are estimated to be between 0.9 and 4.8 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 49 percent below to 163 percent above the 2014 emission estimate of 1.8 MMT CO₂ Eq. Indirect N₂O emissions in 2014 are between 0.1 and 1.9 MMT CO₂ Eq., ranging from a -85 percent to 212 percent around the estimate of 0.6 MMT CO₂ Eq.

Table 6-52: Quantitative Uncertainty Estimates of N₂O Emissions from Soils in *Settlements Remaining Settlements* (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emissions (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate (MMT CO ₂ Eq.) | | | |
|---|------------------|---|--|----------------|----------------|----------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Settlements Remaining Settlements: | | | | | | |
| Direct N ₂ O Fluxes from Soils | N ₂ O | 1.8 | 0.9 | 4.8 | -49% | +163% |
| Indirect N ₂ O Fluxes from Soils | N ₂ O | 0.6 | 0.1 | 1.9 | -85% | +212% |

Note: These estimates include direct and indirect N₂O emissions from N fertilizer additions to both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

⁵⁷ No uncertainty is provided with the USGS fertilizer consumption data (Ruddy et al. 2006) so a conservative ±50 percent is used in the analysis.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

The spreadsheet containing fertilizer and sewage sludge applied to settlements and calculations for N₂O and uncertainty ranges have been checked and verified.

Planned Improvements

A minor improvement is planned to update the uncertainty analysis for direct emissions from settlements to be consistent with the most recent activity data for this source.

6.11 Land Converted to Settlements (IPCC Source Category 4E2)

Land-use change is constantly occurring, and land under a number of uses undergoes urbanization in the United States each year. Given the lack of available information relevant to this particular IPCC source category, it is not possible to separate CO₂ or N₂O fluxes on *Land Converted to Settlements* from fluxes on *Settlements Remaining Settlements* at this time.

6.12 Other Land Remaining Other Land (IPCC Source Category 4F1)

Land use is constantly occurring, and areas under a number of differing land-use types remain in their respective land-use type each year, just as other land can remain as other land. While the magnitude of *Other Land Remaining Other Land* is known (see Table 6-7), research is ongoing to track C pools in this land use. Until such time that reliable and comprehensive estimates of C for *Other Land Remaining Other Land* can be produced, it is not possible to estimate CO₂ or N₂O fluxes on *Other Land Remaining Other Land* at this time.

6.13 Land Converted to Other Land (IPCC Source Category 4F2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to other land each year, just as other land is converted to other uses. While the magnitude of these area changes is known (see Table 6-7), research is ongoing to track C across *Other Land Remaining Other Land* and *Land Converted to Other Land*. Until such time that reliable and comprehensive estimates of C across these land-use and land-use change categories can be produced, it is not possible to separate CO₂, CH₄ or N₂O fluxes on *Land Converted to Other Land* from fluxes on *Other Land Remaining Other Land* at this time.

6.14 Other (IPCC Source Category 4H)

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

In the United States, yard trimmings (i.e., grass clippings, leaves, and branches) and food scraps account for a significant portion of the municipal waste stream, and a large fraction of the collected yard trimmings and food scraps are put in landfills. Carbon (C) contained in landfilled yard trimmings and food scraps can be stored for very long periods.

Carbon-storage estimates are associated with particular land uses. For example, harvested wood products are accounted for under *Forest Land Remaining Forest Land* because these wood products are considered a component of the forest ecosystem. The wood products serve as reservoirs to which C resulting from photosynthesis in trees is transferred, but the removals in this case occur in the forest. Carbon stock changes in yard trimmings and food scraps are associated with settlements, but removals in this case do not occur within settlements. To address this complexity, yard trimming and food scrap C storage is reported under the “Other” source category.

Both the amount of yard trimmings collected annually and the fraction that is landfilled have declined over the last decade. In 1990, over 53 million metric tons (wet weight) of yard trimmings and food scraps were generated (i.e., put at the curb for collection to be taken to disposal sites or to composting facilities) (EPA 2015a). Since then, programs banning or discouraging yard trimmings disposal have led to an increase in backyard composting and the use of mulching mowers, and a consequent 2.3 percent decrease in the tonnage of yard trimmings generated (i.e., collected for composting or disposal). At the same time, an increase in the number of municipal composting facilities has reduced the proportion of collected yard trimmings that are discarded in landfills—from 72 percent in 1990 to 32 percent in 2014. The net effect of the reduction in generation and the increase in composting is a 57 percent decrease in the quantity of yard trimmings disposed of in landfills since 1990.

Food scrap generation has grown by 55 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 76 percent in 2014, the tonnage disposed of in landfills has increased considerably (by 45 percent). Although the total tonnage of food scraps disposed in landfills has increased from 1990 to 2014, the annual carbon stock net changes from food scraps have decreased (as shown in Table 6-53 and Table 6-54), due to smaller annual differences in the amount of food waste disposed in landfills. Overall, the decrease in the landfill disposal rate of yard trimmings has more than compensated for the increase in food scrap disposal in landfills, and the net result is a decrease in annual landfill C storage from 26.0 MMT CO₂ Eq. (7.1 MMT C) in 1990 to 11.6 MMT CO₂ Eq. (3.2 MMT C) in 2014 (Table 6-53 and Table 6-54).

Table 6-53: Net Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills (MMT CO₂ Eq.)

| Carbon Pool | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Yard Trimmings | (21.0) | (7.4) | (9.3) | (9.2) | (9.1) | (8.5) | (8.5) |
| Grass | (1.8) | (0.6) | (0.9) | (0.9) | (0.9) | (0.8) | (0.8) |
| Leaves | (9.0) | (3.4) | (4.2) | (4.2) | (4.2) | (3.9) | (3.9) |
| Branches | (10.2) | (3.4) | (4.1) | (4.1) | (4.1) | (3.8) | (3.8) |
| Food Scraps | (5.0) | (4.0) | (3.9) | (3.5) | (3.1) | (3.2) | (3.1) |
| Total Net Flux | (26.0) | (11.4) | (13.2) | (12.7) | (12.2) | (11.7) | (11.6) |

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Table 6-54: Net Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills (MMT C)

| Carbon Pool | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Yard Trimmings | (5.7) | (2.0) | (2.5) | (2.5) | (2.5) | (2.3) | (2.3) |
| Grass | (0.5) | (0.2) | (0.3) | (0.2) | (0.2) | (0.2) | (0.2) |

| | | | | | | | |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Leaves | (2.5) | (0.9) | (1.2) | (1.1) | (1.1) | (1.1) | (1.1) |
| Branches | (2.8) | (0.9) | (1.1) | (1.1) | (1.1) | (1.0) | (1.0) |
| Food Scraps | (1.4) | (1.1) | (1.1) | (1.0) | (0.9) | (0.9) | (0.8) |
| Total Net Flux | (7.1) | (3.1) | (3.6) | (3.5) | (3.3) | (3.2) | (3.2) |

Notes: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Methodology

When wastes of biogenic origin (such as yard trimmings and food scraps) are landfilled and do not completely decompose, the C that remains is effectively removed from the terrestrial C cycle. Empirical evidence indicates that yard trimmings and food scraps do not completely decompose in landfills (Barlaz 1998, 2005, 2008; De la Cruz and Barlaz 2010), and thus the stock of C in landfills can increase, with the net effect being a net atmospheric removal of C. Estimates of net C flux resulting from landfilled yard trimmings and food scraps were developed by estimating the change in landfilled C stocks between inventory years, based on methodologies presented for the Land Use, Land-Use Change, and Forestry sector in IPCC (2003). Carbon stock estimates were calculated by determining the mass of landfilled C resulting from yard trimmings or food scraps discarded in a given year; adding the accumulated landfilled C from previous years; and subtracting the mass of C that was landfilled in previous years that decomposed.

To determine the total landfilled C stocks for a given year, the following were estimated: (1) The composition of the yard trimmings; (2) the mass of yard trimmings and food scraps discarded in landfills; (3) the C storage factor of the landfilled yard trimmings and food scraps; and (4) the rate of decomposition of the degradable C. The composition of yard trimmings was assumed to be 30 percent grass clippings, 40 percent leaves, and 30 percent branches on a wet weight basis (Oshins and Block 2000). The yard trimmings were subdivided, because each component has its own unique adjusted C storage factor (i.e., moisture content and C content) and rate of decomposition. The mass of yard trimmings and food scraps disposed of in landfills was estimated by multiplying the quantity of yard trimmings and food scraps discarded by the proportion of discards managed in landfills. Data on discards (i.e., the amount generated minus the amount diverted to centralized composting facilities) for both yard trimmings and food scraps were taken primarily from *Advancing Sustainable Materials Management: Facts and Figures 2013* (EPA 2015a), which provides data for 1960, 1970, 1980, 1990, 2000, 2005, 2009 and 2011 through 2013. To provide data for some of the missing years, detailed backup data were obtained from historical data tables that EPA developed for 1960 through 2013 (EPA 2015b). Remaining years in the time series for which data were not provided were estimated using linear interpolation. Data for 2014 are not yet available, so they were set equal to 2013 values. The EPA (2015a) report and historical data tables (EPA 2015b) do not subdivide the discards (i.e., total generated minus composted) of individual materials into masses landfilled and combusted, although it provides a mass of overall waste stream discards managed in landfills⁵⁸ and combustors with energy recovery (i.e., ranging from 67 percent and 33 percent, respectively, in 1960 to 92 percent and 8 percent, respectively, in 1985); it is assumed that the proportion of each individual material (food scraps, grass, leaves, branches) that is landfilled is the same as the proportion across the overall waste stream.

The amount of C disposed of in landfills each year, starting in 1960, was estimated by converting the discarded landfilled yard trimmings and food scraps from a wet weight to a dry weight basis, and then multiplying by the initial (i.e., pre-decomposition) C content (as a fraction of dry weight). The dry weight of landfilled material was calculated using dry weight to wet weight ratios (Tchobanoglous et al. 1993 as cited by Barlaz 1998) and the initial C contents and the C storage factors were determined by Barlaz (1998, 2005, 2008) (Table 6-55).

The amount of C remaining in the landfill for each subsequent year was tracked based on a simple model of C fate. As demonstrated by Barlaz (1998, 2005, 2008), a portion of the initial C resists decomposition and is essentially persistent in the landfill environment. Barlaz (1998, 2005, 2008) conducted a series of experiments designed to

⁵⁸ EPA (2015a and 2015b) reports discards in two categories: “combustion with energy recovery” and “landfill, other disposal,” which includes combustion without energy recovery. For years in which there is data from previous EPA reports on combustion without energy recovery, EPA assumes these estimates are still applicable. For 2000 to present, EPA assumes that any combustion of MSW that occurs includes energy recovery, so all discards to “landfill, other disposal” are assumed to go to landfills.

measure biodegradation of yard trimmings, food scraps, and other materials, in conditions designed to promote decomposition (i.e., by providing ample moisture and nutrients). After measuring the initial C content, the materials were placed in sealed containers along with methanogenic microbes from a landfill. Once decomposition was complete, the yard trimmings and food scraps were re-analyzed for C content; the C remaining in the solid sample can be expressed as a proportion of the initial C (shown in the row labeled “C Storage Factor, Proportion of Initial C Stored (Percent)” in Table 6-55).

The modeling approach applied to simulate U.S. landfill C flows builds on the findings of Barlaz (1998, 2005, 2008). The proportion of C stored is assumed to persist in landfills. The remaining portion is assumed to degrade over time, resulting in emissions of CH₄ and CO₂. (The CH₄ emissions resulting from decomposition of yard trimmings and food scraps are accounted for in the Waste chapter.) The degradable portion of the C is assumed to decay according to first-order kinetics. The decay rates for each of the materials are shown in Table 6-55.

The first-order decay rates, *k*, for each refuse type were derived from De la Cruz and Barlaz (2010). De la Cruz and Barlaz (2010) calculate first-order decay rates using laboratory data published in Eleazer et al. (1997), and a correction factor, *f*, is found so that the weighted average decay rate for all components is equal to the EPA AP-42 default decay rate (0.04) for mixed MSW for regions that receive more than 25 inches of rain annually (EPA 1995). Because AP-42 values were developed using landfill data from approximately 1990, 1990 waste composition for the United States from EPA’s *Characterization of Municipal Solid Waste in the United States: 1990 Update* was used to calculate *f*. This correction factor is then multiplied by the Eleazer et al. (1997) decay rates of each waste component to develop field-scale first-order decay rates.

De la Cruz and Barlaz (2010) also use other assumed initial decay rates for mixed MSW in place of the AP-42 default value based on different types of environments in which landfills in the United States are found, including dry conditions (less than 25 inches of rain annually, *k*=0.02) and bioreactor landfill conditions (moisture is controlled for rapid decomposition, *k*=0.12). As in Section 7.1 Landfills (which estimates CH₄ emissions), the overall MSW decay rate is estimated by partitioning the U.S. landfill population into three categories, based on annual precipitation ranges of: (1) Less than 20 inches of rain per year; (2) 20 to 40 inches of rain per year; and (3) greater than 40 inches of rain per year. These correspond to overall MSW decay rates of 0.020, 0.038, and 0.057 year⁻¹, respectively.

De la Cruz and Barlaz (2010) calculate component-specific decay rates corresponding to the first value (0.020 year⁻¹), but not for the other two overall MSW decay rates. To maintain consistency between landfill methodologies across the Inventory, the correction factors (*f*) were developed for decay rates of 0.038 and 0.057 year⁻¹ through linear interpolation. A weighted national average component-specific decay rate was calculated by assuming that waste generation is proportional to population (the same assumption used in the landfill methane emission estimate), based on population data from the 2000 U.S. Census. The component-specific decay rates are shown in Table 6-55.

For each of the four materials (grass, leaves, branches, food scraps), the stock of C in landfills for any given year is calculated according to Equation 1:

$$LFC_{i,t} = \sum_n^t W_{i,n} \times (1 - MC_i) \times ICC_i \times \{ [CS_i \times ICC_i] + [(1 - (CS_i \times ICC_i)) \times e^{-k(t-n)}] \}$$

where,

| | | |
|--------------------------|---|---|
| <i>t</i> | = | Year for which C stocks are being estimated (year), |
| <i>i</i> | = | Waste type for which C stocks are being estimated (grass, leaves, branches, food scraps), |
| <i>LFC_{i,t}</i> | = | Stock of C in landfills in year <i>t</i> , for waste <i>i</i> (metric tons), |
| <i>W_{i,n}</i> | = | Mass of waste <i>i</i> disposed of in landfills in year <i>n</i> (metric tons, wet weight), |
| <i>n</i> | = | Year in which the waste was disposed of (year, where 1960 < <i>n</i> < <i>t</i>), |
| <i>MC_i</i> | = | Moisture content of waste <i>i</i> (percent of water), |
| <i>CS_i</i> | = | Proportion of initial C that is stored for waste <i>i</i> (percent), |
| <i>ICC_i</i> | = | Initial C content of waste <i>i</i> (percent), |
| <i>e</i> | = | Natural logarithm, and |
| <i>k</i> | = | First-order decay rate for waste <i>i</i> , (year ⁻¹). |

For a given year t , the total stock of C in landfills ($TLFC_t$) is the sum of stocks across all four materials (grass, leaves, branches, food scraps). The annual flux of C in landfills (F_t) for year t is calculated in Equation 2 as the change in stock compared to the preceding year:

$$F_t = TLFC_t - TLFC_{(t-1)}$$

Thus, as seen in Equation 1, the C placed in a landfill in year n is tracked for each year t through the end of the Inventory period (2014). For example, disposal of food scraps in 1960 resulted in depositing about 1,135,000 metric tons of C. Of this amount, 16 percent (179,000 metric tons) is persistent; the remaining 84 percent (956,000 metric tons) is degradable. By 1965, more than half of the degradable portion (518,000 metric tons) decomposes, leaving a total of 617,000 metric tons (the persistent portion, plus the remainder of the degradable portion).

Continuing the example, by 2014, the total food scraps C originally disposed of in 1960 had declined to 179,000 metric tons (i.e., virtually all degradable C had decomposed). By summing the C remaining from 1960 with the C remaining from food scraps disposed of in subsequent years (1961 through 2014), the total landfill C from food scraps in 2014 was 41.5 million metric tons. This value is then added to the C stock from grass, leaves, and branches to calculate the total landfill C stock in 2014, yielding a value of 264.7 million metric tons (as shown in Table 6-56). In exactly the same way total net flux is calculated for forest C and harvested wood products, the total net flux of landfill C for yard trimmings and food scraps for a given year (Table 6-54) is the difference in the landfill C stock for that year and the stock in the preceding year. For example, the net change in 2014 shown in Table 6-54 (3.2 MMT C) is equal to the stock in 2014 (264.7 MMT C) minus the stock in 2013 (261.5 MMT C).

The C stocks calculated through this procedure are shown in Table 6-56.

Table 6-55: Moisture Contents, C Storage Factors (Proportions of Initial C Sequestered), Initial C Contents, and Decay Rates for Yard Trimmings and Food Scraps in Landfills

| Variable | Yard Trimmings | | | Food Scraps |
|--|----------------|--------|----------|-------------|
| | Grass | Leaves | Branches | |
| Moisture Content (% H ₂ O) | 70 | 30 | 10 | 70 |
| C Storage Factor, Proportion of Initial C Stored (%) | 53 | 85 | 77 | 16 |
| Initial C Content (%) | 45 | 46 | 49 | 51 |
| Decay Rate (year ⁻¹) | 0.323 | 0.185 | 0.016 | 0.156 |

Table 6-56: C Stocks in Yard Trimmings and Food Scraps in Landfills (MMT C)

| Carbon Pool | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Yard Trimmings | 155.8 | 202.9 | 213.6 | 216.1 | 218.6 | 220.9 | 223.2 |
| Grass | 14.5 | 18.1 | 19.0 | 19.3 | 19.5 | 19.7 | 20.0 |
| Leaves | 66.7 | 87.3 | 92.2 | 93.4 | 94.5 | 95.6 | 96.6 |
| Branches | 74.6 | 97.5 | 102.3 | 103.4 | 104.5 | 105.6 | 106.6 |
| Food Scraps | 17.6 | 32.8 | 38.0 | 38.9 | 39.8 | 40.7 | 41.5 |
| Total Carbon Stocks | 173.5 | 235.6 | 251.6 | 255.0 | 258.4 | 261.5 | 264.7 |

Uncertainty and Time-Series Consistency

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

A Monte Carlo (Approach 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 6-57. Total yard trimmings and food scraps CO₂ flux in 2014 was estimated to be between -18.0 and -4.5 MMT CO₂ Eq. at a 95 percent confidence level (or 19 of 20 Monte Carlo stochastic simulations). This indicates a range of

44 percent below to 64 percent above the 2014 flux estimate of -11.6 MMT CO₂ Eq. More information on the uncertainty estimates for Yard Trimmings and Food Scraps in Landfills is contained within the Uncertainty Annex.

Table 6-57: Approach 2 Quantitative Uncertainty Estimates for CO₂ Flux from Yard Trimmings and Food Scraps in Landfills (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Flux Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Flux Estimate ^a | | | |
|--------------------------------|-----------------|--|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Yard Trimmings and Food Scraps | CO ₂ | (11.6) | (18.0) | (4.5) | -44% | +64% |

^a Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Parentheses indicate negative values or net C sequestration.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current Inventory has been revised relative to the previous report. Generation and recovery data for yard trimmings and food scraps was not previously provided for every year from 1960 in the *Advancing Sustainable Materials Management: Facts and Figures 2013* report. EPA has since released historical data, which included data for each year from 1960 through 2013. The recalculations based on these historical data resulted in changes ranging from a one percent increase in sequestration in 2001 to a 7 percent decrease in sequestration in 2013, and an average 0.66 percent decrease in sequestration across the 1990 through 2013 time series compared to the previous Inventory.

Planned Improvements

Future work is planned to evaluate the consistency between the estimates of C storage described in this chapter and the estimates of landfill CH₄ emissions described in the Waste chapter. For example, the Waste chapter does not distinguish landfill CH₄ emissions from yard trimmings and food scraps separately from landfill CH₄ emissions from total bulk (i.e., municipal solid) waste, which includes yard trimmings and food scraps.

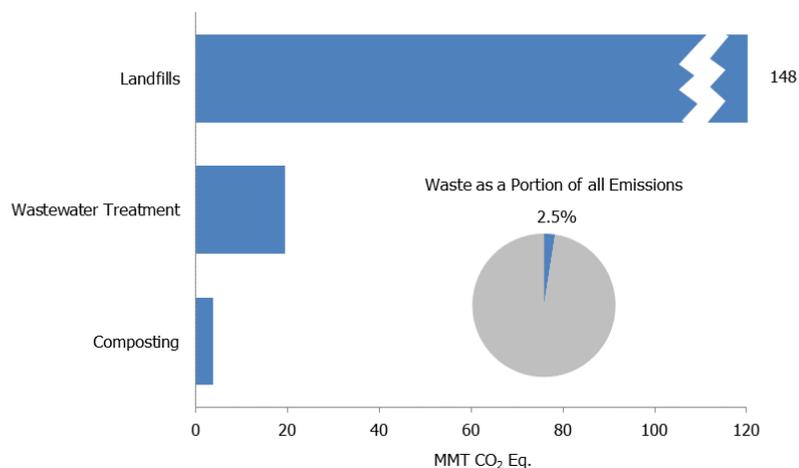
In addition, additional data will be evaluated from recent peer-reviewed literature that may modify the default C storage factors, initial C contents, and decay rates for yard trimmings and food scraps in landfills. Based upon this evaluation, changes may be made to the default values. Whether to update the weighted national average component-specific decay rate using new U.S. Census data, if any are available, will also be investigated.

The yard waste composition will also be evaluated to determine if changes need to be made based on changes in residential practices, research will be conducted to determine if there are changes in the allocation of yard trimmings. For example, leaving grass clippings in place is becoming a more common practice, thus reducing the percentage of grass clippings in yard trimmings disposed in landfills.

7. Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 7-1). Landfills accounted for approximately 20.2 percent of total U.S. anthropogenic methane (CH₄) emissions in 2014, the third largest contribution of any CH₄ source in the United States. Additionally, wastewater treatment and composting of organic waste accounted for approximately 2.0 percent and less than one percent of U.S. CH₄ emissions, respectively. Nitrous oxide (N₂O) emissions from the discharge of wastewater treatment effluents into aquatic environments were estimated, as were N₂O emissions from the treatment process itself. Nitrous oxide emissions from composting were also estimated. Together, these waste activities account for 1.7 percent of total U.S. N₂O emissions. Nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) are emitted by waste activities, and are addressed separately at the end of this chapter. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 7-1 and Table 7-2.

Figure 7-1: 2014 Waste Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



Box 7-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report and this chapter are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC 2006).¹ Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.² The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard,

¹ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

² See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>>.

U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. Emissions and sinks provided in the current Inventory do not preclude alternative examinations, but rather presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC.³ The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted. The UNFCCC incorporated the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* as the standard for Annex I countries at the Nineteenth Conference of the Parties (Warsaw, November 11-23, 2013). This chapter presents emission estimates calculated in accordance with the methodological guidance provided in these guidelines.

Overall, in 2014, waste activities generated emissions of 171.4 MMT CO₂ Eq., or 2.5 percent of total U.S. greenhouse gas emissions.

Table 7-1: Emissions from Waste (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 195.6 | 171.8 | 159.4 | 161.5 | 159.2 | 161.1 | 164.7 |
| Landfills | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |
| Wastewater Treatment | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 |
| Composting | 0.4 | 1.9 | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 |
| N₂O | 3.7 | 6.0 | 6.1 | 6.4 | 6.5 | 6.6 | 6.7 |
| Wastewater Treatment | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| Composting | 0.3 | 1.7 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 |
| Total | 199.3 | 177.8 | 165.5 | 167.8 | 165.7 | 167.8 | 171.4 |

Note: Totals may not sum due to independent rounding.

Table 7-2: Emissions from Waste (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| CH₄ | 7,823 | 6,871 | 6,377 | 6,459 | 6,369 | 6,445 | 6,589 |
| Landfills | 7,182 | 6,161 | 5,685 | 5,774 | 5,691 | 5,772 | 5,919 |
| Wastewater Treatment | 626 | 636 | 618 | 610 | 601 | 592 | 588 |
| Composting | 15 | 75 | 73 | 75 | 77 | 81 | 82 |
| N₂O | 12 | 20 | 21 | 21 | 22 | 22 | 22 |
| Wastewater Treatment | 11 | 15 | 15 | 16 | 16 | 16 | 16 |
| Composting | 1 | 6 | 5 | 6 | 6 | 6 | 6 |

Note: Totals may not sum due to independent rounding.

Carbon dioxide (CO₂), CH₄, and N₂O emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires and hazardous industrial waste, because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2014 resulted in 9.7 MMT CO₂ Eq. emissions, more than half of which is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 7.4.

³ For example, see <<http://www.epa.gov/ghgreporting/ghgrp-methodology-and-verification>>.

Box 7-2: Waste Data from the Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. EPA published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as EPA's Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons and requires reporting by 41 industrial categories. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year.

EPA's GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections for source categories in this chapter, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this Inventory. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards. This may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions for source categories in EPA's GHGRP may differ from those used in this Inventory in meeting the UNFCCC reporting guidelines. In line with the UNFCCC reporting guidelines, the Inventory report is a comprehensive accounting of all emissions from source categories identified in the *2006 IPCC Guidelines* (IPCC 2006). Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the EPA's GHGRP website.⁴

EPA presents the data collected by EPA's GHGRP through a data publication tool that allows data to be viewed in several formats including maps, tables, charts and graphs for individual facilities or groups of facilities.⁵

7.1 Landfills (IPCC Source Category 5A1)

In the United States, solid waste is managed by landfilling, recovery through recycling or composting, and combustion through waste-to-energy facilities. Disposing of solid waste in modern, managed landfills is the most commonly used waste management technique in the United States. More information on how solid waste data are collected and managed in the United States is provided in Box 7-1. The municipal solid waste (MSW) and industrial waste landfills referred to in this section are all modern landfills that must comply with a variety of regulations as discussed in Box 7-3. Disposing of waste in illegal dumping sites is not considered to have occurred in years later than 1980 and these sites are not considered to contribute to net emissions in this section for the timeframe of 1990 to the current Inventory year. MSW landfills, or sanitary landfills, are sites where MSW is managed to prevent or minimize health, safety, and environmental impacts. Waste is deposited in different cells and covered daily with soil; many have environmental monitoring systems to track performance, collect leachate, and collect landfill gas. Industrial waste landfills are constructed in a similar way as MSW landfills, but accept waste produced by industrial activity, such as factories, mills, and mines.

After being placed in a landfill, organic waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria. These methane (CH₄) producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent biogenic carbon dioxide (CO₂) and 50 percent CH₄, by volume. Landfill biogas also

⁴ See

<<http://www.ccdsupport.com/confluence/display/ghgp/Detailed+Description+of+Data+for+Certain+Sources+and+Processes>>.

⁵ See <<http://ghgdata.epa.gov>>.

contains trace amounts of non-methane organic compounds (NMOC) and volatile organic compounds (VOC) that either result from decomposition by-products or volatilization of biodegradable wastes (EPA 2008).

Methane and CO₂ are the primary constituents of landfill gas generation and emissions. However, the *2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines* set an international convention to not report biogenic CO₂ released due to landfill decomposition in the Waste sector (IPCC 2006). Carbon dioxide emissions from landfills are estimated and reported under the Land Use, Land-Use Change, and Forestry (LULUCF) sector (see Box 7-4). Additionally, emissions of NMOC and VOC are not estimated because they are considered to be emitted in trace amounts. Nitrous oxide (N₂O) emissions from the disposal and application of sewage sludge on landfills are also not explicitly modeled as part of greenhouse gas emissions from landfills. Nitrous oxide emissions from sewage sludge applied to landfills as a daily cover or for disposal are expected to be relatively small because the microbial environment in an anaerobic landfill is not very conducive to the nitrification and denitrification processes that result in N₂O emissions. Furthermore, the *2006 IPCC Guidelines* did not include a methodology for estimating N₂O emissions from solid waste disposal sites “because they are not significant.” Therefore, only CH₄ generation and emissions are estimated for landfills under the Waste sector.

Methane generation and emissions from landfills are a function of several factors, including: (1) the total amount of waste-in-place, which is the total waste landfilled annually over the operational lifetime of a landfill; (2) the characteristics of the landfill receiving waste (e.g., composition of waste-in-place, size, climate, cover material); (3) the amount of CH₄ that is recovered and either flared or used for energy purposes; and (4) the amount of CH₄ oxidized as the landfill gas passes through the cover material into the atmosphere. Each landfill has unique characteristics, but all managed landfills practice similar operating practices, including the application of a daily and intermediate cover material over the waste being disposed of in the landfill to prevent odor and reduce risks to public health. Based on recent literature, the specific type of cover material used can affect the rate of oxidation of landfill gas (RTI 2011). The most commonly used cover materials are soil, clay, and sand. Some states also permit the use of green waste, tarps, waste derived materials, sewage sludge or biosolids, and contaminated soil as a daily cover. Methane production typically begins within the first year after the waste is disposed of in a landfill and will continue for 10 to 60 years or longer as the degradable waste decomposes over time.

In 2014, landfill CH₄ emissions were approximately 148.0 MMT CO₂ Eq. (5,919 kt), representing the third largest source of CH₄ emissions in the United States, behind natural gas systems and enteric fermentation. Emissions from MSW landfills accounted for approximately 95 percent of total landfill emissions, while industrial landfills accounted for the remainder. Approximately 1,900 to 2,000 operational MSW landfills exist in the United States, with the largest landfills receiving most of the waste and generating the majority of the CH₄ emitted (EPA 2015b; EPA 2015c). Conversely, there are approximately 3,200 MSW landfills in the United States that have been closed since 1980 (for which a closure data is known, [EPA 2015b; WBJ 2010]). While the number of active MSW landfills has decreased significantly over the past 20 years, from approximately 6,326 in 1990 to approximately 2,000 in the 2010s, the average landfill size has increased (EPA 2015c; BioCycle 2010; WBJ 2010). The exact number of active and closed dedicated industrial waste landfills is not known at this time, but the Waste Business Journal total for landfills accepting industrial and construction and demolition debris for 2010 is 1,305 (WBJ 2010). Only 176 facilities with industrial waste landfills reported under Subpart TT (Industrial Waste Landfills) of EPA’s Greenhouse Gas Reporting Program (GHGRP) since reporting began in 2011, indicating that there may be several hundreds of industrial waste landfills that are not required to report under EPA’s GHGRP, or that the actual number of industrial waste landfills in the United States is relatively low compared to MSW landfills.

The estimated annual quantity of waste placed in MSW landfills increased 39 percent from approximately 205 MMT in 1990 to 226 MMT in 2000 and then decreased by 11 percent to 262 MMT in 2014 (see Annex 3.14). The annual amount of waste generated and subsequently disposed in MSW landfills varies annually and depends on several factors (e.g., the economy, consumer patterns, recycling and composting programs, inclusion in a garbage collection service). The total amount of MSW generated is expected to increase as the U.S. population continues to grow, but the percentage of waste landfilled may decline due to increased recycling and composting practices. The estimated quantity of waste placed in industrial waste landfills (from the pulp and paper, and food processing sectors) has remained relatively steady since 1990, ranging from 9.7 MMT in 1990 to 11.3 MMT in 2014.

Net CH₄ emissions have decreased since 1990, and have fluctuated around 6 MMT over the past few years (see Table 7-4). This slowly decreasing trend since the 1990’s can be mostly attributed to an approximately 21 percent reduction in the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills over the time series (EPA 2015c) and an increase in the amount of landfill gas collected

and combusted (i.e., used for energy or flared) at MSW landfills, resulting in lower net CH₄ emissions from MSW landfills. For instance, in 1990, approximately 0.7 MMT of CH₄ were recovered and combusted from landfills, while in 2014, approximately 7.5 MMT of CH₄ were recovered and combusted, representing an average annual increase in the quantity of CH₄ recovered and combusted at MSW landfills from 1990 to 2014 of 11 percent (see Annex 3.14). Landfill gas collection and control is not accounted for at industrial waste landfills in this chapter (see the Methodology discussion for more information).

The quantity of recovered CH₄ that is either flared or used for energy purposes at MSW landfills has continually increased as a result of 1996 federal regulations that require large MSW landfills to collect and combust landfill gas (see 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005). Voluntary programs that encourage CH₄ recovery and beneficial reuse, such as EPA's Landfill Methane Outreach Program (LMOP) and federal and state incentives that promote renewable energy (e.g., tax credits, low interest loans, and Renewable Portfolio Standards), have also contributed to increased interest in landfill gas collection and control. In 2014, an estimated 10 new landfill gas-to-energy (LFGTE) projects (EPA 2015a; EPA 2015b) and 3 new flares began operation. While the amount of landfill gas collected and combusted continues to increase every year, the rate of increase in collection and combustion no longer exceeds the rate of additional CH₄ generation from the amount of organic MSW landfilled as the U.S. population grows.

Table 7-3: CH₄ Emissions from Landfills (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| MSW Landfills | 205.3 | 287.0 | 321.0 | 325.2 | 328.6 | 332.0 | 335.4 |
| Industrial Landfills | 12.1 | 15.9 | 16.4 | 16.4 | 16.5 | 16.5 | 16.6 |
| Recovered | (17.9) | (131.8) | (179.5) | (181.2) | (187.0) | (188.2) | (187.7) |
| Oxidized ^a | (20.0) | (17.1) | (15.8) | (16.0) | (15.8) | (16.0) | (16.4) |
| Total | 179.6 | 154.0 | 142.1 | 144.4 | 142.3 | 144.3 | 148.0 |

^a Includes oxidation at municipal and industrial landfills.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 7-4: CH₄ Emissions from Landfills (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| MSW Landfills | 8,214 | 11,482 | 12,839 | 13,008 | 13,144 | 13,280 | 13,418 |
| Industrial Landfills | 484 | 636 | 656 | 657 | 659 | 661 | 665 |
| Recovered | (718) | (5,272) | (7,178) | (7,249) | (7,480) | (7,529) | (7,507) |
| Oxidized ^a | (798) | (685) | (632) | (642) | (632) | (641) | (658) |
| Total | 7,182 | 6,161 | 5,685 | 5,774 | 5,691 | 5,772 | 5,919 |

^a Includes oxidation at municipal and industrial landfills.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

Methane emissions from landfills were estimated as the CH₄ produced from MSW landfills, plus the CH₄ produced by industrial waste landfills, minus the CH₄ recovered and combusted from MSW landfills, minus the CH₄ oxidized before being released into the atmosphere:

$$CH_{4,Solid\ Waste} = [CH_{4,MSW} + CH_{4,Ind} - R] - Ox$$

where,

- CH_{4,Solid Waste} = CH₄ emissions from solid waste
- CH_{4,MSW} = CH₄ generation from MSW landfills
- CH_{4,Ind} = CH₄ generation from industrial landfills
- R = CH₄ recovered and combusted (only for MSW landfills)
- Ox = CH₄ oxidized from MSW and industrial waste landfills before release to the atmosphere

The methodology for estimating CH₄ emissions from landfills is based on the first order decay (FOD) model described by the 2006 IPCC Guidelines. Methane generation is based on nationwide MSW generation data, to

which a national average disposal factor is applied; it is not landfill-specific. The amount of CH₄ recovered, however, is landfill-specific, but only for MSW landfills due to a lack of data specific to industrial waste landfills. Values for the CH₄ generation potential (L₀) and the decay rate constant (k) used in the first order decay model were obtained from an analysis of CH₄ recovery rates for a database of 52 landfills and from published studies of other landfills (RTI 2004; EPA 1998; SWANA 1998; Peer, Thorneloe, and Epperson 1993). The decay rate constant was found to increase with average annual rainfall; consequently, values of k were developed for three ranges of rainfall, or climate types (wet, arid, and temperate). The annual quantity of waste placed in landfills was apportioned to the three ranges of rainfall based on the percent of the U.S. population in each of the three ranges. Historical census data were used to account for the shift in population to more arid areas over time (U.S. Census Bureau 2015). An overview of the data sources and methodology used to calculate CH₄ generation and recovery is provided below, while a more detailed description of the methodology used to estimate CH₄ emissions from landfills can be found in Annex 3.14.

States and local municipalities across the United States do not consistently track and report quantities of MSW generated or collected for management, nor are end-of-life disposal methods reported to a centralized system. Therefore, national MSW landfill waste generation and disposal data are obtained from secondary data, specifically the State of Garbage (SOG) surveys, published approximately every two years, with the most recent publication date of 2014. The SOG survey is the only continually updated nationwide survey of waste disposed in landfills in the United States and is the primary data source with which to estimate nationwide CH₄ generation from MSW landfills. The SOG surveys use the principles of mass balance where all MSW generated is equal to the amount of MSW landfilled, combusted in waste-to-energy plants, composted, and/or recycled (BioCycle 2010; Shin 2014). This approach assumes that all waste management methods are tracked and reported to state agencies. Survey respondents are asked to provide a breakdown of MSW generated and managed by landfilling, recycling, composting, and combustion (in waste-to-energy facilities) in actual tonnages as opposed to reporting a percent generated under each waste disposal option. The data reported through the survey have typically been adjusted to exclude non-MSW materials (e.g., industrial and agricultural wastes, construction and demolition debris, automobile scrap, and sludge from wastewater treatment plants) that may be included in survey responses. In the most recent survey, state agencies were asked to provide already filtered, MSW-only data. Where this was not possible, they were asked to provide comments to better understand the data being reported. All state disposal data are adjusted for imports and exports across state lines where imported waste is included in a particular state's total while exported waste is not. Methodological changes have occurred over the time frame the SOG survey has been published, and this has affected the fluctuating trends observed in the data (RTI 2013).

The SOG survey is voluntary and not all states provide data for each survey year. Where no waste generation data are provided by a state in the SOG survey, the amount generated is estimated by multiplying the waste per capita from a previous SOG survey by that particular state's population. If that particular state did not report any waste generation data in the previous SOG survey, the average nationwide waste per capita rate for the current SOG survey is multiplied by that particular state's population. The quantities of waste generated across all states are summed and that value is then used as the nationwide quantity of waste generated in a given reporting year. Additionally, because the SOG survey does not account for waste generated in U.S. Territories, waste generation for the territories was estimated using population data obtained from the U.S. Census Bureau (2014) and national per capita solid waste generation from the SOG survey (Shin 2014).

State-specific landfill waste generation data and a national average disposal factor for 1989 through 2008 were obtained from the SOG survey every two years (i.e., 2002, 2004, 2006, and 2008 as published in BioCycle 2006, and 2008 as published in BioCycle 2010). The most recent SOG survey provides data for 2011 (Shin 2014). State-specific landfill waste generation data for the years in-between the SOG surveys (e.g., 2001, 2003, 2005, 2007, 2009, 2010, 2012, 2013, and 2014) were either interpolated or extrapolated based on the SOG data and the U.S. Census population data. Because the most recent SOG survey was published in 2014 for the 2011 year, the annual quantities of waste generated for the years 2012 to 2014 were extrapolated based on the 2011 data and population growth. Waste generation data for 2012 through 2014 will be updated as new SOG surveys are published.

Estimates of the quantity of waste landfilled from 1989 to 2014 are determined by applying an average national waste disposal factor to the total amount of waste generated (i.e., the SOG data). A waste disposal factor is determined for each year an SOG survey is published and equals the ratio of the total amount of waste landfilled in the United States to the total amount of waste generated in the United States. The waste disposal factor is interpolated or extrapolated for the years in-between the SOG surveys, as is done for the amount of waste generated for a given survey year.

Estimates of the annual quantity of waste landfilled for 1960 through 1988 were obtained from EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990: Report to Congress* (EPA 1993) and an extensive landfill survey by the EPA's Office of Solid Waste in 1986 (EPA 1988). Although waste placed in landfills in the 1940s and 1950s contributes very little to current CH₄ generation, estimates for those years were included in the FOD model for completeness in accounting for CH₄ generation rates and are based on the population in those years and the per capita rate for land disposal for the 1960s. For calculations in the current Inventory, wastes landfilled prior to 1980 were broken into two groups: wastes disposed in landfills (Methane Conversion Factor, MCF, of 1) and those disposed in dumps (MCF of 0.6). All calculations after 1980 assume waste is disposed in managed, modern landfills. See Annex 3.14 for more details.

Methane recovery is currently only accounted for at MSW landfills. Data collected through EPA's GHGRP for industrial waste landfills (Subpart TT) show that only two of the 176 facilities, or 1 percent of facilities, have active gas collection systems (EPA 2015b). EPA's GHGRP is not a national database and comprehensive data regarding gas collection systems have not been published for industrial waste landfills. Assumptions regarding a percentage of landfill gas collection systems, or a total annual amount of landfill gas collected for the non-reporting industrial waste landfills have not been made for the Inventory methodology.

The estimated landfill gas recovered per year (R) at MSW landfills was based on a combination of four databases and including recovery from flares and/or landfill gas-to-energy projects:

- EPA's GHGRP dataset for MSW landfills (EPA 2015b);
- A database developed by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007);
- A database of LFGTE projects that is primarily based on information compiled by the EPA LMOP (EPA 2015a); and
- The flare vendor database (contains updated sales data collected from vendors of flaring equipment).

The same landfill may be included one or more times across these four databases. To avoid double- or triple-counting CH₄ recovery, the landfills across each database were compared and duplicates identified. A hierarchy of recovery data is used based on the certainty of the data in each database. In summary, the GHGRP > EIA > LFGTE > flare vendor database. The rationale for this hierarchy is described below.

EPA's GHGRP MSW landfills database was first introduced as a data source for the 1990 to 2013 Inventory. EPA's GHGRP MSW landfills database contains facility-reported data that undergoes rigorous verification, thus it is considered to contain the least uncertain data of the four databases. However, as mentioned earlier, this database is unique in that it only contains a portion of the landfills in the United States (although, presumably the highest emitters since only those landfills that meet a certain CH₄ generation threshold must report) and only contains data for 2010 and later. Directly reported values for CH₄ recovery to the GHGRP database were used for years 2010 through 2014. Methane recovery prior to 2010 has been estimated using an Excel forecasting function so that the GHGRP data source can be applied to the entire time series (1990 to 2014) instead of 2010 to 2014 only. If a landfill in EPA's GHGRP was also in the LFGTE or EIA databases, the landfill gas project information, specifically the project start year, from either the LFGTE or EIA databases was used as the cutoff year for the estimated CH₄ recovery in the GHGRP database. For example, if a landfill reporting under EPA's GHGRP was also included in the LFGTE database under a project that started in 2002 that is still operational, the CH₄ recovery in the GHGRP database was back-calculated to the year 2002 only. This method, although somewhat uncertain, can be refined in future Inventory years after further investigating the landfill gas project start years for landfills in the GHGRP database.

If a landfill in the GHGRP MSW landfills database was also in the EIA, LFGTE, and/or flare vendor database, the avoided emissions were only based on EPA's GHGRP MSW landfills database to avoid double or triple counting the recovery amounts. In other words, the recovery from the same landfill was not included in the total recovery from the EIA, LFGTE, or flare vendor databases.

If a landfill in the EIA database was also in the LFGTE and/or the flare vendor database, the CH₄ recovery was based on the EIA data because landfill owners or operators directly reported the amount of CH₄ recovered using gas flow concentration and measurements, and because the reporting accounted for changes over time. However, as the EIA database only includes facility-reported data through 2006, the amount of CH₄ recovered for years 2007 and later were assumed to be the same as in 2006 for landfills that are in the EIA database, but not in the GHGRP or LFGTE databases. This quantity likely underestimates flaring because the EIA database does not have information

on all flares in operation for the years after 2006. However, nearly all (93 percent) of landfills in the EIA database also report to the GHGRP, which means that only seven percent of landfills in the EIA database are counted in the total recovery.

If both the flare data and LFGTE recovery data were available for any of the remaining landfills (i.e., not in the EIA or GHGRP databases), then the avoided emissions were based on the LFGTE data, which provides reported landfill-specific data on gas flow for direct use projects and project capacity (i.e., megawatts) for electricity projects. The LFGTE database is based on the most recent EPA LMOP database (published annually). The remaining portion of avoided emissions is calculated by the flare vendor database, which estimates CH₄ combusted by flares using the midpoint of a flare's reported capacity. New flare vendor sales data were unable to be obtained for the current Inventory year. Given that each LFGTE project is likely to also have a flare, double counting reductions from flares and LFGTE projects in the LFGTE database was avoided by subtracting emission reductions associated with LFGTE projects for which a flare had not been identified from the emission reductions associated with flares (referred to as the flare correction factor). A further explanation of the methodology used to estimate the landfill gas recovered can be found in Annex 3.14.

The destruction efficiencies reported through EPA's GHGRP were applied to the landfills in the GHGRP MSW landfills database. The median value of the reported destruction efficiencies was 99 percent for all reporting years (2010 through 2014). A destruction efficiency of 99 percent was applied to CH₄ recovered to estimate CH₄ emissions avoided due to the combusting of CH₄ in destruction devices (i.e., flares) in the EIA, LFGTE, and flare vendor databases. The 99 percent destruction efficiency value selected was based on the range of efficiencies (86 to greater than 99 percent) recommended for flares in EPA's *AP-42 Compilation of Air Pollutant Emission Factors*, Draft Section 2.4, Table 2.4-3 (EPA 2008). A typical value of 97.7 percent was presented for the non-CH₄ components (i.e., volatile organic compounds and non-methane organic compounds) in test results (EPA 2008). An arithmetic average of 98.3 percent and a median value of 99 percent are derived from the test results presented in EPA (2008). Thus, a value of 99 percent for the destruction efficiency of flares has been used in the Inventory methodology. Other data sources supporting a 99 percent destruction efficiency include those used to establish New Source Performance Standards (NSPS) for landfills and in recommendations for shutdown flares used by the EPA LMOP.

Emissions from industrial waste landfills were estimated from industrial production data from 2013 extrapolated to 2014 (ERG 2014), waste disposal factors, and the FOD model. The Inventory methodology assumes over 99 percent of the organic waste placed in industrial waste landfills originates from the food processing (meat, vegetables, fruits) and pulp and paper sectors (EPA 1993), thus estimates of industrial landfill emissions focused on these two sectors. There are currently no data sources that track and report the amount and type of waste disposed of in the universe of industrial waste landfills in the United States. EPA's GHGRP provides some insight into waste disposal in industrial waste landfills and supports the focus of the Inventory on the two selected sectors, but is not comprehensive. Therefore, the amount of waste landfilled is assumed to be a fraction of production that is held constant over the time series as explained in Annex 3.14. The composition of waste disposed of in industrial waste landfills is expected to be more consistent in terms of composition and quantity than that disposed of in MSW landfills.

The amount of CH₄ oxidized by the landfill cover at both municipal and industrial waste landfills was assumed to be 10 percent of the CH₄ generated that is not recovered (IPCC 2006; Mancinelli and McKay 1985; Czepiel et al. 1996). To calculate net CH₄ emissions, both CH₄ recovered and CH₄ oxidized were subtracted from CH₄ generated at municipal and industrial waste landfills.

Uncertainty and Time-Series Consistency

Several types of uncertainty are associated with the estimates of CH₄ emissions from MSW and industrial waste landfills. The primary uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH₄ production: the amount and composition of waste placed in every MSW and industrial waste landfill for each year of a landfill's operation. The *SOG survey* is the only nationwide data source that compiles the amount of MSW disposed at the state-level. The surveys do not include information on waste composition and there are no comprehensive data sets that compile quantities of waste disposed or waste composition by landfill. EPA's GHGRP allows facilities to report annual quantities of waste disposed by composition, but most MSW landfills report annual waste disposed as bulk MSW versus the detailed waste

composition data. Some MSW landfills have conducted detailed waste composition studies, but the data are scarce over the time series and across the country. EPA is currently compiling the waste composition studies and data that have been performed in the past decade and may revise the default waste composition applied to MSW landfilled in the FOD model in future Inventory estimates.

The approach used in the solid waste emission estimates assumes that the CH₄ generation potential (L₀) and the rate of decay that produces CH₄ from MSW, as determined from several studies of CH₄ recovery at MSW landfills, are representative of conditions at U.S. MSW landfills. When this top-down approach is applied at the nationwide level, the uncertainties are assumed to be less than when applying this approach to individual landfills and then aggregating the results to the national level. In other words, the Inventory methodology is not facility-specific modeling and while this approach may over- or under-estimate CH₄ generation at some landfills if used at the facility-level, the end result is expected to balance out because it is being applied nationwide. There is also a high degree of uncertainty and variability associated with the FOD model, particularly when a homogeneous waste composition and hypothetical decomposition rates are applied to heterogeneous landfills (IPCC 2006).

The lack of landfill-specific information regarding the number and type of industrial waste landfills in the United States is a primary uncertainty with respect to the industrial waste generation and emissions estimates. The approach used here assumes that the majority (99 percent) of industrial waste disposed of in industrial waste landfills consists of waste from the pulp and paper and food processing sectors. However, because waste generation and disposal data are not available in an existing data source for all U.S. industrial waste landfills, a straight disposal factor is applied over the entire time series to the amount of waste generated to determine the amounts disposed. Industrial waste facilities reporting under EPA's GHGRP do report detailed waste stream information, and these data have been used to improve, for example, the DOC value used in the Inventory methodology for the pulp and paper sector.

Aside from the uncertainty in estimating landfill CH₄ generation, uncertainty also exists in the estimates of the landfill gas oxidized. A constant oxidation factor of 10 percent as recommended by the IPCC for managed landfills is used for both MSW and industrial waste landfills regardless of climate, the type of cover material, and/or presence of a gas collection system. The number of published field studies measuring the rate of oxidation has increased substantially since the *2006 IPCC Guidelines* were published and, as discussed in the Potential Improvements section, efforts are being made to review the literature and revise this value based on recent, peer-reviewed studies.

Another significant source of uncertainty lies with the estimates of CH₄ recovered by flaring and gas-to-energy projects at MSW landfills. The GHGRP MSW landfills database was added as a fourth recovery database in the 1990 through 2013 Inventory report. Relying on multiple databases for a complete picture introduces uncertainty because the coverage and characteristics of each database differs, which increases the chance of double counting avoided emissions. Additionally, the methodology and assumptions that go into each database differ. For example, the flare database assumes the midpoint of each flare capacity at the time it is sold and installed at a landfill; in reality, the flare may be achieving a higher capacity, in which case the flare database would underestimate the amount of CH₄ recovered.

The LFGTE database is updated annually. The flare database is populated by the voluntary sharing of flare sales data by select vendors and is not able to be obtained annually, which likely underestimates recovery for landfills not included in the three other recovery databases used by the Inventory. The EIA database has not been updated since 2006 and has, for the most part, been replaced by the GHGRP MSW landfills database. To avoid double counting and to use the most relevant estimate of CH₄ recovery for a given landfill, a hierarchical approach is used among the four databases. GHGRP data are given precedence because CH₄ recovery is directly reported by landfills and undergoes a rigorous verification process; the EIA data are given second priority because facility data were directly reported; the LFGTE data are given third priority because CH₄ recovery is estimated from facility-reported LFGTE system characteristics; and the flare data are given fourth priority because this database contains minimal information about the flare, no site-specific operating characteristics, and includes smaller landfills not included in the other three databases (Bronstein et al. 2012). The coverage provided across the databases most likely represents the complete universe of landfill CH₄ gas recovery; however, the number of unique landfills between the four databases does differ.

The IPCC default value of 10 percent for uncertainty in recovery estimates was used for two of the four recovery databases in the uncertainty analysis where metering of landfill gas was in place (for about 64 percent of the CH₄ estimated to be recovered). This 10 percent uncertainty factor applies to the LFGTE database; 12 percent to the EIA database; and 1 percent for the GHGRP MSW landfills dataset because of the supporting information provided and

rigorous verification process. For flaring without metered recovery data (the flare database), a much higher uncertainty value of 50 percent is used. The compounding uncertainties associated with the four databases in addition to the uncertainties associated with the FOD model and annual waste disposal quantities leads to the large upper and lower bounds for MSW landfills presented in Table 7-5. Industrial waste landfills are shown with a lower range of uncertainty due to the smaller number of data sources and associated uncertainty involved. For example, three data sources are used to generate the annual quantities of MSW waste disposed over the 1940 to current year timeframe, while industrial waste landfills rely on two data sources.

The results of the 2006 IPCC Guidelines Approach 2 quantitative uncertainty analysis are summarized in Table 7-5. In 2014, landfill CH₄ emissions were estimated to be between 86.4 and 230.0 MMT CO₂ Eq., which corresponds to a range of 38 percent below to 64 percent above the 2014 emission estimate of 148.0 MMT CO₂ Eq.

Table 7-5: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Landfills (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a (%) | | | |
|------------|-----------------|--|--|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Landfills | CH ₄ | 148.0 | 86.4 | 230.0 | -38% | +64% |
| MSW | CH ₄ | 133.0 | 72.5 | 216.7 | -42% | +73% |
| Industrial | CH ₄ | 15.0 | 10.4 | 18.7 | -30% | +25% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

QA/QC and Verification

A Quality Assurance/Quality Control analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are performed for the transcription of the published data set used to populate the Inventory data set, including the published GHGRP and LFGTE databases, but are not performed on the data itself against primary data used. A primary focus of the QA/QC checks was to ensure that CH₄ recovery estimates were not double-counted and that all LFGTE projects and flares were included in the respective project databases. Both manual and electronic checks were used to ensure that emission avoidance from each landfill was calculated only once. The primary calculation spreadsheet is tailored from the IPCC waste model and has been verified previously using the original, peer-reviewed IPCC waste model. All model input values were verified by secondary QA/QC review.

Recalculations Discussion

Four major methodological recalculations were performed for the current Inventory.

First, a rigorous review of the flare and LFGTE projects across the four recovery databases was conducted. Extensive corrections were made to avoid double counting of projects across the recovery databases. The largest change compared to the previous Inventory was in the LFGTE database where an additional 382 projects were matched to facilities reporting under the GHGRP (note that a landfill may have multiple projects and new facilities have reported under the GHGRP for the first time since the initial landfill matching exercise in 2012). This additional matching results in a decrease in total recovery compared to the previous Inventory by approximately 1 MMT. The second largest change compared to the previous Inventory was in the flare database where 79 flare projects were matched to facilities reporting under the GHGRP or included in the LFGTE database. These projects, which were double-counted in previous Inventories, account for approximately 0.44 MMT of avoided emissions. Oftentimes, the name of a landfill and/or address differs between the databases and additional Internet searching allows for the landfills to be matched. Additionally, several facilities in the LFGTE database were removed because

they were not in the published LMOP database for the current or past two years (EPA 2015a). The LFGTE is an enhanced version of the LMOP database and if a landfill is no longer in the LMOP database, the Inventory assumes it was added erroneously. These revisions resulted in larger than expected changes to the annual quantities of the annual CH₄ recovery estimates used in the net CH₄ emissions compared to the previous Inventory, and, in turn, an increase in net CH₄ emissions across the time series.

Second, the GHGRP CH₄ recovery data were back-calculated for landfills in the GHGRP database for years prior to the first GHGRP reporting year (typically 2010 for most landfills). In the previous Inventory, there was a significant change in the total recovery between years 2009 and 2010. This methodological change was made to smooth the recovery data for years prior to 2009. An Excel forecast function was used to back-calculate recovery to an assumed project start year based on four years of reported recovery data for each landfills and project information contained in the LFGTE and EIA databases.

Third, the flare correction factor was revised. This effort included reviewing the 27 flare projects included in the flare correction factor to identify them with landfills in the GHGRP, LFGTE, or EIA databases, or match them to existing operational or closed landfills through and Internet search (RTI 2015a). The number of flares included in the flare correction factor decreased from 27 to 19. The impact on CH₄ recovery varies by year and is a modest amount.

Fourth, the DOC value for landfilled pulp and paper waste was revised from 0.20 to 0.15 based a literature review of pulp and paper waste characterization studies (RTI 2015b) and data reported under the GHGRP. A representative DOC value is likely to be within the range of 0.15 to 0.16 as calculated using the facility-specific DOC values reported under Subpart TT and data presented in Heath et al. (2010). However, a lower DOC value of 0.10 was calculated when considering only the 21 out of 76 pulp and paper facilities that provided waste-stream-specific DOC values in their 2013 annual reports. Further refined data may be available in future GHGRP reporting years as additional facilities choose to perform waste stream-specific analyses. Revising the DOC value for pulp and paper waste to 0.15 at this time is a conservative approach. This value will be re-assessed in future Inventory years as more information becomes available.

The overall impact to the Inventory from these changes resulted in an average increase of nearly 14 percent across the time series. A significant increase in net CH₄ emissions for the years 2010 through 2013 ranging from 20 to 52 percent higher in the current Inventory compared to the 1990 to 2013 Inventory.

Planned Improvements

Improvements being examined for future Inventory estimates include: (1) investigating alternative data sources for nationwide MSW disposal; (2) incorporating additional data from recent peer-reviewed literature to modify the default oxidation factor applied to MSW and industrial waste landfills (currently 10 percent); (3) either modifying the bulk MSW DOC value or estimating emissions using a waste-specific approach in the FOD model using data from the GHGRP and peer-reviewed literature; (4) reviewing waste-stream specific DOC and decay rate constant (k) value data reported for industrial waste landfills (specifically pulp and paper waste) as reported under EPA's GHGRP; and (5) increasing communications with flare vendors to obtain methane recovery data for landfills not reporting to EPA's GHGRP or providing information to LMOP.

The EPA has relied on a top-down approach to calculate CH₄ generation for MSW landfills. The *SOG survey* has been used in the current and previous Inventories, but is not anticipated to be published as routinely as it has been in the past. EPA is investigating whether a bottom-up approach can be used in future Inventories by supplementing the GHGRP annual waste disposal data with other relevant datasets (e.g., LMOP, state data) to provide the annual waste disposal data needed for the FOD model. EPA's GHGRP requires landfills meeting or exceeding a threshold of 25,000 metric tons of CH₄ generation per year to report a variety of facility-specific information, including historical and current waste disposal quantities by year, CH₄ generation, gas collection system details, CH₄ recovery, and CH₄ emissions. The landfills reporting to the GHGRP are considered the largest emitters, but not all landfills are required to report. However, when this dataset is supplemented with others, such as the EPA LMOP data (incorporated into the Inventory through the LFGTE database), or the Waste Business Journal data, a complete data set of the annual quantity of waste landfilled may be represented.

In the draft for the 1990 through 2014 Inventory released for its public comment period, the EPA incorporated year-to-year, facility-level waste disposal quantities as reported to EPA's GHGRP, supplemented with data from LMOP.

The FOD model was then applied using a bulk waste DOC value of 0.20, as has been utilized as the best methodological approach for previous Inventory emission estimates. This recalculation resulted in a large increase in estimated CH₄ emissions from landfills over the time series of the Inventory. During the public comment period on the draft Inventory, the EPA received comments from the waste industry that, while the 0.20 DOC is appropriate for MSW bulk waste, there is a substantial amount of inert waste disposed in addition to that MSW bulk waste which should instead be assigned a DOC value of zero because it does not contribute to CH₄ generation. According to these waste industry comments, the addition of inerts is a trend that has been occurring for many years at MSW landfills. Despite the use of the same FOD methodology and same assumptions on DOC for estimating emissions from MSW landfills, the EPA had not received this information from the waste industry during previous public comment periods on prior draft Inventory reports. The EPA has determined that further review of the waste disposal quantities and DOC values reported to EPA's GHGRP using the approved reporting requirements is necessary in light of the waste industry comments on the draft Inventory. As such, the recalculation presented in the draft Inventory using the GHGRP waste disposal data was not incorporated for the final Inventory report. The integration of the GHGRP data will be explored further with additional waste industry stakeholder input so that it may be used, and so that recalculated emission estimates can be provided in the 1990 through 2015 Inventory.

A standard CH₄ oxidation factor of 10 percent has been used for both industrial and MSW landfills in prior Inventory reports and is currently recommended as the default for well-managed landfills in the latest *IPCC Guidelines* (2006). Recent comments on the Inventory methodology indicated that a default oxidation factor of 10 percent may be less than oxidation rates achieved at well-managed landfills with gas collection and control. As a first step toward revising this oxidation factor, a literature review was conducted in 2011 (RTI 2011). In addition, facilities reporting under EPA's GHGRP have the option to use an oxidation factor other than 10 percent (e.g., 0, 25, or 35 percent) if the calculated result of CH₄ flux calculations warrants it. Various options are being investigated to incorporate this facility-specific data for landfills reporting under EPA's GHGRP and/or the remaining facilities.

The standard oxidation factor (10 percent) is applied to the total amount of waste generated nationwide. Changing the oxidation factor and calculating the amount of CH₄ oxidized from landfills with gas collection and control requires the estimation of waste disposed in these types of landfills over the entire time series. Although EPA's GHGRP does not capture every landfill in the United States, larger landfills are expected to meet the reporting thresholds and are reporting waste disposal information by year. At this time, data are available to calculate the amount of waste disposed of at landfills with and without gas collection systems in the United States for landfills reporting under EPA's GHGRP. After investigating the landfills not reporting under EPA's GHGRP to determine the presence of a landfill gas collection and control system and waste disposal data, a modification to the Inventory waste model to apply different oxidation factors depending on the presence of a gas collection system may be possible.

Other potential improvements to the methodology may be made in the future using other portions of the GHGRP dataset, specifically for inputs to the FOD equation. The approach used in the Inventory to estimate CH₄ generation assumes a bulk waste-specific DOC value that may not accurately capture the changing waste composition over the time series (e.g., the reduction of organics entering the landfill environment due to increased composting, see Box 7-2). Using data obtained from EPA's GHGRP and any publicly available landfill-specific waste characterization studies in the United States, the methodology may be modified to incorporate a waste composition approach, or revisions may be made to the bulk waste DOC value currently used. Additionally, GHGRP data could be analyzed and a weighted average for the CH₄ correction factor (MCF), fraction of CH₄ (F) in the landfill gas, the destruction efficiency of flares, and the decay rate constant (k) could replace the values currently used in the Inventory. At this time, the majority of landfills reporting under EPA's GHGRP select bulk MSW for their waste composition.

In addition to MSW landfills, industrial waste landfills at facilities emitting CH₄ in amounts equivalent to 25,000 metric tons or more of CO₂ Eq. were required to report their GHG emissions beginning in September 2012 through EPA's GHGRP. Similar data for industrial waste landfills as is required for the MSW landfills are being reported. Any additions or improvements to the Inventory using reported GHGRP data will be made for the industrial waste landfill source category. As mentioned in the recalculation discussion, the DOC value for pulp and paper waste will be reviewed against new GHGRP data to determine if further revisions to the DOC value of 0.15 are necessary. Another potential improvement includes a revision to the waste disposal factor currently used by the Inventory for the pulp and paper sector using production data from pulp and paper facilities that reported annual production and annual disposal data under EPA's GHGRP. The addition of industrial sectors other than pulp and paper and food processing (e.g., metal foundries, petroleum refineries, and chemical manufacturing facilities) to the Inventory may also be investigated.

Lastly, voluntary flare sales data was not able to be obtained from vendors who have previously provided this data. The impacts on the Inventory are minimal considering the coverage of EPA's GHGRP and LMOP, but is necessary to provide a representative picture of the extent of CH₄ recovery in the United States.

Box 7-3: Nationwide Municipal Solid Waste Data Sources

Municipal solid waste generated in the United States can be managed through landfilling, recycling, composting, and combustion with energy recovery. There are two main sources for nationwide solid waste management data in the United States:

- The *BioCycle* and Earth Engineering Center of Columbia University's State of Garbage (SOG) in America surveys; and
- The EPA's *Municipal Solid Waste in The United States: Facts and Figures* reports.

The SOG surveys collect state-reported data on the amount of waste generated and the amount of waste managed via different management options: landfilling, recycling, composting, and combustion. The survey asks for actual tonnages instead of percentages in each waste category (e.g., residential, commercial, industrial, construction and demolition, organics, tires) for each waste management option. If such a breakdown is not available, the survey asks for total tons landfilled. The data are adjusted for imports and exports across state lines so that the principles of mass balance are adhered to, whereby the amount of waste managed does not exceed the amount of waste generated. The SOG reports present survey data aggregated to the state level.

The EPA *Facts and Figures* reports use a materials flow methodology, which relies heavily on a mass balance approach. Data are gathered from industry associations, key businesses, similar industry sources, and government agencies (e.g., the Department of Commerce and the U.S. Census Bureau) and are used to estimate tons of materials and products generated, recycled, or discarded nationwide. The amount of MSW generated is estimated by adjusting the imports and exports of produced materials to other countries. MSW that is not recycled, composted, or combusted is assumed to be landfilled. The data presented in the report are nationwide totals.

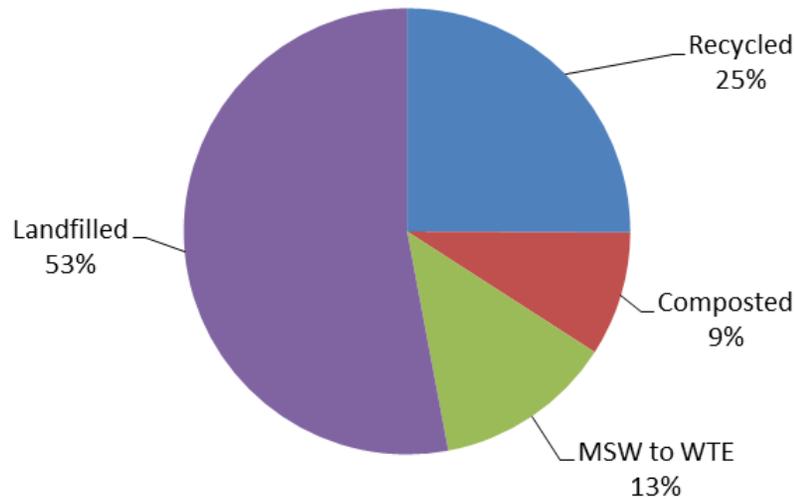
The SOG surveys are the preferred data source for estimating waste generation and disposal amounts in the Inventory because they are considered a more objective, numbers-based analysis of solid waste management in the United States. However, the EPA *Facts and Figures* reports are useful when investigating waste management trends at the nationwide level and for typical waste composition data, which the SOG surveys do not request.

In this Inventory, emissions from solid waste management are presented separately by waste management option, except for recycling of waste materials. Emissions from recycling are attributed to the stationary combustion of fossil fuels that may be used to power on-site recycling machinery, and are presented in the stationary combustion chapter in the Energy sector, although the emissions estimates are not called out separately. Emissions from solid waste disposal in landfills and the composting of solid waste materials are presented in the Landfills and Composting chapters in the Waste sector of this report. In the United States, almost all incineration of MSW occurs at waste-to-energy (WTE) facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Incineration chapter of the Energy sector of this report.

Box 7-4: Overview of the Waste Sector

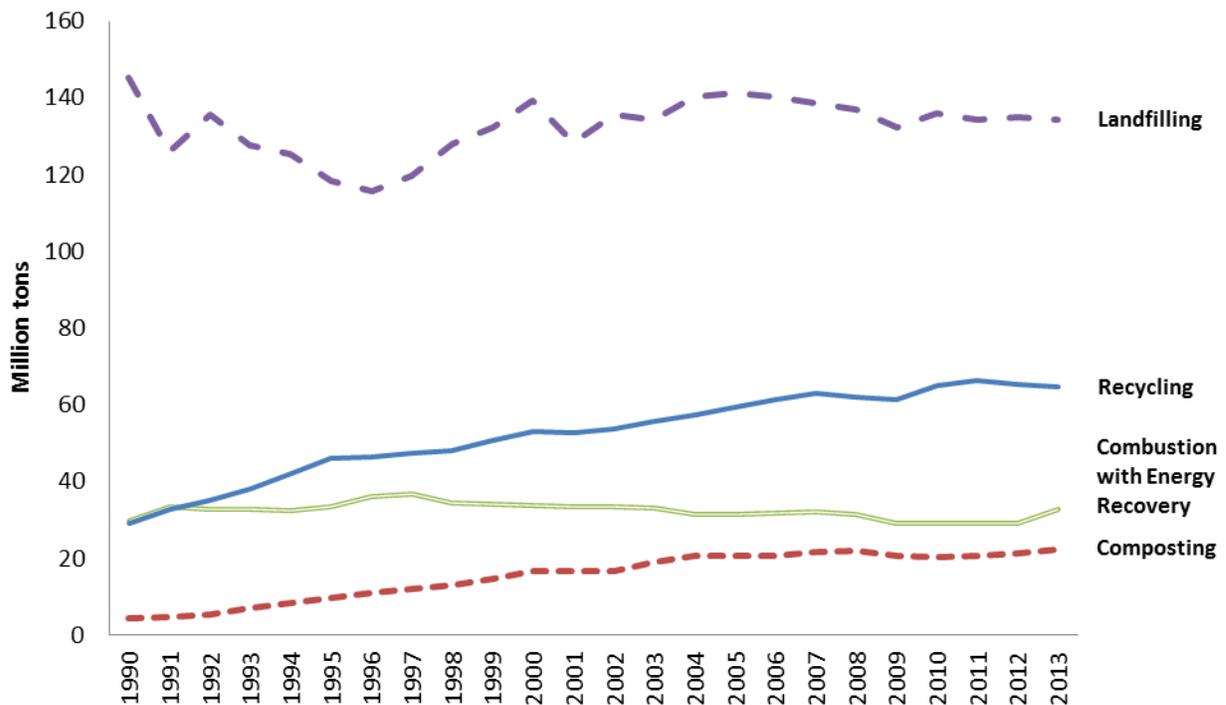
As shown in Figure 7-2 and Figure 7-3, landfilling of MSW is currently and has been the most common waste management practice. A large portion of materials in the waste stream are recovered for recycling and composting, which is becoming an increasingly prevalent trend throughout the country. Materials that are composted and recycled would have normally been disposed of in a landfill.

Figure 7-2: Management of Municipal Solid Waste in the United States, 2013



Source: EPA (2015c).

Figure 7-3: MSW Management Trends from 1990 to 2013



Source: EPA (2015c).

Table 7-6 presents a typical composition of waste disposed of at a typical MSW landfill in the United States over time. It is important to note that the actual composition of waste entering each landfill will vary from that presented in Table 7-6. Understanding how the waste composition changes over time, specifically for the degradable waste types, is important for estimating greenhouse gas emissions. For certain degradable waste types (i.e., paper and paperboard), the amounts discarded have decreased over time due to an increase in waste recovery, including recycling and composting (see Table 7-6 and Figure 7-4) do not reflect the impact of backyard composting on yard

trimming generation and recovery estimates. The recovery of food trimmings has been consistently low. Increased recovery of degradable materials reduces the CH₄ generation potential and CH₄ emissions from landfills.

Table 7-6: Materials Discarded in the Municipal Waste Stream by Waste Type from 1990 to 2013 (Percent)

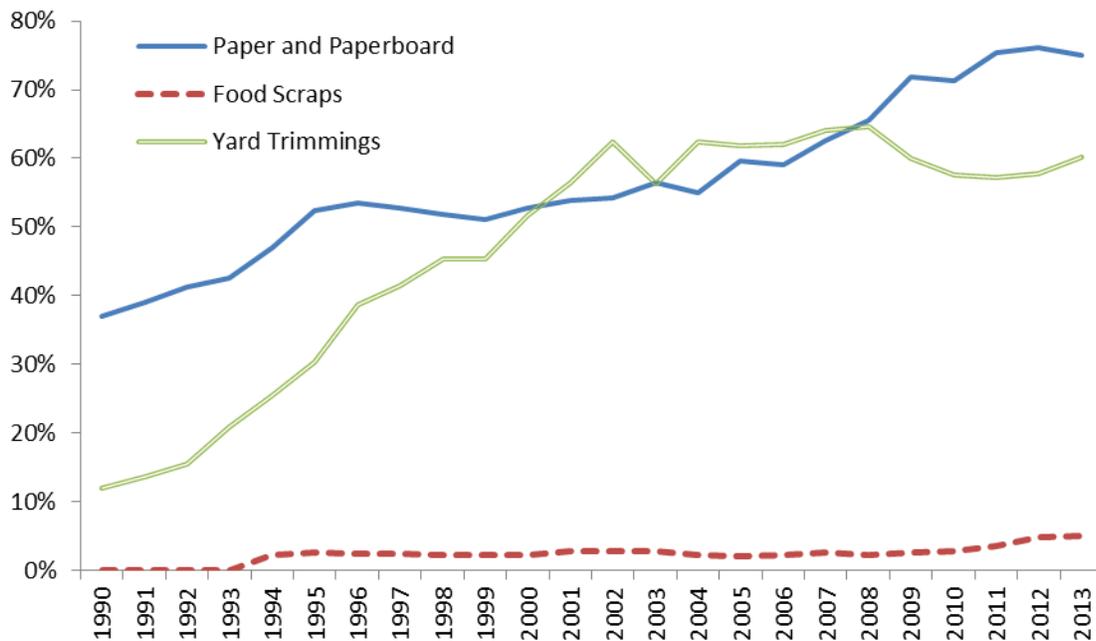
| Waste Type | 1990 | 2005 | 2009 | 2010 | 2011 | 2012 | 2013 |
|--------------------------------|-------|-------|-------|-------|-------|-------|-------|
| Paper and Paperboard | 30.0% | 24.5% | 14.8% | 16.2% | 14.8% | 14.8% | 15.1% |
| Glass | 6.0% | 5.7% | 5.0% | 5.1% | 5.1% | 5.1% | 5.0% |
| Metals | 7.2% | 7.7% | 8.0% | 8.8% | 8.9% | 9.0% | 9.1% |
| Plastics | 9.6% | 15.7% | 15.8% | 17.4% | 17.8% | 17.6% | 17.7% |
| Rubber and Leather | 3.1% | 3.5% | 3.7% | 3.7% | 3.8% | 3.8% | 3.9% |
| Textiles | 2.9% | 5.5% | 6.3% | 6.7% | 6.8% | 7.4% | 7.7% |
| Wood | 6.9% | 7.4% | 7.7% | 8.1% | 8.2% | 8.2% | 8.0% |
| Other ^a | 1.4% | 1.8% | 1.9% | 2.0% | 2.0% | 2.0% | 2.0% |
| Food Scraps ^b | 13.6% | 17.9% | 19.1% | 21.0% | 21.4% | 21.1% | 21.1% |
| Yard Trimmings ^c | 17.6% | 7.0% | 7.6% | 8.6% | 8.8% | 8.7% | 8.1% |
| Miscellaneous Inorganic Wastes | 1.7% | 2.1% | 2.2% | 2.3% | 2.4% | 2.4% | 2.4% |

^a Includes electrolytes in batteries and fluff pulp, feces, and urine in disposable diapers. Details may not add to totals due to rounding (EPA 2015c).

^b Data for food scraps were estimated using sampling studies in various parts of the country in combination with demographic data on population, grocery store sales, restaurant sales, number of employees, and number of prisoners, students, and patients in institutions (EPA 2015c).

^c Data for yard trimmings were estimated using sampling studies, population data, and published sources documenting legislation affecting yard trimmings disposal in landfills (EPA 2015c).

Figure 7-4: Percent of Recovered Degradable Materials from 1990 to 2013 (Percent)



Source: EPA 2015c

Box 7-5: Description of a Modern, Managed Landfill

Modern, managed landfills are well-engineered facilities that are located, designed, operated, and monitored to ensure compliance with federal, state, and tribal regulations. Municipal solid waste (MSW) landfills must be designed to protect the environment from contaminants which may be present in the solid waste stream. Additionally, many new landfills collect and destroy landfill gas through flares or landfill gas-to-energy projects. Requirements for affected MSW landfills may include:

- Siting requirements to protect sensitive areas (e.g., airports, floodplains, wetlands, fault areas, seismic impact zones, and unstable areas);
- Design requirements for new landfills to ensure that Maximum Contaminant Levels (MCLs) will not be exceeded in the uppermost aquifer (e.g., composite liners and leachate collection systems);
- Leachate collection and removal systems;
- Operating practices (e.g., daily and intermediate cover, receipt of regulated hazardous wastes, use of landfill cover material, access options to prevent illegal dumping, use of a collection system to prevent stormwater run-on/run-off, record-keeping);
- Air monitoring requirements (explosive gases);
- Groundwater monitoring requirements;
- Closure and post-closure care requirements (e.g., final cover construction); and
- Corrective action provisions.

Specific federal regulations that affected MSW landfills must comply with include the 40 CFR Part 258 (Subtitle D of RCRA), or equivalent state regulations and the New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart WWW. Additionally, state and tribal requirements may exist.⁶

7.2 Wastewater Treatment (IPCC Source Category 5D)

Wastewater treatment processes can produce anthropogenic methane (CH₄) and nitrous oxide (N₂O) emissions. Wastewater from domestic and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants.⁷ Treatment may either occur on site, most commonly through septic systems or package plants, or off site at centralized treatment systems. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients. In the United States, approximately 20 percent of domestic wastewater is treated in septic systems or other on-site systems, while the rest is collected and treated centrally (U.S. Census Bureau 2013).

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream. Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions, where the latter condition produces CH₄. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions. The generation of N₂O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the nitrogen (N) present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO₃) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the

⁶ For more information regarding federal MSW landfill regulations, see http://www.epa.gov/osw/nonhaz/municipal/landfill/msw_regs.htm.

⁷ Throughout the Inventory, emissions from domestic wastewater also include any commercial and industrial wastewater collected and co-treated with domestic wastewater.

biological conversion of nitrate into dinitrogen gas (N₂). Nitrous oxide can be an intermediate product of both processes, but has typically been associated with denitrification. Recent research suggests that higher emissions of N₂O may in fact originate from nitrification (Ahn et al. 2010). Other more recent research suggests that N₂O may also result from other types of wastewater treatment operations (Chandran 2012).

The principal factor in determining the CH₄ generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are the Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD (or BOD) concentrations will generally yield more CH₄ than wastewater with lower COD (or BOD) concentrations. BOD represents the amount of oxygen that would be required to completely consume the organic matter contained in the wastewater through aerobic decomposition processes, while COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable). Because BOD is an aerobic parameter, it is preferable to use COD to estimate CH₄ production. The principal factor in determining the N₂O generation potential of wastewater is the amount of N in the wastewater. The variability of N in the influent to the treatment system, as well as the operating conditions of the treatment system itself, also impact the N₂O generation potential.

In 2014, CH₄ emissions from domestic wastewater treatment were 9.0 MMT CO₂ Eq. (361 kt CH₄). Emissions remained fairly steady from 1990 through 1997, but have decreased since that time due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems (EPA 1992, 1996, 2000, and 2004; U.S. Census 2013). In 2014, CH₄ emissions from industrial wastewater treatment were estimated to be 5.7 MMT CO₂ Eq. (227 kt CH₄). Industrial emission sources have generally increased across the time series through 1999 and then fluctuated up and down with production changes associated with the treatment of wastewater from the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries. Table 7-7 and Table 7-8 provide CH₄ and N₂O emission estimates from domestic and industrial wastewater treatment.

With respect to N₂O, the United States identifies two distinct sources for N₂O emissions from domestic wastewater: emissions from centralized wastewater treatment processes, and emissions from effluent from centralized treatment systems that has been discharged into aquatic environments. The 2014 emissions of N₂O from centralized wastewater treatment processes and from effluent were estimated to be 0.3 MMT CO₂ Eq. (1.1 kt N₂O) and 4.5 MMT CO₂ Eq. (15.2 kt N₂O), respectively. Total N₂O emissions from domestic wastewater were estimated to be 4.8 MMT CO₂ Eq. (16.2 kt N₂O). Nitrous oxide emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

Table 7-7: CH₄ and N₂O Emissions from Domestic and Industrial Wastewater Treatment (MMT CO₂ Eq.)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| CH₄ | 15.7 | 15.9 | 15.5 | 15.3 | 15.0 | 14.8 | 14.7 |
| Domestic | 10.5 | 10.0 | 9.6 | 9.4 | 9.2 | 9.0 | 9.0 |
| Industrial ^a | 5.1 | 5.9 | 5.9 | 5.9 | 5.8 | 5.8 | 5.7 |
| N₂O | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| Domestic | 3.4 | 4.3 | 4.5 | 4.7 | 4.8 | 4.8 | 4.8 |
| Total | 19.1 | 20.2 | 20.0 | 20.0 | 19.8 | 19.6 | 19.5 |

^a Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Table 7-8: CH₄ and N₂O Emissions from Domestic and Industrial Wastewater Treatment (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-------------------------|------------|------------|------------|------------|------------|------------|------------|
| CH₄ | 626 | 636 | 618 | 610 | 601 | 592 | 588 |
| Domestic | 421 | 401 | 384 | 376 | 368 | 361 | 361 |
| Industrial ^a | 205 | 235 | 235 | 234 | 232 | 231 | 227 |
| N₂O | 11 | 15 | 15 | 16 | 16 | 16 | 16 |
| Domestic | 11 | 15 | 15 | 16 | 16 | 16 | 16 |

^a Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Methodology

Domestic Wastewater CH₄ Emission Estimates

Domestic wastewater CH₄ emissions originate from both septic systems and from centralized treatment systems, such as publicly owned treatment works (POTWs). Within these centralized systems, CH₄ emissions can arise from aerobic systems that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted. Methane emissions from septic systems were estimated by multiplying the U.S. population by the percent of wastewater treated in septic systems (about 20 percent) and an emission factor (10.7 g CH₄/capita/day), and then converting the result to kt/year. Methane emissions from POTWs were estimated by multiplying the total BOD₅ produced in the United States by the percent of wastewater treated centrally (about 80 percent), the relative percentage of wastewater treated by aerobic and anaerobic systems, the relative percentage of wastewater facilities with primary treatment, the percentage of BOD₅ treated after primary treatment (67.5 percent), the maximum CH₄-producing capacity of domestic wastewater (0.6), and the relative MCFs for well-managed aerobic (zero), not well managed aerobic (0.3), and anaerobic (0.8) systems with all aerobic systems assumed to be well-managed. Methane emissions from anaerobic digesters were estimated by multiplying the amount of biogas generated by wastewater sludge treated in anaerobic digesters by the proportion of CH₄ in digester biogas (0.65), the density of CH₄ (662 g CH₄/m³ CH₄), and the destruction efficiency associated with burning the biogas in an energy/thermal device (0.99). The methodological equations are:

$$\begin{aligned} \text{Emissions from Septic Systems} &= A \\ &= \text{US}_{\text{POP}} \times (\% \text{ onsite}) \times (\text{EF}_{\text{SEPTIC}}) \times 1/10^9 \times \text{Days} \end{aligned}$$

$$\begin{aligned} \text{Emissions from Centrally Treated Aerobic Systems} &= B \\ &= [(\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ aerobic}) \times (\% \text{ aerobic w/out primary}) + (\% \text{ collected}) \times \\ &(\text{total BOD}_5 \text{ produced}) \times (\% \text{ aerobic}) \times (\% \text{ aerobic w/primary}) \times (1 - \% \text{ BOD removed in prim. treat.})] \times (\% \\ &\text{operations not well managed}) \times (B_0) \times (\text{MCF-aerobic_not_well_man}) \end{aligned}$$

$$\begin{aligned} \text{Emissions from Centrally Treated Anaerobic Systems} &= C \\ &= [(\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ anaerobic}) \times (\% \text{ anaerobic w/out primary}) + (\% \text{ collected}) \\ &\times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ anaerobic}) \times (\% \text{ anaerobic w/primary}) \times (1 - \% \text{ BOD removed in prim. treat.})] \\ &\times (B_0) \times (\text{MCF-anaerobic}) \end{aligned}$$

$$\begin{aligned} \text{Emissions from Anaerobic Digesters} &= D \\ &= [(\text{POTW_flow_AD}) \times (\text{digester gas}) / (\text{per capita flow})] \times \text{conversion to m}^3 \times (\text{FRAC_CH}_4) \times (365.25) \times \\ &(\text{density of CH}_4) \times (1 - \text{DE}) \times 1/10^9 \end{aligned}$$

$$\text{Total CH}_4 \text{ Emissions (kt)} = A + B + C + D$$

where,

$$\text{US}_{\text{POP}} = \text{U.S. population}$$

| | |
|---------------------------------|---|
| % onsite | = Flow to septic systems / total flow |
| % collected | = Flow to POTWs / total flow |
| % aerobic | = Flow to aerobic systems / total flow to POTWs |
| % anaerobic | = Flow to anaerobic systems / total flow to POTWs |
| % aerobic w/out primary | = Percent of aerobic systems that do not employ primary treatment |
| % aerobic w/primary | = Percent of aerobic systems that employ primary treatment |
| % BOD removed in prim. treat. | = 32.5% |
| % operations not well managed | = Percent of aerobic systems that are not well managed and in which some anaerobic degradation occurs |
| % anaerobic w/out primary | = Percent of anaerobic systems that do not employ primary treatment |
| % anaerobic w/primary | = Percent of anaerobic systems that employ primary treatment |
| EF _{SEPTIC} | = Methane emission factor (10.7 g CH ₄ /capita/day) – septic systems |
| Days | = days per year (365.25) |
| Total BOD ₅ produced | = kg BOD/capita/day × U.S. population × 365.25 days/yr |
| B _o | = Maximum CH ₄ -producing capacity for domestic wastewater (0.60 kg CH ₄ /kg BOD) |
| 1/10 ⁶ | = Conversion factor, kg to kt |
| MCF-aerobic_not_well_man. | = CH ₄ correction factor for aerobic systems that are not well managed (0.3) |
| MCF-anaerobic | = CH ₄ correction factor for anaerobic systems (0.8) |
| DE | = CH ₄ destruction efficiency from flaring or burning in engine (0.99 for enclosed flares) |
| POTW_flow_AD | = Wastewater influent flow to POTWs that have anaerobic digesters (MGD) |
| digester gas | = Cubic feet of digester gas produced per person per day (1.0 ft ³ /person/day) |
| per capita flow | = Wastewater flow to POTW per person per day (100 gal/person/day) |
| conversion to m ³ | = Conversion factor, ft ³ to m ³ (0.0283) |
| FRAC_CH ₄ | = Proportion CH ₄ in biogas (0.65) |
| density of CH ₄ | = 662 (g CH ₄ /m ³ CH ₄) |
| 1/10 ⁹ | = Conversion factor, g to kt |

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2016) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. Table 7-9 presents U.S. population and total BOD₅ produced for 1990 through 2014, while Table 7-10 presents domestic wastewater CH₄ emissions for both septic and centralized systems in 2014. The proportions of domestic wastewater treated onsite versus at centralized treatment plants were based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, 2009, 2011, and 2013 *American Housing Surveys* conducted by the U.S. Census Bureau (U.S. Census 2013), with data for intervening years obtained by linear interpolation and data for 2014 forecasted using 1990 to 2013 data. The percent of wastewater flow to aerobic and anaerobic systems, the percent of aerobic and anaerobic systems that do and do not employ primary treatment, and the wastewater flow to POTWs that have anaerobic digesters were obtained from the 1992, 1996, 2000, and 2004 *Clean Watershed Needs Survey* (EPA 1992, 1996, 2000, and 2004). Data for intervening years were obtained by linear interpolation and the years 2004 through 2014 were forecasted from the rest of the time series. The BOD₅ production rate (0.09 kg/capita/day) and the percent BOD₅ removed by primary treatment for domestic wastewater were obtained from Metcalf and Eddy (2003). The maximum CH₄-producing capacity (0.6 kg CH₄/kg BOD₅) and both MCFs used for centralized treatment systems were taken from IPCC (2006), while the CH₄ emission factor (10.7 g CH₄/capita/day) used for septic systems were taken from Leverenz et al. (2010). The CH₄ destruction efficiency for methane recovered from sludge digestion operations, 99 percent, was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in *AP-42 Compilation of Air Pollutant Emission Factors*, Chapter 2.4 (EPA 1998), efficiencies used to establish New Source Performance Standards (NSPS) for landfills, along with data from CAR (2011), Sullivan (2007), Sullivan (2010), and UNFCCC (2012). The cubic feet of digester gas produced per person per day (1.0 ft³/person/day) and the proportion of CH₄ in biogas (0.65) come from Metcalf and Eddy (2003). The wastewater flow to a POTW (100 gal/person/day) was taken from the Great Lakes-Upper Mississippi River Board of State and Provincial Public Health and Environmental Managers, "*Recommended Standards for Wastewater Facilities (Ten-State Standards)*" (2004).

Table 7-9: U.S. Population (Millions) and Domestic Wastewater BOD₅ Produced (kt)

| Year | Population | BOD ₅ |
|------|------------|------------------|
| 1990 | 253 | 8,333 |
| 2005 | 300 | 9,853 |
| 2010 | 313 | 10,304 |
| 2011 | 316 | 10,381 |
| 2012 | 318 | 10,459 |
| 2013 | 321 | 10,536 |
| 2014 | 323 | 10,613 |

Sources: U.S. Census Bureau (2016); Metcalf & Eddy (2003).

Table 7-10: Domestic Wastewater CH₄ Emissions from Septic and Centralized Systems (2014, MMT CO₂ Eq. and Percent)

| | CH ₄ Emissions (MMT CO ₂ Eq.) | % of Domestic Wastewater CH ₄ |
|--|---|--|
| Septic Systems | 5.9 | 65.8% |
| Centralized Systems (including anaerobic sludge digestion) | 3.1 | 34.2% |
| Total | 9.0 | 100% |

Note: Totals may not sum due to independent rounding.

Industrial Wastewater CH₄ Emission Estimates

Methane emission estimates from industrial wastewater were developed according to the methodology described in IPCC (2006). Industry categories that are likely to produce significant CH₄ emissions from wastewater treatment were identified and included in the Inventory. The main criteria used to identify these industries are whether they generate high volumes of wastewater, whether there is a high organic wastewater load, and whether the wastewater is treated using methods that result in CH₄ emissions. The top five industries that meet these criteria are pulp and paper manufacturing; meat and poultry processing; vegetables, fruits, and juices processing; starch-based ethanol production; and petroleum refining. Wastewater treatment emissions for these sectors for 2014 are displayed in Table 7-11 below. Table 7-12 contains production data for these industries.

Table 7-11: Industrial Wastewater CH₄ Emissions by Sector (2014, MMT CO₂ Eq. and Percent)

| | CH ₄ Emissions (MMT CO ₂ Eq.) | % of Industrial Wastewater CH ₄ |
|----------------------|---|--|
| Meat & Poultry | 4.3 | 76% |
| Pulp & Paper | 1.0 | 17% |
| Fruit & Vegetables | 0.1 | 3% |
| Petroleum Refineries | 0.1 | 3% |
| Ethanol Refineries | 0.1 | 2% |
| Total | 5.7 | 100% |

Note: Totals may not sum due to independent rounding.

Table 7-12: U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (MMT)

| Year | Pulp and Paper ^a | Meat (Live Weight Killed) | Poultry (Live Weight Killed) | Vegetables, Fruits and Juices | Ethanol | Petroleum Refining |
|------|-----------------------------|---------------------------------|------------------------------------|----------------------------------|---------|-----------------------|
| 1990 | 128.9 | 27.3 | 14.6 | 38.7 | 2.5 | 702.4 |
| 2005 | 138.5 | 31.4 | 25.1 | 42.9 | 11.7 | 818.6 |
| 2010 | 126.7 | 33.7 | 25.9 | 43.2 | 39.7 | 848.6 |
| 2011 | 126.1 | 33.8 | 26.2 | 44.3 | 41.6 | 858.8 |
| 2012 | 124.4 | 33.8 | 26.1 | 45.6 | 39.5 | 856.1 |
| 2013 | 122.8 | 33.6 | 26.5 | 45.1 | 39.8 | 878.7 |
| 2014 | 120.9 | 32.2 | 26.9 | 45.6 | 42.8 | 903.9 |

^aPulp and paper production is the sum of woodpulp production plus paper and paperboard production.

Sources: Lockwood-Post (2002); FAO (2016); USDA (2016a); RFA (2016); EIA (2016).

Methane emissions from these categories were estimated by multiplying the annual product output by the average outflow, the organics loading (in COD) in the outflow, the maximum CH₄ producing potential of industrial wastewater (B_o), and the percentage of organic loading assumed to degrade anaerobically in a given treatment system (MCF). Ratios of BOD:COD in various industrial wastewaters were obtained from EPA (1997a) and used to estimate COD loadings. The B_o value used for all industries is the IPCC default value of 0.25 kg CH₄/kg COD (IPCC 2006).

For each industry, the percent of plants in the industry that treat wastewater on site, the percent of plants that have a primary treatment step prior to biological treatment, and the percent of plants that treat wastewater anaerobically were defined. The percent of wastewater treated anaerobically onsite (TA) was estimated for both primary treatment (%TA_p) and secondary treatment (%TA_s). For plants that have primary treatment in place, an estimate of COD that is removed prior to wastewater treatment in the anaerobic treatment units was incorporated. The values used in the %TA calculations are presented in Table 7-13 below.

The methodological equations are:

$$\text{CH}_4 (\text{industrial wastewater}) = [P \times W \times \text{COD} \times \%TA_p \times B_o \times \text{MCF}] + [P \times W \times \text{COD} \times \%TA_s \times B_o \times \text{MCF}]$$

$$\%TA_p = [\%Plants_o \times \%WW_{a,p} \times \%COD_p]$$

$$\%TA_s = [\%Plants_a \times \%WW_{a,s} \times \%COD_s] + [\%Plants_t \times \%WW_{a,t} \times \%COD_s]$$

where,

| | |
|---|--|
| CH ₄ (industrial wastewater) | = Total CH ₄ emissions from industrial wastewater (kg/year) |
| P | = Industry output (metric tons/year) |
| W | = Wastewater generated (m ³ /metric ton of product) |
| COD | = Organics loading in wastewater (kg/m ³) |
| %TA _p | = Percent of wastewater treated anaerobically on site in primary treatment |
| %TA _s | = Percent of wastewater treated anaerobically on site in secondary treatment |
| %Plants _o | = Percent of plants with onsite treatment |
| %WW _{a,p} | = Percent of wastewater treated anaerobically in primary treatment |
| %COD _p | = Percent of COD entering primary treatment |
| %Plants _a | = Percent of plants with anaerobic secondary treatment |
| %Plants _t | = Percent of plants with other secondary treatment |
| %WW _{a,s} | = Percent of wastewater treated anaerobically in anaerobic secondary treatment |
| %WW _{a,t} | = Percent of wastewater treated anaerobically in other secondary treatment |
| %COD _s | = Percent of COD entering secondary treatment |
| B _o | = Maximum CH ₄ producing potential of industrial wastewater (default value of 0.25 kg CH ₄ /kg COD) |
| MCF | = CH ₄ correction factor, indicating the extent to which the organic content (measured as COD) degrades anaerobically |

Alternate methodological equations for calculating %TA were used for secondary treatment in the pulp and paper industry to account for aerobic systems with anaerobic portions. These equations are:

$$\%TA_a = [\%Plants_a \times \%WW_{as} \times \%COD_s] + [\%Plant_{st} \times \%WW_{at} \times \%COD_s]$$

$$\%TA_{at} = [\%Plants_{at} \times \%WW_{as} \times \%COD_s]$$

where,

| | |
|------------------|---|
| $\%TA_a$ | = Percent of wastewater treated anaerobically on site in secondary treatment |
| $\%TA_{at}$ | = Percent of wastewater treated in aerobic systems with anaerobic portions on site in secondary treatment |
| $\%Plants_a$ | = Percent of plants with anaerobic secondary treatment |
| $\%Plants_{a,t}$ | = Percent of plants with partially anaerobic secondary treatment |
| $\%WW_{a,s}$ | = Percent of wastewater treated anaerobically in anaerobic secondary treatment |
| $\%WW_{a,t}$ | = Percent of wastewater treated anaerobically in other secondary treatment |
| $\%COD_s$ | = Percent of COD entering secondary treatment |

As described below, the values presented in Table 7-13 were used in the emission calculations and are described in detail in ERG (2008), ERG (2013a), and ERG (2013b).

Table 7-13: Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (percent)

| Variable | Industry | | | | | | |
|------------------|----------------|-----------------|--------------------|----------------------------|-------------------------------|-------------------------------|--------------------|
| | Pulp and Paper | Meat Processing | Poultry Processing | Fruit/Vegetable Processing | Ethanol Production – Wet Mill | Ethanol Production – Dry Mill | Petroleum Refining |
| $\%TA_p$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%TA_s$ | 0 | 33 | 25 | 4.2 | 33.3 | 75 | 23.6 |
| $\%TA_a$ | 2.2 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%TA_{a,t}$ | 11.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%Plants_o$ | 0 | 100 | 100 | 11 | 100 | 100 | 100 |
| $\%Plants_a$ | 5 | 33 | 25 | 5.5 | 33.3 | 75 | 23.6 |
| $\%Plants_{a,t}$ | 28 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%Plants_t$ | 35 | 67 | 75 | 5.5 | 66.7 | 25 | 0 |
| $\%WW_{a,p}$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%WW_{a,s}$ | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| $\%WW_{a,t}$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| $\%COD_p$ | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| $\%COD_s$ | 42 | 100 | 100 | 77 | 100 | 100 | 100 |

Sources: ERG (2008); ERG (2013a); and ERG (2013b).

Pulp and Paper. Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids (World Bank 1999; Nemerow and Dasgupta 1991). Secondary treatment (storage, settling, and biological treatment) mainly consists of lagooning. In determining the percent that degrades anaerobically, both primary and secondary treatment were considered. In the United States, primary treatment is focused on solids removal, equalization, neutralization, and color reduction (EPA 1993). The vast majority of pulp and paper mills with on-site treatment systems use mechanical clarifiers to remove suspended solids from the wastewater. About 10 percent of pulp and paper mills with treatment systems use settling ponds for primary treatment and these are more likely to be located at mills that do not perform secondary treatment (EPA 1993). However, because the vast majority of primary treatment operations at U.S. pulp and paper mills use mechanical clarifiers, and less than 10 percent of pulp and paper wastewater is managed in primary settling ponds that are not expected to have anaerobic conditions, negligible emissions are assumed to occur during primary treatment.

Approximately 42 percent of the BOD passes on to secondary treatment, which consists of activated sludge, aerated stabilization basins, or non-aerated stabilization basins. Based on EPA's *OAQPS Pulp and Paper Sector Survey*, 5.3 percent of pulp and paper mills reported using anaerobic secondary treatment for wastewater and/or pulp

condensates (ERG 2013a). Twenty-eight percent of mills also reported the use of quiescent settling ponds. Using engineering judgment, these systems were determined to be aerobic with possible anaerobic portions. For the truly anaerobic systems, an MCF of 0.8 is used, as these are typically deep stabilization basins. For the partially anaerobic systems, an MCF of 0.2 is used, which is the IPCC suggested MCF for shallow lagoons.

A time series of CH₄ emissions for 1990 through 2001 was developed based on production figures reported in the Lockwood-Post Directory (Lockwood-Post 2002). Data from the Food and Agricultural Organization of the United Nations (FAO) database FAOSTAT were used for 2002 through 2014 (FAO 2016). The overall wastewater outflow varies based on a time series outlined in ERG (2013a) to reflect historical and current industry wastewater flow, and the average BOD concentrations in raw wastewater was estimated to be 0.4 gram BOD/liter (EPA 1997b; EPA 1993; World Bank 1999). The COD:BOD ratio used to convert the organic loading to COD for pulp and paper mills was 2 (EPA 1997a).

Meat and Poultry Processing. The meat and poultry processing industry makes extensive use of anaerobic lagoons in sequence with screening, fat traps, and dissolved air flotation when treating wastewater on site. About 33 percent of meat processing operations (EPA 2002) and 25 percent of poultry processing operations (U.S. Poultry 2006) perform on-site treatment in anaerobic lagoons. The IPCC default B_o of 0.25 kg CH₄/kg COD and default MCF of 0.8 for anaerobic lagoons were used to estimate the CH₄ produced from these on-site treatment systems. Production data, in carcass weight and live weight killed for the meat and poultry industry, were obtained from the USDA *Agricultural Statistics Database and the Agricultural Statistics Annual Reports* (USDA 2016a). Data collected by EPA's Office of Water provided estimates for wastewater flows into anaerobic lagoons: 5.3 and 12.5 m³/metric ton for meat and poultry production (live weight killed), respectively (EPA 2002). The loadings are 2.8 and 1.5 g BOD/liter for meat and poultry, respectively. The COD:BOD ratio used to convert the organic loading to COD for both meat and poultry facilities was 3 (EPA 1997a).

Vegetables, Fruits, and Juices Processing. Treatment of wastewater from fruits, vegetables, and juices processing includes screening, coagulation/settling, and biological treatment (lagooning). The flows are frequently seasonal, and robust treatment systems are preferred for on-site treatment. Effluent is suitable for discharge to the sewer. This industry is likely to use lagoons intended for aerobic operation, but the large seasonal loadings may develop limited anaerobic zones. In addition, some anaerobic lagoons may also be used (Nemerow and Dasgupta 1991). Consequently, 4.2 percent of these wastewater organics are assumed to degrade anaerobically. The IPCC default B_o of 0.25 kg CH₄/kg COD and default MCF of 0.8 for anaerobic treatment were used to estimate the CH₄ produced from these on-site treatment systems. The USDA National Agricultural Statistics Service (USDA 2016a) provided production data for potatoes, other vegetables, citrus fruit, non-citrus fruit, and grapes processed for wine. Outflow and BOD data, presented in Table 7-14, were obtained from EPA (1974) for potato, citrus fruit, and apple processing, and from EPA (1975) for all other sectors. The COD:BOD ratio used to convert the organic loading to COD for all fruit, vegetable, and juice facilities was 1.5 (EPA 1997a).

Table 7-14: Wastewater Flow (m³/ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production

| Commodity | Wastewater Outflow (m ³ /ton) | BOD (g/L) |
|-------------------|--|-----------|
| Vegetables | | |
| Potatoes | 10.27 | 1.765 |
| Other Vegetables | 8.60 | 0.784 |
| Fruit | | |
| Apples | 3.66 | 1.371 |
| Citrus | 10.11 | 0.317 |
| Non-citrus | 12.42 | 1.204 |
| Grapes (for wine) | 2.78 | 1.831 |

Sources: EPA (1974); EPA (1975).

Ethanol Production. Ethanol, or ethyl alcohol, is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar-based feedstocks (e.g., molasses and beets), starch- or grain-based feedstocks (e.g., corn, sorghum, and beverage waste), and cellulosic biomass feedstocks (e.g., agricultural wastes, wood, and bagasse). Ethanol can also be produced synthetically from ethylene or hydrogen and carbon monoxide. However, synthetic ethanol comprises

only about 2 percent of ethanol production, and although the U.S. Department of Energy (DOE) predicts cellulosic ethanol to greatly increase in the coming years, currently it is only in an experimental stage in the United States. Currently, ethanol is mostly made from sugar and starch crops, but with advances in technology, cellulosic biomass is increasingly used as ethanol feedstock (DOE 2013).

Ethanol is produced from corn (or other starch-based feedstocks) primarily by two methods: wet milling and dry milling. Historically, the majority of ethanol was produced by the wet milling process, but now the majority is produced by the dry milling process. The dry milling process is cheaper to implement, and has become more efficient in recent years (Rendleman and Shapouri 2007). The wastewater generated at ethanol production facilities is handled in a variety of ways. Dry milling facilities often combine the resulting evaporator condensate with other process wastewaters, such as equipment wash water, scrubber water, and boiler blowdown and anaerobically treat this wastewater using various types of digesters. Wet milling facilities often treat their steepwater condensate in anaerobic systems followed by aerobic polishing systems. Wet milling facilities may treat the stillage (or processed stillage) from the ethanol fermentation/distillation process separately or together with steepwater and/or wash water. Methane generated in anaerobic digesters is commonly collected and either flared or used as fuel in the ethanol production process (ERG 2006).

Available information was compiled from the industry on wastewater generation rates, which ranged from 1.25 gallons per gallon ethanol produced (for dry milling) to 10 gallons per gallon ethanol produced (for wet milling) (Ruocco 2006a; Ruocco 2006b; Merrick 1998; Donovan 1996; NRBP 2001). COD concentrations were also found to be about 3 g/L (Ruocco 2006a; Merrick 1998; White and Johnson 2003). The amount of wastewater treated anaerobically was estimated, along with how much of the CH₄ is recovered through the use of biomethanators. Biomethanators are anaerobic reactors that use microorganisms under anaerobic conditions to reduce COD and organic acids and recover biogas from wastewater (ERG 2006). Methane emissions were then estimated as follows:

$$\text{Methane} = [\text{Production} \times \text{Flow} \times \text{COD} \times 3.785 \times ((\% \text{Plants}_o \times \% \text{WW}_{a,p} \times \% \text{COD}_p) + [\% \text{Plants}_a \times \% \text{WW}_{a,s} \times \% \text{COD}_s]) + [\% \text{Plants}_t \times \% \text{WW}_{a,t} \times \% \text{COD}_s]] \times B_o \times \text{MCF} \times \% \text{Not Recovered}] + [\text{Production} \times \text{Flow} \times 3.785 \times \text{COD} \times ((\% \text{Plants}_o \times \% \text{WW}_{a,p} \times \% \text{COD}_p) + [\% \text{Plants}_a \times \% \text{WW}_{a,s} \times \% \text{COD}_s]) + [\% \text{Plants}_t \times \% \text{WW}_{a,t} \times \% \text{COD}_s]] \times B_o \times \text{MCF} \times (\% \text{Recovered}) \times (1 - \text{DE})] \times 1/10^9$$

where,

| | |
|----------------------|---|
| Production | = gallons ethanol produced (wet milling or dry milling) |
| Flow | = gallons wastewater generated per gallon ethanol produced (1.25 dry milling, 10 wet milling) |
| COD | = COD concentration in influent (3 g/l) |
| 3.785 | = conversion, gallons to liters |
| %Plants _o | = percent of plants with onsite treatment (100%) |
| %WW _{a,p} | = percent of wastewater treated anaerobically in primary treatment (0%) |
| %COD _p | = percent of COD entering primary treatment (100%) |
| %Plants _a | = percent of plants with anaerobic secondary treatment (33.3% wet, 75% dry) |
| %Plants _t | = percent of plants with other secondary treatment (66.7% wet, 25% dry) |
| %WW _{a,s} | = percent of wastewater treated anaerobically in anaerobic secondary treatment (100%) |
| %WW _{a,t} | = percent of wastewater treated anaerobically in other secondary treatment (0%) |
| %COD _s | = percent of COD entering secondary treatment (100%) |
| B _o | = maximum methane producing capacity (0.25 g CH ₄ /g COD) |
| MCF | = methane conversion factor (0.8 for anaerobic systems) |
| % Recovered | = percent of wastewater treated in system with emission recovery |
| % Not Recovered | = 1 - percent of wastewater treated in system with emission recovery |
| DE | = destruction efficiency of recovery system (99%) |
| 1/10 ⁹ | = conversion factor, g to kt |

A time series of CH₄ emissions for 1990 through 2014 was developed based on production data from the Renewable Fuels Association (RFA 2016).

Petroleum Refining. Petroleum refining wastewater treatment operations have the potential to produce CH₄ emissions from anaerobic wastewater treatment. EPA's Office of Air and Radiation performed an Information Collection Request (ICR) for petroleum refineries in 2011.⁸ Of the responding facilities, 23.6 percent reported using

⁸ Available online at <<https://refineryicr.rti.org/>>.

non-aerated surface impoundments or other biological treatment units, both of which have the potential to lead to anaerobic conditions (ERG 2013b). In addition, the wastewater generation rate was determined to be 26.4 gallons per barrel of finished product (ERG 2013b). An average COD value in the wastewater was estimated at 0.45 kg/m³ (Benyahia et al. 2006).

The equation used to calculate CH₄ generation at petroleum refining wastewater treatment systems is presented below:

$$\text{Methane} = \text{Flow} \times \text{COD} \times \text{TA} \times B_o \times \text{MCF}$$

where,

| | |
|----------------|---|
| Flow | = Annual flow treated through anaerobic treatment system (m ³ /year) |
| COD | = COD loading in wastewater entering anaerobic treatment system (kg/m ³) |
| TA | = Percent of wastewater treated anaerobically on site |
| B _o | = maximum methane producing potential of industrial wastewater (default value of 0.25 kg CH ₄ /kg COD) |
| MCF | = methane conversion factor (0.3) |

A time series of CH₄ emissions for 1990 through 2014 was developed based on production data from the Energy Information Association (EIA 2016).

Domestic Wastewater N₂O Emission Estimates

Nitrous oxide emissions from domestic wastewater (wastewater treatment) were estimated using the IPCC (2006) methodology, including calculations that take into account N removal with sewage sludge, non-consumption and industrial/commercial wastewater N, and emissions from advanced centralized wastewater treatment plants:

- In the United States, a certain amount of N is removed with sewage sludge, which is applied to land, incinerated, or landfilled (N_{SLUDGE}). The N disposal into aquatic environments is reduced to account for the sewage sludge application.
- The IPCC methodology uses annual, per capita protein consumption (kg protein/person-year). For this Inventory, the amount of protein available to be consumed is estimated based on per capita annual food availability data and its protein content, and then adjusts that data using a factor to account for the fraction of protein actually consumed.
- Small amounts of gaseous nitrogen oxides are formed as byproducts in the conversion of nitrate to N gas in anoxic biological treatment systems. Approximately 7 g N₂O is generated per capita per year if wastewater treatment includes intentional nitrification and denitrification (Scheehle and Doorn 2001). Analysis of the 2004 CWNS shows that plants with denitrification as one of their unit operations serve a population of 2.4 million people. Based on an emission factor of 7 g per capita per year, approximately 21.2 metric tons of additional N₂O may have been emitted via denitrification in 2004. Similar analyses were completed for each year in the Inventory using data from CWNS on the amount of wastewater in centralized systems treated in denitrification units. Plants without intentional nitrification/denitrification are assumed to generate 3.2 g N₂O per capita per year.

Nitrous oxide emissions from domestic wastewater were estimated using the following methodology:

$$N_2O_{TOTAL} = N_2O_{PLANT} + N_2O_{EFFLUENT}$$

$$N_2O_{PLANT} = N_2O_{NIT/DENIT} + N_2O_{WOUT NIT/DENIT}$$

$$N_2O_{NIT/DENIT} = [(US_{POPND}) \times EF_2 \times F_{IND-COM}] \times 1/10^9$$

$$N_2O_{WOUT NIT/DENIT} = \{[(US_{POP} \times WWTP) - US_{POPND}] \times F_{IND-COM} \times EF_1\} \times 1/10^9$$

$$N_2O_{EFFLUENT} = \{[(US_{POP} \times WWTP) - (0.9 \times US_{POPND})] \times \text{Protein} \times F_{NPR} \times F_{NON-COM} \times F_{IND-COM} - N_{SLUDGE}\} \times EF_3 \times 44/28 \times 1/10^6$$

where,

$$N_2O_{TOTAL} = \text{Annual emissions of } N_2O \text{ (kt)}$$

| | |
|--------------------------------|--|
| N_2O_{PLANT} | = N_2O emissions from centralized wastewater treatment plants (kt) |
| $N_2O_{\text{NIT/DENIT}}$ | = N_2O emissions from centralized wastewater treatment plants with nitrification/denitrification (kt) |
| $N_2O_{\text{WOUT NIT/DENIT}}$ | = N_2O emissions from centralized wastewater treatment plants without nitrification/denitrification (kt) |
| N_2O_{EFFLUENT} | = N_2O emissions from wastewater effluent discharged to aquatic environments (kt) |
| US_{POP} | = U.S. population |
| US_{POPND} | = U.S. population that is served by biological denitrification (from CWNS) |
| $WWTP$ | = Fraction of population using WWTP (as opposed to septic systems) |
| EF_1 | = Emission factor (3.2 g N_2O /person-year) – plant with no intentional denitrification |
| EF_2 | = Emission factor (7 g N_2O /person-year) – plant with intentional denitrification |
| Protein | = Annual per capita protein consumption (kg/person/year) |
| F_{NPR} | = Fraction of N in protein, default = 0.16 (kg N/kg protein) |
| $F_{\text{NON-COM}}$ | = Factor for non-consumed protein added to wastewater (1.4) |
| $F_{\text{IND-COM}}$ | = Factor for industrial and commercial co-discharged protein into the sewer system (1.25) |
| N_{SLUDGE} | = N removed with sludge, kg N/yr |
| EF_3 | = Emission factor (0.005 kg N_2O -N/kg sewage-N produced) – from effluent |
| 0.9 | = Amount of nitrogen removed by denitrification systems |
| 44/28 | = Molecular weight ratio of N_2O to N_2 |

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2016) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. The fraction of the U.S. population using wastewater treatment plants is based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, 2009, 2011, and 2013 *American Housing Survey* (U.S. Census 2013). Data for intervening years were obtained by linear interpolation and data from 2014 were forecasted using 1990 to 2013 data. The emission factor (EF_1) used to estimate emissions from wastewater treatment for plants without intentional denitrification was taken from IPCC (2006), while the emission factor (EF_2) used to estimate emissions from wastewater treatment for plants with intentional denitrification was taken from Scheehle and Doorn (2001). Data on annual per capita protein intake were provided by the U.S. Department of Agriculture Economic Research Service (USDA 2016b). Protein consumption data for 2011 through 2014 were extrapolated from data for 1990 through 2010. An emission factor to estimate emissions from effluent (EF_3) has not been specifically estimated for the United States, thus the default IPCC value (0.005 kg N_2O -N/kg sewage-N produced) was applied (IPCC 2006). The fraction of N in protein (0.16 kg N/kg protein) was also obtained from IPCC (2006). The factor for non-consumed protein and the factor for industrial and commercial co-discharged protein were obtained from IPCC (2006). Sludge generation was obtained from EPA (1999) for 1988, 1996, and 1998 and from Beecher et al. (2007) for 2004. Intervening years were interpolated, and estimates for 2005 through 2014 were forecasted from the rest of the time series. The amount of nitrogen removed by denitrification systems was taken from EPA (2008). An estimate for the N removed as sludge (N_{SLUDGE}) was obtained by determining the amount of sludge disposed by incineration, by land application (agriculture or other), through surface disposal, in landfills, or through ocean dumping (US EPA 1993b; Beecher et al. 2007; McFarland 2001; US EPA 1999). In 2014, 289 kt N was removed with sludge. Table 7-15 presents the data for U.S. population, population served by biological denitrification, population served by wastewater treatment plants, available protein, protein consumed, and nitrogen removed with sludge.

Table 7-15: U.S. Population (Millions), Population Served by Biological Denitrification (Millions), Fraction of Population Served by Wastewater Treatment (percent), Available Protein (kg/person-year), Protein Consumed (kg/person-year), and Nitrogen Removed with Sludge (kt-N/year)

| Year | Population | Population _{ND} | WWTP Population | Available Protein | Protein Consumed | N Removed |
|------|------------|--------------------------|-----------------|-------------------|------------------|-----------|
| 1990 | 253 | 2.0 | 75.6 | 43.1 | 33.2 | 214.2 |
| 2005 | 300 | 2.7 | 78.8 | 44.9 | 34.7 | 261.1 |
| 2010 | 313 | 3.0 | 80.0 | 43.8 | 33.7 | 276.4 |
| 2011 | 316 | 3.0 | 80.6 | 45.0 | 34.7 | 279.5 |

| | | | | | | |
|------|-----|-----|------|------|------|-------|
| 2012 | 318 | 3.0 | 81.0 | 45.1 | 34.7 | 282.6 |
| 2013 | 321 | 3.1 | 81.4 | 45.1 | 34.8 | 285.6 |
| 2014 | 323 | 3.1 | 81.1 | 45.2 | 34.8 | 288.7 |

Sources: Beecher et al. (2007); McFarland (2001); U.S. Census (2013); U.S. Census (2016); USDA (2016b); US EPA (1992); US EPA (1993b); US EPA (1996); US EPA (1999); US EPA (2000); US EPA (2004).

Uncertainty and Time-Series Consistency

The overall uncertainty associated with both the 2014 CH₄ and N₂O emission estimates from wastewater treatment and discharge was calculated using the 2006 IPCC Guidelines Approach 2 methodology (IPCC 2006). Uncertainty associated with the parameters used to estimate CH₄ emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N₂O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 7-16. Methane emissions from wastewater treatment were estimated to be between 9.0 and 15.0 MMT CO₂ Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 39 percent below to 2 percent above the 2014 emissions estimate of 14.7 MMT CO₂ Eq. Nitrous oxide emissions from wastewater treatment were estimated to be between 1.1 and 10.1 MMT CO₂ Eq., which indicates a range of approximately 76 percent below to 108 percent above the 2014 emissions estimate of 4.8 MMT CO₂ Eq.

Table 7-16: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Wastewater Treatment (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate ^a | | | |
|-----------------------------|-----------------------|---|--|-------------|-----------------|-----------------|
| | | | Lower Bound | Upper Bound | Lower Bound (%) | Upper Bound (%) |
| Wastewater Treatment | CH₄ | 14.7 | 9.0 | 15.0 | -39% | +2% |
| Domestic | CH ₄ | 9.0 | 5.7 | 9.7 | -37% | +8% |
| Industrial | CH ₄ | 5.7 | 2.4 | 6.8 | -58% | +20% |
| Wastewater Treatment | N₂O | 4.8 | 1.1 | 10.1 | -76% | +108% |

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed on activity data, documentation, and emission calculations. This effort included a Tier 1 analysis, including the following checks:

- Checked for transcription errors in data input;
- Ensured references were specified for all activity data used in the calculations;
- Checked a sample of each emission calculation used for the source category;
- Checked that parameter and emission units were correctly recorded and that appropriate conversion factors were used;
- Checked for temporal consistency in time series input data for each portion of the source category;
- Confirmed that estimates were calculated and reported for all portions of the source category and for all years;
- Investigated data gaps that affected emissions estimates trends; and
- Compared estimates to previous estimates to identify significant changes.

All transcription errors identified were corrected. The QA/QC analysis did not reveal any systemic inaccuracies or incorrect input values.

Recalculations Discussion

Production data were updated to reflect revised U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) datasets. Updates to meat and poultry data based on changes to the 2012 *Census for Agriculture* and 2013 and 2014 annual revisions resulted in animal population changes for beef from 2008 to 2013, veal from 2009 to 2013, and lamb and muttons in 2009 (Bertramsen 2016). In addition, the most recent USDA Economic Research Service (ERS) data were used to update protein data values from 1990 through 2010. The updated ERS data also resulted in changes in forecasted values from 2011 (Cooper 2014).

The estimated number of ethanol plants using dry milling versus wet milling were updated for 1990 to 2014 with data provided by Renewable Fuels Association (RFA) (Cooper 2014). This change resulted in updated values for ethanol produced (both dry and wet) for the entire time series.

Planned Improvements

Due to circumstances, only very limited improvements were made to the wastewater treatment section of this Inventory. As a result, the planned improvements detailed previously will continue to be investigated for possible inclusion in a future Inventory. Below is a brief summary of ongoing investigations.

- EPA is continuing its evaluation of Greenhouse Gas Reporting Program (GHGRP) reports for improvements to activity data and for verifying methodologies currently in use in the Inventory to estimate emissions.
- EPA is working with the National Council of Air and Stream Improvement (NCASI) to determine if there are sufficient data available to update the estimates of organic loading in pulp and paper wastewaters treated on-site.
- EPA is investigating the inclusion of constructed and semi-natural treatment wetlands in Inventory calculations using IPCC's 2013 wetlands supplement (IPCC 2014) using CWNS treatment system data or other data sources.
- EPA is continuing its review of other industrial wastewater treatment sources for those industries believed to discharge significant loads of BOD and COD, including dairy processing wastewater.

Over the longer term, potential sources for updating inventory data continue to be monitored, including:

- Updated sources of activity data for wastewater treatment system type to distinguish between aerobic, anaerobic, and aerobic systems with the potential to generate CH₄;
- Water Environment Federation (WEF) biosolid data as a potential source of digester, sludge, and biogas data from POTWs;
- Reports based on international research and other countries' inventory submissions to inform potential updates to the Inventory's emission factors, methodologies, or included industries;
- Research by groups such as the Water Environment Research Federation (WERF) on emissions from various types of municipal treatment systems, country-specific N₂O emission factors, and flare efficiencies;
- Sources of data for development of a country-specific methodology for N₂O emissions associated with on-site industrial wastewater treatment operations, including the appropriateness of using IPCC's default factor for domestic wastewater (0.005 kg N₂O-N/kg N);
- Data collected by WERF that indicate septic soil systems are a source of N₂O for the potential development of appropriate emission factors for septic system N₂O emissions;
- Additional data sources for improving the uncertainty of the estimate of N entering municipal treatment systems; and
- Data to update the value used for N content of sludge, the amount of sludge produced, and sludge disposal practices, along with increasing the transparency of the fate of sludge produced in wastewater treatment.

See Section 7.2 of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 through 2013* for full detail of these planned improvements.

7.3 Composting (IPCC Source Category 5B1)

Composting of organic waste, such as food waste, garden (yard) and park waste, and wastewater treatment sludge and/or biosolids, is common in the United States. Advantages of composting include reduced volume of the waste, stabilization of the waste, and destruction of pathogens in the waste. The end products of composting, depending on its quality, can be recycled as a fertilizer and soil amendment, or be disposed of in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide (CO₂). Methane (CH₄) is formed in anaerobic sections of the compost, which are created when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. This CH₄ is then oxidized to a large extent in the aerobic sections of the compost. The estimated CH₄ released into the atmosphere ranges from less than one percent to a few percent of the initial carbon (C) content in the material (IPCC 2006). Depending on how well the compost pile is managed, nitrous oxide (N₂O) emissions can be produced. The formation of N₂O depends on the initial nitrogen content of the material and is mostly due to nitrogen oxide (NO_x) denitrification during the later composting stages. Emissions vary and range from less than 0.5 percent to 5 percent of the initial nitrogen content of the material (IPCC 2006). Animal manures are typically expected to generate more N₂O than, for example, yard waste; however, data are limited.

From 1990 to 2014, the amount of waste composted in the United States has increased from 3,810 kt to 20,533 kt, an increase of approximately 439 percent. The amount of material composted in the United States in the last decade has increased by approximately 11 percent. Emissions of CH₄ and N₂O from composting have increased by the same percentage. In 2014, CH₄ emissions from composting (see Table 7-17 and Table 7-18) were 2.1 MMT CO₂ Eq. (82 kt), and N₂O emissions from composting were 1.8 MMT CO₂ Eq. (6 kt). The wastes composted primarily include yard trimmings (grass, leaves, and tree and brush trimmings) and food scraps from the residential and commercial sectors (such as grocery stores; restaurants; and school, business, and factory cafeterias). The composted waste quantities reported here do not include backyard composting or agricultural composting.

The growth in composting since the 1990s and specifically over the past decade is attributable to primarily three factors: (1) the enactment of legislation by state and local governments that discouraged the disposal of yard trimmings in landfills, (2) yard trimming collection and yard trimming drop off sites provided by local solid waste management districts/divisions, and (3) an increased awareness of the environmental benefits of composting. Most bans on the disposal of yard trimmings were initiated in the early 1990s by state or local governments (U.S. Composting Council 2010). By 2010, 25 states, representing about 50 percent of the nation's population, had enacted such legislation (BioCycle 2010). An additional 16 states are known to have commercial-scale composting facilities (Shin 2014). Despite these factors, the total amount of waste composted exhibited a downward trend after peaking in 2008 (see Table 7-17 and Figure 7-5), but has been increasing since 2010 and the annual quantity composted is now on par with the 2008 quantity composted. While there is no definitive reason for the decreasing trend in the amount of waste composted, it is most likely a result of the recession and the fact that the quantities composted are estimated using a mass balance approach on the municipal waste stream across the entire United States. As presented in Figure 7-5, the quantity of CH₄ and N₂O emitted from composting operations across the time-series parallels the trends for the quantities composted, although the trend in emissions has a much lower slope compared to the quantities composted.

Table 7-17: CH₄ and N₂O Emissions from Composting (MMT CO₂ Eq.)

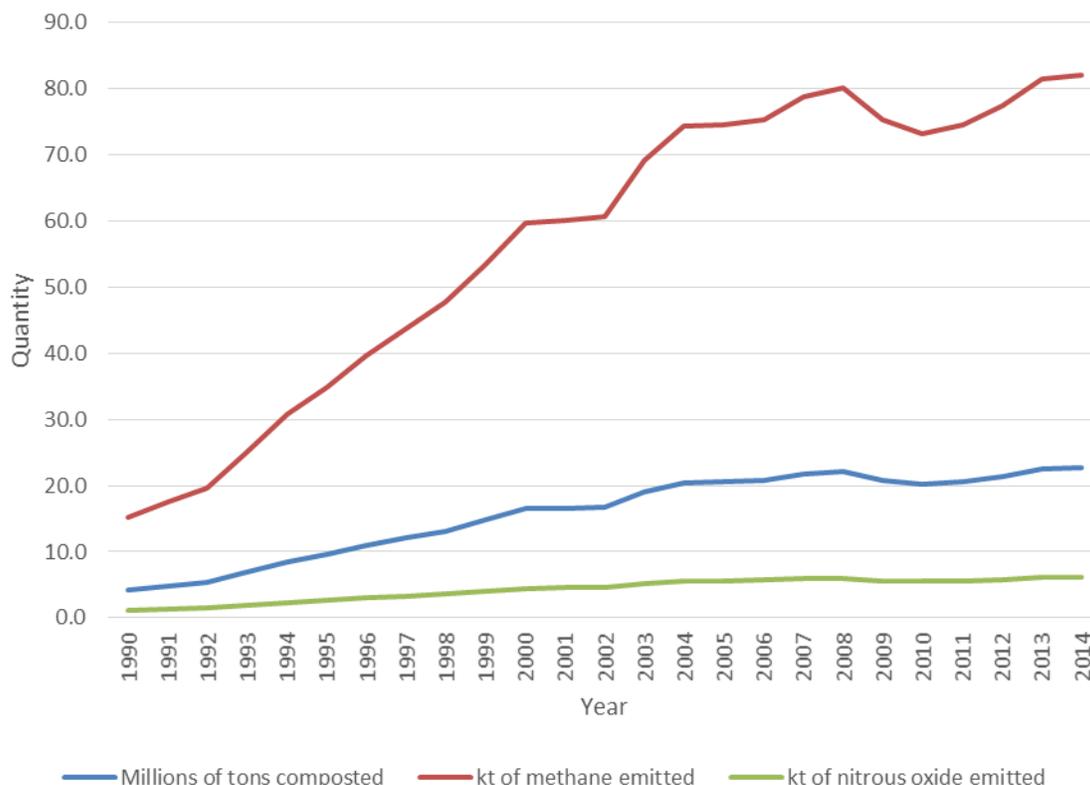
| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|------------|------------|------------|------------|------------|------------|------------|
| CH ₄ | 0.4 | 1.9 | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 |
| N ₂ O | 0.3 | 1.7 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 |
| Total | 0.7 | 3.5 | 3.5 | 3.5 | 3.7 | 3.9 | 3.9 |

Note: Totals may not sum due to independent rounding.

Table 7-18: CH₄ and N₂O Emissions from Composting (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|------------------|------|------|------|------|------|------|------|
| CH ₄ | 15 | 75 | 73 | 75 | 77 | 81 | 82 |
| N ₂ O | 1 | 6 | 5 | 6 | 6 | 6 | 6 |

Figure 7-5: CH₄ and N₂O Emitted from Composting Operations between 1990 and 2014 (kt or million tons)



Methodology

Methane and N₂O emissions from composting depend on factors such as the type of waste composted, the amount and type of supporting material (such as wood chips and peat) used, temperature, moisture content (e.g., wet and fluid versus dry and crumbly), and aeration during the composting process.

The emissions shown in Table 7-17 and Table 7-18 were estimated using the IPCC default (Tier 1) methodology (IPCC 2006), which is the product of an emission factor and the mass of organic waste composted (note: no CH₄ recovery is expected to occur at composting operations in the emission estimates presented):

$$E_i = M \times EF_i$$

where,

| | | |
|--------|---|---|
| E_i | = | CH ₄ or N ₂ O emissions from composting, kt CH ₄ or N ₂ O |
| M | = | mass of organic waste composted in kt |
| EF_i | = | emission factor for composting, 4 t CH ₄ /kt of waste treated (wet basis) and 0.3 t N ₂ O/kt of waste treated (wet basis) (IPCC 2006) |
| i | = | designates either CH ₄ or N ₂ O |

Estimates of the quantity of waste composted (M) are presented in Table 7-19. Estimates of the quantity composted for 1990, 2005 and 2007 through 2009 were taken from EPA's *Municipal Solid Waste in the United States: 2010 Facts and Figures* (EPA 2011); estimates of the quantity composted for 2006 were taken from EPA's *Municipal Solid Waste In The United States: 2006 Facts and Figures* (EPA 2007); estimates of the quantity composted for 2011 through 2012 were taken from EPA's *Municipal Solid Waste In The United States: 2012 Facts and Figures* (EPA 2014); estimates of the quantity composted for 2013 was taken from EPA's *Advancing Sustainable Materials Management: Facts and Figures 2013* (EPA 2015); and estimates of the quantity composted for 2014 were

extrapolated using the 2013 quantity composted and a ratio of the U.S. population in 2013 and 2014 (U.S. Census Bureau 2015).

Table 7-19: U.S. Waste Composted (kt)

| Activity | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|-----------------|-------|--------|--------|--------|--------|--------|--------|
| Waste Composted | 3,810 | 18,643 | 18,298 | 18,661 | 19,351 | 20,358 | 20,533 |

Uncertainty and Time-Series Consistency

The estimated uncertainty from the 2006 IPCC Guidelines is ± 50 percent for the Approach 1 methodology. Emissions from composting in 2014 were estimated to be between 1.9 and 5.8 MMT CO₂ Eq., which indicates a range of 50 percent below to 50 percent above the actual 2014 emission estimate of 3.9 MMT CO₂ Eq. (see Table 7-20).

Table 7-20: Approach 1 Quantitative Uncertainty Estimates for Emissions from Composting (MMT CO₂ Eq. and Percent)

| Source | Gas | 2014 Emission Estimate (MMT CO ₂ Eq.) | Uncertainty Range Relative to Emission Estimate (MMT CO ₂ Eq.) (%) | | | |
|------------|------------------------------------|---|--|-------------|-------------|-------------|
| | | | Lower Bound | Upper Bound | Lower Bound | Upper Bound |
| Composting | CH ₄ , N ₂ O | 3.9 | 1.9 | 5.8 | -50% | +50% |

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. A primary focus of the QA/QC checks was to ensure that the amount of waste composted annually was correct according to the latest EPA *Advancing Sustainable Materials Management: Facts and Figures* report.

Recalculations Discussion

The estimated amount of waste composted in 2013 was updated based on new data contained in EPA's *Advancing Sustainable Materials Management: Facts and Figures 2013* report (EPA 2015) relative to the previous report. The amounts of CH₄ and N₂O emission estimates presented in Table 7-17 and Table 7-18 were revised accordingly.

Planned Improvements

For future Inventories, additional efforts will be made to improve the estimates of CH₄ and N₂O emissions from composting. For example, a literature search on emission factors and their drivers (e.g., the type of composting system, material composition, management technique, impact of varying climatic regions) is underway. The purpose of this literature review is to compile all published emission factors to determine whether the emission factors used in the current methodology should be revised, or expanded to account for various composting system, material composition, management techniques, and/or geographical/climatic differences. For example, composting systems that primarily compost food waste may generate CH₄ at different rates than composting yard trimmings because the food waste may have a higher moisture content and more readily degradable material. Further cooperation with estimating emissions in the Land Use, Land-Use Change, and Forestry (LULUCF) Other section will also be investigated.

7.4 Waste Incineration (IPCC Source Category 5C1)

As stated earlier in this chapter, carbon dioxide (CO₂), nitrous oxide (N₂O), and methane (CH₄) emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires and hazardous industrial waste, because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2014 resulted in 9.7 MMT CO₂ Eq. emissions, over half of which (4.9 MMT CO₂ Eq.) is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 3.3 of the Energy chapter.

Additional sources of emissions from waste incineration include non-hazardous industrial waste incineration and medical waste incineration. As described in Annex 5 of this report, data are not readily available for these sources and emission estimates are not provided. An analysis of the likely level of emissions was conducted based on a 2009 study of hospital/ medical/ infectious waste incinerator (HMIWI) facilities in the United States (RTI 2009). Based on that study's information of waste throughput and an analysis of the fossil-based composition of the waste, it was determined that annual greenhouse gas emissions for medical waste incineration would be below 500 kt CO₂ Eq. per year and considered insignificant for the purposes of Inventory reporting under the UNFCCC. More information on this analysis is provided in Annex 5.

7.5 Waste Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, waste generating and handling processes are also sources of indirect greenhouse gas emissions. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) from waste sources for the years 1990 through 2014 are provided in Table 7-21.

Table 7-21: Emissions of NO_x, CO, and NMVOC from Waste (kt)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | 2014 |
|----------------------------|------------|------------|-----------|-----------|-----------|-----------|-----------|
| NO_x | + | 2 | 1 | 1 | 1 | 1 | 1 |
| Landfills | + | 2 | 1 | 1 | 1 | 1 | 1 |
| Wastewater Treatment | + | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous ^a | + | 0 | 0 | 0 | 0 | 0 | 0 |
| CO | 1 | 7 | 5 | 5 | 5 | 5 | 5 |
| Landfills | 1 | 6 | 5 | 4 | 4 | 4 | 4 |
| Wastewater Treatment | + | + | + | + | + | + | + |
| Miscellaneous ^a | + | 0 | 0 | 0 | 0 | 0 | 0 |
| NMVOCs | 673 | 114 | 44 | 38 | 38 | 38 | 39 |
| Wastewater Treatment | 57 | 49 | 19 | 17 | 17 | 17 | 17 |
| Miscellaneous ^a | 557 | 43 | 17 | 15 | 15 | 15 | 15 |
| Landfills | 58 | 22 | 8 | 7 | 7 | 7 | 7 |

+ Does not exceed 0.5 kt.

^aMiscellaneous includes TSDFs (Treatment, Storage, and Disposal Facilities under the Resource Conservation and Recovery Act [42 U.S.C. § 6924, SWDA § 3004]) and other waste categories.

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2014 for non-electric generating unit (EGU) and non-mobile sources are held constant from 2011 in EPA (2015). Emission estimates of these gases were provided by sector, using a “top down” estimating procedure—emissions were calculated either for individual sources or for many sources combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Uncertainty and Time-Series Consistency

No quantitative estimates of uncertainty were calculated for this source category. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

8. Other

The United States does not report any greenhouse gas emissions under the Intergovernmental Panel on Climate Change (IPCC) “Other” sector.

9. Recalculations and Improvements

Each year, emission and sink estimates are recalculated and revised for all years in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the *2006 IPCC Guidelines* (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is *good practice* to change or refine methods when available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.”

The results of all methodological changes and historical data updates made in the current Inventory report are presented in this section; detailed descriptions of each recalculation are contained within each source’s description found in this report, if applicable. Table 9-1 summarizes the quantitative effect of these changes on U.S. greenhouse gas emissions and sinks and Table 9-2 summarizes the quantitative effect on annual net CO₂ fluxes, both relative to the previously published U.S. Inventory (i.e., the 1990 through 2013 report). These tables present the magnitude of these changes in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.).

The Recalculations Discussion section of each source’s description in the respective chapter of this Inventory presents the details of each recalculation. In general, when methodological changes have been implemented, the entire time series (i.e., 1990 through 2013) has been recalculated to reflect the change, per IPCC (2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies.

The following ten emission sources and sinks underwent some of the most significant methodological and historical data changes. These emission sources consider only methodological and historical data changes. A brief summary of the recalculations and/or improvements undertaken is provided for each of the ten sources.

- *Natural Gas Systems (CH₄)*. EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. EPA carefully evaluated relevant information available, and made several updates, including revisions to production segment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility emissions, transmission and storage station activity and emissions data, distribution segment emissions data for pipelines, distribution segment M&R station activity and emissions data, and distribution segment customer meter emissions data. From December 2015 through February 2016, the EPA released four draft memos that discussed the changes under consideration and requested stakeholder feedback on those changes. The impact of all revisions to natural gas systems is an average annual increase in emissions of 12.9 MMT CO₂ Eq. relative to the previous Inventory.
- *Petroleum Systems (CH₄)*. The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, EPA’s Greenhouse Gas Reporting Program (GHGRP) data, and new studies. The EPA carefully evaluated relevant information available, and made revisions to the production segment methodology for the 2016 Inventory including revised equipment activity data, revised pneumatic controller activity and emissions data, and included a separate estimate for hydraulically fractured oil completions, which were previously not estimated as a distinct subcategory of oil well completions. All these changes resulted in an average annual increase in emissions of 20.7 MMT CO₂ Eq. relative to the previous Inventory.

- *Landfills (CH₄)*. Four major methodological recalculations were performed for the current Inventory. First, a rigorous review of the flare and landfill gas-to-energy (LFGTE) projects across the four recovery databases was conducted. Extensive corrections were made to avoid double counting of projects across the recovery databases. Additionally, several facilities in the LFGTE database were removed because they were not in the published LMOP database for the current or past two years (EPA 2015). Second, the GHGRP CH₄ recovery data were back-calculated for landfills in the GHGRP database for years prior to the first GHGRP reporting year (typically 2010 for most landfills). Third, the flare correction factor was revised. Fourth, the DOC value for landfilled pulp and paper waste was revised from 0.20 to 0.15 based a literature review of pulp and paper waste characterization studies (RTI 2015) and data reported under the GHGRP. The overall impact to the Inventory from these changes resulted in an average increase of nearly 14 percent across the time series. A significant increase in net CH₄ emissions for the years 2010 through 2013 ranging from 20 to 52 percent higher in the current inventory compared to the 1990 to 2013 inventory. These changes resulted in an average annual decrease in emissions of 6.4 MMT CO₂ Eq. relative to the previous Inventory.
- *Agricultural Soil Management (N₂O)*. Methodological recalculations in the current Inventory are associated with the following improvements: (1) driving the DAYCENT simulations with updated input data for land management from the National Resources Inventory extending the time series through 2010; (2) accounting for N inputs from residues associated with additional crops not simulated by DAYCENT including most vegetable crops; (3) modifying the number of experimental study sites used to quantify model uncertainty for direct N₂O emissions; and (4) using DAYCENT for direct N₂O emissions from most flooded rice lands, instead of using the Tier 1 approach for all rice lands. These changes resulted in an increase in emissions of approximately 24 percent on average relative to the previous Inventory and a decrease in the upper bound of the 95 percent confidence interval for direct N₂O emissions from 26 to 24 percent. The differences in emissions and uncertainty are mainly due to increasing the number of study sites used to quantify model uncertainty. These changes resulted in an average annual increase in emissions of 60.1 MMT CO₂ Eq. relative to the previous Inventory.
- *Land Converted to Grassland - Changes in Agricultural Soil Carbon Stocks (CO₂)*. Methodological recalculations in the current Inventory are associated with the following improvements, including: (1) incorporation of updated NRI data for 1990 through 2010; (2) inclusion of federal grasslands in the Tier 2 analysis; (3) improving the simulation of hydric soils in DAYCENT, and (4) incorporating the aboveground biomass C stock losses with Forest Land Converted to Grassland. These changes resulted in an average annual increase in emissions of 49.0 MMT CO₂ Eq. relative to the previous Inventory.
- *Land Converted to Cropland - Changes in Agricultural Carbon Stocks (CO₂)*. Methodological recalculations in the current Inventory are associated with the following improvements: (1) incorporation of updated NRI data for 1990 through 2010; (2) inclusion of federal croplands; (3) improving the simulation of hydric soils in DAYCENT, and (4) incorporating the aboveground biomass C stock losses with Forest Land Converted to Cropland. These changes in SOC stocks resulted in an average annual decrease in emissions of 21.8 MMT CO₂ Eq. relative to the previous Inventory.
- *Cropland Remaining Cropland - Changes in Agricultural Carbon Stocks (CO₂ sink)*. Methodological recalculations in the current Inventory are associated with the following improvements: (1) incorporation of updated NRI data for 1990 through 2010; and (2) inclusion of federal croplands; and (3) improving the simulation of hydric soil. These changes in SOC stocks resulted in an average annual decrease in sequestration of 16.5 MMT CO₂ Eq. relative to the previous Inventory.
- *Forest Land Remaining Forest Land - Changes in Forest Carbon Stock (CO₂ sink)*. Forest ecosystem stock and stock-change estimates differ from the previous Inventory report principally due to the adoption of a new accounting framework (Woodall et al. 2015). The major differences between the framework used this year and past accounting approaches is the sole use of annual FIA data and the back-casting of forest C stocks across the 1990s based on forest C stock density and land use change information obtained from the nationally consistent annual forest inventory coupled with in situ observations of non-tree C pools such as soils, dead wood, and litter. The use of this accounting framework has enabled the creation of the two land use sections for forest C stocks: *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. In prior submissions (e.g., the 1990 through 2013 Inventory submission), the C stock changes from *Land Converted to Forest Land* were a part of the *Forest Land Remaining Forest Land* section and it was not possible to disaggregate the estimates. A second major change was the adoption of a new approach to estimate forest soil C, the largest C stock in the

United States. For detailed discussion of these new approaches please refer to the Methodology section, Annex 3.13, Domke et al. (in prep), and Woodall et al. (2015). In addition to these major changes, the refined land representation analysis described in Section 6.1 Representation of the U.S. Land Base which identifies some of the forest land in south central and southeastern coastal Alaska as unmanaged; this is in contrast to past assumptions of “managed” land for these forest lands included in the FIA database. Therefore, the C stock and flux estimates for southeast and south central coastal Alaska, as included here, reflect that adjustment, which effectively reduces the managed forest area by approximately 5 percent.

In addition to the creation of explicit estimates of removals and emissions by *Forest Land Remaining Forest Land* versus *Land Converted to Forest Land*, the accounting framework used this year eliminated the use of periodic data (which may be inconsistent with annual inventory data) which contributed to a data artifact in prior estimates of emissions/removals from 1990 to the present. In the previous Inventory report, there was a reduction in net sequestration from 1995 to 2000 followed by an increase in net sequestration from 2000 to 2004. This artifact of comparing inconsistent inventories of the 1980s through 1990s to the nationally consistent inventories of the 2000s has been removed in this Inventory. Overall, there were net C additions to HWP in use and in SWDS combined due, in large part, to updated data on products in use from 2010 to the present. All these changes resulted in an average annual increase in sequestration of 8.9 MMT CO₂ Eq. relative to the previous Inventory.

- *Substitution of Ozone Depleting Substances (HFCs)*. For the current Inventory, reviews of the large retail food and refrigerated transport end-uses resulted in revisions to the Vintaging Model since the previous Inventory report. In addition, a vending machine end-use was added to the Vintaging Model since the previous Inventory. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. For the large retail food end-use, assumptions regarding new installations by system type and refrigerant transitions were revised based on a review of data collected by EPA's GreenChill Partnership and the California Air Resources Board's Refrigerant Management Program. Based on a literature review of technical reports and relevant datasets, the refrigerated transport end-use was updated from an aggregate end-use that covered all the various refrigerated transport modes through average assumptions of charge size, leak rates, stock, and lifetimes to separate end-uses by mode, including road transport, intermodal containers, merchant fishing, reefer ships, and vintage and modern rail. The vending machine end-use was added based on a review of technical reports and sales data. Combined, these assumption changes and additions decreased CO₂-equivalent greenhouse gas emissions on average by 5 percent between 1990 and 2014. Overall, these changes resulted in an average annual decrease in emissions of 6.3 MMT CO₂ Eq. relative to the previous Inventory.
- *Grassland Remaining Grassland - Changes in Agricultural Carbon Stock (CO₂ sink)*. Methodological recalculations in the current Inventory are associated with the following improvements, including (1) incorporation of updated NRI data for 1990 through 2010; (2) inclusion of federal grasslands in the Tier 2 analysis; and (3) improving the simulation of hydric soils in DAYCENT. These changes in soil organic carbon (SOC) stocks resulted in an average annual increase in sequestration of 4.9 MMT CO₂ Eq. relative to the previous Inventory.

Table 9-1: Revisions to U.S. Greenhouse Gas Emissions (MMT CO₂ Eq.)

| Gas/Source | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | Average Annual Change |
|---|--------------|---------------|---------------|--------------|--------------|--------------|-----------------------|
| CO₂ | (8.6) | (11.2) | (15.8) | (9.4) | (9.1) | (2.6) | (10.2) |
| Fossil Fuel Combustion | + | (0.5) | (8.9) | (3.7) | (1.3) | (0.1) | (1.1) |
| <i>Electricity Generation</i> | NC | NC | NC | NC | NC | (1.6) | (0.1) |
| <i>Transportation</i> | NC | (0.8) | (3.7) | (3.9) | (4.0) | (5.4) | (1.5) |
| <i>Industrial</i> | + | 0.2 | (0.1) | (0.8) | (1.3) | (5.0) | (0.2) |
| <i>Residential</i> | NC | + | (0.1) | (0.4) | (0.6) | 0.1 | + |
| <i>Commercial</i> | NC | + | (0.1) | (0.3) | (0.4) | 0.3 | + |
| <i>U.S. Territories</i> | NC | NC | (4.8) | 1.7 | 5.0 | 11.6 | 0.6 |
| Non-Energy Use of Fuels | 0.5 | + | (0.5) | 0.2 | 0.7 | 1.8 | 0.1 |
| Natural Gas Systems | 0.1 | 0.1 | 0.1 | 0.1 | 0.4 | 0.6 | 0.1 |
| Cement Production | NC | NC | NC | NC | NC | + | + |
| Lime Production | + | + | + | + | + | + | + |
| Other Process Uses of Carbonates | NC | NC | NC | NC | NC | 6.0 | 0.2 |
| Glass Production | NC | NC | NC | NC | NC | 0.2 | + |
| Soda Ash Production and Consumption | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Carbon Dioxide Consumption | NC | NC | 3.2 | 3.3 | 3.2 | 3.3 | 0.5 |
| Incineration of Waste | NC | NC | NC | NC | + | (0.7) | + |
| Titanium Dioxide Production | NC | NC | NC | NC | NC | 0.1 | + |
| Aluminum Production | NC | NC | NC | NC | NC | NC | NC |
| Iron and Steel Production & Metallurgical Coke Production | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| Ferroalloy Production | NC | NC | NC | NC | NC | NC | NC |
| Ammonia Production | NC | NC | NC | NC | NC | (0.2) | + |
| Urea Consumption for Non-Agricultural Purposes | NC | NC | NC | NC | NC | (0.5) | + |
| Phosphoric Acid Production | (0.1) | (0.1) | + | + | + | (0.1) | (0.1) |
| Petrochemical Production | + | (0.7) | (0.1) | (0.1) | + | (0.1) | (0.2) |
| Silicon Carbide Production and Consumption | NC | NC | NC | NC | NC | + | + |
| Lead Production | NC | NC | NC | NC | NC | + | + |
| Zinc Production | NC | NC | NC | NC | NC | NC | NC |
| Petroleum Systems | (0.9) | (1.0) | + | (0.3) | (1.2) | (2.3) | (0.9) |
| Magnesium Production and Processing | + | + | + | NC | NC | + | + |
| <i>Biomass – Wood^a</i> | NC | NC | NC | NC | NC | 3.0 | 0.1 |
| <i>International Bunker Fuels^a</i> | NC | NC | NC | NC | NC | NC | NC |
| <i>Biomass – Ethanol^a</i> | NC | NC | NC | NC | NC | NC | NC |
| CH₄^b | 28.4 | 9.5 | 55.2 | 56.5 | 66.8 | 85.2 | 21.3 |
| Stationary Combustion | + | + | + | + | + | + | + |
| Mobile Combustion | + | (0.3) | + | + | + | + | (0.1) |
| Coal Mining | NC | NC | NC | NC | NC | NC | NC |
| Abandoned Underground Coal Mines | NC | NC | NC | NC | NC | NC | NC |
| Natural Gas Systems | 27.6 | 1.0 | 6.6 | 10.8 | 18.2 | 18.2 | 12.9 |
| Petroleum Systems | 7.2 | 25.4 | 32.7 | 34.3 | 35.1 | 39.5 | 20.7 |
| Petrochemical Production | + | (0.1) | + | + | + | + | + |
| Silicon Carbide Production and Consumption | NC | NC | NC | NC | NC | NC | NC |
| Iron and Steel Production & Metallurgical Coke Production | (1.1) | (0.8) | (0.6) | (0.7) | (0.7) | (0.7) | (0.9) |
| Ferroalloy Production | NC | NC | NC | NC | NC | NC | NC |
| Enteric Fermentation | NC | NC | 0.2 | 0.2 | 0.4 | 0.9 | 0.1 |
| Manure Management | NC | NC | + | 0.1 | + | + | + |
| Rice Cultivation | 4.0 | 4.1 | 0.8 | 3.4 | 2.6 | 3.6 | 2.7 |
| Field Burning of Agricultural Residues | (0.1) | + | + | + | + | + | + |
| Landfills | (6.7) | (11.5) | 20.3 | 23.1 | 27.0 | 29.7 | (6.4) |

| | | | | | | | |
|--|-------------|---------------|--------------|--------------|--------------|--------------|--------------|
| Wastewater Treatment | + | + | + | + | (0.1) | (0.2) | + |
| Composting | NC | NC | NC | NC | NC | 0.1 | + |
| Incineration of Waste | NC | NC | NC | NC | NC | NC | NC |
| <i>International Bunker Fuels^a</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> |
| N₂O^b | 76.3 | 41.7 | 50.3 | 44.6 | 43.7 | 48.2 | 51.4 |
| Stationary Combustion | + | + | + | + | + | + | + |
| Mobile Combustion | + | (3.7) | (0.1) | (0.1) | (0.2) | (0.2) | (1.4) |
| Adipic Acid Production | NC | NC | NC | NC | NC | NC | NC |
| Nitric Acid Production | + | + | + | + | + | NC | + |
| Manure Management | 0.2 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.1 |
| Agricultural Soil Management | 79.3 | 53.5 | 56.4 | 57.3 | 57.1 | 54.9 | 60.1 |
| Field Burning of Agricultural Residues | + | + | + | + | + | + | + |
| Wastewater Treatment | NC | + | (0.2) | (0.1) | (0.1) | (0.1) | (0.1) |
| N ₂ O from Product Uses | NC | NC | NC | NC | NC | NC | NC |
| Incineration of Waste | NC | NC | NC | NC | NC | NC | NC |
| Composting | NC | NC | NC | NC | NC | 0.1 | + |
| Semiconductor Manufacture | NC | NC | NC | + | + | + | + |
| <i>International Bunker Fuels^a</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> | <i>NC</i> |
| HFCs | NC | (11.4) | (3.1) | (3.0) | (3.5) | (3.7) | (6.3) |
| Substitution of Ozone Depleting Substances | NC | (11.4) | (3.2) | (3.1) | (3.4) | (4.0) | (6.3) |
| HCFC-22 Production | NC | NC | (3.2) | (3.1) | (3.4) | (4.0) | (6.3) |
| Semiconductor Manufacture | NC | + | NC | NC | NC | NC | NC |
| Magnesium Production and Processing | NC | NC | + | + | + | + | + |
| PFCs | NC | + | NC | NC | NC | NC | NC |
| Aluminum Production | NC | NC | 0.1 | 0.1 | + | + | + |
| Semiconductor Manufacture | NC | + | NC | NC | NC | NC | NC |
| SF₆ | NC | + | 0.1 | 0.1 | + | + | + |
| Electrical Transmission and Distribution | NC | + | + | + | (0.1) | 0.3 | + |
| Semiconductor Manufacture | NC | + | + | + | (0.1) | 0.3 | + |
| Magnesium Production and Processing | NC | NC | + | + | + | + | + |
| NF₃ | NC | + | NC | NC | NC | + | + |
| Semiconductor Manufacture | NC | + | + | + | + | + | + |
| Net Change in Total Emissions^b | 96.1 | 28.6 | 86.6 | 88.8 | 97.9 | 127.0 | |
| Percent Change | 1.5% | 0.4% | 1.3% | 1.3% | 1.5% | 1.9% | |

Note: Net change in total emissions presented without LULUCF.

NC - No Change

+ Absolute value does not exceed 0.05 MMT CO₂ Eq. or 0.05 percent.

^a Not included in emissions total.

^b Totals effect of recalculations is underestimated because the 1990 through 2013 Inventory included emissions from LULUCF in totals.

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 9-2: Revisions to Total Net Flux from Land Use, Land-Use Change, and Forestry (MMT CO₂ Eq.)

| Land Use Category | 1990 | 2005 | 2010 | 2011 | 2012 | 2013 | Average Annual Change |
|--|---------------|--------------|---------------|---------------|--------------|--------------|-----------------------|
| Forest Land Remaining Forest Land | (82.8) | 117.9 | 20.9 | 23.9 | 29.6 | 39.1 | (11.4) |
| Changes in Forest Carbon Stock ^a | (84.1) | 115.2 | 23.4 | 37.2 | 37.3 | 36.6 | (8.9) |
| Non-CO ₂ Emissions from Forest Fires | 1.3 | 2.7 | (2.5) | (13.2) | (7.7) | 2.5 | (2.6) |
| N ₂ O Fluxes from Forest Soils ^b | NC | NC | NC | NC | NC | NC | NC |
| Land Converted to Forest Land | NC* | NC* | NC* | NC* | NC* | NC* | NC* |
| Changes in Forest Carbon Stock | NC* | NC* | NC* | NC* | NC* | NC* | NC* |
| Cropland Remaining Cropland | 30.9 | 13.9 | 27.7 | 13.3 | 14.0 | 12.5 | 16.5 |
| Changes in Agricultural Carbon Stock ^c | 30.9 | 13.9 | 27.7 | 13.3 | 13.8 | 14.2 | 16.5 |
| CO ₂ Emissions from Liming | NC | NC | NC | + | 0.2 | (2.0) | (0.1) |
| CO ₂ Emissions from Urea Fertilization | NC | NC | NC | NC | NC | 0.3 | + |
| Land Converted to Cropland | 41.2 | 12.3 | 7.5 | 5.4 | 6.0 | 6.0 | 21.8 |
| Changes in Agricultural Carbon Stock ^c | 41.2 | 12.3 | 7.5 | 5.4 | 6.0 | 6.0 | 21.8 |
| Grassland Remaining Grassland | (11.0) | (7.5) | (19.0) | (8.6) | (8.0) | (8.3) | (4.9) |
| Changes in Agricultural Carbon Stock ^c | (11.0) | (7.5) | (19.0) | (8.6) | (8.0) | (8.3) | (4.9) |
| Land Converted to Grassland | 46.5 | 52.1 | 48.2 | 48.7 | 49.1 | 49.1 | 49.0 |
| Changes in Agricultural Carbon Stock ^c | 46.5 | 52.1 | 48.2 | 48.7 | 49.1 | 49.1 | 49.0 |
| Wetlands Remaining Wetlands | NC | NC | NC | NC | NC | NC | NC |
| Peatlands Remaining Peatlands | NC | NC | NC | NC | NC | NC | NC |
| Settlements Remaining Settlements | NC | + | + | + | + | + | + |
| Changes in Carbon Stocks in Urban Trees | NC | NC | NC | NC | NC | NC | NC |
| N ₂ O Fluxes from Settlement Soils ^d | NC | + | + | + | + | + | + |
| Other | NC | NC | + | 0.5 | 0.5 | 0.9 | 0.1 |
| Landfilled Yard Trimmings and Food Scraps | NC | NC | + | 0.5 | 0.5 | 0.9 | 0.1 |
| LULUCF Emissions^e | 1.3 | 2.7 | (2.5) | (13.2) | (7.4) | 0.8 | |
| Net Change in LULUCF Total Net Flux^f | 22.8 | 185.2 | 87.3 | 96.1 | 98.4 | 98.1 | |
| LULUCF Sector Total^g | 24.1 | 187.9 | 84.9 | 82.9 | 90.9 | 98.9 | |
| Percent Change | 3.2% | 21.2% | 10.0% | 9.8% | 10.8% | 11.5% | |

NC - No Change

+ Absolute value does not exceed 0.05 MMT CO₂ Eq. or 0.05 percent.

* Indicates a new source for the current Inventory year

^a Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

^b Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*, but not from land-use conversion.

^c Estimates include C stock changes in all pools.

^d Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

^e LULUCF emissions include the CO₂, CH₄, and N₂O emissions reported for Non-CO₂ Emissions from Forest Fires, N₂O Fluxes from Forest Soils, CO₂ Emissions from Liming, CO₂ Emissions from Urea Fertilization, Peatlands Remaining Peatlands, and N₂O Fluxes from Settlement Soils.

^f LULUCF Total Net Flux includes any C sequestration gains and losses from all land use and land use conversion categories.

^g The LULUCF Sector Total is the net sum of all emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO₂ (i.e., sinks or negative emissions) from the atmosphere.

Notes: Numbers in parentheses indicate an increase in C sequestration. Totals may not sum due to independent rounding.

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PROPOSED REGULATION ORDER

Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

§ 95665. Purpose and Scope.

The purpose of this article is to establish greenhouse gas emission standards for crude oil and natural gas facilities identified in section 95666. This article is designed to serve the purposes of the California Global Warming Solutions Act, AB 32, as codified in sections 38500-38599 of the Health and Safety Code.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95666. Applicability.

- (a) This article applies to owners or operators of equipment and components listed in section 95668 located within California, including California waters, that are associated with facilities in the sectors listed below, regardless of emissions level:
- (1) Onshore and offshore crude oil or natural gas production; and,
 - (2) Crude oil, condensate, and produced water separation and storage; and,
 - (3) Natural gas underground storage; and,
 - (4) Natural gas gathering and boosting stations; and,
 - (5) Natural gas processing plants; and,
 - (6) Natural gas transmission compressor stations.
- (b) Owners and operators must ensure that their facilities, equipment, and components comply at all times with all requirements of this subarticle, including all of the standards and requirements identified in section 95668. Owners and operators are jointly and severally liable for compliance with this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95667. Definitions.

- (a) For the purposes of this article, the following definitions apply:
- (1) "Air district or local air district" means the local Air Quality Management District or the local Air Pollution Control District.

- (2) "Air Resources Board or ARB" means the California Air Resources Board.
- (3) "API gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.
- (4) "Centrifugal compressor" means equipment that increases the pressure of natural gas by centrifugal action.
- (5) "Centrifugal compressor seal" means a wet or dry seal around the compressor shaft where the shaft exits the compressor case.
- (6) "Circulation tank" means a tank or portable tank used to circulate, store, or hold liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment.
- (7) "Continuous bleed" means the continuous venting of natural gas from a gas powered pneumatic device to the atmosphere. Continuous bleed pneumatic devices must vent continuously in order to operate.
- (8) "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- (9) "Condensate" means hydrocarbon or other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- (10) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pipe, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, pneumatic device, pneumatic pump, centrifugal compressor wet seal, or reciprocating compressor rod packing or seal.
- (11) "Critical component" means any component that would require the shutdown of a critical process unit if that component was shutdown or disabled. ..
- (12) "Critical process unit" means a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

- (13) "Crude oil and produced water separation and storage" means all activities associated with separating, storing or holding of emulsion, crude oil, condensate, or produced water at facilities to which this subarticle applies.
- (14) "Emissions" means the discharge of natural gas into the atmosphere.
- (15) "Emulsion" means any mixture of crude oil, condensate, or produced water with varying quantities of natural gas entrained in the liquids.
- (16) "Equipment" means any stationary or portable machinery, object, or contrivance covered by this subarticle, as set out by sections 95666 and 95668.
- (17) "Facility" means any building, structure, or installation to which this subarticle applies and which has the potential to emit natural gas. Facilities include all buildings, structures, or installations which:
- (1) Are under the same ownership or operation, or which are owned or operated by entities which are under common control;
 - (2) Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and,
 - (3) Are located on one or more contiguous or adjacent properties.
- (18) "Flash or flashing" means a process during which gas entrained in crude oil, condensate, or produced water under pressure is released when the liquids are subject to a decrease in pressure or increase in temperature, such as when the liquids are transferred from an underground reservoir to the earth's surface.
- (19) "Flash analysis testing" means the determination of emissions from crude oil, condensate, and produced water by using sampling and laboratory procedures used for measuring the volume and composition of gases released from the liquids, including the molecular weight, the weight percent of individual compounds, and a gas-oil or gas-water ratio.
- (20) "Inaccessible component" means any component located over fifteen feet above ground when access is required from the ground; or any component located over six (6) feet away from a platform when access is required from the platform.
- (21) "Intermittent bleed" means the intermittent venting of natural gas from a gas powered pneumatic device to the atmosphere. Intermittent bleed pneumatic devices may vent all or a portion of their supply gas when control action is necessary but do not vent continuously.

- (22) "Leak or fugitive leak" means the unintentional release of emissions at a rate greater than or equal to the leak thresholds specified in this article.
- (23) "Leak detection and repair or LDAR" means the inspection of components to detect leaks of total hydrocarbons and the repair of components with leaks above specified standards within specified timeframes.
- (24) "Liquids unloading" means an activity conducted with the use of pressurized natural gas to remove liquids that accumulate at the bottom of a natural gas well and obstruct gas flow.
- (25) "Minimize" means tightening, adjusting, or replacing components or equipment for the purpose of stopping or reducing leaks below the lowest leak threshold specified in this subarticle.
- (26) "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases. Its constituents include the greenhouse gases methane and carbon dioxide, as well as heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.
- (27) "Natural gas gathering and boosting station" means all equipment and components located within a facility fence line associated with moving natural gas to a processing plant or natural gas transmission pipeline.
- (28) "Natural gas processing plant" means a plant used for the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures.
- (29) "Natural gas transmission compressor station" means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines.
- (30) "Natural gas transmission pipeline" means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717z (2015).
- (31) "Natural gas underground storage" means all equipment and components associated with the subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns.
- (32) "Offshore" means all marine waters located within the boundaries of the State of California.

- (33) "Onshore" means all lands located within the boundaries of the State of California.
- (34) "Operator" means any entity, including an owner or contractor, having operational control of components or equipment, including leased, contracted, or rented components and equipment to which this subarticle applies.
- (35) "Owner" means the entity that owns or operates components or equipment to which this subarticle applies.
- (36) "Photo-ionization detector or PID instrument" means a gas detection device that utilizes ultra-violet light to ionize gas molecules and is commonly employed in the detection of non-methane volatile organic compounds.
- (37) "Pneumatic device" means an automation device that uses natural gas, compressed air, or electricity to control a process.
- (38) "Pneumatic pump" means a device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.
- (39) "Pond" means an excavation or impoundment for the storage and disposal of produced water and is not used for crude oil separation or processing.
- (40) "Portable equipment" means equipment designed for, and capable of, being carried or moved from one location to another and which it resides for less than 365 days. Portability indicators include, but are not limited to, the presence of wheels, skids, carrying handles, dolly, trailer, or platform.
- (41) "Portable pressurized separator" means a pressure vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is capable of separating and sampling crude oil, condensate, or produced water at the steady-state temperature and pressure of the separator required for sampling.
- (42) "Portable tank" means a tank that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled.
- (43) "Pressure vessel" means any a hollow container used to hold gas or liquid and rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas.
- (44) "Production" means all activities associated with the production or recovery of emulsion, crude oil, condensate, produced water, or natural gas at facilities to which this subarticle applies.

- (45) "Produced water" means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.
- (46) "Reciprocating natural gas compressor" means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.
- (47) "Reciprocating natural gas compressor rod packing" means a seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that vents into the atmosphere
- (48) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.
- (49) "Separator" means any tank used for the separation of crude oil, condensate, produced water, or natural gas.
- (50) "Separator and tank system" means a separator and any tank or sump connected directly to the separator. For the purpose of this article, in crude oil production, a pressure vessel used to separate crude oil and produced water is also considered a separator; in dry natural gas production, a pressure vessel used to separate gas from water is also considered a separator. .
- (51) "Successful repair" means tightening or adjusting or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the lowest leak threshold specified in this subarticle.
- (52) "Sump" means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used to separate, store, or hold emulsion, crude oil, condensate, or produced water.
- (53) "Tank" means any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or produced water and that is designed to operate below 15 psig normal operating pressure.
- (54) "Underground injection well" means, for the purpose of this subarticle, any well that is used for the subsurface injection of natural gas for disposal.
- (55) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections,

and flow-inducing devices used to collect and route emissions to a processing, sales gas, or fuel gas system; to an underground injection well; or to a vapor control device.

- (56) "Vapor control device" means destructive or non-destructive equipment used to control emissions.
- (57) "Vapor control efficiency" means the ability of a vapor control device to control emissions, expressed as a percentage, which can be estimated by calculation or by measuring the total hydrocarbon concentration at the inlet and outlet of the vapor control device.
- (58) "Vapor pressure" means the equilibrium partial vapor pressure exerted by an organic liquid measured at maximum tank temperature.
- (59) "Vent or venting" means the intentional or automatic release of natural gas into the atmosphere from components, equipment or activities described in this subarticle.
- (60) "Well" means a boring in the earth that is designed to bring emulsion, crude oil, condensate, produced water, or natural gas to the surface, or to inject natural gas into underground storage.
- (61) "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the formation and as further defined by the Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Chapter 4, Subchapter 2, Article 2, section 1761(a) (December 30, 2014).

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code

§ 95668. Standards.

(a) Crude Oil, Condensate, and Produced Water Separation and Storage

- (1) Except as provided in section 95668(a)(2), the requirements in sections 95668(a)(3) through (9) apply to pressure vessels, separators, tanks, and sumps at facilities listed in section 95666:.
- (2) The requirements of this subsection do not apply to the following:
 - (A) Pressure vessels, separators, tanks, and sumps that have not contained crude oil, condensate, or produced water for at least 30 calendar days.
 - (B) Tanks used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from any newly constructed well for up

to 30 calendar days following initial production from that well but only if the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.

- (3) Beginning January 1, 2017, pressure vessels not already subject to a district leak detection and repair program shall comply with the leak detection and repair requirements specified in section 95669.
- (4) Beginning January 1, 2017 and by no later than September 1, 2017, owners or operators of new and existing separator and tank systems which are not controlled for emissions with the use of a vapor collection system shall conduct annual flash analysis testing of the crude oil, condensate, or produced water as described below.
 - (A) Conduct flash analysis testing in accordance with the ARB Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water as described in Appendix C.
 - (B) Sum the annual flash analysis testing results for methane for the crude oil, condensate, and produced water.
 - (C) Maintain a record of flash analysis testing as specified in section 95671 and report the results to ARB as specified in section 95672.
 - (D) Demonstrate that the results of the flash analysis testing are representative of the crude oil, condensate, and produced water processed or stored in the separator and tank system. The ARB Executive Officer may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.
- (5) Beginning January 1, 2018, owners or operators of separator and tank systems with a measured annual flash emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system with the use of a vapor collection system as specified in section 95668(c).
- (6) Beginning January 1, 2018, separators, tanks, and covered sumps subject to the vapor collection system requirements specified in section 95668(a)(6) shall comply with the leak detection and repair requirements specified in section 95669.
- (7) Owners or operators of separator and tanks systems with a flash emission rate less than or equal to 10 metric tons per year of methane shall conduct flash analysis testing and reporting annually. If the results of flash analysis testing are less than or equal to 10 metric tons per year of methane using three

consecutive years of test results the owner or operator may reduce the frequency of testing and reporting to once every five years.

- (8) Flash analysis testing, record keeping, and reporting shall be conducted within one calendar year of adding a new well to the separator and tank system since the time of previous flash analysis testing.
- (9) Flash emissions shall be recalculated if the annual crude oil, condensate, or produced water throughput increases by more than 10 percent since the time of the previous flash analysis testing provided that the increase in throughput is not a result of adding a new well to the separator and tank system which requires additional flash analysis testing as specified in section 95668(a)(8).
 - (A) The owner or operator shall maintain and make available upon request by the ARB Executive Officer a record of the revised flash emission calculation.

(b) *Circulation Tanks for Well Stimulation Treatments*

- (1) Beginning January 1, 2018, circulation tanks used in conjunction with well stimulation treatments used at facilities listed in section 95666 shall be controlled for emissions of natural gas according to one of the following methods:
 - (A) The circulated liquids shall be controlled for emissions of natural gas prior to entering the circulation tank using a pressure vessel or separator and a vapor collection system as specified in section 95668(c) and the circulation tank shall be covered and comply with the leak detection and repair requirements specified in section 95669; or,
 - (B) Circulation tanks shall be covered and controlled for emissions of natural gas using a vapor collection system as described in section 95668(c) and the tank shall comply with the leak detection and repair requirements specified in section 95669.

(c) *Vapor Collection Systems and Vapor Control Devices*

- (1) Beginning January 1, 2018, the following requirements apply to equipment at facilities listed in section 95666 that are subject to the vapor collection system and control device requirements specified in this subarticle:
- (2) Unless section 95668(c)(3) applies, the vapor collection system shall direct the collected vapors to one of the following:
 - (A) Existing sales gas system; or,
 - (B) Existing fuel gas system; or,

- (C) Existing underground injection well not currently under review by the Division of Oil and Gas and Geothermal Resources.
- (3) If no existing sales gas system, fuel gas system, or underground injection well specified in section 95668(c)(2) is available at the facility, the owner or operator must control the collected vapors as follows:
- (A) For facilities without an existing vapor control device installed at the facility, the owner or operator must install a new vapor control device as specified in section 95668(c)(4); or,
 - (B) For facilities currently operating a vapor control device and which are required to control additional vapors as a result of this subarticle, the owner or operator must replace the existing vapor control device with a new vapor control device as specified in section 95668(c)(4) to control all of the collected vapors.
- (4) Any vapor control device required in section 95668(c)(3) must meet the following requirements:
- (A) If the vapor control device is to be installed in a region classified as in attainment with all state or federal ambient air quality standards, the vapor control device must achieve at least 95% vapor control efficiency of total emissions and must meet all applicable federal, state, and local air district requirements; or,
 - (B) If the vapor control device is to be installed in a region classified as non-attainment with, or which has not been classified as in attainment of, all state and federal ambient air quality standards, the owner or operator must install one of the following devices that meets all applicable federal, state, and local air district requirements:
 - 1. A non-destructive vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not result in emissions of nitrogen oxides (NO_x); or,
 - 2. A vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not generate more than 15 parts per million volume (ppmv) NO_x when measured at 3% oxygen.
- (5) If the collected vapors cannot be controlled as specified in section 95668(c)(2) through (4), the equipment subject to the vapor collection and control requirements specified in this subarticle may not be used or installed and must be removed from service by January 1, 2018.
- (6) Vapor collection systems and control devices are allowed up to 30 calendar days per year for maintenance. A time extension to perform maintenance not

to exceed 14 calendar days may be granted by the ARB Executive Officer. The owner or operator is responsible for maintaining a record of the number of calendar days per calendar year that the vapor collection system or vapor control device is out of service and shall provide a record of such activity at the request of the ARB Executive Officer..

- (A) If an alternate vapor control device compliant with this section is installed prior to conducting maintenance and the vapor collection and control system continues to collect and control vapors during the maintenance operation, the event does not count towards the 30 calendar day limit.
- (B) Vapor collection system and control device shutdowns that result from utility power outages are not subject to enforcement action provided the equipment resumes normal operation as soon as normal utility power is restored. Vapor collection system and control device shutdowns that result from utility power outages do not count towards the 30 calendar day limit for maintenance.

(d) Reciprocating Natural Gas Compressors

- (1) The following requirements apply to reciprocating natural gas compressors at crude oil or natural gas production facilities listed in section 95666 which are not covered under section 95668(d)(2):
 - (A) Beginning January 1, 2017, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.
 - (B) Beginning January 1, 2017, for any compressors without a vapor collection system used to control the rod packing or seal vent gas, the rod packing or seal shall comply with the leak detection and repair requirements specified in section 95669; and,
 - (C) The owner or operator shall maintain a record of the rod packing or seal leak concentration measurement as specified in Appendix A, Table 5.
 - (D) A reciprocating natural gas compressor with a rod packing or seal leak concentration measured above the minimum standard specified in section 95669 and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within 180 calendar days from the date of the initial leak concentration measurement, whichever is sooner.
- (2) The following requirements apply to reciprocating natural gas compressors at natural gas gathering and boosting stations, processing plants, transmission

compressor stations, and underground natural gas storage facilities listed in section 95666 and which are not covered under section 95668(d)(1):

- (A) Beginning January 1, 2017, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.
- (B) Beginning January 1, 2017, any compressor without a vapor collection system used to control the rod packing or seal vent gas shall be equipped with a meter or instrumentation that can measure the rod packing or seal emissions flow rate; or,
- (C) The compressor shall be equipped with a clearly identified access port installed in the rod packing or seal vent stack at a height of no more than six (6) feet above ground level for making individual or combined rod packing or seal emission flow rate measurements; and,
- (D) The rod packing or seal emissions flow rate shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature.
- (E) Beginning January 1, 2018, a compressor with a rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute (scfm), or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be repaired or replaced within 30 calendar days from the date of the initial emission flow rate measurement.
- (F) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified in section 95688(d)(2)(E) and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within 180 days from the date of the initial flow rate measurement, whichever is sooner.

(e) *Centrifugal Natural Gas Compressors with Wet Seals*

- (1) The following requirements apply to centrifugal natural gas compressors with wet seals at facilities listed in section 95666:
- (2) Beginning January 1, 2017, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.

- (3) Beginning January 1, 2017, any compressor without a vapor collection system used to control the wet seal vent gas shall be equipped with a meter or instrumentation that can measure the wet seal emissions flow rate; or
- (4) The compressor shall be equipped with a clearly identified access port installed in the wet seal vent stack at a height of no more than six (6) feet above ground level for making wet seal emission flow rate measurements; and,
- (5) The wet seal emissions flow rate shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature.
- (6) Beginning January 1, 2018, a compressor with a wet seal emission flow rate greater than three (3) scfm or a combined wet seal emission flow rate greater than the number of wet seals multiplied by three (3) scfm shall control the wet seal emission vent gas with the use of a vapor collection system as specified in section 95668(c); or,
- (7) Minimize the wet seal emission flow rate within 30 calendar days from the date of the initial emission flow rate measurement and replace the wet seal with a dry seal by no later than January 1, 2020.
- (8) A centrifugal natural gas compressor with a wet seal emission flow rate measured above the standard specified in section 95668(e)(6) and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within 180 days from the date of the initial flow rate measurement, whichever is sooner.

(f) *Natural Gas Powered Pneumatic Devices and Pumps*

- (1) Except as provided in section 95668(f)(2), the requirements in sections 95668(f)(3) through (6) apply to natural gas powered pneumatic devices and pumps at facilities listed in section 95666:
- (2) A natural gas powered pneumatic device installed prior to January 1, 2015 may be used provided it meets all of the following requirements:
 - (A) The device does not vent natural gas at a rate greater than 6 standard cubic feet per hour (scfh); and,
 - (B) The device is clearly marked with a permanent tag that identifies the vent rate as less than or equal to 6 scfh; and,

- (C) The device is tested during each inspection period as specified in section 95669 by using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,
 - (D) A device with a measured emissions flow rate greater than 6 scfh shall be repaired or replaced within 14 calendar days from the date of the initial emission flow rate measurement.
- (3) Beginning January 1, 2018, pneumatic devices shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669..
 - (4) Beginning January 1, 2018, intermittent bleed pneumatic devices shall not vent natural gas when not actuating determined by testing the device when not actuating in accordance with the leak detection and repair requirements specified in section 95669.
 - (5) Beginning January 1, 2018, pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.
 - (6) Beginning January 1, 2018, pneumatic devices and pumps shall be retrofitted or replaced to prevent natural gas from venting to the atmosphere or shall be controlled according to one of the following methods:
 - (A) Collect all vented natural gas with the use of a vapor collection system as specified in section 95668(c); or,
 - (B) Use compressed air or electricity to operate.

(g) *Liquids Unloading of Natural Gas Wells*

- (1) Beginning January 1, 2018, owners or operators of natural gas wells at facilities listed in section 95666 that are vented to the atmosphere for the purpose of liquids unloading shall perform one of the following:
 - (A) Collect the vented natural gas with the use of a vapor collection system as specified in section 95668(c); or,
 - (B) Measure the volume of natural gas vented by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); or,
 - (C) Calculate the volume of natural gas vented using the Liquid Unloading Calculation listed in Appendix B or according to the Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions,

Title 17, Division 3, Chapter 1, Subchapter 10, Article 2, Section 95153(e)
(February, 2015).

- (2) Owners or operators must maintain and report a record of the volume of natural gas vented to perform liquids unloading as well as equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) once per calendar year as specified in sections 95670 and 95671 of this subarticle.

(h) Natural Gas Underground Storage Facility Well Monitoring Requirements

- (1) The following requirements apply to natural gas underground storage facilities listed in section 95666:
- (2) By January 1, 2017, each facility shall develop a plan for surface leak monitoring at the facility on a continuous basis or, if continuous is not feasible, a daily basis. The plan will be evaluated based on sensitivity of instrumentation, coverage of the facility, appropriateness for site, and other relevant criteria. The ARB Executive Officer will approve, [in full or in part, or disapprove, in full or in part](#), the plans with full implementation of monitoring by January 1, 2018.

[Staff is considering a leak emission reduction requirement for large or catastrophic leaks at any oil and gas facility covered by this regulation]

§ 95669. Leak Detection and Repair

- (a) The following requirements apply to components at facilities listed in section 95666 which are not already subject to a local air district leak detection and repair program.
- (b) Beginning January 1, 2017, an owner or operator shall audio-visually (by hearing and by sight) inspect components for leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for unmanned facilities.
- (c) Any audio-visual inspection that indicates a leak which cannot be repaired immediately shall be tested as specified in section 95669(f) within 24 hours after conducting the audio-visual inspection.
- (d) Except as provided in section 95669(e), the requirements in sections 95669(f) through (o) apply to components at facilities listed in section 95666:
- (e) Leak detection and repair requirements do not apply to the following unless required by the local air district:

- (1) Components at a facility upstream of a transfer of custody meter used exclusively for the delivery of commercial quality natural gas to the facility.
 - (2) Components incorporated into produced water lines located downstream of produced water tanks that are controlled with the use of a vapor collection system.
 - (3) Components that are buried below ground. Well casing that extends to the surface is not considered a buried component.
 - (4) One-half inch and smaller stainless steel tube fittings including those used for instrumentation.
 - (5) Components incorporated in lines operating exclusively under negative pressure or below atmospheric pressure.
 - (6) Components and piping located downstream from the point where crude oil, condensate, or natural gas transfer of custody occurs, including components and piping located outside the facility boundaries of natural gas compressor stations and underground storage facilities.
 - (7) Temporary components or equipment used for general maintenance purposes and used less than 300 hours per calendar year if the owner or operator maintains and can provide a record of the date when the components were installed and the number of hours the components have been in operation.
 - (8) Components which are unsafe to monitor when conducting EPA Method 21 measurements and as documented in a safety manual or policy and approved by the ARB Executive Officer.
- (f) Beginning January 1, 2017, components shall be inspected at least once each calendar quarter for leaks of total hydrocarbons in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 excluding the use of PID instruments.
- (1) The quarterly inspection frequency may be reduced to annually provided that both of the following conditions are met:
 - (A) All components have been measured below the number of allowable leaks for each leak threshold specified in Table 4 for five (5) consecutive calendar quarters.
 - (B) The change in inspection frequency is substantiated by documentation and approved by the ARB Executive Officer.

- (2) The inspection frequency shall revert to quarterly at any time the number of allowable leaks specified in Table 4 is exceeded during any inspection period.
- (g) Owners or operators shall maintain and report a record of each leak inspection and the component leak concentration(s) and repair date(s) as specified in sections 95671 and 95672.
- (h) Owners or operators shall minimize leaks immediately, but not later than one (1) calendar day after initial leak detection.
- (i) Hatches shall remain closed at all times except during sampling, adding process material, or attended maintenance operations.
- (j) Open-ended lines and valves located at the end of lines shall be sealed with a blind flange, plug, cap or a second closed valve, at all times except during operations requiring liquid or gaseous process fluid flow through the open-ended line.
- (k) Components or component parts which incur five (5) repair actions within a continuous 12-month period shall be replaced or removed from service.
- (l) From January 1, 2017 and through December 31, 2018, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:
 - (1) Leaks with measured total hydrocarbons greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.
 - (2) Leaks with measured total hydrocarbons greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.
 - (3) Components measured above the standards specified and which have been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be repaired to minimize the leak to the maximum extent possible within one (1) calendar day of initial leak detection and the final repair shall be completed by the end of the next process shutdown or within 180 days from the date of initial leak detection, whichever is sooner.

Table 1
Repair Time Periods January 1, 2017 through December 31, 2018

| Leak Threshold | Repair Time Period |
|------------------------|---|
| 10,000-49,999 ppmv | 14 calendar days |
| 50,000 ppmv or greater | 5 calendar days |
| Critical Components | Next shutdown or within 180 calendar days |

- (m) By January 1, 2019, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:
- (1) Leaks with measured total hydrocarbons greater than or equal to 1,000 ppmv but not greater than 9,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.
 - (2) Leaks with measured total hydrocarbons greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.
 - (3) Leaks with measured total hydrocarbons greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within two (2) calendar days of initial leak detection.

Table 2
Repair Time Periods On or After January 1, 2019

| Leak Threshold | Repair Time Period |
|------------------------|---|
| 1,000-9,999 ppmv | 14 calendar days |
| 10,000-49,999 ppmv | 5 calendar days |
| 50,000 ppmv or greater | 2 calendar days |
| Critical Components | Next shutdown or within 180 calendar days |

- (n) Upon detection of a component with a leak concentration measured above the standards specified, the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the component until all of the following conditions are met:
- (1) The leaking component has been repaired or replaced; and,

- (2) The component has been re-inspected and measured below the lowest standard specified for the inspection year when measured in accordance with EPA Reference Method 21, excluding the use of PID instruments.
 - (3) Components measured above the standards specified and which have been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be repaired to minimize the leak to the maximum extent possible within one (1) calendar day of initial leak detection and the final repair shall be completed by the end of the next process shutdown or within 180 days from the date of initial leak detection, whichever is sooner.
- (o) Compliance with Leak Detection and Repair Requirements:
- (1) The failure of an owner or operator to meet any of the requirements specified shall constitute a violation of this subarticle.
 - (2) Between January 1, 2017 and December 31, 2018, no facility shall exceed the number of allowable leaks specified in Table 3 during any inspection period as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.
 - (3) By January 1, 2019, no facility shall exceed the number of allowable leaks specified in Table 4 during any inspection period as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.
 - (4) By January 1, 2019, no component shall exceed a leak of total hydrocarbons greater than or equal to 50,000 ppmv as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.

**Table 3 - Allowable Leaks Per Number of Components Inspected
January 1, 2017 through December 31, 2018**

| Leak Threshold | 200 or Less Components | More than 200 Components |
|------------------------|-------------------------------|---------------------------------|
| 10,000-49,999 ppmv | 5 | 2% of total inspected |
| 50,000 ppmv or greater | 2 | 1% of total inspected |

**Table 4 - Allowable Leaks Per Number of Components Inspected
On or After January 1, 2019**

| Leak Threshold | 200 or Less Components | More than 200 Components |
|------------------------|-------------------------------|---------------------------------|
| 1,000-9,999 ppmv | 5 | 2% of total inspected |
| 10,000-49,999 ppmv | 2 | 1% of total inspected |
| 50,000 ppmv or greater | 0 | 0 |

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95670. Critical Components

- (a) Beginning January 1, 2017, critical components used in conjunction with a critical process unit at facilities listed in section 95666 must be pre-approved by the ARB Executive Officer if owners or operators wish to claim any critical component exemptions available under this subarticle.
- (b) Each critical component shall be identified as shown in Appendix A, Table A3 and submitted to ARB for approval by no later than June 30, 2017 or within 180 days from the installation of a new critical component.
- (c) Owners or operators must provide sufficient documentation showing that a critical component is required as part of a critical process unit and that shutting down the critical component would result in emissions greater than the emissions measured from the component.
- (d) Approval of a critical component may be granted only if owners or operators fully comply with this section. The ARB Executive Officer retains discretion to deny any application for approval.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code

§ 95671. Record Keeping Requirements.

- (a) Beginning January 1, 2017, owners or operators of facilities listed in section 95666 subject to requirements specified in sections 95668 and 95669 shall maintain, and make available upon request by ARB a copy of the following records:

Flash Analysis Testing

- (1) Maintain, for at five years from the date of each test, a record of flash analysis testing that shall include the following:

- (A) A sketch or diagram of each separator and tank system tested that identifies the liquid sampling location and all pressure vessels, separators tanks, sumps, and ponds within the system; and,
- (B) A record of the flash analysis testing results, calculations, and a description of the separator and tank system as specified in Appendix A Table A1; and,
- (C) A field testing form for each flash analysis test conducted as specified in Appendix C Form 1; and,
- (D) The laboratory report(s) for each flash analysis test conducted.

Liquids Unloading of Natural Gas Wells

- (2) Maintain, for at least two years following the measurement or calculation, a record of the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) as specified in Appendix A Table A2.

Leak Detection and Repair

- (3) Maintain, for at least two years from each inspection, a record of each leak detection and repair inspection as specified in Appendix A Table A4.
- (4) Maintain, for at least two years from each inspection, a component leak concentration and repair form for each inspection as specified in Appendix A Table A5.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95672. Reporting Requirements.

- (a) Beginning January 1, 2018, owners or operators of facilities listed in section 95666 subject to requirements specified in sections 95668 and 95669 shall report the following information to ARB within the timeframes specified:

Flash Analysis Testing(1) Within 90 days of performing flash analysis testing, report the test results, calculations, and a description of the separator and tank system as specified in Appendix A Table A1..

Liquids Unloading of Natural Gas Wells

- (2) Annually, report the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading as specified in Appendix A Table A3.

Leak Detection and Repair

- (3) Once per calendar year, report the results of each leak detection inspection conducted during the calendar year as specified in Appendix A Table A4.
 - (4) Once per calendar year, report the initial and final component leak concentration(s) for each inspection conducted during the calendar year as specified in Appendix A Table A5.
- (b) Reports may be e-mailed electronically to ARB with the subject line "O&G GHG Regulation Reporting" to oil&gas@arb.ca.gov or mailed to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95673. Implementation.

(a) Implementation by ARB and by the Local Air Districts

- (1) The requirements of this subarticle are provisions of state law and are enforceable by both ARB and the local air districts where equipment covered by this subarticle is located. Local air districts may incorporate the terms of this subarticle into local air district rules. An owner or operator of equipment subject to this subarticle must pay any fees assessed by a local air district for the purposes of recovering the district's cost of implementing and enforcing the requirements of this subarticle. Any penalties secured by a local air district as the result of an enforcement action that it undertakes to enforce the provisions of this subarticle may be retained by the local air district.
- (2) The ARB Executive Officer, at his or her discretion, may enter into an agreement or agreements with any local air district to further define implementation and enforcement processes, including arrangements further specifying approaches for implementation and enforcement of this subarticle,

and for information sharing between ARB and local air districts relating to this subarticle.

- (3) Implementation and enforcement of the requirements of this subarticle by a local air district may in no instance result in a standard, requirement, or prohibition less stringent than provided for by this subarticle, as determined by the Executive Officer. The terms of any local air district permit or rule relating to this subarticle do not alter the terms of this subarticle, which remain as separate requirements for all sources subject to this subarticle.
- (4) Implementation and enforcement of the requirements of this subarticle by a local air district, including inclusion or exclusion of any of its terms within any local air district permit, or within a local air district rule, or registration of a facility with a local air district or ARB, does not in any way waive or limit ARB's authority to implement and enforce upon the requirements of this subarticle. A facility's permitting or registration status also in no way limits the ability of a local air district to enforce the requirements of this subarticle.

(b) *Requirements for Covered Entities*

- (1) Local Air District Permitting Requirements
 - (A) Owners or operators of facilities or equipment regulated by this subarticle, and who are required by federal, state, or local law to hold local air district permits that cover those facilities or equipment shall ensure that their local air district permits for those facilities or equipment contain terms ensuring compliance with this article. This requirement applies to facilities or equipment upon issuance of any new local air district permit covering these facilities or equipment, or upon the scheduled renewal of an existing permit covering these facilities or equipment.
 - (B) If, after the effective date of this subarticle, any local air district amends or adopts permitting rules that result in additional equipment or facilities regulated by this subarticle becoming subject to local air district permitting requirements, then owners or operators of that equipment or facility must ensure that any applicable local air district permits for that equipment or facility ensures compliance with this subarticle upon issuance of any relevant permit.
- (2) Registration Requirements (A) Owners or operators of facilities or equipment that is regulated by this subarticle shall register the equipment at each facility by reporting the following information to ARB as specified in Appendix A Table A6 no later than January 1, 2019, unless the local air district has established a registration or permitting program that collects at least the following information, and has entered into an MOU with ARB specifying how information is to be shared with ARB.

1. The owner or operator's name and contact information.
 2. The address or location of each facility with equipment regulated by this subarticle.
 3. A description of all equipment covered by this subarticle located at each facility including the following:
 - (a) The number of crude oil or natural gas wells at the facility.
 - (b) A list identifying all pressure vessels, tanks, separators, sumps, and ponds at the facility, including the size of each tank and separator in units of barrels.
 - (c) The annual crude oil, natural gas, and produced water throughput of the facility.
 - (d) A list identifying all reciprocating and centrifugal natural gas compressors at the facility,
 - (e) A count of all pneumatic devices and pumps at the facility.
 4. The permit numbers of all local air district permits issued for the facility or equipment, and an identification of permit terms that ensure compliance with the terms of this subarticle, or an explanation of why such terms are not included.
 5. An attestation that all information provided in the registration is provided by a party authorized by the owner or operator to do so, and that the information is true and correct.
- (B) Updates to these reports, recording any changes in this information, must be filed with ARB, or, as relevant, with the local air district no later than January 1 of the calendar year after the year in which any information required by this subarticle has changed. .
- (3) Owners or operators of equipment subject to this subarticle must comply with all the requirements of sections 95666, 95667, 95668, 95669, 95670, 95671, 95672, and 95673 of this subarticle, regardless of whether or not they have complied with the permitting and registration requirements of this subsection.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39603, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600, 40701, 40702, 41511, 42300, 42301, and 42311, Health and Safety Code.

§ 95674. Enforcement.

- (a) Failure to comply with the requirements of this subarticle at each individual piece of equipment subject to this subarticle constitutes a single, separate, violation of this subarticle.
- (b) Each day, or portion thereof, that an owner or operator is not in full compliance with the requirements of this subarticle is a single, separate, violation of this subarticle.
- (c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle.
- (d) Failure to submit any report required by this subarticle shall constitute a single, separate violation of this subarticle for each day or portion thereof that the report has not been received after the date the report is due.
- (e) Failure to retain and failure to produce any record that this subarticle requires to be retained or produced shall each constitute a single, separate violation of this subarticle for each day or portion thereof that the record has not been retained or produced.
- (f) Falsifying any information or record required to be submitted or retained by this subarticle, or submitting or producing inaccurate information, shall be a violation of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 38580, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95675. No Preemption of More Stringent Air District or Federal Requirements

This regulation does not preempt any more stringent requirements imposed by any Air District. Compliance with this subarticle does not excuse noncompliance with any Federal regulation. The ARB Executive Officer retains authority to determine whether an Air District requirement is more stringent than any requirement of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95676. Severability

Each part of this subarticle is deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of the subarticle shall continue in full force and effect.

DRAFT: February 1, 2016

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

Appendix A Record Keeping and Reporting Forms

**Table A1
Flash Analysis Testing Record Keeping and Reporting Form**

| | | | | | | |
|---|------------------|------------------|------------------|----------------------------------|----------------------|--------------------|
| Tank System ID: | | | | | | |
| Testing Date: | | | | | | |
| Facility Name: | | | | Air District: | | |
| Owner/Operator Name: | | | | Signature*: | | |
| Address: | | | | | | |
| City: | | | State: | | Zip: | |
| Contact Person: | | | | Phone Number: | | |
| Crude Oil or Condensate Flash Test and Calculation Results | | | | | | |
| API Gravity | GOR (scf/bbl) | Molecular Weight | WT% CH4 | Sample Temp (°F) | Throughput (bbl/day) | Metric Tons CH4/Yr |
| | | | | | | |
| Produced Water Flash Test and Calculation Results | | | | | | |
| GWR (scf/bbl) | Molecular Weight | WT% CH4 | Sample Temp (°F) | Throughput (bbl/day) | Metric Tons CH4/Yr | |
| | | | | | | |
| Days in Operation per Year: | | | | | | |
| Combined Annual Methane Emission Rate: | | | | | MTCH4/Yr | |
| Separator and Tank System Description | | | | | | |
| Total Number in Separator and Tank System | | | | Total Number on Vapor Collection | | |
| Wells: | | | | | | |
| Pressure Vessels: | | | | | | |
| Separators: | | | | | | |
| Tanks: | | | | | | |
| Sumps: | | | | | | |
| Ponds: | | | | | | |

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

**Table A2
Liquids Unloading Record Keeping and Reporting Form**

| Facility Name: | | Air District: | |
|----------------------|---------|------------------------------------|------------------------|
| Owner/Operator Name: | | Signature*: | |
| Address: | | | |
| City: | | State: | Zip: |
| Contact Person: | | Phone Number: | |
| | | | |
| Date | Well ID | Volume of Natural Gas Vented (Mcf) | Automation Equipment** |
| | | | |
| | | | |
| | | | |
| | | | |

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

**Automation equipment includes foaming agent, velocity tubing, plunger lift, etc.

**Table A3
Designated Critical Component Form**

| | | | |
|------------------------|--|---------------|----------------|
| Facility Name: | | Air District: | |
| Owner/Operator Name: | | Signature*: | |
| Address: | | | |
| City: | | State: | Zip: |
| Contact Person: | | Phone Number: | |
| | | | |
| Component Description: | | | Approval Date: |
| | | | |
| | | | |

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

**Table A4
Leak Detection and Repair Inspection
Record Keeping and Reporting Form**

| | | |
|---|--------|--------------------------------------|
| Inspection Date: | | |
| Facility Name: | | Air District: |
| Owner/Operator Name: | | Signature*: |
| Address: | | |
| City: | State: | Zip: |
| Contact Person: | | Phone Number: |
| Inspection Company Name: | | |
| Total Number of Components Inspected: | | |
| Number of Leaks per Leak Threshold Category | | Percentage of Total Number Inspected |
| 1,000 to 9,999 ppmv: | | |
| 10,000 to 49,999 ppmv: | | |
| 50,000 ppmv or Greater: | | |

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Appendix B

Calculation for Determining Vented Natural Gas Volume from Liquids Unloading of Natural Gas Wells

$$E_{scf} = \left(\frac{V * P_1 * T_2}{P_2 * T_1} \right) + (FR * HR)$$

Where:

E_{scf} is the natural gas emissions per event in scf

$V = \pi * r^2 * D$ (volume of the well)

$r = \frac{CD}{2}$ (radius of the well)

CD is the casing diameter in feet

D is the depth of the well in feet

P_1 is the shut-in pressure of the well in psia

P_2 is 14.7 psia (standard surface pressure)

T_1 is the temperature of the well at shut-in pressure in °F

T_2 is 60 °F (standard surface temperature)

FR is the metered flowrate of the well or the sales flowrate of the well in scf/hour

HR is the hours the well was left open to atmosphere during unloading

$$CH_4 \text{ emissions} = E_{scf} * MF_{CH_4} * MV * MW_{CH_4} * \left(\frac{\text{metric ton}}{2204.6 \text{ lb}} \right)$$

Where:

$CH_4 \text{ emissions}$ is in metric tons per event

$MF_{CH_4} = \frac{\text{lbmole } CH_4}{\text{lbmole gas}}$ (mole fraction of CH₄ in the natural gas)

$MV = \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}}$ (molar volume)

$MW_{CH_4} = \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4}$ (molecular weight of CH₄)

Appendix C

Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water

1. PURPOSE AND APPLICABILITY

In crude oil and natural gas production, flash emissions may occur when gas entrained in crude oil, condensate, or produced water is released from the liquids due to a decrease in pressure or increase in temperature, such as when the liquids are transferred from an underground reservoir to the earth's surface. This procedure is used for determining the annual flash emission rate from tanks used to separate, store, or hold crude oil, condensate or produced water. The laboratory methods required to conduct this procedure are used to measure methane and other gaseous compounds.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

This procedure is conducted by collecting one sample of crude oil or condensate and one sample of produced water upstream of a separator or tank where flashing may occur. Samples shall be collected under pressure and according to the methods specified in this procedure. If a pressure vessel is not available upstream of a separator or tank that can be used for collecting samples under pressure, sampling shall be conducted using a portable pressurized separator.

Two sampling methods are specified for collecting liquid samples while maintaining a positive pressure within a sampling cylinder to prevent flashing within the cylinder. The first method requires a double valve cylinder for collecting crude oil or produced water samples. The second method requires a cylinder equipped with a pressurized piston for collecting condensate or produced water samples. Both methods shall be conducted as specified in this procedure.

The laboratory methods specified for this procedure are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (EPA), and Gas Processor Association (GPA) methods. These laboratory methods measure the volume and composition of gases that flash from the liquids, including a Gas-Oil or Gas-Water Ratio, as well as the molecular weight and weight percent of the gaseous compounds. The laboratory results are used with the crude oil or condensate or produced water throughput to calculate the mass of emissions that are flashed from the liquids per year.

3. DEFINITIONS

For the purposes of this procedure, the following definitions apply:

- 3.1** "Air Resources Board or ARB" means the California Air Resources Board.
- 3.2** "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.
- 3.3** "Condensate" means hydrocarbon and other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- 3.4** "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- 3.5** "Double valve cylinder" means a metal cylinder equipped with valves on either side for collecting crude oil or produced water samples.
- 3.6** "Emissions" means the discharge of natural gas into the atmosphere.
- 3.7** "Emulsion" means any mixture of crude oil, condensate, or produced water with varying amounts of natural gas contained in the liquid.
- 3.8** "Flash or flashing" means a process during which gas entrained in crude oil, condensate, or produced water under pressure is released when subject to a decrease in pressure or increase in temperature, such as when liquids are transferred from an underground reservoir to a tank on the earth's surface.
- 3.9** "Gas-Oil Ratio (GOR)" means a measurement used to describe the volume of gas that is flashed from a barrel of crude oil or condensate.
- 3.10** "Gas-Water Ratio (GWR)" means a measurement used to describe the volume of gas that is flashed from a barrel of produced water.
- 3.11** "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, of which its constituents include methane, carbon dioxide, and heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.
- 3.12** "Operating pressure" means the steady-state pressure of the vessel from which a sample is collected. If no pressure gauge is available or the sampling train pressure gauge reading is greater than +/- 5 psig of the

vessel pressure, the sampling train pressure gauge reading shall be used to record the steady state pressure on Form 1.

- 3.13** "Operating temperature" means the steady-state temperature of the vessel from which a sample is collected. If no temperature gauge is available or the sampling train temperature gauge reading is greater than +/- 4°F of the vessel temperature, the sampling train temperature gauge reading shall be used to record the steady state temperature on Form 1.
- 3.14** "Percent water cut" means the volume percentage of produced water to crude oil or condensate.
- 3.15** "Piston cylinder" means a metal cylinder containing an internal pressurized piston for collecting condensate or produced water samples.
- 3.16** "Portable pressurized separator" means a sealed vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is used for separating and sampling crude oil, condensate, or produced water at the steady-state temperature and pressure of the separator and tank system required for sampling.
- 3.17** "Pressure vessel" means any vessel rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas..
- 3.18** "Produced water" means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.
- 3.19** "Separator" means any tank designed to contain a normal working pressure of less than 15 psig and is used for the separation of crude oil, condensate, produced water, or natural gas.
- 3.20** "Separator and tank system" means any combination of pressure vessels or tanks used to separate, store, or hold emulsion, crude oil, condensate, or produced water with varying quantities of natural gas.
- 3.21** "Tank" means any container constructed primarily of non-earthen materials used for the purpose of storing or holding emulsion, crude oil, condensate, or produced water.
- 3.22** "Throughput" means the average volume of crude oil, condensate, or produced water expressed in units of barrels per day.

4. BIASES AND INTERFERENCES

- 4.1 The sampling method used to collect a liquid sample will have an impact on the final results reported. Liquid samples shall be collected in accordance with the sampling procedures specified in this procedure.
- 4.2 The location from where a sample is collected will have an impact on the final results reported. Liquid samples shall be collected from a pressure vessel or portable pressurized separator as specified in this procedure.
- 4.3 Collecting liquid samples from a pressure vessel or portable pressurized separator that periodically drains liquids will have an impact on the final results reported. Samples shall not be collected from a pressure vessel or portable pressurized separator while it periodically drains liquids.
- 4.4 Collecting liquid samples using an empty double valve cylinder without displacing an immiscible liquid from the cylinder will allow gases to flash from the cylinder and will have an impact on the final results reported. Samples collected using a double valve cylinder shall be collected as specified in this procedure.
- 4.5 Displacing liquids from a double valve cylinder that are reactive and not immiscible with the sample liquid collected will result in gas composition or volume errors and will affect the final results reported. Displacement liquids shall be pre-tested by a laboratory to verify that the liquid is non-reactive and is immiscible with the sample liquid collected.
- 4.6 Non-calibrated equipment including pressure or temperature gauges will have an impact the final results reported. All pressure and temperature measurements shall be conducted with calibrated gauges as specified in this procedure.
- 4.7 Conducting laboratory procedures other than those specified in this procedure will have an impact on the final results reported. All laboratory methods and quality control and quality assurance procedures shall be conducted as specified in this procedure.

5. SAMPLING EQUIPMENT SPECIFICATIONS

- 5.1 A pressure gauge capable of measuring liquid pressures of less than 50 pound per square inch gauge pressure within +/-10% accuracy.
- 5.2 A pressure gauge capable of measuring liquid pressures greater than 50 pounds per square inch gauge pressure within +/- 5% accuracy.
- 5.3 A temperature gauge capable of reading liquid temperature within +/- 2°F and within a range of 32°F to 250°F.

- 5.4 A graduated cylinder capable of measuring liquid in at least five (5) milliliter increments with at least the same capacity as the double valve cylinder used for liquid sampling.
- 5.5 A portable pressurized separator that is sealed from the atmosphere and is used for collecting crude oil, condensate, and produced water samples at the steady state temperature and pressure of the separator and tank system being sampled.

6. SAMPLING EQUIPMENT

- 6.1 A double valve cylinder or a piston cylinder.
- 6.2 A graduated cylinder for use with double valve cylinder.
- 6.3 A waste container suitable for capturing and disposing sample liquid.
- 6.4 High-pressure rated metal components and control valves that can withstand the temperature and pressure of the pressure vessel or portable pressurized separator being sampled.
- 6.5 Pressure gauges with minimum specifications listed in section 5.
- 6.6 A temperature gauge with minimum specifications listed in section 5.
- 6.7 If required, a portable pressurized separator with minimum specifications listed in section 5.

7. DATA REQUIREMENTS

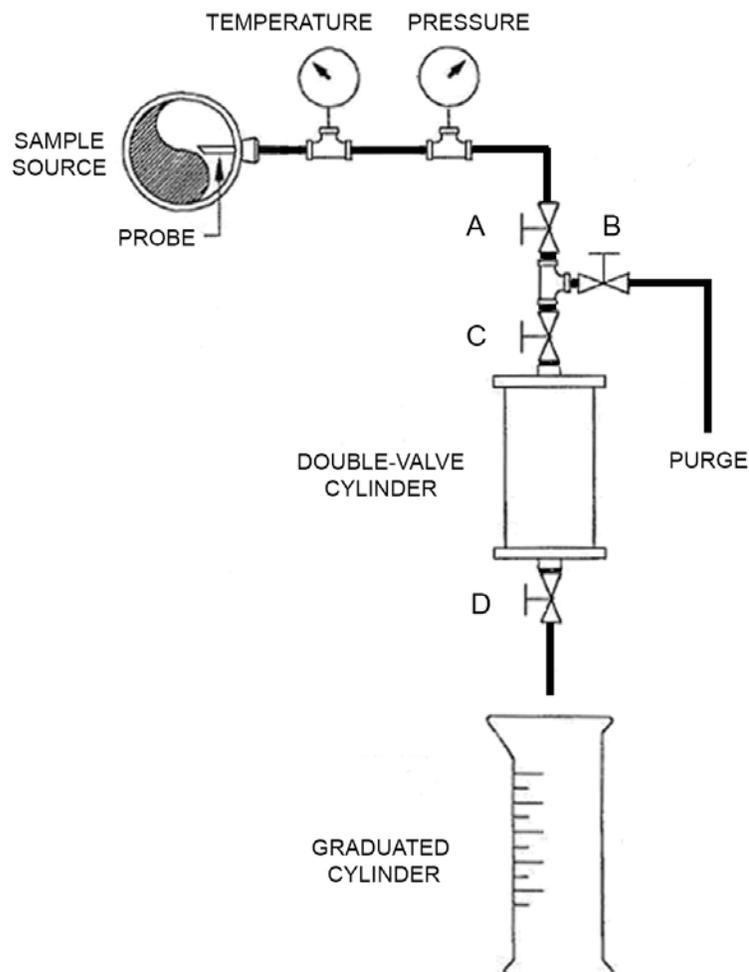
- 7.1 The data requirements required to conduct this procedure shall be provided by the facility owner or operator prior to conducting the sampling methods specified in this procedure. Field sampling shall not be performed until all data requirements are provided as listed in section 7.2 and as specified on Form 1.
- 7.2 For each pressure vessel or portable pressurized separator sampled, the following data shall be recorded on the sample cylinder identification tag and on Form 1 prior to conducting a sample collection method:
 - (a) The separator identification number or description.,
 - (b) The separator temperature and pressure if available.
 - (c) Crude oil or condensate throughput.
 - (d) Produced water throughput.
 - (e) Percent water cut.

- (f) Gas flow rate of three phase separator if available.
- (g) Number of wells in the separator and tank system.
- (h) Days of operation per year.

8. DOUBLE VALVE CYLINDER SAMPLING METHOD

- 8.1** The double valve cylinder sampling method is used for collecting crude oil or produced water samples and is not applicable for collecting samples of condensate. Liquid samples of condensate shall be collected using the piston cylinder sampling method specified in section 9.
- 8.2** Fill the double valve cylinder with non-reactive liquid that is immiscible with the liquid to be collected to prevent flashing within the cylinder and to prevent the displacement liquid from mixing or attaining homogeneity with the sample liquid.
- 8.3** Locate a pressure vessel immediately upstream of the separator or tank required for testing and verify it is pressurized to at least 15 psig. Install a portable pressurized separator if no pressure vessel is available immediately upstream of the separator or tank that can be used to collect crude oil and produced water samples.
- 8.4** Record the sample collection data requirements specified in section 7 on the cylinder identification tag and on Form 1.
- 8.5** Locate the sampling port(s) for collecting liquid samples.
- 8.6** Connect the sampling train as illustrated in Figure 1 to the sampling port on the pressure vessel or portable pressurized separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.
- 8.7** Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.
- 8.8** Prepare for sampling: Orient the double-valve cylinder in the vertical position so that displacement liquid can readily be discharged from the cylinder. Note that the orientation of valves C and D depend on the type of sample being collected and the liquid used for displacement. Based on density differences in liquids, the heaviest liquid must be introduced or expelled from the bottom of cylinder. See Figure 2
- 8.9** Slowly open valve C to the full open position and place the outlet of valve D into the graduated cylinder.

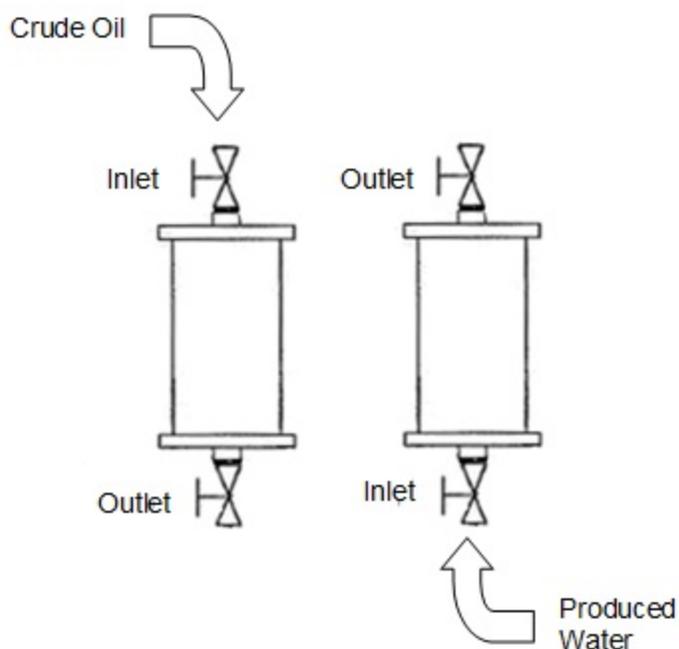
Figure 1: Double Valve Cylinder Sampling Train



8.10 Collect liquid sample: Slowly open valve D to allow a slow displacement of the non-reactive displacement liquid at a rate between 150 and 200 milliliters per minute (3 drips per second) to prevent the sample liquid from flashing inside the cylinder. Continue until 80 to 95 percent of the displacement liquid is measured in the graduated cylinder, then close valves D and C.

8.11 Record the steady state pressure and temperature on Form 1.

Figure 2: Double Valve Cylinder Orientation



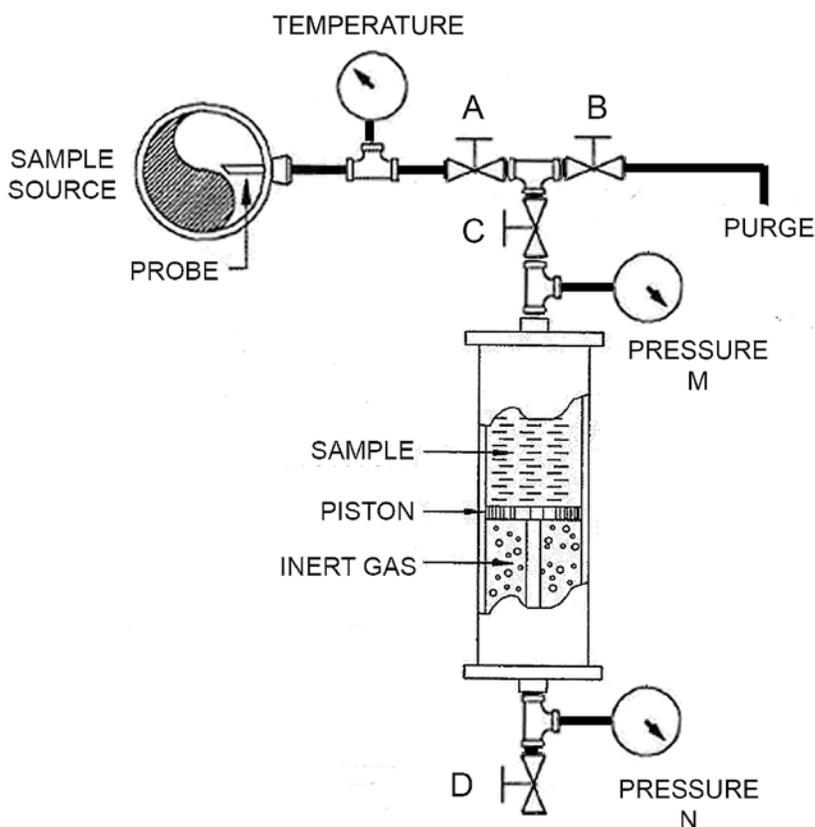
- 8.12 Record the double valve cylinder volume and the volume of liquid sampled on the cylinder identification tag and on Form 1.
- 8.13 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.
- 8.14 Remove sampling train: With valves D and C closed, purge any remaining liquid in the sampling train through valve B. Then close valves A and B. Disconnect the sampling train from the pressure vessel or portable pressurized separator.
- 8.15 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 8.16 Transport the cylinder to the laboratory for conducting the laboratory methods specified in section 12.

9. PISTON CYLINDER SAMPLING METHOD

- 9.1 Locate a pressure vessel immediately upstream of the separator or tank required for testing and verify it is pressurized to at least 15 psig. Install a portable pressurized separator if no pressure vessel is available immediately upstream of the separator or tank that can be used to collect condensate and produced water samples.

- 9.2 Record the sample collection data requirements specified in section 7 on the cylinder identification tag and on Form 1.
- 9.3 Locate the sampling port(s) for collecting liquid samples.
- 9.4 Connect the sampling train as illustrated in Figure 3 to the pressure vessel or pressurized portable separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.
- 9.5 Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.

Figure 3: Piston Cylinder Sampling Train



- 9.6 Prepare for sampling: With valve B closed and valve A open, slowly open valve C to the full open position, then slowly open valve D until the pressure indicated on Gauge N is equal to Gauge M.

- 9.7 Collect liquid sample: Slowly open Valve D to allow liquid to enter the piston cylinder at a rate of 150 to 200 milliliters per minute until 80 to 95 percent of the cylinder is filled with liquid. Then close valves C and D.
- 9.8 Record the steady state pressure and temperature on Form 1.
- 9.9 Record the cylinder volume and volume of liquid sampled on the cylinder identification tag and on Form 1.
- 9.10 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.
- 9.11 Remove sampling train: Place the outlet of valve B into the waste container and slowly open valve B to purge all liquid from the sampling train. Then close valves A and B. Disconnect the sampling train from the pressure vessel or portable pressurized separator.
- 9.12 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 9.13 Transport the cylinder to the laboratory for conducting the laboratory methods as specified in section 12.

10. LABORATORY REQUIREMENTS AND METHODS

10.1 Quality Control, Quality Assurance, and Field Records

- (a) Quality control requirements shall be performed in accordance with the laboratory methods specified in this test procedure.
- (b) Each day of sampling, at least one field duplicate sample shall be collected per matrix type (crude oil, condensate, produced water). The field duplicate samples are collected to demonstrate acceptable method precision by the laboratory at the time of analysis. Through this process the laboratory can evaluate the consistency of sample collection and analytical measurements as well as matrix variation. The laboratory should establish control limits based on relative percent difference to evaluate the validity of the measured results.
- (c) Laboratory procedures shall be in place for establishing acceptance criteria for field activities described in sections 7, 8 and 9 of this procedure. All deviations from the acceptance criteria shall be documented. Deviations from the acceptance criteria may or may not affect data quality.

- (d) Laboratory procedures shall be in place to ensure that field staff have been trained on the sampling methods specified in this procedure and retrained on sampling methods if this procedure changes.
- (e) Field records shall provide direct evidence and support necessary for technical interpretations, judgments, and discussions concerning project activities and shall, at a minimum, include a completed copy of Form 1 as provided in this procedure for each sample collected.

10.2 Laboratory Flash Analysis Equipment

- (a) All laboratory equipment used to conduct measurements shall be calibrated in accordance with the manufacturer specifications and in accordance with the laboratory methods specified in this procedure.
- (b) Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. All test methods and quality control requirements shall be conducted in accordance with each laboratory method specified.
- (c) The minimum reporting limit of the instruments used for reporting gaseous compounds must be at least 100 parts per million (ppm) for both hydrocarbon and fixed gases.
- (d) The laboratory apparatus used for heating sample cylinders must be capable of heating and maintaining the steady state temperature measured at the time of sampling as reported on Form 1.
- (e) The laboratory apparatus used for collecting gas flashed from liquids must be capable of precisely measuring gas volume, temperature, and pressure.
- (f) The laboratory vessel used for collecting gas flashed from liquids must be capable of collecting or storing gas for chromatography analysis without sample degradation and without compromising the integrity of the sample.
- (g) Additional sample preparation guidance can be found in GPA 2174, GPA 2261 and GPA 2177.

10.3 Laboratory Flash Analysis Procedure

- (a) Heat the sample cylinder to the sample collection temperature as reported on Form 1 and allow the temperature to stabilize for a minimum of 30 minutes.

- (b) After the cylinder temperature has stabilized, open the cylinder and collect all gas flashed from the liquid for a minimum of 30 minutes while monitoring the gas pressure and temperature.
- (c) After all gas has flashed from the cylinder for a minimum of 30 minutes, ensure that the gas pressure has stabilized at ambient pressure with no changes in gas pressure observed. In the event that the gas pressure changes or remains above ambient pressure after 30 minutes, continue to allow the cylinder to flash until the gas pressure stabilizes at ambient pressure. The collected gas sample can now be used for gas chromatography analysis.
- (d) At least 0.20 standard cubic feet of sample gas per barrel of liquid is required to conduct the laboratory procedures specified in this procedure. If insufficient gas volume is collected during the flash analysis procedure, additional laboratory analyses cannot be completed while maintaining the accuracy requirements specified in this procedure.
- (e) After the flash analysis procedure is completed, remove all liquid from the sample cylinder and measure the total liquid volume and volume fractions (for example, 300ml total volume, 285 ml crude oil, 15 ml water) and adjust for any displacement liquid that was not displaced during the sample collection procedure.

10.4 Gas-Oil and Gas-Water Ratio Calculation Methodology

- (a) Convert the volume of gas vapor measured during the laboratory flash analysis procedure to standard atmospheric conditions as derived from the Ideal Gas Law as follows:

$$Vapor_{Std} = \frac{(Volume_{Lab})(459.67 + 60F)(P_{Lab})}{(459.67 + T_{Lab})(14.696)} \quad \text{Equation 4}$$

Where:

Vapor_{Std} = Standard cubic feet of vapor at 60°F and 14.696 psia.

Volume_{Lab} = Volume of vapor measured at laboratory conditions.

T_{Lab} = Temperature of vapor at laboratory conditions, °F.

P_{Lab} = Pressure of vapor at laboratory conditions, psia.

459.67 = Conversion from Fahrenheit to Rankine

60F = Standard temperature of 60°F.

14.696 = Standard atmospheric pressure, psia.

- (b) Convert the volume of crude oil or produced water measured after conducting the laboratory flash analysis procedure to standard conditions as follows:

$$Liquid_{Std} = \left(\frac{Mass_{Liquid}}{Density_{60F}} \right) \left(\frac{1 \text{ gallon}}{3785.412 \text{ ml}} \right) \left(\frac{1 \text{ STB}}{42 \text{ gallons}} \right) \quad \text{Equation 5}$$

Where:

Liquid_{Std} = Standard volume of post-flash liquid at 60°F, barrels.

Mass_{Liquid} = Mass of liquid at laboratory conditions, grams.

Density_{60F} = Density of liquid at 60°F, grams/milliliter.

3785.412 = Conversion from milliliter to US gallons.

STB = Stock Tank Barrel.

42 gallons = Volume of a stock tank barrel at 60°F.

- (d) Calculate the Gas-Oil or Gas-Water Ratio as follows:

$$G = \frac{(Vapor_{Std})}{(Liquid_{Std})} \quad \text{Equation 6}$$

Where:

G = The Gas-Oil or Gas-Water Ratio.

Vapor_{Std} = Standard cubic feet of vapor at 60°F and 14.696 psia.

Liquid_{Std} = Standard volume of post-flash liquid at 60°F, barrels.

Note: For condensate, the volume of liquid used for calculating the Gas-Oil Ratio shall be obtained from the piston cylinder measurement reported on Form 1 at the time of liquid sampling due to the rapid flashing of condensate that occurs during the laboratory flash analysis procedure.

10.5 Analytical Laboratory Methods and Requirements

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water.

- (a) Oxygen, Nitrogen, Carbon Dioxide, Hydrogen Sulfide (High-Level), Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, Decanes+: Evaluate per GPA 2286, ASTM D-1945, ASTM D-3588, and ASTM D-2597 (GC/TCD).
- (b) BTEX: Evaluate per EPA 8021 B (GC/FID) or use ASTM D-3170, GPA 2286, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.
- (c) API Gravity of whole oil at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer).

Note: if water is entrained in sample, use ASTM D 287. If needed calculate Specific Gravity 60/60°F = 141.5 / (131.5 + API Gravity at 60°F)

- (d) Specific Gravity of Produced Water at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer). If needed calculate API at 60°F = (141.5 / SG at 60°F) - 131.5
- (e) Molecular Weight of gaseous phase by calculation per ASTM D-3588.
- (f) Water and Sediment in Crude Oil by Centrifuge Method per ASTM D-4007.

10.6 Nitrogen and Oxygen Correction

Samples containing oxygen may be an indication that ambient air was introduced during the sample collection or laboratory procedures. For the purpose of this procedure, the detection of oxygen shall be assumed to have been contributed by ambient air that was not contained in the original liquid sample. Any detectable amount of oxygen requires a result for nitrogen to be corrected and the result for oxygen to be reported as zero as follows:

- (a) For the purposes of this procedure, ambient air contains 79% nitrogen and 21% oxygen.
- (b) Correct the amount of nitrogen contained in the sample as follows:

$$Correction_{N_2} = \%N_2 - \left(\frac{79}{21} x \%O_2 \right) \quad \text{Equation 7}$$

Where:

Correction_{N₂} = Corrected value of nitrogen in the sample.

%N₂ = Mole percent of nitrogen in the sample.

%O₂ = Mole percent of oxygen in the sample.

- (c) If the corrected value for nitrogen calculated in section 10.6(b) is less than or equal to zero, report a value of zero for nitrogen and zero for oxygen and normalize all remaining values to 100% after removing the contributions of nitrogen and oxygen from the summed total; or,
- (d) If the corrected value for nitrogen calculated in section 10.6(b) is greater than zero, use the value for nitrogen calculated in section 10.6(b) and zero for oxygen and normalize all remaining values to 100%.

11. CALCULATING RESULTS

The following calculations are performed in conjunction with the data requirements specified in section 7 and the laboratory reports specified in section 12. The same calculations are used for crude oil, condensate, and produced water.

11.1 Calculate the volume of gas flashed from the liquid per year using the Gas Oil or Gas Water Ratio obtained from the laboratory report as follows:

$$Ft^3 / Year = (G) \left(\frac{Barrels}{Day} \right) \left(\frac{Days}{Year} \right) \quad \text{Equation 1}$$

Where:

$Ft^3/Year$ = standard cubic feet of gas produced per year
 G = Gas Oil or Gas Water Ratio (from laboratory report)
 Barrels/Day = barrels per day of liquid (Form 1)
 Days/Year = days of operation per year (Form 1)

11.2 Convert the gas volume to pounds as follows: **Equation 2**

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year} \right) \left(\frac{gram}{gram - mole} \right) \left(\frac{gram - mole}{23.690 l} \right) \left(\frac{28.317 l}{Ft^3} \right) \left(\frac{lb}{454 grams} \right)$$

Where:

$Mass_{Gas} / Year$ = pounds of gas per year
 $Ft^3/Year$ = cubic feet of gas produced per year (Equation 1)
 Gram/Gram-Mole = Molecular weight (from laboratory report)
 23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60⁰F

11.3 Calculate the annual mass of methane as follows:

$$Mass_{Methane} / Year = \left(\frac{WT\% \text{ Methane}}{100} \right) \left(\frac{Mass_{Gas}}{Year} \right) \left(\frac{metric ton}{2205 lb} \right) \quad \text{Equation 3}$$

Where:

$Mass_{Methane} / Year$ = metric tons of methane
 $Mass_{Gas} / Year$ = pounds of gas per year (Equation 2)
 WT% Methane = Weight % of methane (from laboratory report)

12. LABORATORY REPORTS

- 12.1** The results of this procedure are used by owners or operators of separator and tank systems to report annual methane flash emissions to ARB. The following information shall be compiled as a report by the laboratory conducting this procedure and provided to the owner or operator each time flash analysis testing is conducted:
- (a) A sketch or diagram of the separator and tank system depicting the sampling location; and,
 - (b) A copy of Form 1 as specified in this procedure for each liquid sample collected; and,
 - (c) The laboratory results for each liquid sample evaluated as specified in section 12.4; and,
 - (d) Other documentation or information necessary to support technical interpretations, judgments, and discussions.
- 12.2** Reports shall be made available to the owner or operator no later than 60 days from the date of liquid sampling.
- 12.3** Reports shall be maintained by the laboratory conducting this procedure for a minimum of five (5) years from the date of liquid sampling and additional copies shall be made available at the request of the owner or operator.
- 12.4** Laboratory reports shall include, at minimum, a listing of results obtained using the laboratory methods specified in this procedure and as specified in Table 1.

Table 1: Laboratory Data Requirements

| |
|--|
| WT% CO ₂ , CH ₄ |
| WT% C ₂ -C ₉ , C ₁₀ + |
| WT% BTEX |
| WT% O ₂ |
| WT% N ₂ |
| WT% H ₂ S |
| Molecular Weight of gas sample (gram/gram-mole) |
| Liquid phase specific gravity of produced water |
| Gas Oil or Gas Water Ratio (scf/stock tank barrel) |
| API gravity of whole oil or condensate at 60°F |
| Water and Sediment of whole oil (ASTM D-4007) |

| |
|---------------------------------|
| Post-Test Cylinder Water Volume |
| Post-Test Cylinder Oil Volume |

13. ALTERNATIVE TEST PROCEDURES, SAMPLING METHODS OR LABORATORY METHODS

Alternative test procedures, sampling methods, or laboratory methods other than those specified in this procedure shall only be used if prior written approval is obtained from ARB. In order to secure ARB approval of an alternative test procedure, sampling method, or laboratory method, the applicant is responsible for demonstrating to the ARB's satisfaction that the alternative test procedure, sampling method, or laboratory method is equivalent to those specified in this test procedure.

- (1) Such approval shall be granted on a case-by-case basis only. Because of the evolving nature of technology and procedures and methods, such approval shall not be granted in subsequent cases without a new request for approval and a new demonstration of equivalency.
- (2) Documentation of any such approvals, demonstrations, and approvals shall be maintained in the ARB files and shall be made available upon request.

13. REFERENCES

| | |
|--------------|---|
| ASTM D-70 | <i>Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)</i> |
| ASTM D-287 | <i>Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)</i> |
| ASTM D-1945M | <i>Standard Test Method for Analysis of Natural Gas by Gas Chromatography</i> |
| ASTM D-2597 | <i>Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i> |
| ASTM D-3710 | <i>Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography</i> |
| ASTM D-3588 | <i>Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels</i> |

| | |
|------------------|---|
| ASTM D-4007 | <i>Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method</i> |
| ASTM D-4052 | <i>Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter</i> |
| ASTM D-5002 | <i>Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer</i> |
| ASTM D-5504 | <i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence</i> |
| ASTM D-6228 | <i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection</i> |
| EPA Method 15 | <i>Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources</i> |
| EPA Method 16 | <i>Semicontinuous Determination of Sulfur Emissions from Stationary Sources</i> |
| EPA Method 8021B | <i>Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors</i> |
| EPA Method 8260B | <i>Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)</i> |
| EPA Method TO-14 | <i>Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography</i> |
| EPA Method TO-15 | <i>Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)</i> |
| GPA 2174 | <i>Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography</i> |
| GPA 2177 | <i>Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i> |
| GPA 2261 | <i>Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography</i> |

DRAFT: February 1, 2016

GPA 2286 Method for the Extended Analysis of Natural Gas and Similar
Gaseous Mixtures by Temperature Program Gas
Chromatography

SCAQMD 307 South Coast Air Quality Management District Determination of
Sulfur in a Gaseous Matrix

**FORM 1
Flash Analysis Testing Field Data Form**

| | |
|---|-----------------------------------|
| Date of Testing: | |
| Production Company Name: | |
| Address: | |
| City: | |
| Contact: | Phone: |
| Sampling Company Name: | |
| Address: | |
| City: | |
| Contact: | Phone: |
| | |
| Portable Pressurized Separator ID: | |
| Pressure Vessel ID: | |
| Steady State Pressure: | psig |
| Steady State Temperature: | °F |
| Crude Oil or Condensate Throughput: | Barrels/Day |
| Produced Water Throughput: | Barrels/Day |
| Gas Flow Rate (if metered): | Mcf/Day |
| Days of Operation of Separator and Tank System per Year: | |
| Percent Water Cut: % | Number of wells in system: |
| Sample Type (circle one): crude oil condensate produced water | |
| Sample Cylinder ID Number: | |
| Cylinder Type: | Displacement Liquid: |
| Cylinder Volume: ml | Volume of Liquid Collected: ml |



Final Report

**For Determining Bleed Rates for Pneumatic Devices in British
Columbia**

December 18, 2013

Executive Summary

Regulations in BC stipulate that all greenhouse gas (GHG) emissions from pneumatic instruments and pumps must be tracked for reporting and compliance purposes. In order to help industry quantify these emissions more efficiently and cost effectively, the BC Climate Action Secretariat (CAS), Ministry of Natural Gas Development and Canadian Association of Petroleum Producers (CAPP) engaged The Prasino Group (Prasino) to determine bleed rates for a suite of common pneumatic controllers and pumps. This survey is the first of its kind and was funded by the Science and Community Knowledge (SCEK) Fund.

Pneumatic controllers and pumps use pressurized fuel gas to perform operations such as pressure control, temperature control, liquid level controller and chemical injection. This fuel gas is subsequently released to the atmosphere after the operation is performed. The bleed rate of a pneumatic device is defined as the amount of fuel gas released to the atmosphere per hour. Figure 1 shows the breakdown of GHG emissions from the oil and gas sector in BC with a detailed breakdown of the sources of vented methane. The high bleed pneumatic controllers and pumps, which are the subject of this study, contribute 436,000 tCO₂e of the 1,723,000 tCO₂e from vented methane. The amount of contribution from pneumatic devices and pumps is expected to change as a result of this study.

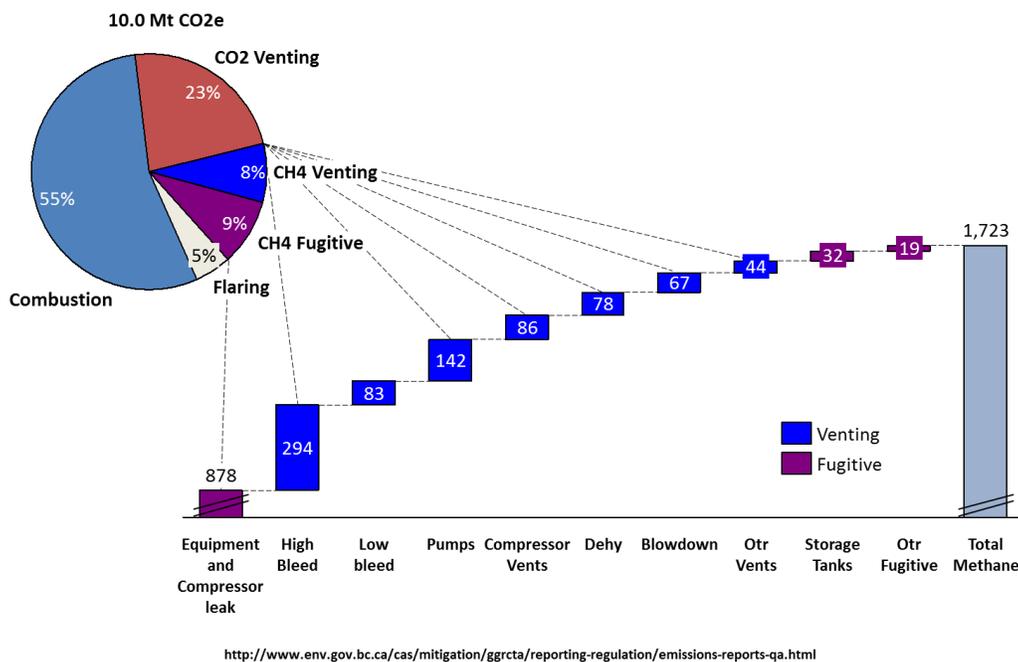


Figure 1: Detailed Breakdown of vented and fugitive methane sources in the BC oil and gas sector (source BC CAS 2013).

The purpose of the survey was to determine the average bleed rate of pneumatic controllers and pumps when operating under field conditions in BC. Bleed rates were sampled from pneumatic devices using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding, areas. Descriptive statistics, general linear models and regression analysis was performed on the data to investigate the bleed rates and draw robust, relevant conclusions.

All outcomes were achieved. The results of the analysis led to the development of three generic bleed rates and twenty specific bleed rates for common pneumatic controllers and pumps for BC's oil and gas industry. These bleed rates can be used in the development of emission factors for GHG reporting and potentially offset purposes.

Table 1: Summary of Findings

| Pneumatic Device | Average Bleed Rate (m ³ /hr) | Coefficients ¹ (supply pressure, injection pressure, strokes per min) | Equivalent Device |
|--|---|--|------------------------------|
| Generic High Bleed Controller | 0.2605 | 0.0012 | - |
| Generic High Bleed Intermittent Controller | 0.2476 | 0.0012 | - |
| Pressure Controllers | | | |
| Fisher 4150 | 0.4209 | 0.0019 | 4150K, 4150R, 4160, CVS 4150 |
| Fisher C1 | 0.0649 | 0.0003 | - |
| Fisher 4660 | 0.0151 | - | 4660A |
| Level Controllers | | | |
| Fisher 2500 | 0.3967 | 0.0011 | 2500S, 2503, L3 |
| Fisher 2680 | 0.2679 | 0.0014 | 2680A |
| Fisher 2900 | 0.1447 | - | 2900A, 2901, 2901A |
| Fisher L2 | 0.2641 | 0.0012 | - |
| Murphy L1200 | 0.2619 | 0.0012 | L1100, L1200N, L1200DVO |
| Norriseal 1001 | 0.1868 | - | 1001A, 1001XL |
| SOR 1530 | 0.0531 | - | - |
| Positioners | | | |
| Fisher Fieldvue DVC6000 | 0.2649 | 0.0011 | 6030, 6020, 6010 |
| Temperature Controllers | | | |
| Kimray HT-12 | 0.0351 | - | - |
| Transducers | | | |
| Fairchild TXI7800 | 0.1543 | 0.0009 | TXI7850 |
| Fisher 546 | 0.3547 | 0.0017 | 546S |
| Fisher i2P-100 | 0.2157 | 0.0009 | - |
| Pumps | | | |
| Generic Piston Pump | 0.5917 | 0.00202, 0.000059, 0.0167 | - |
| Generic Diaphragm Pump | 1.0542 | 0.0005, 0.000027, 0.0091 | - |
| Morgan HD312 | 1.1292 | 0.00418, 0.000034, 0.0073 | HD312-3K, HD312-5K |
| Texsteam 5100 | 0.9670 | 0.0003, 0.000034, 0.0207 | 5100LP, 5100H |
| Williams P125 | 0.4098 | 0.00019, 0.000024, 0.0076 | - |
| Williams P250 | 0.8022 | 0.00096, 0.000042, 0.0079 | - |
| Williams P500 | 0.6969 | 0.00224, -0.000031, 0.0046 | - |

¹ Controllers that do not have a coefficient should use the mean bleed rate instead of the bleed rate equation.

Table of Contents

| | |
|---|-----------|
| Executive Summary | i |
| Table of Contents..... | iii |
| 1. Introduction | 1 |
| 2. Sampling Methodology | 1 |
| 2.1 Pneumatic Controllers | 2 |
| 2.2 Pneumatic Pumps | 4 |
| 2.3 Sampling Approach..... | 4 |
| 2.3.1 Bleed Rate Metering | 5 |
| 2.3.2 Sample Size..... | 7 |
| 2.3.3 Data Collection and Transfer..... | 7 |
| 2.3.4 Errors, Uncertainty and Biases | 8 |
| 3. Sample Characteristics | 11 |
| 3.1 Pneumatic Controllers | 11 |
| 3.2 Pneumatic Pumps | 12 |
| 3.3 Producers..... | 12 |
| 3.4 District and Sub-District..... | 12 |
| 4. Analysis | 14 |
| 4.1 Analysis for Determining a Generic Bleed Rate | 15 |
| 4.2 Bleed Rate Equations..... | 16 |
| 5. Comparison of Bleed Rates..... | 18 |
| 6. Discussion..... | 19 |
| 6.1 Outliers | 19 |
| 6.2 Throttling vs. Snap-Acting Controllers | 19 |
| 6.3 Manufacturer Specification | 20 |
| 6.4 Gas vs. Air vs. Propane | 20 |
| 6.5 Calscan Vent Gas Meter | 21 |
| 6.6 Producer and Sub-District..... | 21 |
| 6.7 Adding a Device Model to the Survey | 21 |
| 6.8 Mean vs. Median | 21 |
| 6.9 General Linear Model | 22 |
| 6.10 Summer vs. Winter Sampling | 22 |
| 7. Applications of the Analysis..... | 22 |
| 8. Observations | 23 |
| 9. Conclusion | 24 |
| References..... | 24 |
| Appendix A: Compilation of All Known Pneumatic Controllers | 27 |
| Appendix B: Initial List of Pneumatic Devices Included in the Sample | 32 |
| Appendix C: Field Sampling Guide..... | 34 |
| Appendix D: Box Plot Distributions | 35 |
| Appendix E: Bleed Rate Equation Coefficients | 37 |

1. Introduction

This report outlines the methodology and analytical methods used to develop bleed rates for reporting GHG emissions from pneumatic controllers and pumps (collectively referred to as ‘devices’) in British Columbia (BC). The development of emissions factors may allow for an alternative method of monitoring and reporting GHGs from pneumatic devices, as per an agreement between the Canadian Association of Petroleum Producers (CAPP) and the B.C. Ministry of Environment’s Climate Action Secretariat (CAS). The Prasino Group (Prasino) has been engaged by the Science and Community Environmental Knowledge Fund (SCEK) in order to develop these bleed rates based on quantitative sampling of pneumatic devices in BC. This document is the final project report and builds off the subsequent three reports (Sampling Methodology, First Round Sampling Report and Final Sampling Report) that were submitted to SCEK. This document is meant to be a standalone report and describes:

- The sampling methodology used to obtain the field bleed rate samples;
- The characteristics of the samples;
- The statistical analysis performed on the field bleed rate samples as well as a discussion of the results; and
- The recommended bleed rates for each pneumatic device included in the survey.

2. Sampling Methodology

Pneumatic devices used in B.C.’s oil and gas sector fall into two categories:

1. Pneumatic chemical injection pumps (typically injecting methanol into a pipeline); and,
2. Pneumatic controllers, which regulate pressure, temperature, fluid level, or some other process variable.

There are dozens of manufacturers of the types of pneumatic devices listed above. Even though the device types perform similar functions, they have inherently different bleed rates. Due to constraints, it was necessary to narrow sampling to the most common or representative devices. A “Device Selection Approach” was used to narrow the sample and determine the most common devices in the field.

Figure 2 below outlines the steps that were followed to develop the initial list of devices for sampling. Further detail will be provided in the next section. The following section describes the process that was used for selecting which devices to include in the sampling regime.

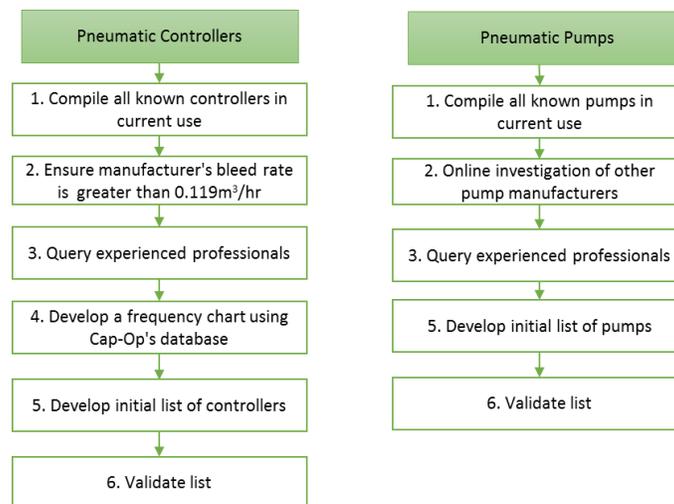


Figure 2: Device Selection Approach²

2.1 Pneumatic Controllers

In order to determine which pneumatic controllers to include in our sample, multiple steps were undertaken as illustrated in

Figure 2. Through this process, 15 controllers were identified as common. For the rare devices that are not within the scope of this project, a generic high-bleed rate has been developed for all high-bleed controllers. This ensures that any pneumatic controller can apply a bleed rate that is representative of field conditions.

Step 1: Compile All Known Controllers

Prasino initially developed a complete list of all known pneumatic low and high-bleed controllers that were anticipated to be used in the upstream oil and gas industry in BC. Using one or more of the sources listed below, the make, model, and manufacturers' stated bleed rate of each controller was determined:

- *Canadian Environmental Technology Advancement Corporation-West (CETAC): Efficient Use of Fuel Gas in Chemical Injection Pumps. Fuel Gas Best Management Practices.* The BMP lists manufacturer bleed rates of controllers in m³/hr of natural gas.
- *Pacific Carbon Trust (PCT): High-Bleed to Low-Bleed Conversion for Pneumatic Controllers. Meta-Protocol for Oil and Gas Emission Reductions Projects.* In the protocol, the bleed rates were stated in standard cubic feet per hour (scfh) of air, based on manufacturer stated specifications. The volume of air bled was converted to natural gas by multiplying by 1.3³. When a range of bleed rates was listed, the highest value was taken to be conservative.
- *Environmental Protection Agency: Gas STAR – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* This document stated the bleed rates of high- and low-bleed controllers in scfh of air. These values were converted to m³/hr of natural gas.
- *Western Climate Initiative (WCI): Final Essential Requirements of Mandatory Reporting.* This report references the BMP, PCT Protocol and EPA Gas STAR for the pneumatic controller list and bleed rates. The manufacturer bleed rates in this document are in m³/hr.
- *Manufacturer websites* were referenced to determine the steady state air consumption for pneumatic controllers. The highest steady state air consumption was recorded. The bleed rates were stated in m³/hr and scfh.
- *Cap-Op Energy samples from the DEEPP database* were used to look at controllers and pumps that are already in the field and have been sampled previously by GreenPath Energy Ltd⁴.

Step 2: Equivalent Devices

Controllers may have different makes and models but serve the same function. Controllers are considered equivalent devices if they have interchangeable parts. A list of equivalent devices was compiled using information from device vendors and subject matter experts, and is presented in Appendix A (J. Anhalt, personal communication, July 2013; B. Van Vliet, personal communication, July 2013).

² "Cap-Op's Database" refers to Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP), which was queried for historical pneumatic controller information. Cap-Op Energy is a sub-contractor to Prasino.

³ The value 1.3 is based on the density and molar mass of air and natural gas in ideal gas conditions. This manner of conversion is an industry standard.

⁴ GreenPath Energy Ltd. is the contractor who was responsible for completing the field sampling protocol.

Step 3: Ensure Manufacturer Bleed Rates are Greater than 0.119 m³/hr

Manufacturer bleed rates were used to determine which controllers are considered high bleed and therefore relevant for sampling. However, these manufacturer bleed rates are based on manufacturer lab testing and may not reflect actual field conditions. The steady state bleed rates reported are static bleed rates of controllers that are not actuating and thus dynamic bleeding is not captured. Therefore, the manufacturer bleed rates may not accurately express the actual vented natural gas through these controllers because the steady state does not include dynamic bleeding. The relationship between the bleed rates of controllers that are running on dirty/wet natural gas compared to air is unknown. It is likely that controllers operating in the field bleed more than controllers tested in a laboratory using air.

The current definition whether a controller is a high or low bleed controller is based on the WCI Reporting Regulation definition: “high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m³/hr.”

Many controllers have manufacturer bleed rates just below 0.17 m³/hr, and thus appear to be a low-bleed controller. Since manufacturers do not consider the dynamic bleed rate in their stated bleed rate, many low-bleed controllers in fact bleed more than 0.17 m³/hr on a regular basis. To ensure all relevant controllers that bleed more than 0.17 m³/hr (including static and dynamic bleeding) are included within the sample, the manufacturer bleed rates were compared to a limit of 0.119 m³/hr (CAS, 2013). In many cases, the manufacturer states a range of bleed rates that are dependent on other operating parameters of the controller (i.e. 1.4 scfh at 20 psi vs. 3 scfh at 30 psi). In this case, the highest bleed rate was recorded to ensure that all controllers with the potential to bleed higher than 0.17 m³/hr were included. Refer to Appendix A for highest manufacturer bleed rates. Controllers that have been excluded from sampling as a result of this step are represented at the bottom of the table in Appendix A.

Step 4: Query Subject Matter Experts

Subject matter experts were queried as per the request of CAS to determine if the list of pneumatic devices was inclusive and representative. Several low-bleed controllers below the limit of 0.119 m³/hr have been included based on these discussions to investigate if controllers that are labelled according to manufacturer specification actually perform as a low bleed device in the field. Four low-bleed controllers were included in the survey: Fisher C1, Fisher 4660, SOR 1530 and Kimray HT-12. The results of the query are represented in Appendix A.

Step 5: Determine the Frequency of Occurrence of Controllers

Using Cap-Op’s DEEPP database, the eligible list of all pneumatic controllers was filtered down to focus sampling on devices that are considered common. Cap-Op Energy has an extensive +2000 sample database from previous work on pneumatic devices from the upstream oil and gas industry in Alberta and BC. This database was used as a proxy for determining which controllers are common among producers in the Canadian oil and gas industry. The samples could not however be included in the survey because they were taken using the Bacharach High-Flow Sampler and this survey is using the Calscan vent gas bellows meter for reasons presented in Section 2.4.3. These eligible controllers were compared with the extensive field samples database from Cap-Op Energy’s DEEPP to examine the frequency of eligible controllers previously surveyed in the field. The results are depicted in Figure 3 below.

Step 6: Develop Initial List

The common list of pneumatic controllers used to guide first round sampling can be found in Appendix B. The results include:

- The top 10 controllers represent 89% of the surveyed controllers in the Cap-Op database.
- The top 15 controllers represent 97% of the surveyed controllers in the Cap-Op database.
- Rare devices are those that comprise the remaining 3% of the surveyed controllers in the Cap-Op database.

This initial list was used to guide first round of sampling because the selected devices were anticipated to be frequent enough to produce statistically valid emissions factors.

Step 7: Validate list

Upon completion of the first round of sampling the original list was compared with what was observed in the field to determine if the anticipated list of 15 devices was the most common. Based on survey data collected in the field, two devices were found to be common and added to the sample: Fairchild TXI7800; and Murphy L1200. Two devices were found to be rarer than initially thought and thus have been removed from the sample population: Fisher 2660 (no devices found in the field); and Dyna-Flo 4000 (two devices found in the field).

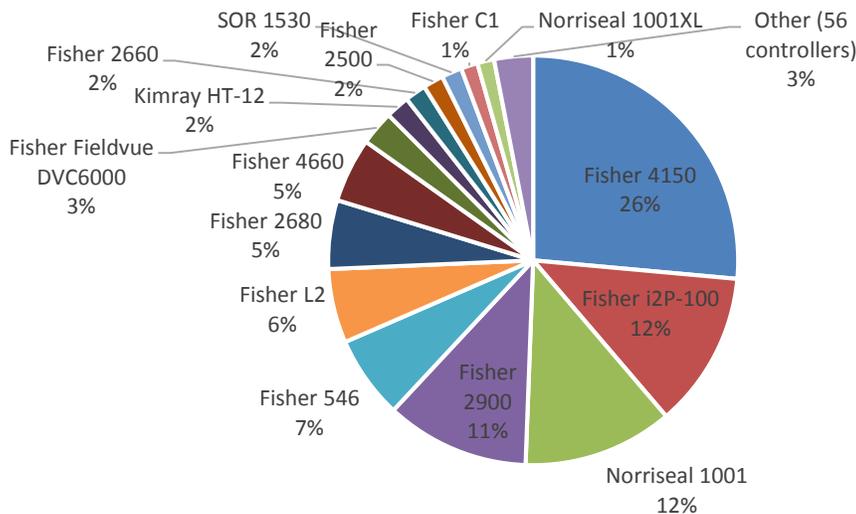


Figure 3: Frequency of pneumatic controllers found in the Cap-Op database

2.2 Pneumatic Pumps

The methodology used for determining the list of pneumatic pumps does not mirror the methodology used for pneumatic controllers because the Cap-Op database does not contain sufficient pump field samples to draw similar conclusions. The list of pneumatic pumps was compiled from the CAPP (2008), PCT (2011) and the Cap-Op DEEPP database. These sources were cross-referenced with manufacturer websites and subject matter experts to make a comprehensive initial list, presented in Appendix B. This initial list was used to guide first round of sampling; however, all pumps were sampled in the first round to determine which types were common among the producers sampled. Five common pumps were identified after the first round of sampling and were targeted during the second round of sampling: Texsteam 5100; Morgan HD 312; Williams P125; Williams P250; Williams P500.

2.3 Sampling Approach

The following section provides detail on how the field samples were collected as well as justification for which companies and geographic areas were selected for sampling.

The analysis and discussions in this report distinguish the ‘sample set’ or ‘sample’ from the ‘population’. In general, this analysis operates under the assumptions that the true number and state of the population (i.e. all pneumatic devices in BC) is unknown. Determining whether the sample is representative of the population, and to what extent is a major

component of this report and helps to characterize the validity of the results. Statistical analyses and conclusions are contingent on the assumption of an unknown population.

2.3.1 Bleed Rate Metering

The metering requirements for this project are unique and as such there are few options for determining gas vent rates from devices in a cost effective manner.

The desired meter must have the following characteristics:

- Mobility – the meter will have to be mobile such that the sampling teams can apply the meter to pneumatic devices in-service at various facilities throughout BC. This requires a relatively simple installation and removal procedure, with a low weight and portability such that it can be moved by one or two people to within a few feet of an existing pneumatic device as it is installed on-site. Breaking, cutting or disassembling process pipes, flanges or joints is not acceptable, however vent tubing may be intercepted for measurement.
- Range – the meter must be designed to accommodate the measurement of flow rates between zero and approximately 1m³/h of gas at pressures ranging from atmospheric to a few feet of water column with minimal back pressure.
- Explosive Environment – All electronic devices intended for use within CSA classified zones require intrinsically safe electronic enclosures such that potentially arcing /sparking ignition sources are completely isolated from potentially explosive atmospheres that occur in oil and gas facilities. This is a minimum safety requirement for all sampling team and on-site personnel.

The desired meter should have the following characteristics:

- Time series data to distinguish static and dynamic operation on pneumatic devices.
- Minimal to no back pressure
- High precision, 2% or less uncertainty on reported values
- High accuracy, with correction for variable parameters such as gas composition, temperature, barometric pressure, humidity, etc.

Based on an extensive review of meters available in the industry, two options which were found to be best candidates included the Bacharach High Flow Sampler and the Calscan Hawk 9000 Vent Gas Meter. The Bacharach High Flow Sampler is designed to measure the rate of gas leakage around various processes in natural gas transmission, storage and compressor facilities. This is accomplished by sampling at a very large flow rate (8 to 10 scfh) to completely capture any gas leaking from the component. By accurately measuring the flow rate of the sampling stream and the natural gas concentration, it is possible to calculate the rate of gas leak.

Prasino elected to use the Hawk 9000 vent gas meter (supplied by Calscan Energy) to measure and digitally log flow vent gas over time (which will vary based on the device sampled). This allowed for both the static and dynamic bleed rates for pneumatic controllers, as well as the dump cycles for pneumatic pumps and level controllers, to be captured. A drawback of the Bacharach High Flow Sampler is that it captures a snapshot in time; rather than a time series measurement. The Bacharach High Flow Sampler can fail to capture the dynamic bleeding events. The Hawk 9000 meter uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). In addition, the Hawk uses a precision pressure sensor, an external temperature probe and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences. As a result, flow measurement accuracies within $\pm 2\%$ ⁵. A picture of the Calscan Hawk 9000 is presented in Figure 3 and an example output chart is provided in Figure 5 below.



Figure 4: Calscan Hawk 9000 Meter

⁵ The meter is calibrated from -40°C to +60°C and uses “Gas Rate Algorithm AGA7” and “Equation of State AGA8”.

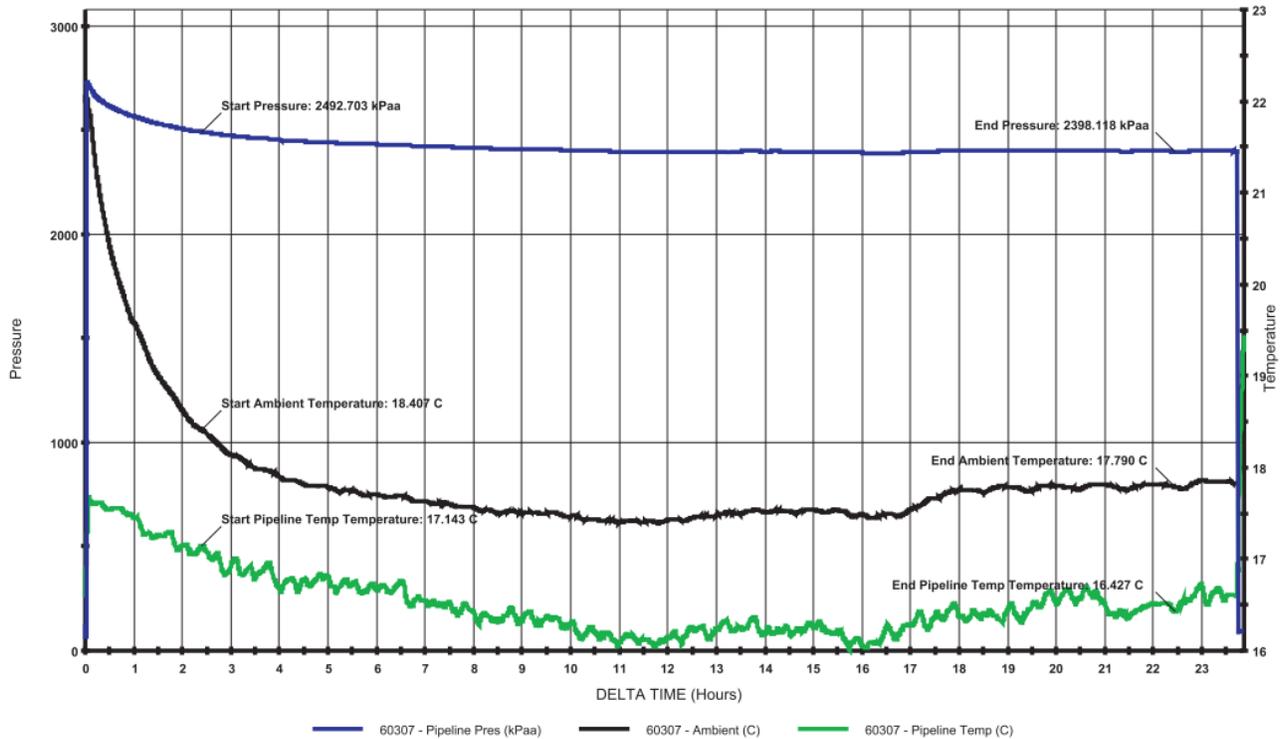


Figure 5: Example of Calscan Output Graph

2.3.2 Sample Size

The sampling program aimed to collect thirty samples of each device type identified as common according to Section 2.0 Sampling Methodology. Thirty was chosen as a minimum sample size in order to allow for statistical inferences to be drawn. When the sample size is sufficiently large (conventionally, 30 or larger), the standard error can be used to calculate a one-tail 95% confidence interval. As the sample population increases, the confidence interval should get smaller due to a decreased standard error (McClave and Sincich, 2003). In general, when calculating confidence interval, larger sample sizes and narrow confidence intervals must be balanced against the cost of additional sampling and the diminishing returns of incrementally smaller improvements to confidence intervals with each additional sample. Thirty samples for each common device type allows for the quantification of bleed rates with confidence intervals within a realistic budget and time frame.

2.3.3 Data Collection and Transfer

To manage the large amount of data that was collected during this sampling program, Cap-Op designed a software application (app) to be used in the field in order to increase data quality and tracking, and eliminate manual data recording. A field sampling guide was followed by the Greenpath sampling team and is provided in Appendix C.

All parameters were inputted into the app at the sampling location. Where appropriate, the app has dropdown menus to increase efficiency in compiling data. Numeric input fields have expected ranges of values and options for the units, so that if a value is entered outside of the range a message appears for the user to ensure the input is correct.

When the user has access to internet, the app will sync with Cap-Op Energy's DEEPP. The DEEPP will provide various functionalities for managing the data collected in the field including data storage and organizing the data into the desired output format of a download-able Excel files.

Controller

Cap-Op Controller ID# *: CS00004

Controller Type *:

Make *:

Model *:

Controller Serial #:

Supply Pressure *: **Units**

Controller Action *:

Condition of Controller *:

Gas Type *:

Quality of Gas *: N/A

Liquids Content : N/A

Sweet or Sour: N/A

Notes :

Take a Controller Photo

Perform Sample
Back to Site Overview
Cancel & Don't Save

Figure 6: Screen Shot of Cap-Op Energy's Data Collection App

2.3.4 Errors, Uncertainty and Biases

Errors, uncertainty and biases are part of every analysis and are discussed here for transparency and clarity. Overall, through critical review of the potential errors, uncertainties and biases inherent to this study, robust and reliable results can be attained.

An error is an unsupported result or conclusion that arose through improper application of methods, calculations, or data management. Every effort has been made to eliminate errors from the analysis and a system of checks has been employed to eliminate error from the analysis. Error can be eliminated from analysis, while bias and uncertainty cannot be.

Uncertainty, as it pertains to measurement of physical states or processes, describes the precision (or lack thereof) at which a characteristic or parameter can be defined. The precision associated with the measurement of bleed rates from a pneumatic device can be characterized through review of the techniques used to measure the parameters in question.

The meter chosen for this project (see Section 2.3.1) uses self-actuating, reciprocating bellows to discretely count fixed volumes of gas being vented from the device in five second intervals. The limitations associated with this type of measurement, and the uncertainties imposed, include:

- Volumes of gas vented lower than the fixed volume of one inflated bellow in a five second interval cannot be resolved. The uncertainty of any values of bleed rate reported by the meter under this value is large. This effect is typically characterized as the ‘turn-down ratio’ of a meter and every meter will have limits, turn-down or some range beyond which its reported values are unreliable. The Hawk 9000 meter has the range of flows that is appropriate for the intent of this study and thus mitigates this form of uncertainty to the extent possible.
- Pressures of vented gas lower than the back pressure imposed by the meter will significantly alter the value of gas being vented by the device. Back-pressure is a significant concern when measuring pneumatic control devices since the performance and bleed rate of the device may be inherently dependent on the back pressure of vented gas. This uncertainty impacts all ranges of gas flow, but in general will impose large uncertainty on high flows of gas since back pressure increases with flow. Devices which reported a zero bleed rate may actually have simply been ‘plugged’ by the internal actuating mechanisms of the meter. In general, it is impossible to measure the state of a system without disturbing the system, and this effect is unavoidable regardless of the type or extent of metering equipment chosen. It is anticipated that while the metering system chosen does impose a back pressure which may be more significant than other metering systems, the benefits of this metering system (time series bleed rate values and temperature pressure compensation) outweigh the detrimental effects of back pressure on the validity of results.
- Gas compositions vary from location to location and from moment to moment and the estimation of gas composition at each measurement point is a source of uncertainty. It is prohibitively expensive to have real-time gas composition parameters available to the measurement devices such that the uncertainty associated with gas composition could be further reduced. The estimations and assumptions made on gas composition for temperature and pressure correction of measured volumes is considered appropriate for the scope of this project.
- Digitization of data imposes uncertainty to values recorded during measurement through the limitation of significant digits (decimal places). The uncertainty imposed through the significant digits carried by data management systems in this project is considered to have contributed a negligible degree of uncertainty to the overall result.

In general, a statistic is biased if it is determined by an approach or method which systematically gives rise to differences between sample data and population data. Every effort was made in this sampling approach to avoid or minimize the effects of biases, nevertheless biases exist and are discussed below:

- Opportunistic Sampling Approach - The sampling approach used is a non-probability technique called opportunistic sampling, where sampling locations were chosen purposefully. The locations were chosen based on the following criteria:
 - The proximity to Fort St. John. Fort St. John is arguably a hub of oil and gas production within BC, with a majority of activity found within 500 km. In order to determine device bleed rates in an efficient and cost-effective manner, sampling was focused in this area. Sampling did not occur in the Fort Nelson region because many sites in Northern BC are winter access only or only accessible by helicopter.
 - The accessibility due to seasonality. Field locations with winter access only were excluded from the survey due to logistics and cost.
 - Producer identified device “hot spots”. Areas with a high concentration of devices were identified by cross-referencing producer’s inventories with the list of common devices.

- Sweet natural gas well-sites were preferred, followed by compressor stations and batteries, then sour gas well sites. Sweet sites were preferred over sour sites because they are typically run off compressed natural gas, whereas sour sites are typically run off propane or air. Well-sites were preferred over larger facilities because they typically house the common pneumatic controllers and pumps.

Opportunistic sampling has known limitations, including the sampling error⁶ which cannot be estimated, and that exclusion bias may arise from the non-random choice of sampling locations. However, random sampling was logistically impractical in this scenario and all efforts to minimize exclusion bias were made, by choosing sampling locations that were representative of a multitude of producers operating in BC, and production fields and sub-districts.

The effect of this exclusion bias is that the statistics describing the sample, may not accurately reflect the population statistics, and the extent to which this occurs cannot be determined. The likelihood and impact of this bias has been minimized by ensuring a sufficiently large sample size (the greater the sample size, the less selection biases will impact a result).

- Producer Influence – The sampling approach described above inherently allows for a set of biases which are the possibility for intentional and unintentional skewed sampling. Since permission was required from producers to access sites, and moreover, recommendations on which sites to visit were solicited from producers, it must be acknowledged that the producers may have unintentionally directed sampling to areas with more or less bleeding devices.
- Location – Pneumatic devices in the province of BC are limited to operation in the northern boreal shield or boreal plains climates at altitudes approximately centered around 690m above sea level. Oil and gas reserves are limited to those found in the western Canadian sedimentary basin and are not representative of global conditions. Biases arise from these geographic limitations and apply should the results of this study be implicated in jurisdictions outside of BC, however are irrelevant within the context of BC pneumatic device emissions.

⁶ *Sampling error* is an estimation of the difference between the true population mean and the sample mean, usually expressed in terms of standard error. Standard error cannot be reliably calculated using non-probability sampling techniques, although a mean, standard deviation, and confidence interval can be calculated with large (>30) sample numbers.

3. Sample Characteristics

In order to calculate a statistically significant bleed rate, with 95% confidence, a minimum of 30 samples was required per device. A total of 765 samples were taken across 28 producing fields in BC and 2 producing fields in Alberta.

Table 2. Number of Samples by Device Type

| Device Type | | Number of Samples |
|------------------------------|------------------------|-------------------|
| Pneumatic Controllers | Level Controller | 254 |
| | Positioner | 43 |
| | Pressure Controller | 142 |
| | Temperature Controller | 41 |
| | Transducer | 101 |
| Pneumatic Pumps | Chemical Injection | 184 |

3.1 Pneumatic Controllers

Table 3 (below) summarises the number of samples by controller device. Devices in the “other” category were used to develop a generic emissions factor for pneumatic devices not specifically listed here.

Table 3. Pneumatic Controllers Sampled

| Pneumatic Controllers | First Round Samples | Second Round Samples | Total |
|-------------------------------|---------------------|----------------------|------------|
| Pressure Controllers | | | |
| Fisher 4150 | 35 | 11 | 46 |
| Fisher C1 | 27 | 3 | 30 |
| Fisher 4660 | 29 | 1 | 30 |
| Level Controllers | | | |
| Fisher L2 | 37 | 11 | 48 |
| Murphy L1200 | 27 | 4 | 31 |
| Norriseal 1001 | 47 | 10 | 57 |
| SOR 1530 | 28 | 3 | 31 |
| Fisher 2900 | 22 | 8 | 30 |
| Fisher 2680 | 22 | 10 | 32 |
| Fisher 2500 | 8 | 4 | 12 |
| Positioner | | | |
| Fisher Fieldvue (DVC) | 20 | 12 | 32 |
| Temperature Controller | | | |
| Kimray HT-12 | 36 | 0 | 36 |
| Transducer | | | |
| Fisher i2P-100 | 37 | 0 | 37 |
| Fisher 546 | 27 | 3 | 30 |
| Fairchild TXI7800 | 36 | 1 | 37 |
| Other | 53 | 7 | 64 |
| Total | 491 | 90 | 581 |

3.2 Pneumatic Pumps

The sampling results for pump devices are summarised in Table 4 (below).

Table 4. Pneumatic Pumps Sampled

| Pneumatic Pumps | First Round Samples | Second Round Samples | Total |
|-----------------|---------------------|----------------------|------------|
| Morgan HD312 | 3 | 32 | 35 |
| Texsteam 5100 | 47 | 0 | 47 |
| Williams P125 | 50 | 0 | 50 |
| Williams P250 | 28 | 0 | 28 |
| Williams P500 | 12 | 0 | 12 |
| Other | 9 | 3 | 12 |
| Total | 149 | 35 | 184 |

3.3 Producers

To reduce sampling bias, a cross-section of oil and gas producing companies were included in the survey to ensure sampling was representative and spread across producers as well as producing fields. Figure 3 (below) shows the breakdown of sampling across the eight producers.

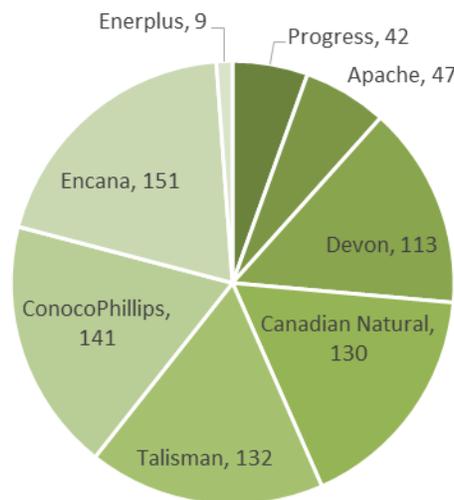


Figure 7: Breakdown of Samples by Producer

3.4 District and Sub-District

Table 5 outlines the number of samples per district as well as a breakdown of samples by producing field. Samples were collected from areas in northeastern BC; in the Fort St John, Brooks, Dawson Creek, Grand Prairie and Hanna districts (Figure 8). In total samples were taken from 30 different producing fields, with 756 samples coming from BC and 9 from Alberta.



Figure 8: Sampling Location

Table 5. Number of Samples by District and Sub-District

| Producing Field | Number of Samples |
|----------------------|-------------------|
| Dawson Creek | 254 |
| Bissette | 111 |
| Brassey | 7 |
| Half Moon | 7 |
| Redwillow River | 41 |
| Sundown | 25 |
| Swan Lake | 63 |
| Fort St. John | 394 |
| Beaverdam | 5 |
| Blueberry | 42 |
| Buick Creek | 29 |
| Bullmoose | 4 |
| Bulrush | 11 |
| Burnt River | 42 |
| Cecil Lake | 27 |
| Eagle | 36 |
| Farrell | 9 |
| Farrell Creek West | 43 |
| Ladyfern | 14 |
| Monais | 4 |
| Muskrat | 33 |
| Nancy | 26 |
| North Cache | 7 |

| Producing Field | Number of Samples |
|----------------------------------|-------------------|
| North Pine | 5 |
| Owl | 1 |
| Septimus | 16 |
| Stoddart | 29 |
| Sukunka | 11 |
| Grand Prairie⁷ | 108 |
| Hiding Creek | 45 |
| Noel | 63 |
| Hanna (AB) | 7 |
| Leo | 7 |
| Brooks (AB) | 2 |
| Verger | 2 |
| Total | 765 |

4. Analysis

The analytical approach began by determining the mean sample bleed rate for each pneumatic controller and pump included in the survey. Table 6 below show the mean bleed rates, the 95% confidence interval (CI) and the standard deviation for the 20 common devices included in the survey. These bleeds rates are corrected for temperature, pressure and gas type.

Table 6: Results of Analysis by Device Model

| Pneumatic Device | Number of Samples | Average Bleed Rate (m ³ /hr) | 95% Confidence Interval (m ³ /hr) | Standard Deviation (m ³ /hr) |
|--------------------------------|-------------------|---|--|---|
| Pressure Controllers | | | | |
| Fisher 4150 | 46 | 0.4209 | 0.5322 | 0.4593 |
| Fisher C1 | 30 | 0.0649 | 0.0981 | 0.1106 |
| Fisher 4660 | 30 | 0.0151 | 0.0329 | 0.0592 |
| Level Controllers | | | | |
| Fisher 2500 | 12 | 0.3967 | 0.5559 | 0.3353 |
| Fisher 2680 | 32 | 0.2679 | 0.3782 | 0.3793 |
| Fisher 2900 | 30 | 0.1447 | 0.2496 | 0.3490 |
| Fisher L2 | 48 | 0.2641 | 0.3538 | 0.3779 |
| Murphy L1200 | 31 | 0.2619 | 0.3618 | 0.3383 |
| Norriseal 1001 | 57 | 0.1868 | 0.2670 | 0.3679 |
| SOR 1530 | 31 | 0.0531 | 0.0841 | 0.1049 |
| Positioners | | | | |
| Fisher Fieldvue DVC6000 | 32 | 0.2649 | 0.3633 | 0.3386 |
| Temperature Controllers | | | | |

⁷ Samples labelled Grand Prairie were taken from producing fields in BC.

| Pneumatic Device | Number of Samples | Average Bleed Rate (m ³ /hr) | 95% Confidence Interval (m ³ /hr) | Standard Deviation (m ³ /hr) |
|--------------------|-------------------|---|--|---|
| Kimray HT-12 | 36 | 0.0351 | 0.0621 | 0.0987 |
| Transducers | | | | |
| Fairchild TXI7800 | 37 | 0.1543 | 0.1877 | 0.1234 |
| Fisher 546 | 30 | 0.3547 | 0.4279 | 0.2436 |
| Fisher i2P-100 | 37 | 0.2157 | 0.2602 | 0.1646 |
| Pumps | | | | |
| Morgan HD312 | 35 | 1.1292 | 1.3592 | 0.8271 |
| Texsteam 5100 | 47 | 0.9670 | 1.1467 | 0.7490 |
| Williams P125 | 50 | 0.4098 | 0.5092 | 0.4272 |
| Williams P250 | 28 | 0.8022 | 1.0156 | 0.6863 |
| Williams P500 | 12 | 0.6969 | 0.9741 | 0.5836 |

4.1 Analysis for Determining a Generic Bleed Rate

The next step of the analysis was to determine if a generic bleed rate could be generated for high-bleed controllers and pumps. Devices that were determined to be high bleeding (i.e. bleed rate > 0.17 m³/hr) were grouped together in the analysis. If the calculated mean bleed rate was larger than the threshold, the device was included in the analysis, and if the calculated mean bleed rate was smaller than the threshold, the device was excluded from the analysis for determining a generic bleed rate. Certain controllers that are considered low-bleeding according to WCI or manufacturer specifications actually bled above the low bleed threshold and were therefore included in the analysis. Using Minitab, a statistical analysis software, a general linear model (GLM) was performed on the data to determine if there was a significant difference between the mean bleed rates of controllers and pumps. The results are presented in Table 7.

Table 7: Results of the Overview Analysis

| Pneumatic Device | Number of Samples | Average Bleed Rate (m ³ /hr) | 95% Confidence Interval (m ³ /hr) | Standard Deviation (m ³ /hr) | P-Value |
|-------------------------|-------------------|---|--|---|---------|
| High Bleed Controllers | 406 | 0.2605 | 0.2880 | 0.3371 | 0.129 |
| High Bleed Intermittent | 195 | 0.2476 | .2893 | 0.3537 | 0.738 |
| Piston Pumps | 96 | 0.5917 | 0.6926 | 0.6007 | 0.060 |
| Diaphragm Pumps | 85 | 1.0542 | 1.1948 | 0.7878 | 0.362 |

For high bleed controllers, a p-value > 0.05 was calculated, meaning that there was no significant differences between the mean bleed rates. The mean bleed rate is representative of the population and can therefore be applied to any high bleed controller model. For intermittent high bleed controller, a p-value > 0.05 was calculated, meaning that there was no significant differences between the mean bleed rates. The mean bleed rate is representative of the population and can therefore be applied to any intermittent high bleed controller model. For all pumps, a p-value < 0.05 was calculated, meaning that there is a significant difference between all pump models and a generic bleed rate may not be representative of the entire population. Due to the large variance in bleed rates across all pumps, the pumps were grouped into two categories: diaphragm pumps and piston pumps. A p-value > 0.05 was calculated for both types of pumps, meaning that the mean bleed rate is representative of the entire population.

Box plot distributions of all field samples are presented in Appendix D.

4.2 Bleed Rate Equations

The most accurate bleed rate would take into account quantitative variables. A regression analysis was performed to investigate which quantitative variables affected the bleed rate. A regression analysis showed that there was a positive correlation between certain pneumatic controller bleed rates and supply pressure. A regression analysis showed that there was a positive correlation between pneumatic pump bleed rates, supply pressure, injection pressure and strokes per minute.

Controller Bleed Rate Equation $Bleed Rate_j = m * SP_j$

Where:

m = the supply pressure coefficient (see Appendix E)

SP_j = the supply pressure of controller j

Pump Bleed Rate Equation⁸ $Bleed Rate_j = (g * SP_j) + (n * DP_j) + (p * SPM_j)$

Where:

g = the supply pressure coefficient (see Appendix E)

SP_j = the supply pressure of pump j, (kPa)

n = the discharge pressure coefficient, (see Appendix E)

DP_j = the discharge pressure of pump j, (kPa)

p = the strokes per minute coefficient (see Appendix E)

SPM_j = the strokes per minute of pump j

For producers who know the operating conditions of their devices, they should use the following bleed rate equations. It should be noted that this method will only provide a more accurate bleed rate compared to the average bleed rate shown in Table 7 and Table 8 if the producer is certain of the operating conditions. Adding complexity may increase the overall error in bleed rates if operating conditions are estimated. Figure 9 provides an overview of the approach used to analyze the data.

⁸ It should be noted that if the pump is operating at less than five strokes per minute, the emissions equation is not applicable and the mean bleed rate should be used.

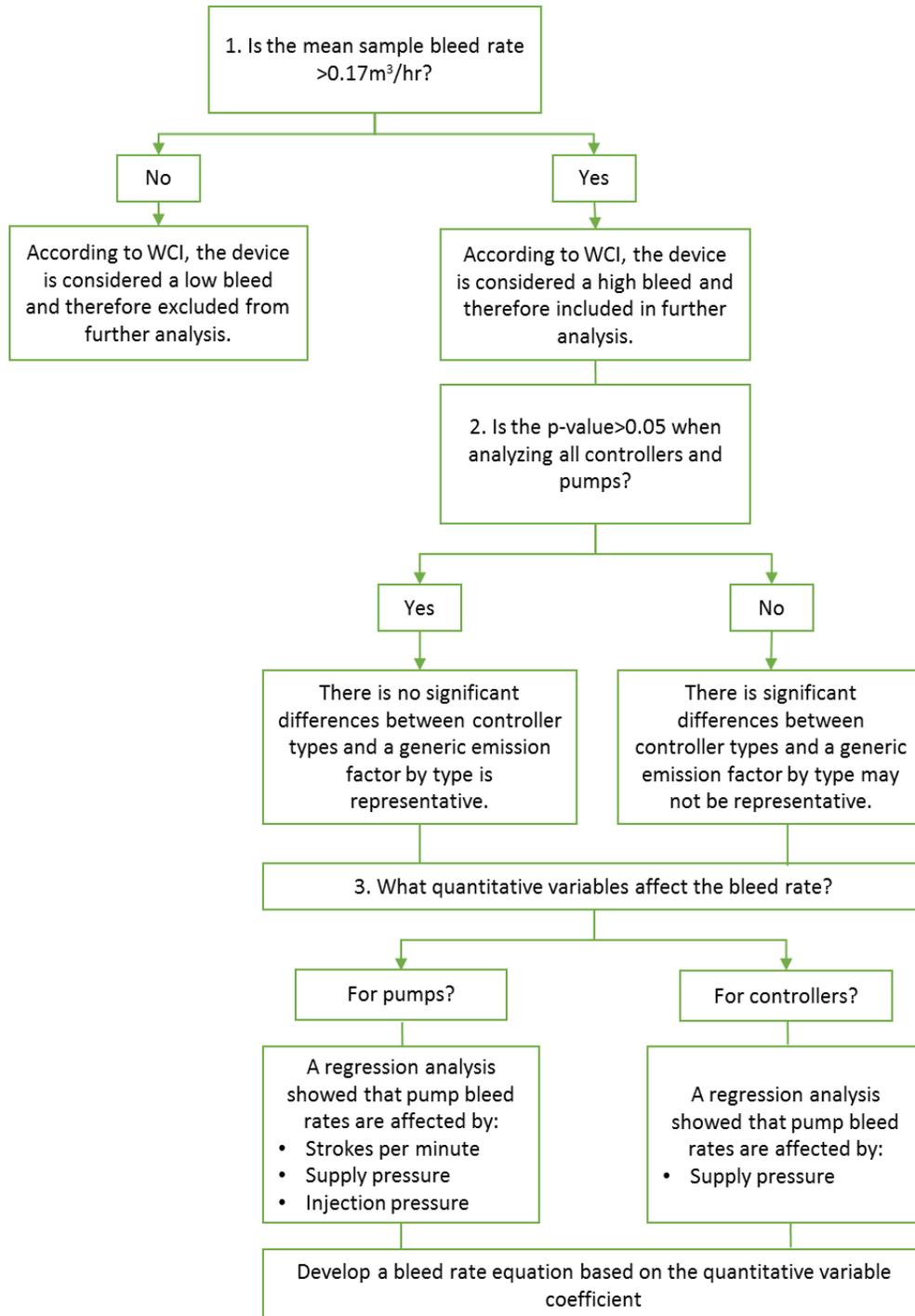


Figure 9: Diagram Illustrating the Quantitative Analysis

5. Comparison of Bleed Rates

Table 8 and Table 9 compare the average bleed rate to the manufacturer’s specification as well as previously published bleed rates. A discussion on variability between the mean bleed rate and the manufacturer specification is provided in Section 6 below. A discussion on variability between the mean bleed rate and the EPA default is provided below. Overall, the average bleed rate for high bleed and intermittent controllers were lower than the EPA default; however, the average bleed rate for low bleed controllers and pumps were both higher than the EPA default. These findings align with a similar study that was performed in the United States by the University of Texas (Allen *et al.* 2013).

Table 8: Comparison of Pneumatic Controller Bleed Rates

| Pneumatic Controllers | Average Bleed Rate (m ³ /hr) | Manufacturer Specification (m ³ /hr) | WCI (m ³ /hr) | CAPP (m ³ /hr) | EPA (m ³ /hr) |
|-------------------------------|---|---|--------------------------|---------------------------|--------------------------|
| Pressure Controllers | | | | | |
| Fisher 4150 | 0.421 | 0.691 | 0.736 | 0.680-1.841 | 0.071-0.821 |
| Fisher C1 ⁹ | 0.065 | 0.097 | 0.147 | - | - |
| Fisher 4660 | 0.015 | 0.174 | 0.142 | - | 0.142 |
| Level Controllers | | | | | |
| Fisher L2 ⁹ | 0.264 | 0.032 | 0.043 | - | - |
| Fisher 2500 | 0.397 | 1.100 | 1.189 | 1.189 | 0.283-2.03 |
| Fisher 2680 ⁹ | 0.268 | 0.040 | 0.028 | <0.028 | <0.028 |
| Fisher 2900 | 0.145 | 0.453 | 0.651 | 0.510-3.60 | - |
| Murphy L1200 ¹⁰ | 0.262 | - | - | - | - |
| Norriseal 1001 ⁹ | 0.187 | 0.057 | 0.057 | 0.006 | 0.006 |
| SOR 1530 ⁷ | 0.053 | 0.142 | - | - | - |
| Positioners | | | | | |
| Fisher DVC6000 | 0.265 | 0.38 | 0.396 | 0.400-1.39 | 0.396 |
| Temperature Controller | | | | | |
| Kimray HT-12 ⁹ | 0.035 | 0.000 | - | - | - |
| Transducer | | | | | |
| Fairchild TXI7800 | 0.154 | 0.380 | 0.241 | - | - |
| Fisher 546 | 0.355 | 0.648 | 0.850 | 0.423-1.700 | 0.595 |
| Fisher i2P-100 | 0.216 | 0.180 | 0.283 | - | - |

⁹ Considered a low bleed controller according to manufacturer specification and WCI’s definition <0.17m³/hr.

¹⁰ This pneumatic device was not on the initial list for pneumatics but was included due to prominence in the field.

Table 9. Comparison of pneumatic pump bleed rates.

| Pneumatic Pumps | Mean Bleed Rate (m ³ /hr) | Max Air Consumption (Man Specification ¹¹ (m ³ /hr) | CAPP (m ³ /hr) ¹² | WCI (m ³ /hr) ¹³ | EPA (m ³ /hr) |
|-----------------|--------------------------------------|---|---|--|--------------------------|
| Morgan HD312 | 1.1292 | 1.35 | 0.236 | 0.3945 | 0.3767 |
| Texsteam 5100 | 0.9670 | 2.31 | 0.236 | 0.3945 | 0.3767 |
| Williams P125 | 0.4098 | 0.21 | 0.236 | 0.3945 | 0.3767 |
| Williams P250 | 0.8022 | 1.33 | 0.236 | 0.3945 | 0.3767 |
| Williams P500 | 0.6969 | 2.46 | 0.236 | 0.3945 | 0.3767 |

6. Discussion

6.1 Outliers

Outliers were not excluded from the sample population because the purpose of the survey was to capture real field conditions and generate a bleed rate that is representative of all field conditions. Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.

6.2 Throttling vs. Snap-Acting Controllers

Two types of controllers were sampled in the field, throttling and snap-acting controllers. Throttling controllers bleed continuously as they constantly throttle between static and dynamic states. Actuating or intermittent bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed. The static bleed rate is steady-state gas consumption. When a controller performs an action, the pressurized gas is subsequently vented through the controller to the atmosphere, also known as the dynamic bleed rate.

The dynamic bleed rate can be much greater than the static bleed rate based on the operating conditions of the controller. The total bleed rate (static + dynamic) depends on the frequency the controller is performing an action. Snap-acting controllers typically have greater variability in dynamic and static action due to the intermittency of the actions. Snap-acting controllers are predominantly in their static, inactive state until an action is required, which results in a short burst of dynamic bleeding.

Figure 10 shows an example of how the bleed rate varies over time for a snap-acting controller. The difference between the static rate and the amplitude of the dynamic event is the dynamic bleed rate. The most important variable that dictates the bleed rate however is the frequency of the dynamic events, which is dependent on a number of variables (dry/wet gas, tank size, etc.) Level controllers are a prime example of a snap-acting controller because they only dynamically bleed when they are prompted by an event, typically to empty a liquids tank.

¹¹ The stated manufacturer max air consumption value assumes a supply pressure of 690 kPa (100 psi), which is a max supply pressure.

¹² <http://www.capp.ca/getdoc.aspx?DocId=86223&DT=NTV>

¹³ <http://www.theclimateregistry.org/downloads/2010/04/Final-OGP-Protocol.pdf>

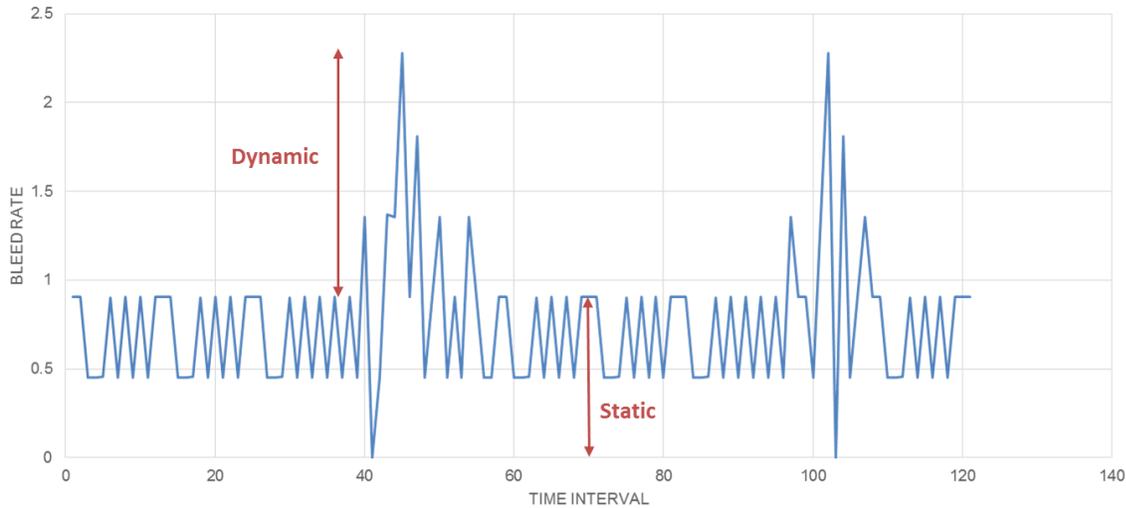


Figure 10: Graph Showing the Dynamic and Static Action

Since the sampling methodology limited the sample time to 30 minutes, there was variability in the amount of static and dynamic action that was captured from a given controller. This variability was due to the frequency of dynamic events. Depending on operating conditions, certain controllers did not perform an action within the 30 minute timeframe, so only the static bleed rate was captured. For example, if a level controller dumps on average every four hours, the sampling team may or may not have caught the dynamic bleed rate of the controller. This created variability in the amount of dynamic versus static bleeds that were captured by an individual sample; however, due to our large sample sets, this variability is representative of how controllers are performing under real operating condition.

This variance was mostly seen in level controllers because they are snap-acting and operate in an on or off type condition. The level controller samples showed a range of values depending on how many dynamic events occurred over a sampling period. This was an expected outcome because level controllers have primarily static bleed rates with variable dynamic events. Our analysis captured both static and dynamic events over the sampling time frame and are both accounted for when using the average as a representative bleed rate for the samples with skewed and bimodal distribution.

6.3 Manufacturer Specification

Differences are observed between the average bleed rate and the manufacturer specification. It should be noted that this variability was expected. The manufacturer specification measures the steady-state air consumption in a lab setting. The purpose of the survey is to determine the average bleed rate of pneumatic controllers and pumps when operating under real field conditions. The field bleed rates differed from manufacturer rates because they are operating under real world conditions with variability in dynamic and static action. For pumps, the field bleed rates are different than manufacturer rates because they are provided with a maximum air consumption using a maximum supply pressure.

6.4 Gas vs. Air vs. Propane

The majority of the field samples were taken at sweet well sites; however, as devices became harder to find, the sampling team targeted compressor stations and batteries as well as sour sites in order to reach the 30 sample threshold. A handful of air samples were obtained from larger facilities because typically, bigger facilities run compressed air instead of pressurized natural gas. A handful of propane samples were obtained from sour well sites because an alternative to process natural gas is required at sour sites, so pressurized propane is typically used. Air and propane samples were corrected using a density ratio in order to compare equivalent volumes of natural gas bled.

6.5 Calscan Vent Gas Meter

When determining which metering device to use during sampling, the Calscan bellows meter was chosen over the Bacharach High-Flow Sampler because it has greater accuracy and has the ability to capture the static and dynamic bleed rates (see Section 2.3.1 for a complete discussion on the differences). A drawback exists; however, that should be discussed and may explain some of the variability in the data. It is well-known that metering a device can affect the operation of the device when hooked up due to back pressure. It is possible that certain controllers didn't produce enough pressure when hooked up to overcome the back pressure, resulting in a zero reading.

6.6 Producer and Sub-District

A multitude of producers and sub districts within British Columbia were sampled; however, the purpose was not to determine differences between producers and sub-districts but determine generic BC wide bleed rates that reflect values from a variety of locations and producers. Since we have taken our samples from a variety of fields, the average bleed rate captures the variability between producers and sub-districts. The intent of the survey was not to determine whether producers and sub-districts were influencing variables; however, the methodology was designed to ensure that these variables were accounted.

6.7 Adding a Device Model to the Survey

If a producer wishes to develop an average bleed rate for a controller or pump that was outside the scope of this survey, they can follow the sampling methodology outlined in Section 2. A minimum of 30 bleed rates per device model must be achieved using a mass flow meter from a variety of producing fields and producers. Please reference the Project Methodology (July 29th 2013) report for the full protocol.

6.8 Mean vs. Median

Many of the snap acting level controllers had skewed or bi-modal distribution. Typically the median is used to represent the value for central tendency in non-normal distributions; however, the goal for this project was to develop an average where all the samples are weighted equally. The mean is recommended because it weights all samples equally; whereas the median would neglect samples on the tail of the distribution. The median would not accurately reflect the combined static and dynamic bleed rate; whereas the mean places equal weight on each sample. Using the median as a measure of central tendency would ignore the data that represents the dynamic action over the course of sampling. Thus, when calculating the most accurate bleed rate, the mean is more representative than the median because of static and dynamic actions.

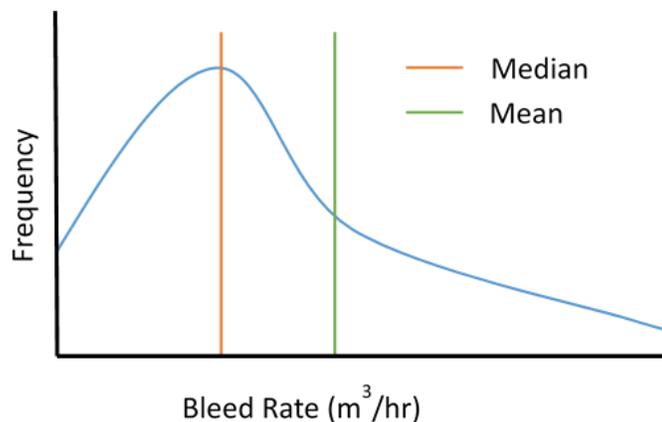


Figure 11: Non-Normal Distribution

6.9 General Linear Model

A general linear model is a statistical test that analyzes variance between sample populations. It was chosen to compare the samples because some populations showed a non-normal distribution and because the samples sizes differed. This statistical test incorporates different ANOVA tests and non-parametric tests to produce an accurate p-value. A general linear model is more robust when dealing with different normalities and variance in sample populations compared to a standard ANOVA and was therefore selected (Bolker *et al.* 2009).

6.10 Summer vs. Winter Sampling

The sampling was performed over the summer months of August and early September. The Calscan Hawk 9000 meter normalized all the samples for temperature and pressure differences in order to eliminate the different operating variables. A known constraint of our sampling methodology was that not all chemical injection pumps operate in the summer months. To eliminate this issue, the sampling team would turn the pump on and perform samples at three normal operating speeds (high, medium and low strokes per minute).

7. Applications of the Analysis

The mean bleed rates calculated in this survey are applicable for GHG reporting. A decision tree is provided in **Figure 12** and Figure 13 below to aid producers in determining which bleed rate to apply.

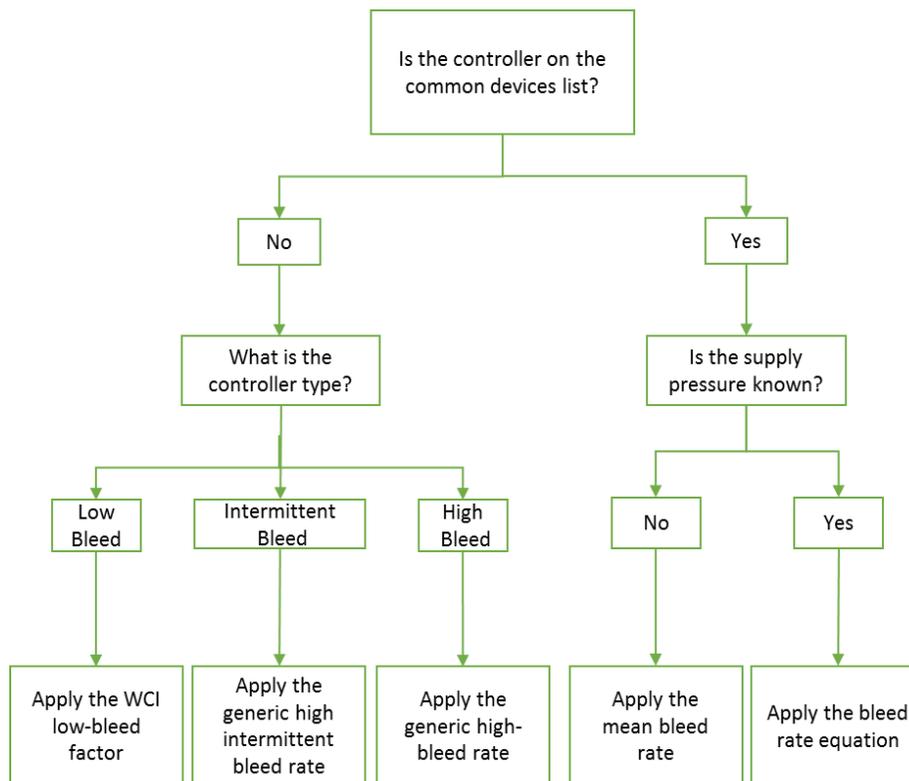


Figure 12: Controller Decision Tree

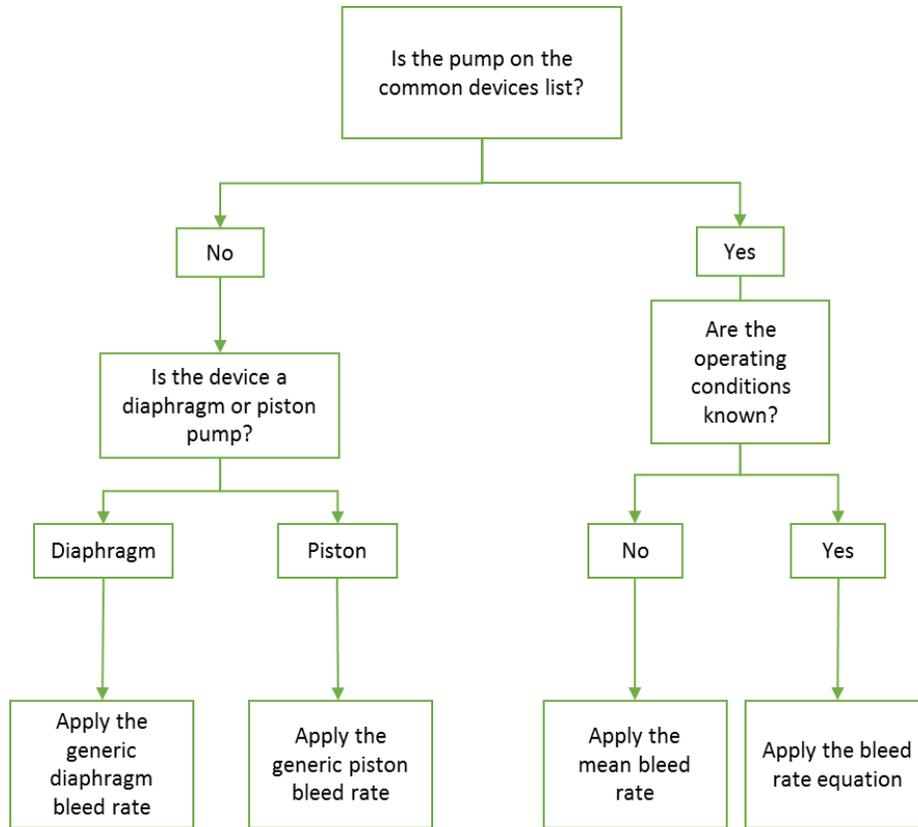


Figure 13: Pump Decision Tree

8. Observations

This study involved comprehensive analysis of pneumatic devices and a significant fieldwork program. This, combined with the fact that this study was one of the first of its kind, resulted in the research team observing several instances where the general body of scientific knowledge in this area could be advanced. These are outlined below:

1. Dynamic vs. static bleed rates: By nature, controller devices have a baseline bleed rate with dynamic events where more gas may be vented. In this study, the maximum sampling time was set at 30 minutes for each device, which added variability to the amount static and dynamic action captured in the sampling of snap-acting controllers (see section 6.2 for further discussion). The time interval between dynamic events may be longer than a 30 minute cycle. Future surveys investigating intermittent bleeding controllers, if undertaken, may consider capturing two complete dynamic cycles if reasonably practicable.
2. Categorisation of ‘high’, ‘intermittent’, and ‘low bleed’: The survey was focused around high-bleed pneumatic controllers. It was observed that for some high bleed devices the calculated mean bleed rate fell below the 0.17m³/hr WCI high bleed threshold and some tested low bleed controllers were higher. As an analysis of the observed differences were not within the scope of the project no further work to assess possible cause was undertaken, at this time. It is observed that future studies may consider all types of pneumatic controllers so that categorisation can be more fully tested and to ensure that field tested emission factors are available for all emitting pneumatic devices.

9. Conclusion

The purpose of the survey was to determine a representative average bleed rate for high bleed pneumatic controllers and pneumatic pumps when operating under field conditions. All outcomes were achieved. The results of the analysis led to the development of three generic bleed rates and twenty specific bleed rates for common pneumatic controllers and pumps for BC's oil and gas industry. These bleed rates can be used in the development of emission factors for GHG reporting and potentially offset purposes.

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Appendix A: Compilation of All Known Pneumatic Controllers

| Description | Manufacturer | Model | Manufacturer Rate (m ³ /h NG) | Source | Equivalent Devices | Sample? | Justification |
|---------------------|-----------------|----------------|--|-----------------------|------------------------------------|---------|---------------|
| Pressure Controller | Ametek | Series 40 | 0.22 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Positioner | Becker | HPP-5 | 0.18 | WCI | | Yes | High-bleed |
| Pressure Controller | Bristol Babcock | Series 502 A/D | 0.22 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Pressure Controller | Dyna-Flo | 4000 | 0.89 | WCI | Dyna-Flo 5000 | Yes | High-bleed |
| Pressure Controller | Dyna-Flo | 4000LB | 0.13 | Dyna-Flo | | Yes | High-bleed |
| Transducer | Fairchild | TXI 7800 | 0.31 | WCI | | Yes | High-bleed |
| Transducer | Fisher | 546 | 1.10 | WCI | Fisher 546S Fisher 546 | Yes | High-bleed |
| Transducer | Fisher | 646 | 0.29 | WCI | | Yes | High-bleed |
| Transducer | Fisher | 846 | 0.44 | WCI/CAPP BMP/GAS Star | Fisher 846S | Yes | High-bleed |
| Level Controller | Fisher | 2500 | 1.55 | WCI | | Yes | High-bleed |
| Level Controller | Fisher | 2900 | 0.85 | WCI/CAPP BMP/GAS Star | Fisher 2901 Fisher 2900A | Yes | High-bleed |
| Positioner | Fisher | 3582 | 0.59 | WCI | | Yes | High-bleed |
| Positioner | Fisher | 3590 | 1.10 | WCI | | Yes | High-bleed |
| Positioner | Fisher | 3660 | 0.26 | WCI | | Yes | High-bleed |
| Positioner | Fisher | 3661 | 0.38 | WCI | | Yes | High-bleed |
| Pressure Controller | Fisher | 4100 | 1.83 | WCI | Fisher 4101 | Yes | High-bleed |
| Pressure Controller | Fisher | 4150 | 0.96 | WCI | Fisher 4150K Fisher 4160R CVS 4150 | Yes | High-bleed |

| Description | Manufacturer | Model | Manufacturer Rate (m ³ /h NG) | Source | Equivalent Devices | Sample? | Justification |
|-------------------------|--------------|------------------|--|-----------------------|--|---------|---------------|
| | | | | | Fisher 4150K Fisher 4160 | | |
| Temperature Controller | Fisher | 4156 | | | Fisher 4156 Fisher 4166 | Yes | High-bleed |
| Pressure Controller | Fisher | 4194 | 0.16 | WCI | | Yes | High-bleed |
| Pressure Controller | Fisher | 4195 | 0.16 | WCI | | Yes | High-bleed |
| High-Low Pressure Pilot | Fisher | 4660 | 0.18 | Gas STAR | Fisher 4660A | Yes | High-bleed |
| Positioner | Fisher | Fieldvue DVC5000 | 0.37 | WCI/CAPP BMP/GAS Star | FisherDVC5040 FisherDVC5030 FisherDVC5020 FisherDVC5010 | Yes | High-bleed |
| Level Controller | Fisher | 2900A | | | Fisher 2901A | Yes | High-bleed |
| Positioner | Fisher | 3582i | 0.76 | WCI | | Yes | High-bleed |
| Positioner | Fisher | 3620J | 0.98 | WCI | | Yes | High-bleed |
| Pressure Transmitter | Fisher | C1 | 0.19 | WCI | | Yes | High-bleed |
| Positioner | Fisher | Fieldvue DVC6000 | 0.52 | WCI/CAPP BMP/GAS Star | FisherDVC6030 FisherDVC6020 FisherDVC6010 | Yes | High-bleed |
| Transducer | Fisher | i2P-100 | 0.37 | WCI | Fisher i2P-100, 4-20mA | Yes | High-bleed |
| Pressure Controller | Foxboro | 43AP | 0.66 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Level Controller | Invalco | AE-155 | 1.95 | WCI | | Yes | High-bleed |

| Description | Manufacturer | Model | Manufacturer Rate (m ³ /h NG) | Source | Equivalent Devices | Sample? | Justification |
|------------------------|----------------|----------------------|--|--------------------------------------|----------------------------|---------|---------------|
| Level Controller | Invalco | CT Series | 1.47 | WCI/CAPP BMP/GAS Star | NATCO Flextube (CT Series) | Yes | High-bleed |
| Positioner | Invalco | Flextube (CT Series) | 1.47 | WCI | NATCO Flextube (CT Series) | Yes | High-bleed |
| Pressure Controller | ITT Barton | 338 | 0.22 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Pressure Controller | ITT Barton | 4195 | 0.13 | Gas Star | | Yes | High-bleed |
| Pressure Controller | ITT Barton | 335P | 0.22 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Level Controller | Kimray | Gen2 | 0.54 | Manufacturer's website ¹⁴ | | Yes | High-bleed |
| Temperature Controller | Kimray | HT-12 | | | | Yes | High-bleed |
| Level Controller | Mallard | 3201 | | | | Yes | High-bleed |
| Positioner | Masoneilan | 4600B Series | 0.88 | WCI | | Yes | High-bleed |
| Positioner | Masoneilan | 4700B Series | 0.88 | WCI | | Yes | High-bleed |
| Positioner | Masoneilan | 7400 Series | 1.36 | WCI | | Yes | High-bleed |
| Positioner | Moore Products | 73N-B PtoP | 1.33 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Positioner | Moore Products | 750P | 1.55 | WCI/CAPP BMP/GAS Star | | Yes | High-bleed |
| Transducer | Moore Products | IPX2 | | | | Yes | High-bleed |

¹⁴ <http://mobile.kimray.com/downloads/instruction/GENIIBACKmount.pdf>

| Description | Manufacturer | Model | Manufacturer Rate (m ³ /h NG) | Source | Equivalent Devices | Sample? | Justification |
|---------------------|-----------------|--------------------|--|-----------------------|--------------------|---------|---------------|
| Pressure Controller | Natco | CT | 1.55 | WCI | | Yes | High-bleed |
| Pressure Controller | Norriseal | 4900 | | | | Yes | High-bleed |
| Level Controller | Norriseal | 1005PI | | | | Yes | High-bleed |
| Pressure Controller | Time Mate | 2000 | | | | Yes | High-bleed |
| Level Controller | Wellmark | 2001A | 0.13 | CAPP | | Yes | High-bleed |
| Positioner | YTC | YT-2400 | | | | Yes | High-bleed |
| Level Controller | Fisher | 2660 | 0.04 | CAPP BMP | Fisher 2660A | Yes | PCT |
| Level Controller | Fisher | 2680 | 0.04 | CAPP BMP | Fisher 2680A | Yes | PCT |
| Level Controller | Fisher | L2 | 0.06 | WCI | | Yes | PCT |
| Level Controller | Norriseal | 1001 | 0.07 | WCI | 1001A | No | PCT |
| Level Controller | Norriseal | 1001XL | 0.07 | WCI | | No | PCT |
| Positioner | Becker | ERP-2.0 | 0.00 | WCI/CAPP BMP/GAS Star | | No | Low-bleed |
| Controller | Becker | VRP-SB | 0.00 | Gas Star | | No | Low-bleed |
| Pressure Controller | Bristol Babcock | 358 | 0.07 | Gas Star | | No | Low-bleed |
| Pressure Controller | Bristol Babcock | 359 | 0.07 | Gas Star | | No | Low-bleed |
| Pressure Controller | Bristol Babcock | 5455 Model 624-III | 0.09 | WCI | | No | Low-bleed |

| Description | Manufacturer | Model | Manufacturer Rate (m ³ /h NG) | Source | Equivalent Devices | Sample? | Justification |
|----------------------|-----------------|----------------------------|--|-----------------------|--------------------|---------|---------------|
| Pressure Controller | Bristol Babcock | Series 5453-Model 624 - II | 0.11 | Gas STAR | | No | Low-bleed |
| Pressure Controller | Bristol Babcock | Series 5455 Model-624 10F | 0.11 | WCI/CAPP BMP/GAS Star | | No | Low-bleed |
| Pressure Transmitter | Bristol Babcock | Series 5457-70F | 0.11 | Gas STAR | | No | Low-bleed |
| Transducer | Bristol Babcock | Series 9110-00A | 0.02 | WCI/CAPP BMP/GAS Star | | No | Low-bleed |
| Level Controller | Fisher | 2100 | 0.04 | WCI/CAPP BMP/GAS Star | | No | Low-bleed |
| Positioner | Masoneilan | SVI Digital | 0.04 | CAPP | | No | Low-bleed |
| Positioner | VRC | VP700G | 0.04 | WCI/CAPP BMP/GAS Star | | No | Low-bleed |

Appendix B: Initial List of Pneumatic Devices Included in the Sample

| Pneumatic Controller List | | | | | | |
|--|---------------------|------------------|---|-------------------------|--------------|-------------------|
| <i>This list was developed by analyzing the frequency each controller make/model appeared in Cap-Op's field sample database. These 15 controllers make up 97% of the database.</i> | | | | | | |
| Description | Manufacturer | Model | Equivalents | Name | Count | Percentage |
| Pressure Controller | Fisher | 4150 | Fisher 4150K Fisher 4160R CVS 4150 Fisher 4150K Fisher 4160 | Fisher 4150 | 380 | 26.44% |
| Transducer | Fisher | i2P-100 | Fisher i2P-100, 4-20mA | Fisher i2P-100 | 177 | 12.32% |
| Level Controller | Norriseal | 1001 | 1001A | Norriseal 1001 | 170 | 11.83% |
| Level Controller | Fisher | 2900 | Fisher 2901 Fisher 2900A Fisher 2901A | Fisher 2900 | 163 | 11.34% |
| Transducer | Fisher | 546 | Fisher 546S Fisher 546 | Fisher 546 | 94 | 6.54% |
| Level Controller | Fisher | L2 | | Fisher L2 | 84 | 5.85% |
| Level Controller | Fisher | 2680 | Fisher 2680A | Fisher 2680 | 78 | 5.43% |
| High-Low Pressure Pilot | Fisher | 4660 | Fisher 4660A | Fisher 4660 | 73 | 5.08% |
| Positioner | Fisher | Fieldvue DVC6000 | FisherDVC6030 FisherDVC6020 FisherDVC6010 | Fisher Fieldvue DVC6000 | 39 | 2.71% |
| Temperature Controller | Kimray | HT-12 | | Kimray HT-12 | 27 | 1.88% |
| Level Controller | Fisher | 2660 | Fisher 2660A | Fisher 2660 | 24 | 1.67% |
| Level Controller | Fisher | 2500 | Fisher 2506 | Fisher 2500 | 23 | 1.60% |
| Level Switch | SOR | 1530 | | SOR 1530 | 23 | 1.60% |
| Pressure Transmitter | Fisher | C1 | | Fisher C1 | 19 | 1.32% |
| Level Controller | Norriseal | 1001XL | | Norriseal 1001XL | 19 | 1.32% |
| Total | | | | | | 97% |

Pneumatic Pump List

This is a comprehensive list of known pump models that exist in the field. The list was developed by surveying multiple sources (industry, manufacturers, etc.). First round sampling uncovered which pumps were common (see bolded below) in order to target were sampling.

| Manufacturer | Model |
|-----------------------|-------------------------|
| Arrow | 548 |
| Arrow | 5100 |
| Bruin | 5000 |
| Bruin | BR113LP |
| Checkpoint | 1250 |
| COE | 5100 |
| CVS | 5100 |
| CVS | C-252 |
| Flowmore | 5100 |
| Graco | 716 |
| Ingersoll Rand | - |
| Linc | 84-T Series |
| Linc | 282 |
| Morgan | 4500 |
| Morgan | HD312 |
| Plainsman | - |
| Texsteam | 5100 |
| Timberline | 2500, 5000, 1560 Series |
| Western Chemical Pump | ACE Series |
| Wilden | 5000 |
| Williams | P125 |
| Williams | P250 |
| Williams | P500 |

Appendix C: Field Sampling Guide

The subsequent guidelines were taken from the full Sampling Methodology report and were followed by the GreenPath field sample team:

What to Sample On-Site

- Sample all pneumatic controllers (including their equivalents) from the list provided (found in Appendix B).
- Sample all pumps. If pumps are turned off and you have permission from the operator to turn it on, take separate samples of the pump at different operating speeds (high, medium and low strokes per minute). Limit different operating speeds to speeds that the pump would function under normal operating conditions.

Duration of Sampling

All samples need to:

- be taken for at least 30 min, or
- until 2 ft³ of gas has been collected

Sampling Device

- Attach the Calscan Hawk 9000 positive displacement bellows meter to the pneumatic device according to manufacturer specification.

Appendix D: Box Plot Distributions

A box plot distribution graph is a way to show the distribution of categorical samples. The black line represents the median value for a sample population. The grey box represents the first and third quartile or 50% of the data. The black lines show the range of observations. The median is represented by the horizontal line and the mean is the circle in the grey box.

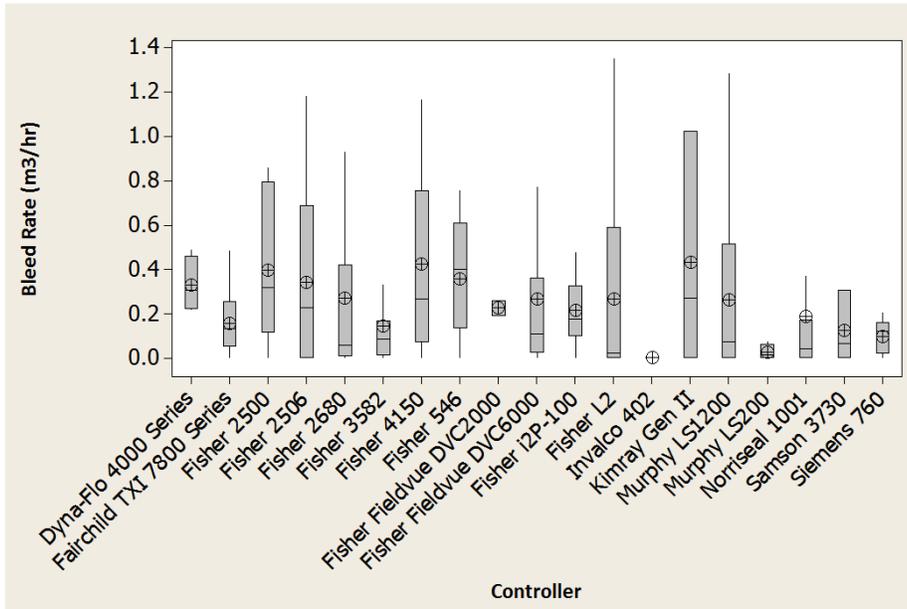


Figure 14: Box Plot Distribution for High-Bleed Controllers

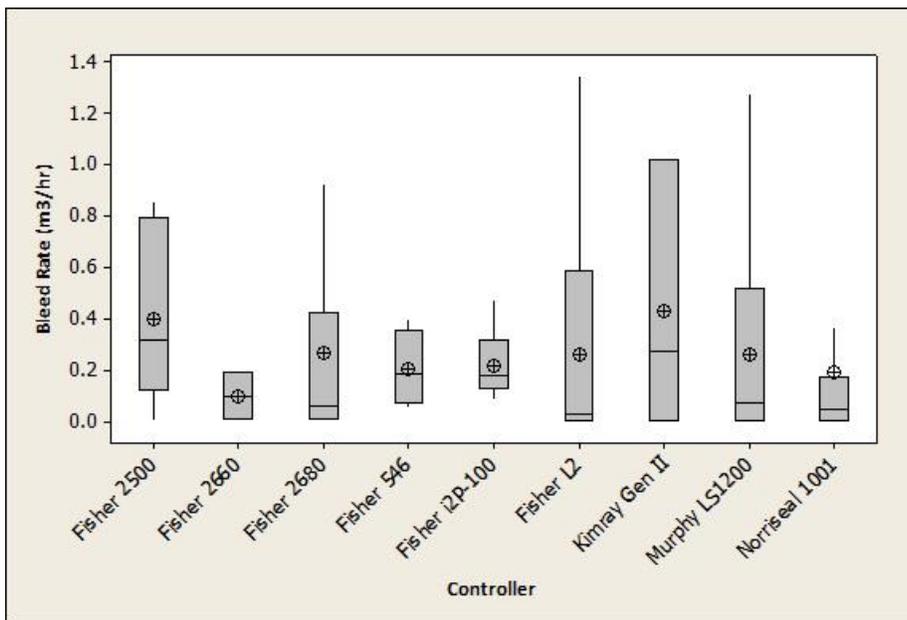


Figure 15: Box Plot Distribution for High Bleed Intermittent Controllers

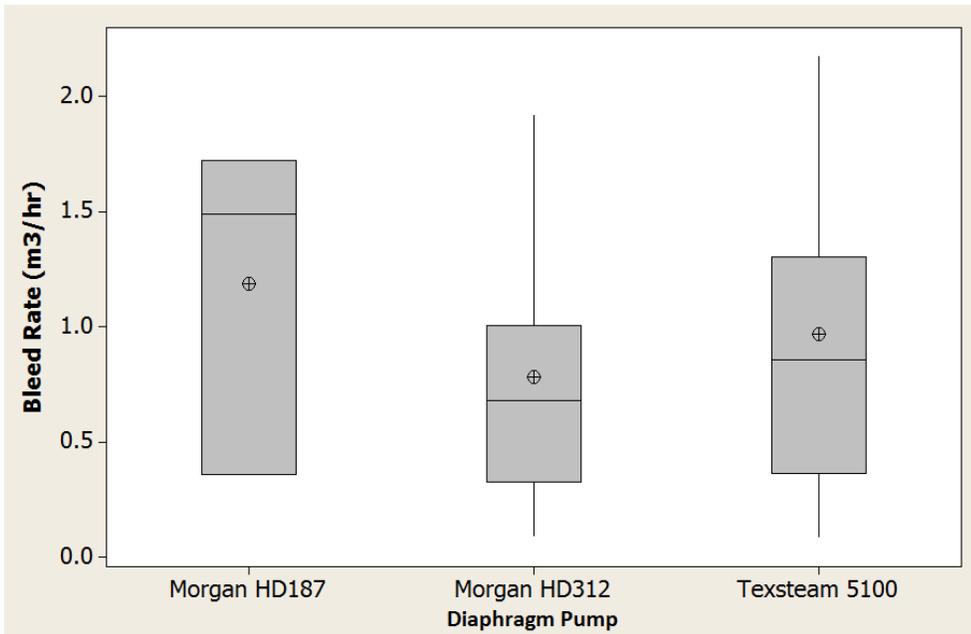


Figure 16: Box Plot Distribution for Diaphragm Pumps

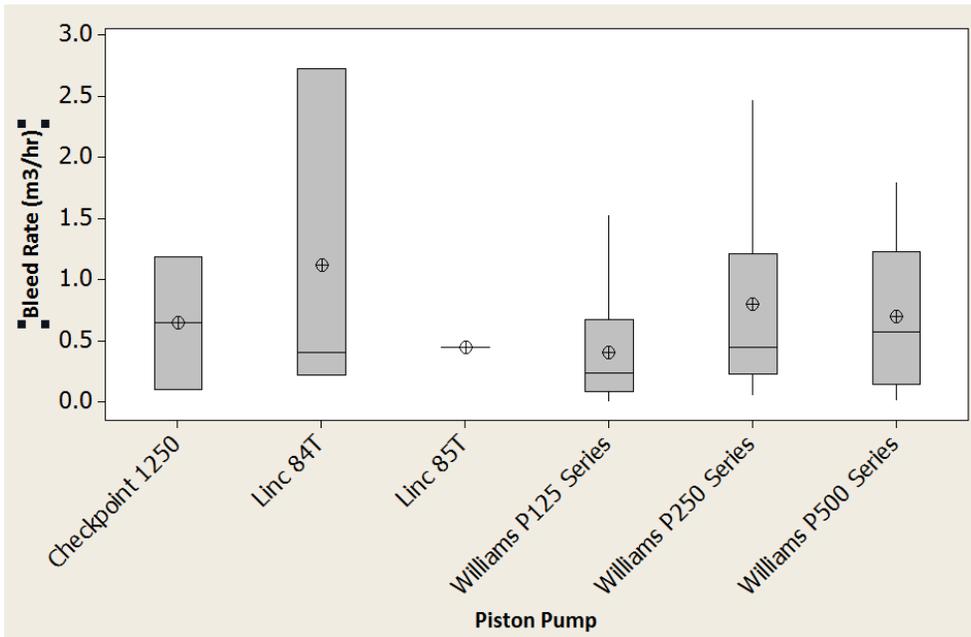


Figure 17: Box Plot Distribution for Piston Pumps

Appendix E: Bleed Rate Equation Coefficients

Pneumatic Controllers

A regression analysis showed that there was a positive correlation between certain pneumatic controller bleed rates and supply pressure.

Table 10: Controller Bleed Rate Equation Coefficients

| Controller | Mean Bleed Rate (m ³ /hr) | Coefficient ¹⁵ | R ² | Correlation ¹⁶ |
|-------------------------------------|--------------------------------------|---------------------------|----------------|---------------------------|
| High Bleed Pneumatic Controllers | 0.2605 | 0.0012 | 0.41 | Positive |
| High Bleed Intermittent Controllers | 0.2476 | 0.0012 | 0.35 | Positive |
| Pressure Controller | | | | |
| Fisher 4150 | 0.4209 | 0.0019 | 0.46 | Positive |
| Fisher C1 | 0.0649 | 0.0003 | 0.25 | Positive |
| Fisher 4660 | 0.0151 | - | 0.05 | Weak |
| Level Controller | | | | |
| Fisher 2500 | 0.3967 | 0.0011 | 0.73 | Strong |
| Fisher 2680 | 0.2679 | 0.0014 | 0.39 | Positive |
| Fisher 2900 | 0.1447 | - | 0.13 | Weak |
| Fisher L2 | 0.2641 | 0.0012 | 0.33 | Positive |
| Murphy L1200 | 0.2619 | 0.0012 | 0.38 | Positive |
| Norriseal 1001 | 0.1868 | - | 0.23 | Weak |
| SOR 1530 | 0.0531 | - | 0.21 | Weak |
| Positioners | | | | |
| Fisher DVC 6000 | 0.2649 | 0.0011 | 0.75 | Strong |
| Temperature Controller | | | | |
| Kimray HT-12 | 0.0351 | - | 0.06 | Weak |
| Transducer | | | | |
| Fairchild TXI7800 | 0.1543 | 0.0009 | 0.60 | Positive |
| Fisher 546 | 0.3547 | 0.0017 | 0.77 | Strong |
| Fisher i2P-100 | 0.2157 | 0.0009 | 0.65 | Strong |

¹⁵ Controllers showing a weak correlation to supply pressure do not have a representative bleed rate equation and should therefore use the mean bleed rate instead of the emission equation.

¹⁶ Strong correlation indicates $R^2 > 0.64$
 Positive correlation indicates $0.25 < R^2 < 0.64$
 Weak correlation indicates $R^2 < 0.25$

Pneumatic Pumps

A regression analysis showed that there was a positive correlation between pneumatic pump bleed rates, supply pressure, injection pressure and strokes per minute. The most accurate bleed rate would take into account these 3 operating variables when calculating the bleed rate for a pneumatic pump.

Table 11: Pump Bleed Rate Equation Coefficients

| Pneumatic Pump | Mean Bleed Rate (m ³ /hr) | Supply Pressure Coefficient (g) ¹⁷ | Injection Pressure Coefficient (n) ¹⁷ | Strokes Per Minute Coefficient (p) ¹⁷ | R ² | Correlation ¹⁸ |
|----------------|--------------------------------------|---|--|--|----------------|---------------------------|
| Diaphragm | 1.0542 | 0.00202 | 0.000059 | 0.0167 | 0.68 | Strong |
| Piston | 0.5917 | 0.00050 | 0.000027 | 0.0091 | 0.49 | Positive |
| Morgan HD312 | 1.1292 | 0.00418 | 0.000034 | 0.0073 | 0.66 | Strong |
| Texsteam 5100 | 0.9670 | 0.00030 | 0.000034 | 0.0207 | 0.74 | Strong |
| Williams P125 | 0.4098 | 0.00019 | 0.000024 | 0.0076 | 0.53 | Positive |
| Williams P250 | 0.8022 | 0.00096 | 0.000042 | 0.0079 | 0.53 | Positive |
| Williams P500 | 0.6969 | 0.00224 | -0.000031 | 0.0046 | 0.74 | Strong |

¹⁷ The coefficients are to be used in the pump bleed rate equation:
 Bleed Rate = m * (Supply Pressure in kPa) + n * (Injection Pressure in kPa) + p * (Strokes per Min)

¹⁸ Strong correlation indicates R²>0.64
 Positive correlation indicates 0.25<R²<0.64
 Weak correlation indicates R²<0.25

made recommendations, including more checks and balances, many of which the IPCC adopted. However, adding complexity adds to the workloads of already overstretched scientists and will never eliminate errors completely. I believe that the process is already rigorous enough and that adding further complexity should be resisted.

Compensate lead authors for their time.

Although practices vary between countries and institutions, there is no system of compensation for IPCC lead authors, other than for travel expenses. The authors devote significant amounts of time, often with no reduction in workload from their main employers. This limits the time that they can spend on the reports.

Lead authors should not profit from being involved in the IPCC, because this could be perceived as a conflict of interest. But governments should offer to cover the costs to their host institutions of teaching relief, or of employing a research assistant to ease their workload, allowing them to maintain scientific output. Although this would increase the cost of producing the reports, the extra expense would be trivial compared with the benefit of having the best possible assessment of climate change.

So why should scientists take part in IPCC assessment reports? Because the future of the world will be severely affected by climate change and we have a responsibility to make the risks known. The IPCC remains the most effective way to do that. ■

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Floods brought parts of Britain to a standstill earlier this year.

Improve economic models of climate change

Costs of carbon emissions are being underestimated, but current estimates are still valuable for setting mitigation policy, say **Richard L. Revesz** and colleagues.

On 31 March, the Intergovernmental Panel on Climate Change (IPCC) released its latest report on the impacts of climate change on humans and ecosystems (see go.nature.com/ad5v1b). These are real risks that need to be accounted for in planning for adaptation and mitigation. Pricing the risks with integrated models of physics and economics lets their costs be compared to those of limiting climate change or investing in greater resilience.

Last year, an interagency working group for the US government used three leading economic models to estimate that a tonne of carbon dioxide emitted now will cause future harms worth US\$37 in today's dollars¹. This 'social cost of carbon' represents the money saved from avoided damage, owing to policies that reduce emissions of carbon dioxide.

Governments, agencies and companies use such estimates to guide decisions about how much to invest in reducing ►

▶ emissions. In the United States, a previous estimate² made in 2010 informed the stricter fuel-economy requirements for new cars. The latest value is motivating President Barack Obama's plan to impose greenhouse-gas limits on coal-fired power plants by next year. Canada, Mexico, the United Kingdom, France, Germany and Norway have used similar numbers to guide regulatory decisions, as has the International Monetary Fund to analyse fossil-fuel subsidies.

Yet the social-cost benchmark is under fire. Industry groups, politicians — including leaders of the energy and commerce committee of the US House of Representatives — and some academics say that uncertainties render the estimate useless.

As legal, climate-science and economics experts, we believe that the current estimate for the social cost of carbon is useful for policy-making, notwithstanding the significant uncertainties. The leading economic models all point in the same direction: that climate change causes substantial economic harm, justifying immediate action to reduce emissions. In fact, because the models omit some major risks associated with climate change, such as social unrest and disruptions to economic growth, they are probably understating future harms. The alternative — assigning no value to reductions in carbon dioxide emissions — would lead to regulation of greenhouse gases that is even more lax.

Instead, climate-economic models need to be extended to include a wider range of social and economic impacts. Gaps need to be filled, such as the economic responses of developing countries and estimates of damages at extreme temperatures. Today, only a

handful of researchers in the United States and Europe specialize in such modelling. A broader programme involving more people exploring more phenomena is needed to better estimate the social cost of carbon and to guide policy-makers. Otherwise policies will become untethered from economic realities.

SOCIAL COST

The models in question aim to integrate estimates of the costs of greenhouse-gas emissions and of steps to reduce them. First, they translate scenarios of economic and population growth, and resulting emissions, into changes in atmospheric composition and global mean temperature. Then the models apply 'damage functions' that approximate the global relationships between temperature changes and the economic costs from impacts such as changes in sea level, cyclone frequency, agricultural productivity and ecosystem function. Finally, the models translate future damages into present monetary value.

Sources of uncertainty are numerous³. They include: how the climate responds to carbon dioxide concentrations; positive and negative feedback loops in the climate system; emissions growth rates for various socio-economic scenarios; the completeness and accuracy of damage functions (especially with regard to catastrophic harms, migration and conflict, weather variability and feedbacks on economic growth); the ability of future generations to adapt to climate change; and

"The models omit social unrest and disruptions to economic growth."

the economic 'discount rate' used to translate future costs to current dollars.

The 2013 US analysis¹ used the then-most recent vintages of three long-standing models: FUND 3.8, DICE 2010, and PAGE09. Each model applies different climatic and economic functions to simplify the complex picture. Despite the range of approaches and uncertainties, each one predicted sizeable economic damage from greenhouse-gas emissions for warming beyond 2°C above pre-industrial levels. Two models, ENVISAGE and CRED, published since the US analysis was structured in 2010, have broadly similar projections to these three (see 'Carbon's costly legacy'). The analysis suggested that — depending on assumptions about how future damages are valued in today's money — the expected global cost of one tonne of carbon dioxide emitted in 2020 is between \$12 and \$64 (with \$43 as the central value).

GREATER HARM

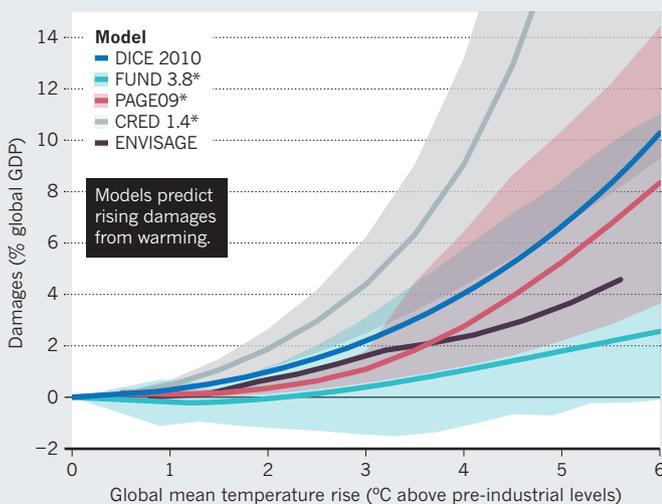
The future costs of climate change could be even higher, for four reasons. First, the impacts of historic temperature changes suggest that societies and economies may be more vulnerable than current models predict and that weather variability is more important than average weather in determining impacts, particularly for crop growth and food security. For example, the yields of some crops may decline rapidly above certain temperatures⁴.

Second, the models omit damages to labour productivity, to productivity growth, and to the value of the capital stock, including buildings and infrastructure. By lowering the annual growth rate, these damages

CARBON'S COSTLY LEGACY

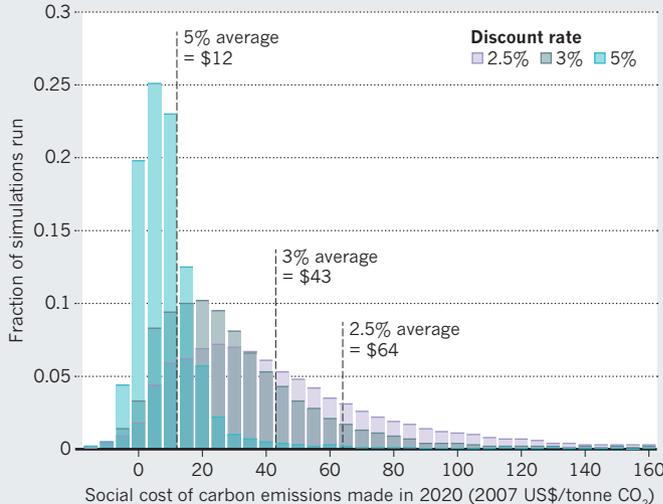
Economic models of climate change project that resulting damage worldwide (A) will increase with future emissions and may cost several per cent of global gross domestic product (GDP) with the warming expected by 2100. Uncertainties in future socio-economics, emission rates and climate impacts result in a range of estimates of the social cost of carbon, which is also affected by the choice of 'discount rate' used to convert future harms into today's money (B).

A PROJECTED DAMAGES



*Shaded regions indicate 5% and 95% confidence intervals for FUND 3.8 and PAGE09, and a high-low range for CRED 1.4.

B SOCIAL COSTS FROM US GOVERNMENT ANALYSIS



SOURCE: A, REF.1 (DICE, FUND, PAGE); ROSON, R. & MENSBRUGHE, D. V. D. (INT. J. SUST. ECON. 4, 270-285 (2012)) (ENVISAGE)/ACKERMAN, F., STANTON, E. A. & BUENO, R. (ECON. 85, 166-176 (2013)) (CRED); B, REF.1



Storms caused chaos on roads in northwestern Italy in 2011.

be beyond human experience. If warming continues unchecked into the twenty-second century, it could render parts of the planet effectively uninhabitable during the hottest days of the summer, with consequences that would be challenging to monetize¹⁰.

The models should be revised more frequently to accommodate scientific developments. Researchers commonly test model sensitivity to new parameters. But the structure and in some cases the calibration of the damage models is stuck in the 1990s, when the original versions were created, owing to a lack of funding.

IPCC reports help to set the research agenda on climate. The release of the Fifth Assessment Report reminds us of the progress so far. It is important to ensure that the sixth assessment takes a substantive step forward. By facilitating efforts to refine estimates of the social cost of carbon, the IPCC will be performing its most important function: informing the global political conversation about how best to address the looming threat of climate change. ■

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could have deeper and longer-lasting effects on the global economy than the static losses of annual economic output currently represented in the three main models^{5,6}. A significant decline in human welfare is possible in the medium and long run owing to the compounding effects of lost growth. Also not taken into account are the risks of climate-induced wars, coups or societal collapses and the resulting economic crises⁷.

Third, the models assume that the value that people attach to ecosystems will remain constant⁸. Yet as a commodity becomes more scarce, its value increases. In the desert, water is extremely valuable. During a flood, dry land is highly prized. Because the services provided by ecosystems are likely to decline as warming degrades them, the costs of future ecosystem damage from climate change will rise faster than the models predict.

Fourth, the US analysis assumes a constant discount rate to translate future harms into today's money. However, for impacts that are both highly uncertain and occurring in the distant future, economists have shown⁹ that a discount rate that declines over time should be used, with discount rates for the far future significantly below those that were used in the 2013 analysis. This approach would

yield a higher present value to the long-term impacts of climate change and thus a higher value for the social cost of carbon.

It is true that future technological developments might better equip society to cope with climate change. And of course overall bias cannot be determined simply by adding biases in each direction. But the bulk of the literature and arguments indicates that social-cost models are underestimating climate-change harms.

BETTER MODELS

What now? Modellers, scientists and environmental economists must continue to step outside their silos and work together to identify research gaps and modelling limitations.

Climate hot spots in the developing world are one such gap, because economic responses in these regions cannot be extrapolated simply from estimates made for developed countries. The impacts of extreme temperatures are also uncertain. Current damage estimates are generally calibrated for warming of less than 3 °C (ref. 6). Yet without mitigation, the IPCC projects that we could see warming in excess of 4 °C by the end of the century. Such conditions would

California Environmental Protection Agency
Air Resources Board

**2007 Oil and Gas
Industry Survey
Results**
*Final Report
(Revised)*



October 2013

**State of California
California Environmental Protection Agency
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2007 Oil and Gas Industry Survey Results
Final Report
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October 2013

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Table of Contents

| | |
|--|------|
| Glossary..... | ix |
| Executive Summary | ES-1 |
| Chapter 1 – Survey Development | 1-1 |
| Chapter 2 – General Information | 2-1 |
| Chapter 3 – Overview of Total California Emissions | 3-1 |
| Chapter 4 – Wells..... | 4-1 |
| Chapter 5 – Electricity Generation and Use | 5-1 |
| Chapter 6 – Vapor Recovery..... | 6-1 |
| Chapter 7 – Combustion Equipment | 7-1 |
| Chapter 8 – Components | 8-1 |
| Chapter 9 – Automated Control Devices | 9-1 |
| Chapter 10 – Inspection and Maintenance..... | 10-1 |
| Chapter 11 – Natural Gas Dehydrators | 11-1 |
| Chapter 12 – Natural Gas Sweetening and Acid Gas Removal | 12-1 |
| Chapter 13 – Other Natural Gas Processing..... | 13-1 |
| Chapter 14 – Total Natural Gas Processing Emissions..... | 14-1 |
| Chapter 15 – Natural Gas Compressors | 15-1 |
| Chapter 16 – Pipeline Pigging and Natural Gas Gathering Pipelines..... | 16-1 |
| Chapter 17 – Separators..... | 17-1 |
| Chapter 18 – Crude Oil Sumps and Pits | 18-1 |
| Chapter 19 – Crude Oil Storage Tanks | 19-1 |
| Chapter 20 – Overview of California Emissions from Crude Oil Production, Processing, and Storage..... | 20-1 |
| Chapter 21 – Overview of California Emissions from Dry Natural Gas Production, Processing, and Storage..... | 21-1 |
| Appendix A : 2007 Oil and Gas Industry Survey | A-1 |
| Appendix B : Emission Calculation Methodologies and Corresponding Emission Factors..... | B-1 |
| Appendix C : Site Visits and Meetings..... | C-1 |
| Appendix D : Internal Combustion Engine Use Categories | D-1 |
| Appendix E : Separator Type Categories..... | E-1 |

List of Tables and Figures

Chapter 1 – Survey Development

| | |
|--|-----|
| Table 1-1: Site Visits and Meetings..... | 1-2 |
|--|-----|

Chapter 2 – General Information

| | |
|--|-----|
| Table 2-1: Number of Facilities by Business Type | 2-2 |
| Table 2-2: Number of Facilities by Primary Business Type | 2-3 |
| Table 2-3: Crude Oil Totals | 2-4 |
| Table 2-4: Natural Gas Totals | 2-5 |
| Table 2-5: Global Warming Potentials..... | 2-6 |

Chapter 3 – Overview of Total California Emissions

| | |
|--|-----|
| Table 3-1: Total California 2007 Emissions (Metric Tons/Year) | 3-1 |
| Table 3-2: Total California Emissions by Primary Business Type (Metric Tons/Year).. | 3-2 |
| Table 3-3: Total California Combustion, Vented, and Fugitive Emissions by Primary Business Type (Metric Tons/Year)..... | 3-2 |
| Table 3-4: Total California Emissions by Air District (Metric Tons/Year) | 3-3 |
| Table 3-5: Total California Combustion, Vented, and Fugitive Emissionsby Air District (Metric Tons/Year) | 3-3 |
| Table 3-6: Combustion Emissions by Combustion Type (Metric Tons/Year) | 3-4 |
| Table 3-7: Combustion Emissions by Primary Business (Metric Tons/Year)..... | 3-4 |
| Table 3-8: Combustion Emissions by Air District (Metric Tons/Year) | 3-5 |
| Table 3-9: Vented Emissions by Source Type (Metric Tons/Year)..... | 3-5 |
| Table 3-10: Vented Emissions by Primary Business Type (Metric Tons/Year) | 3-6 |
| Table 3-11: Vented Emissions by Air District (Metric Tons/Year)..... | 3-6 |
| Table 3-12: Fugitive Emissions by Source Type (Metric Tons/Year)..... | 3-7 |
| Table 3-13: Fugitive Emissions by Primary Business Type (Metric Tons/Year) | 3-7 |
| Table 3-14: Fugitive Emissions by Primary Business Type (Metric Tons/Year) | 3-8 |
| Table 3-15: Total California Emissions by CO ₂ e Range (Metric Tons/Year) | 3-8 |
| Table 3-16: Total California Combustion Emissions by CO ₂ e Range..... | 3-9 |
| Table 3-17: Total California Vented Emissions by CO ₂ e Range (Metric Tons/Year) | 3-9 |
| Table 3-18: Total California Fugitive Emissions by CO ₂ e Range | 3-9 |

Chapter 4 – Wells

| | |
|--|-----|
| Table 4-1: Number of Crude Oil Active Wells and Well Cellars by API Range..... | 4-2 |
| Table 4-2: Number of Natural Gas Active Wells and Well Cellars | 4-2 |
| Table 4-3: Number of Crude Oil New Wells Drilled, Well Completions, Well Workovers and Well Cleanups by API Range | 4-2 |
| Table 4-4: Number of Natural Gas New Wells Drilled, Well Completions, Well Workovers, and Well Cleanups | 4-2 |
| Table 4-5: Emissions of Crude Oil Wells by API Range (Metric Tons/Year) | 4-3 |
| Table 4-6: Emissions of Natural Gas Wells (Metric Tons/Year) | 4-3 |
| Table 4-7: Emissions of Crude Oil Well Cellars by API Range (Metric Tons/Year) | 4-3 |
| Table 4-8: Emissions of Crude Oil Well Workovers by API Range..... | 4-4 |
| Table 4-9: Emissions of Natural Gas Well Workovers (Metric Tons/Year) | 4-4 |

| | |
|---|-----|
| Table 4-10: Emissions of Crude Oil Well Cleanups by API Range..... | 4-4 |
| Table 4-11: Emissions of Natural Gas Well Cleanups (Metric Tons/Year) | 4-4 |

Chapter 5 – Electricity Generation and Use

| | |
|--|-----|
| Table 5-1: Electricity by Primary Business (Metric Tons/Year)..... | 5-1 |
| Table 6-1: Number of Vapor Recovery Units by Type | 6-1 |

Chapter 6 – Vapor Recovery

| | |
|---|-----|
| Table 6-2: Vapor Recovery Combustion Emissions by Type (Metric Tons/Year) | 6-2 |
| Table 6-3: Carbon Adsorber Vented Emissions (Metric Tons/Year)..... | 6-2 |
| Table 6-4: Vapor Recovery Combustion Emissions by Use (Metric Tons/Year) | 6-3 |
| Table 6-5: Number of Combustion Vapor Recovery Units by Size | 6-3 |

Chapter 7 – Combustion Equipment

| | |
|--|-----|
| Table 7-1: External Combustion Emissions by Equipment Type (Metric Tons/Year) ... | 7-2 |
| Table 7-2: Age of External Combustion Units | 7-3 |
| Table 7-3: Internal Combustion Emissions by Equipment Type (Metric Tons/Year) | 7-3 |
| Table 7-4: Age of Internal Combustion Units..... | 7-4 |
| Table 7-5: Combustion Emissions of Internal Combustion Engines by Use..... | 7-4 |
| Table 7-6: Combustion Emissions of Internal Combustion Engines by Type | 7-5 |
| Table 7-7: Turbine Combustion Emissions by Use (Metric Tons/Year) | 7-5 |
| Table 7-8: Turbine Combustion Emissions by Cycle Type (Metric Tons/Year) | 7-6 |
| Table 7-9: Cogeneration Combustion Emissions by Type (Metric Tons/Year) | 7-6 |
| Table 7-10: Combustion Emissions by Combustion Type (Metric Tons/Year) | 7-7 |
| Table 7-11: Combustion Emissions by Primary Business (Metric Tons/Year)..... | 7-7 |
| Table 7-12: Combustion Emissions by Fuel Type (Metric Tons/Year) | 7-8 |

Chapter 8 – Components

| | |
|--|-----|
| Table 8-1: Number of Components by Service Type | 8-1 |
| Table 8-2: Fugitive Emissions of Components by Primary Business Type..... | 8-2 |
| Table 8-3: Fugitive Emissions of Components by Service Type | 8-2 |
| Table 8-4: Fugitive Emissions of Components by Type (Metric Tons/Year)..... | 8-3 |
| Table 8-5: Fugitive Emissions of Natural Gas Components by Type | 8-3 |
| Table 8-6: Fugitive Emissions of Light Crude ¹ Components by Type..... | 8-4 |
| Table 8-7: Fugitive Emissions of Heavy Crude ¹ Components by Type | 8-4 |

Chapter 9 – Automated Control Devices

| | |
|--|-----|
| Table 9-1: Vented Emissions of Automated Control Devices by Primary Business | 9-2 |
| Table 9-2: Vented Emissions of Automated Control Devices by Type | 9-2 |

Chapter 10 – Inspection and Maintenance

| | |
|--|------|
| Table 10-1: Number of Facilities Utilizing Each Leak Threshold | 10-1 |
|--|------|

Chapter 11 – Natural Gas Dehydrators

| | |
|---|------|
| Table 11-1: Vented Emissions of Natural Gas Dehydrators by Type | 11-2 |
| Table 11-2: Fugitive Emissions of Natural Gas Dehydrators by Type | 11-2 |

| | |
|--|------|
| Table 11-3: Volume of Natural Gas Dehydrators by Type..... | 11-2 |
| Table 11-4: Total Emissions of Natural Gas Dehydrators (Metric Tons/Year)..... | 11-3 |
| Table 11-5: Natural Gas Dehydrators Percent with Vapor Recovery | 11-3 |
| Table 11-6: Natural Gas Dehydrators Types of Vapor Recovery | 11-3 |

Chapter 12 – Natural Gas Sweetening and Acid Gas Removal

| | |
|---|------|
| Table 12-1: Vented Emissions of Natural Gas AGR Units by Type..... | 12-2 |
| Table 12-2: Fugitive Emissions of Natural Gas AGR Units by Type..... | 12-2 |
| Table 12-3: Total Emissions of Natural Gas AGR Units (Metric Tons/Year) | 12-3 |
| Table 12-4: Natural Gas AGR Units Percent on Vapor Recovery | 12-3 |
| Table 12-5: Natural Gas AGR Units Types of Vapor Recovery..... | 12-3 |

Chapter 13 – Other Natural Gas Processing

| | |
|--|------|
| Table 13-1: Emissions of Other Natural Gas Processing Units by Type | 13-1 |
| Table 13-2: Other Natural Gas Processing Units Percent on Vapor Recovery | 13-2 |

Chapter 14 – Total Natural Gas Processing Emissions

| | |
|--|------|
| Table 14-1: Total California Emissions (Metric Tons/Year) | 14-1 |
| Table 14-2: Natural Gas Processing Emissions by Type (Metric Tons/Year)..... | 14-1 |

Chapter 15 – Natural Gas Compressors

| | |
|--|------|
| Table 15-1: Number of Compressors by Type | 15-1 |
| Figure 15-1: Reciprocating Compressor..... | 15-2 |
| Figure 15-2: Centrifugal Compressor | 15-2 |
| Figure 15-3: Rotary Compressor | 15-2 |
| Table 15-2: Number of Primary Drivers by Type | 15-3 |
| Table 15-3: Number of Starters by Type | 15-3 |
| Table 15-4: Startup and Blowdown Volumes | 15-3 |
| Table 15-5: Natural Gas Compressor Startup Vented Emissions (Metric Tons/Year) | 15-4 |
| Table 15-6: Natural Gas Compressor Blowdown Vented Emissions..... | 15-4 |
| Table 15-7: Natural Gas Compressor Fugitive Seal Emissions (Metric Tons/Year) ... | 15-4 |
| Table 15-8: Total Emissions of Natural Gas Compressors (Metric Tons/Year) | 15-5 |
| Table 15-9: Compressor Emissions by Primary Business (Metric Tons/Year) | 15-5 |
| Table 15-10: Total Emissions of Natural Gas Compressors by Type..... | 15-5 |
| Table 15-11: Total Emissions of Natural Gas Compressors by Primary Driver | 15-6 |
| Table 15-12: Total Emissions of Natural Gas Compressors by Age | 15-6 |
| Table 15-13: Usage of Natural Gas Compressors by Age | 15-7 |

Chapter 16 – Pipeline Pigging and Natural Gas Gathering Pipelines

| | |
|---|------|
| Table 16-1: Miles of Natural Gas Gathering System Pipelines by Primary Business Type | 16-1 |
| Table 16-2: Natural Gas Gathering System Pipeline Maintenance Activity Volumes | 16-2 |
| Table 16-3: Pigging Operations..... | 16-2 |
| Table 16-4: Natural Gas Vented Emissions from Gathering Pipeline Maintenance and Pigging Operations (Metric Tons/Year)..... | 16-2 |
| Table 16-5: Natural Gas Fugitive Emissions from Gathering Pipelines (Metric Tons/Year) | 16-3 |

Chapter 17 – Separators

| | |
|--|------|
| Table 17-1: Number of Separators by Primary Business Type | 17-1 |
| Table 17-2: Total Emissions of Separators (Metric Tons/Year)..... | 17-2 |
| Table 17-3: Fugitive Emissions of Separators by Type (Metric Tons/Year)..... | 17-2 |
| Table 17-4: Fugitive Emissions of Separators by Subtype (Metric Tons/Year) | 17-3 |
| Table 17-5: Separator Units by Type Percent on Vapor Recovery..... | 17-3 |
| Table 17-6: Separator Units by Subtype Percent with Vapor Recovery | 17-4 |
| Table 17-7: Separator Units by Types of Vapor Recovery | 17-4 |

Chapter 18 – Crude Oil Sumps

| | |
|--|------|
| Table 18-1: Fugitive Emissions of Sumps/Pits by Type (Metric Tons/Year) | 18-1 |
| Table 18-2: Fugitive Emissions of Sumps/Pits by Air District (Metric Tons/Year)..... | 18-2 |
| Table 18-3: Sumps/Pits by Percent on Vapor Recovery | 18-2 |
| Table 18-4: Sumps/Pits by Types of Vapor Recovery | 18-3 |

Chapter 19 – Crude Oil Storage Tanks

| | |
|--|------|
| Table 19-1: Total Emissions of Storage Tanks (Metric Tons/Year) | 19-2 |
| Table 19-2: Fugitive Emissions of Storage Tanks by Type (Metric Tons/Year)..... | 19-2 |
| Table 19-3: Fugitive Emissions of Storage Tanks by Subtype (Metric Tons/Year)..... | 19-2 |
| Table 19-4: Storage Tanks by Type Percent with Vapor Recovery | 19-3 |
| Table 19-5: Storage Tanks by Subtype Percent with Vapor Recovery | 19-3 |
| Table 19-6: Storage Tanks by Types of Vapor Recovery | 19-3 |

Chapter 20 – Overview of California Emissions from Crude Oil Production, Processing, and Storage

| | |
|---|------|
| Table 20-1: Crude Oil Emissions (Metric Tons/Year) | 20-1 |
| Table 20-2: Crude Oil Emissions by Primary Business Type (Metric Tons/Year)..... | 20-1 |
| Table 20-3: Crude Oil Total Emissions by CO ₂ e Range (Metric Tons/Year) | 20-2 |
| Table 20-4: Crude Oil Combustion Emissions by CO ₂ e Range..... | 20-2 |
| Table 20-5: Crude Oil Vented Emissions by CO ₂ e Range (Metric Tons/Year) | 20-2 |
| Table 20-6: Crude Oil Fugitive Emissions by CO ₂ e Range (Metric Tons/Year)..... | 20-3 |
| Table 20-7: Average Total CO ₂ e Emissions per Barrel Crude Oil Produced | 20-4 |
| Table 20-8: Average Combustion CO ₂ e Emissions per Barrel Crude Oil Produced... | 20-4 |
| Table 20-9: Average Vented CO ₂ e Emissions per Barrel Crude Oil Produced | 20-5 |
| Table 20-10: Average Fugitive CO ₂ e Emissions per Barrel Crude Oil Produced | 20-5 |

Chapter 21 – Overview of California Emissions from Dry Natural Gas Production, Processing, and Storage

Table 21-1: Natural Gas Emissions (Metric Tons/Year) 21-1
Table 21-2: Natural Gas Emissions by Primary Business Type (Metric Tons/Year)... 21-1
Table 21-3: Total Natural Gas Emissions by CO₂e Range (Metric Tons/Year) 21-2
Table 21-4: Natural Gas Combustion Emissions by CO₂e Range (Metric Tons/Year) 21-2
Table 21-5: Natural Gas Vented Emissions by CO₂e Range (Metric Tons/Year) 21-2
Table 21-6: Natural Gas Fugitive Emissions by CO₂e Range (Metric Tons/Year)..... 21-2
Table 21-7: Average Total CO₂e Emissions per MSCF Natural Gas Produced 21-3
Table 21-8: Average Combustion CO₂e Emissions per MSCF Natural Gas 21-4
Table 21-9: Average Vented CO₂e Emissions per MSCF Natural Gas Produced..... 21-4
Table 21-10: Average Fugitive CO₂e Emissions per MSCF Natural Gas Produced... 21-4

Glossary

| Term | Definition |
|-------------------------------------|--|
| AB 32 | Assembly Bill 32, The California Global Warming Solutions Act of 2006 (Stats. 2006, ch. 488) |
| Active Wells | Wells that are producing crude oil or natural gas throughout the year |
| AGR Unit | Acid Gas Removal Unit. These units remove sulfur or CO ₂ from natural gas streams. |
| Air District | An air pollution control district (APCD) or air quality management district (AQMD) |
| API Gravity | A scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F |
| ARB | California Air Resources Board |
| Automated Control Device | A device that uses compressed gas or air to affect mechanical motion. Commonly referred to as pneumatic devices. |
| Automated Control Device Actuator | A device that accurately locates the valve plug in a position dictated by the control signal. |
| Automated Control Device Controller | Positions its movable part (a plug, ball or vane) relative to the stationary seat of the valve. |
| Board | California Air Resources Board |
| BTU | British Thermal Unit |
| CEC | California Energy Commission |
| CEIDARS | ARB's California Emission Inventory Development and Reporting System Database |
| Centrifugal Compressor | Centrifugal compressors increase the pressure of natural gas by centrifugal action, employing rotating movement of the drive shaft. |

| Term | Definition |
|-------------------------|--|
| CH ₄ | Methane |
| CHP | Combined Heat and Power |
| CIPA | California Independent Petroleum Association |
| CNG | Compressed natural gas |
| CO ₂ | Carbon dioxide |
| CO ₂ e | Carbon dioxide equivalents |
| Cogeneration | An integrated system that produces electric energy and useful thermal energy. Synonymous with combined heat and power. |
| Combined Cycle Turbine | A turbine that generates electricity and the waste heat of which is used to make steam. The steam is then used to generate electricity through a steam turbine or injected into a geological formation to increase production. |
| Combined Heat and Power | An integrated system that produces electric energy and useful thermal energy. Synonymous with cogeneration. |
| Combustion Emission | Greenhouse gas emission occurring during the exothermic reaction of a fuel with oxygen |
| Compressor | Any machine for raising the pressure of a natural gas stream by drawing in low pressure natural gas and discharging significantly higher pressure natural gas |
| Dehydrator | Equipment that removes water from a natural gas stream by passing it over glycol or a desiccant. |
| DOGGR | Department of Conservation's Division of Oil, Gas, and Geothermal Resources |
| Dry Gas | Natural gas produced from a gas well without associated crude oil |
| EIA | The US Department of Energy's Energy Information Administration |
| EOR | Enhanced oil recovery |

| Term | Definition |
|----------------------------|--|
| External Combustion Engine | An engine where an internal fluid is heated by an external heat source |
| FAR | IPCC Fourth Assessment Report |
| Four-Stroke Engine | An engine in which the piston completes four separate strokes, intake, compression, power, and exhaust, during two separate revolutions of the engine's crankshaft. |
| Fractionation | The process of separating natural gas liquids into their constituent liquid products. |
| Fugitive Emission | Unintentional release of greenhouse gas vapors to the atmosphere |
| Gas Injection EOR | The method of injecting a gas such as natural gas, nitrogen, or carbon dioxide into a geological formation to increase crude oil production |
| GHG | Greenhouse Gas |
| GWP | Global warming potential. Unitless measure of the radiative forcing of a particular compound relative to CO ₂ |
| H ₂ S | Hydrogen Sulfide |
| Heater/Treater | Oil/water separators that use heat to expedite the separation process |
| Heavy Crude | Crude oil with an API gravity of 10 to 20 |
| HHV | Higher Heating Value |
| Hydraulic Fracturing | Well stimulation technique using high pressure pumps to increase fluid pressure at the bottom of a well. This fluid pressure cracks the formation and proppants such as sand or walnut hulls are injected into the newly formed crevices to keep them open when the fluid pressure is removed. |
| I&M Program | Inspection and Maintenance Program |
| Internal Combustion Engine | An engine where fuel is burned inside a combustion chamber. The expansion of the gas applies direct force to a component of |

| Term | Definition |
|---------------------------------|--|
| | the engine such as a piston or turbine blade. |
| IOPA | Independent Oil Producers' Agency |
| IPCC | United Nation's Intergovernmental Panel on Climate Change |
| Lean Burn Engine | Engines that may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. The air to fuel ratios of lean-burn engines range from 20:1 to 50:1 and are typically higher than 24:1. The exhaust excess oxygen levels of lean-burn engines are typically around 8 percent, ranging from 4 to 17 percent. |
| Light Crude | Crude oil with an API gravity of 20 to 30 |
| N ₂ O | Nitrous oxide |
| Natural Gas Gathering Pipelines | Small natural gas pipelines located on a production facility that route natural gas |
| PD | Protected data. In this survey report, data values that do not represent at least three companies. |
| PERP | Portable Equipment Registration Program |
| Pipeline Pig | A device sent down a pipeline to clean or inspect the pipeline. |
| Pits | Open pits that are used for oil/water separation or for emergency containment. |
| Production Facility | Facility that extracts crude oil and/or natural gas |
| Reboiler | Units that heat glycol to remove water, or heat amine to remove acid gas. |
| Reciprocating Compressor | Reciprocating compressors increase the pressure of natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder. |
| Rich Burn Engine | Engines that operate near the stoichiometric air-to-fuel ratio (16:1) with exhaust excess oxygen levels less than 4 percent (typically closer to 1 percent) |
| ROG | Reactive Organic Gas |

| Term | Definition |
|----------------------|---|
| Rotary Compressor | Rotary compressors have blades or a cylinder that rotate off center to compress the natural gas. Synonymous with screw compressors. |
| SAR | IPCC Second Assessment Report |
| Screw Compressor | Screw compressors have blades or a cylinder that rotate off center to compress the natural gas. Synonymous with rotary compressors. |
| Separator | Separators split the fluids that come out of a well by gravity, heat, or both. |
| Simple Cycle Turbine | A turbine that generates electricity and does not utilize the waste heat. |
| Specific Gravity | The ratio of the density of a substance to the density of a reference substance. The reference substance is generally water. |
| Steam Generator | Equipment that produces steam using an external heat source |
| Sump | Open pit that is used for oil/water separation or for emergency containment. |
| TAR | IPCC Third Assessment Report |
| Thermal EOR | The method of injecting steam into a geological formation to increase crude oil production |
| TOG | Total Organic Gas |
| Turbine | An internal combustion engine where the force from the combustion chamber moves a blade rather than a piston. |
| Two-Stroke Engine | In a 2-stroke engine, the air-to-fuel charge is injected with the piston near the bottom of the power stroke. The intake ports are then covered or closed, and the piston moves to the top of the cylinder, compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. As the piston reaches the bottom of the power stroke, exhaust ports or valves are opened to exhaust, or scavenge, the combustion products, and a new air-to-fuel |

| Term | Definition |
|-------------------|--|
| | charge is injected. |
| Ultra-Heavy Crude | Crude oil with an API gravity of less than 10 |
| Ultra-Light Crude | Crude oil with an API gravity of greater than 30 |
| US EPA | United States Environmental Protection Agency |
| Vapor Recovery | Equipment located at the source of potential gas emissions to the atmosphere that is used for collecting and routing the gas back into the process as a product and/or fuel or for destruction. |
| Vented Emission | Intentional release of greenhouse gas vapors to the atmosphere |
| Waterflood EOR | The method of injecting water into a geological formation to increase crude oil production. |
| Well Cellars | Lined or unlined pits around one or more wells that: (a) allow access to the wellhead components for servicing, or (b) contain intermittent flows of crude oil or water during an emergency or from drilling and petroleum production processes. |
| Well Cleanups | Well maintenance activities that include fracturing or removing fluids to increase production. |
| Well Completions | The final step to bringing a newly drilled well into production. |
| Well Workovers | The process of performing major maintenance or remedial treatments on an oil or gas well. |
| WSPA | Western States Petroleum Association |

Executive Summary

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006 (Núñez, Statutes of 2006, chapter 488). AB 32 establishes a comprehensive program of regulatory and market mechanisms to achieve real, cost-effective, quantifiable reductions of greenhouse gases (GHG). AB 32 charges the Air Resources Board (ARB) as the agency responsible for monitoring and regulating many GHG emission sources to reduce California's GHG emissions to 1990 levels by 2020.

Among the measures that the ARB staff is considering to help reach this AB 32 goal is a measure to reduce GHG emissions from upstream crude oil and natural gas production, processing, and storage operations. In order for staff to determine the potential GHG emission reductions, the technical feasibility, and the cost-effectiveness of any potential control measure, the ARB staff conducted a survey of the crude oil and natural gas industry to improve estimates of GHG emissions in California from these operations.

In February 2009, the 2007 Oil and Gas Industry Survey was mailed out to crude oil and natural gas production, processing, and storage facilities in California. The survey was completed by 325 companies representing over 1,600 facilities and approximately 97 percent of the 2007 crude oil and natural gas production in California.

Emissions were calculated using equipment information from the survey and commonly used emission equations and emission factors listed in Appendix B of this report. Total emissions for equipment covered under this survey are estimated to be 17.7 million metric tons of CO₂e. Combustion sources (equipment burning fuel for energy) account for 93 percent of the total CO₂e emissions. The remaining 7 percent of the CO₂e emissions, or about 1.3 million metric tons of CO₂e, come from vented and fugitive sources, which are intentional and unintentional releases of gases to the atmosphere, respectively.

In August 2011, staff released a draft of this report for public comment. Staff finalized this report in December 2011 based on the comments received, which resulted in the addition of a Glossary, minor text changes to improve clarity, and the inclusion of the survey cover letter and survey instructions in Appendix A.

While examining the data in detail at the equipment level as part of potential regulatory development, staff discovered several instances of equipment with unusually large emissions. Upon further review, staff determined these emissions were due to reporting errors, in some cases caused by instructions that were not applicable in specific instances. Staff worked with the survey respondents to correct these reporting errors. Staff recalculated the emissions which, in most cases, were lower. The affected equipment types were dehydrators, acid gas removal units, and other gas processing equipment.

This Revised Final Report contains these corrected emissions, as reflected in revised Chapters 3, 11, 12, 13, 14, 20, and 21. In addition, production and emissions data broken down by air district have been added to Chapters 2 and 3. Other minor text corrections discovered since December 2011 have also been made to this Revised Final Report.

Chapter 1 – Survey Development

Background

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006 (Núñez, Statutes of 2006, chapter 488). This law required the reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020.

AB 32 designated the California Air Resources Board (ARB or Board) as the lead agency for implementing AB 32 and mapped out major milestones for achieving this goal. ARB met the first milestones in 2007 by developing a list of discrete early action measures, assembling an inventory of historic emissions, establishing GHG reporting requirements, and setting the 2020 emissions limit.

In November 2007, ARB published the 1990 – 2004 California GHG inventory. The oil and gas production sector, as well as the natural gas transmission and distribution pipeline system, were identified as large sources of GHG emissions. In late 2007, a team of staff was assembled to evaluate potential reductions from these sectors.

Among the measures that the ARB staff is developing to help reach the AB 32 goal of reducing GHG emissions to 1990 levels by 2020 is one potential measure to reduce emissions from the crude oil and natural gas production, processing, and storage sector. This report provides the results of the 2007 survey of emissions from the crude oil and natural gas production, processing, and storage sector (2007 Oil and Gas Industry Survey).

Development of the 2007 Oil and Gas Industry Survey

In April 2008, ARB staff held a public workshop to discuss preliminary concepts for reducing greenhouse gases from the oil and gas production, transmission and distribution, and refinery sectors. Attendees were encouraged to sign up to be part of industry workgroups. After that workshop, the sector was split into three discrete sections: an oil and gas production section, a natural gas transmission and distribution section, and a refinery section.

Ultimately, the oil and gas production sector contained the following types of facilities:

- Crude oil extraction;
- Natural gas extraction;
- Natural gas storage;
- Crude oil processing not including refineries;
- Natural gas processing including gas plants;
- Crude oil pipelines; and
- Crude oil tank farms not including tank farms at refineries.

The natural gas transmission and distribution sector contained:

- Natural gas transmission pipelines;
- Natural gas distribution pipelines;
- Natural gas compressor stations; and
- Natural gas metering stations.

The refinery sector included only crude oil refineries.

In the months preceding the April 2008 public workshop, staff gathered available data from ARB's California Emission Inventory Development and Reporting System (CEIDARS) database, local air district permit data, and a small amount of individual company data. It was concluded that the quality and uniformity of the data were not robust enough to support regulation development. Staff then proposed surveying the sector to create a current baseline inventory.

To create a comprehensive survey that could be used to create a robust GHG emissions inventory for the oil and gas production sector, staff determined that research, industry and air district meetings, and site visits were necessary. To that end, staff spent the next 10 months educating themselves and developing a survey in cooperation with the industry, industry trade groups, and local air districts (Table 1-1).

Appendix A is a copy of the survey, and Appendix B lists the calculation methods and emission factors used to estimate emissions. Appendix C contains a more detailed version of Table 1-1.

Table 1-1: Site Visits and Meetings

| Date | Action |
|--------------------------|--|
| April 2008 | <ul style="list-style-type: none"> • Staff held public workshop. • Industry and district working groups created. |
| May 2008 to January 2009 | <ul style="list-style-type: none"> • Staff met with the Western States Petroleum Association (WSPA), California Independent Petroleum Association (CIPA), Independent Oil Producers' Agency (IOPA), and air district staff. • Staff toured over twenty oil and gas facilities. • Staff developed a draft survey and worked with the industry and district working groups to revise. • Staff developed general instructions for completing the survey and electronic templates. |
| February 19, 2009 | <ul style="list-style-type: none"> • ARB staff mailed out the Oil and Gas Industry Survey. |
| March 26, 2009 | <ul style="list-style-type: none"> • Staff traveled to Bakersfield to conduct a training seminar for filling out the survey. |
| February to August 2009 | <ul style="list-style-type: none"> • Survey responses were due on April 30, 2009. • Survey database was developed and surveys uploaded as |

| | |
|----------------------------|---|
| | <p>they came in.</p> <ul style="list-style-type: none"> • Staff answered questions from the industry about the survey. • Extensive follow-up with facilities that responded began after the April 30 due date. • By August, the majority of surveys were received. • Staff toured several oil and gas facilities. |
| September to December 2009 | <ul style="list-style-type: none"> • Staffed contacted non-respondents to the survey. • Remaining surveys received and uploaded. |
| December 8, 2009 | <ul style="list-style-type: none"> • Staff conducted a workshop detailing preliminary results from the survey. |
| January to March 2010 | <ul style="list-style-type: none"> • Staff worked with industry to answer questions about facility emissions. • Staff checked data for quality and followed up with facilities. |
| March 18, 2010 | <ul style="list-style-type: none"> • Survey data were frozen. |
| April to May 2010 | <ul style="list-style-type: none"> • Staff developed survey data and emission summaries. • Staff worked with industry working group on emission summaries. |
| June 2010 to January 2011 | <ul style="list-style-type: none"> • Draft survey report developed. |
| April 2011 to June 2011 | <ul style="list-style-type: none"> • Draft survey report reviewed by district and industry working groups. |
| August 2011 | <ul style="list-style-type: none"> • Draft survey report released for public comment. |
| December 2011 | <ul style="list-style-type: none"> • Final survey report released. |

The 2007 Oil and Gas Industry Survey

This report presents the results from the 2007 Oil and Gas Industry Survey conducted by ARB to estimate greenhouse gas emissions in California. This survey was a one-time collection of data intended to accurately quantify operations and processes needed to estimate greenhouse gas emissions. The survey pertained to all upstream crude oil and natural gas facilities regardless of the size of operation.

For the purpose of this survey, upstream crude oil and natural gas facilities include:

Oil or Natural Gas Extraction Facilities: any facility that extracts crude oil, natural gas, or both crude oil and natural gas.

Processing Facilities: any facility that processes crude oil or natural gas for use or distribution. This survey does not include refineries.

Crude Oil Transmission Facilities: crude oil pipelines or crude oil bulk loading operations. This includes ship, truck, or rail car loading facilities.

Storage Facilities: any facility that stores crude oil or natural gas, including underground natural gas storage facilities. This survey excludes crude oil tank farms located on refinery premises.

Additional facilities or operations covered under this survey include:

Drilling or Workover Companies: any owner of drilling or workover rigs that performed well services on crude oil or natural gas facilities.

Cogeneration Plants/Combined Heat and Power: any facility that produced electricity and thermal energy for use at a crude oil extraction or storage facility.

Produced Water Disposal: any facility that stored produced water from crude oil or natural gas extraction or storage facilities.

Some companies considered the data provided in the survey to be trade secret and confidential. To address this concern, but still allow the publishing of survey results, ARB implemented the historical practice of concealing all data values that did not represent at least three companies, otherwise known as the “Three Company Rule.” In addition, this report contains summarized survey data, rather than lists of individual survey responses to further protect confidentiality. Every effort was made to reveal as much of the survey data as possible without compromising the “Three Company Rule.” However, instances did arise where it was necessary to conceal certain portions of the survey results. Throughout this report the term “Protected Data” (or PD) is used to reflect that compliance with the “Three Company Rule” could not be satisfied and the data were concealed to protect company confidentiality.

Chapter 2 – General Information

Survey Response

The 2007 Oil and Gas Industry Survey was sent out to 1,429 companies. ARB received over 750 surveys, representing 389 companies from our original mailing list. Of the remaining 1,040 companies, 960 names were removed due to the following reasons:

- The company was out of business,
- The company had merged or been bought by another, or
- The company was not in the crude oil or natural gas business.

The remaining 80 companies did not respond. Thus, there was an 83 percent response rate for relevant companies. The response rate is probably even greater assuming many of the 80 nonresponsive companies fall into one of the three removal categories above.

This report details the results of this equipment and process survey. The total number of companies that completed the survey was 325. This number is smaller than the 389 companies listed on our mailing list due to several companies being listed with multiple addresses.

In the tables that follow, it should be noted that the percentages reported may not add to 100 percent due to rounding and that percentages that round to less than one percent are shown as zero percent.

The unique nature of crude oil and natural gas extraction added complexity to assigning emissions to a company. Many companies have multiple fields, with multiple facilities. To accommodate this, ARB allowed the company to list a company name, a facility location, and a facility identification number (ID). The facility location was generally the field or lease name and the facility ID was generally an air district identification number. In both cases, the facility location and facility ID were defined by contiguous property boundaries. As a result, 325 companies representing 1,379 facility locations, and 1,632 facility IDs in 17 air districts across California completed the survey. For the remainder of this report, the term “facility” will be used for facility ID.

Table 1 of the 2007 Oil and Gas Industry Survey required companies to fill out general information about each facility and facility location. This included business type. Table 2-1 lists the number of facilities by business type. Because facilities were allowed to list multiple business types for one facility, the total number of facilities by business type is larger than the total number of facilities that completed the survey.

The business type “other” includes the following self-reported facility types:

- CNG compression and marketing
- Cogeneration

- Combined heat and power
- Electricity generation
- Portable heating
- Water disposal
- Vapor recovery services.

Table 2-1: Number of Facilities by Business Type

| Type | Number |
|-----------------------------------|--------------|
| Onshore Crude | 668 |
| Offshore Crude | 17 |
| Onshore Natural Gas | 786 |
| Offshore Natural Gas | 8 |
| Natural Gas Storage | 11 |
| Natural Gas Processing | 282 |
| Crude Pipeline | 111 |
| Crude Storage | 258 |
| Crude Processing | 92 |
| PERP ¹ Equipment Owner | 60 |
| Other | 54 |
| Totals: | 2,347 |

1. PERP = Portable Equipment Registration Program

Throughout the remainder of this report, the term “primary business” will be used. This term is used to assign emissions for a particular facility to its primary business. Primary business type was assigned to each facility using the following list in this order:

- Onshore crude oil production
- Offshore crude oil production
- Onshore natural gas production
- Offshore natural gas production
- Natural gas storage facility
- Natural gas processing
- Crude oil pipeline
- Crude oil storage
- Crude oil processing
- PERP equipment owner
- Other

The above list shows the order in which a primary business was assigned to each facility. Thus, a facility listing the business types “onshore crude”, “natural gas processing”, and “crude storage” would have “onshore crude” designated as its primary business.

Table 2-2 shows the number of facilities by primary business type. Crude storage and crude processing were combined to protect confidential data.

Table 2-2: Number of Facilities by Primary Business Type

| Type | Number |
|---------------------------------|--------------|
| Onshore Crude Production | 668 |
| Offshore Crude Production | 16 |
| Onshore Natural Gas Production | 703 |
| Offshore Natural Gas Production | 0 |
| Natural Gas Storage | 10 |
| Natural Gas Processing | 17 |
| Crude Pipeline | 65 |
| Crude Processing and Storage | 42 |
| PERP Equipment Owner | 58 |
| Other | 53 |
| Totals: | 1,632 |

California Production

Table 2 of the 2007 Oil and Gas Industry Survey required companies to fill out their production for each facility location. This table asked for the number of

- active wells,
- well cellars,
- new wells drilled,
- workovers that required tubing removal,
- well cleanups (also known as liquid unloading), and
- well completions.

The production type was also required. California crude oil production was reported by the American Petroleum Institute (API) gravity range. API gravity measures how heavy or light a petroleum product is compared to water. The lower the API gravity number, the heavier the petroleum product is compared to water. Thus, companies filled out the above list by type of production:

- dry gas production (referred to as Produced Natural Gas in the survey),
- natural gas storage,
- ultra-heavy (API < 10) crude oil production,
- heavy (API 10 - 20) crude oil production ,
- light (API 20 - 30) crude oil production, and
- ultra-light (API > 30) crude oil production.

Table 2 of the 2007 Oil and Gas Industry Survey also gathered production volume, the composition of the natural gas produced, the volume of crude oil transported, and the miles of crude oil pipeline.

Crude oil and natural gas extraction is a large industry in California. In 2007, California produced 243 million barrels of crude oil, making it the fourth largest producer of domestic crude oil (DOGGR, 2008; EIA, 2009b). This production accounts for 38 percent of the total crude oil delivered to California refineries. The other sources of

crude oil delivered to California refineries are 45 percent foreign, 16 percent Alaskan, and one percent from gulf coast states (CEC, 2010).

The 2007 Annual Report of the State Oil and Gas Supervisor stated that 58 percent of California's 2007 crude oil production was extracted through enhanced oil recovery (EOR) techniques (DOGGR, 2008). EOR techniques include thermal, waterflood, and gas injection. Thermal EOR injects steam into the formation, waterflood EOR injects water into the formation, and gas injection EOR injects natural gas, nitrogen, or carbon dioxide into the formation. Of the production that was recovered through EOR techniques, 68 percent used thermal, 27 percent used waterflood, and 5 percent used gas injection techniques (DOGGR, 2008).

The crude oil production reported under ARB's 2007 Oil and Gas Industry Survey represents 96 percent of California's total production. Table 2-3 lists the California crude oil production reported in the 2007 Oil and Gas Industry Survey by API range. Table 2-4 lists the California crude oil production by air district.

There were 882,953,716 barrels of crude oil transported through 6,799 miles of pipeline. This total includes California production and imported crude oil. The amount of crude oil transported through crude oil pipelines is greater than the 639,189,000 barrels delivered to refineries (CEC, 2010) because many crude oil extraction facilities listed crude oil transport from their facility to one of the major pipeline companies. Thus, some crude oil transport was counted twice.

Table 2-3: Crude Oil Totals

| Type | Barrels Crude Oil Produced | Percent of Total Production Reported |
|---------------------------|----------------------------|--------------------------------------|
| Ultra-Heavy Oil (API <10) | 614,683 | 0% |
| Heavy Oil (API 10 - 20) | 156,304,520 | 67% |
| Light Oil (API 20 - 30) | 61,524,698 | 26% |
| Ultra-Light Oil (API >30) | 15,649,398 | 7% |
| Totals: | 234,093,299 | |

Table 2-4: Crude Oil Totals by Air District

| Air District | Ultra-Heavy Oil (API <10) (bbl) | Heavy Oil (API 10 - 20) (bbl) | Light Oil (API 20 - 30) (bbl) | Ultra-Light Oil (API >30) (bbl) |
|-----------------------------|---------------------------------|-------------------------------|-------------------------------|---------------------------------|
| Bay Area AQMD | 0 | 0 | PD | 0 |
| Monterey Bay Unified APCD | 0 | 3,561,595 | PD | PD |
| Santa Barbara County APCD | PD | 13,500,536 | 4,565,827 | 574,103 |
| South Coast AQMD | 0 | 19,027,656 | 10,143,280 | 977,986 |
| San Joaquin Valley APCD | PD | 117,483,089 | 44,194,051 | 13,516,247 |
| San Luis Obispo County APCD | 0 | PD | 0 | PD |
| Ventura County APCD | 0 | 2,190,819 | 2,603,320 | 576,597 |
| Yolo/Solano AQMD | 0 | PD | 0 | 0 |
| Totals: | 614,683 | 156,304,520 | 61,524,698 | 15,649,398 |

Natural gas production and natural gas storage have very similar processes. Natural gas production extracts virgin natural gas that is then processed and sold. Natural gas storage takes clean, processed gas from pipelines or large producers and injects it into a geological formation for storage. The gas is then removed at a later date when needed.

There are discrepancies between the amounts of natural gas produced that was reported to the Energy Information Administration (EIA), the Department of Conservation Division of Oil, Gas, and Geothermal (DOGGR), and the 2007 Oil and Gas Industry survey. According to the EIA Natural Gas 2007 Annual Report (EIA, 2009a), these discrepancies may be due to the way operators fill out their reports. The amount of natural gas extracted that was reported to EIA was 339 billion cubic feet (EIA, 2009a). This amount is larger than the 312 billion cubic feet reported to DOGGR (DOGGR, 2008). The amount reported in the 2007 Oil and Gas Industry survey is shown in Table 2-5 and is larger than both the EIA and DOGGR numbers. However, if the amount combusted onsite is subtracted from the amount produced, the amount available becomes similar to the EIA number. Table 2-6 shows the amount of natural gas reported by air district.

Table 2-5: Natural Gas Totals

| Type | MSCF ¹ Natural Gas Produced | MSCF Natural Gas Combusted | MSCF Natural Gas Available to Consumers |
|----------------|--|----------------------------|---|
| Associated Gas | 291,115,743 | 54,444,514 | 236,671,230 |
| Dry Gas | 99,211,175 | 4,597,875 | 94,613,300 |
| Totals: | 390,326,918 | 59,042,389 | 331,284,529 |

1. MSCF is 1000 standard cubic feet

Table 2-6: Natural Gas Totals by Air District

| Air District | MSCF Associated Gas Produced | MSCF Dry Gas Produced | MSCF Natural Gas Combusted | MSCF Natural Gas Available to Consumers |
|-----------------------------|------------------------------|-----------------------|----------------------------|---|
| Bay Area AQMD | PD | 5,064,381 | 131,967 | PD |
| Butte County AQMD | 0 | PD | PD | PD |
| Colusa County APCD | 0 | 9,131,772 | 288,237 | 8,843,534 |
| Feather River AQMD | 0 | 11,044,326 | 409,389 | 10,634,938 |
| Glenn County APCD | 0 | 8,052,603 | 309,101 | 7,743,502 |
| Monterey Bay Unified APCD | PD | 0 | 2,697 | 271,452 |
| North Coast Unified AQMD | PD | 0 | 14,498 | 95,002 |
| Santa Barbara County APCD | 40,161,649 | PD | 6,753,579 | PD |
| South Coast AQMD | 56,942,823 | PD | 9,160,810 | PD |
| San Joaquin Valley APCD | 185,644,665 | 20,895,394 | 38,195,104 | 168,344,955 |
| San Luis Obispo County APCD | PD | 0 | 103,047 | 2,339,153 |
| Sacramento Metro AQMD | 0 | 15,784,466 | 1,291,556 | 14,492,910 |
| Tehama County APCD | 0 | 7,818,949 | 179,094 | 7,639,855 |
| Ventura County APCD | 4,980,163 | PD | 1,168,313 | PD |
| Yolo/Solano AQMD | PD | 17,254,359 | 1,031,913 | 16,751,007 |
| Totals: | 291,115,743 | 99,211,175 | 59,042,389 | 331,284,529 |

In 2007, 2,326 billion cubic feet of natural gas were delivered to California consumers (EIA, 2009a). This includes gas used in residential, commercial, and industrial

applications; vehicular fuel; and electric power generation. According to the 2007 Oil and Gas Industry survey, California produced 14 percent of the total natural gas used in state. The remaining 86 percent came in through interstate transmission pipelines crossing the border at Arizona, Nevada, and Oregon (EIA, 2009a).

California withdrew 211 billion cubic feet of gas from natural gas storage facilities in 2007. The storage numbers include in-state production and imported natural gas.

Global Warming Potentials

The 2007 Oil and Gas Industry Survey collected comprehensive equipment and process data for the California crude oil and natural gas industry. The data from the survey are used to calculate greenhouse gas (GHG) emissions. The major GHG compounds emitted from this sector are carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). Carbon dioxide equivalents (CO₂e) are calculated by multiplying the mass of the GHG compound by its global warming potential (GWP). GWP numbers are the amount of radiative forcing a particular compound has compared to CO₂. GWP numbers are published by the Intergovernmental Panel on Climate Change (IPCC) in their Assessment Reports. Table 2-5 lists the GWP for CO₂, CH₄, and N₂O from the Second, Third, and Fourth IPCC Assessment Reports (IPCC 2007, 2001, and 1995).

Table 2-7: Global Warming Potentials

| | CO ₂ | CH ₄ | N ₂ O |
|--------------------------------|-----------------|-----------------|------------------|
| Second Assessment Report (SAR) | 1 | 21 | 310 |
| Third Assessment Report (TAR) | 1 | 23 | 296 |
| Fourth Assessment Report (FAR) | 1 | 25 | 298 |

ARB's and US EPA's Mandatory GHG Reporting rules both use the SAR to calculate emissions. To remain consistent with both of these programs, all the CO₂e calculations in this report use the SAR GWP numbers.

Chapter 3 of this report gives an overview of the total emissions calculated from the 2007 Oil and Gas Industry Survey. Chapters 4 through 19 go through the emissions calculated from each table of the survey. The remaining chapters of the report total the emissions for oil production and natural gas production separately.

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Chapter 3 – Overview of Total California Emissions

Total Emissions

This chapter combines the emissions from all equipment surveyed in the 2007 Oil and Gas Industry Survey. These emissions do not include extrapolated emissions for equipment not covered by the survey. The emissions were calculated using equipment information from the survey and the emission equations and emissions factors listed in Appendix B. Table 3-1 shows the total California statewide emissions for the crude oil and natural gas sector for the equipment covered by the survey in 2007. Combustion sources are equipment burning fuel for energy. Vented emissions are intentional releases of vapors to the atmosphere. Fugitive emissions are unintentional releases of vapors to the atmosphere. The majority of the total CO₂e emissions in California are from combustion sources. Only 7 percent of the CO₂e emissions come from vented or fugitive sources.

Table 3-1: Total California 2007 Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 16,073,395 | 10,836 | 314 | 16,398,268 | 93% |
| Vented | 56,021 | 16,026 | 0 | 392,563 | 2% |
| Fugitive | 107,322 | 37,533 | 0 | 895,513 | 5% |
| Totals: | 16,236,738 | 64,394 | 314 | 17,686,345 | |

Table 3-2 lists total CO₂e emissions by primary business type. Primary business type is defined in Chapter 2. The business type “other” includes the following self-reported facility types:

- CNG compression and marketing
- Cogeneration
- Combined heat and power
- Electricity generation
- Portable heating
- Water disposal
- Vapor recovery services

The facility types “crude processing” and “crude storage” were combined to protect confidential company data. The facility types “onshore crude production” and “other” account for 42 percent of the total number of facilities for this sector. However, they emit 84 percent of the total CO₂e for the state. The remaining 58 percent of the facilities account for only 16 percent of the emissions.

**Table 3-2: Total California Emissions by Primary Business Type
(Metric Tons/Year)**

| Type | Number of Facilities | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|----------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Onshore Crude Production | 668 | 9,645,891 | 30,568 | 178 | 10,343,089 | 58% |
| Other | 53 | 4,579,097 | 567 | 108 | 4,624,612 | 26% |
| Natural Gas Processing | 17 | 913,595 | 6,090 | 6 | 1,043,400 | 6% |
| Onshore Natural Gas Production | 703 | 205,336 | 16,247 | 4 | 547,624 | 3% |
| Crude Processing and Storage | 42 | 370,666 | 1,719 | 2 | 407,239 | 2% |
| Natural Gas Storage | 10 | 200,638 | 6,263 | 9 | 334,864 | 2% |
| PERP Equipment Owner | 58 | 148,082 | 339 | 1 | 155,577 | 1% |
| Offshore Crude Production | 16 | 101,807 | 1,772 | 4 | 140,118 | 1% |
| Crude Pipeline | 65 | 71,625 | 829 | 3 | 89,821 | 1% |
| Totals: | 1,632 | 16,236,738 | 64,394 | 314 | 17,686,345 | |

Table 3-3 lists the combustion, vented, fugitive, and total CO₂e emissions by primary business type. The facility types “crude processing” and “crude storage” were combined to protect confidential company data.

**Table 3-3: Total California Combustion, Vented, and Fugitive Emissions
by Primary Business Type (Metric Tons/Year)**

| Type | Number of Facilities | Combustion (CO ₂ e) | Vented (CO ₂ e) | Fugitive (CO ₂ e) | Total CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|----------------------|--------------------------------|----------------------------|------------------------------|-------------------------|------------------------------------|
| Onshore Crude Production | 668 | 9,784,578 | 125,428 | 433,082 | 10,343,089 | 58% |
| Other | 53 | 4,616,047 | 53 | 8,512 | 4,624,612 | 26% |
| Natural Gas Processing | 17 | 879,601 | 24,102 | 139,698 | 1,043,400 | 6% |
| Onshore Natural Gas Production | 703 | 218,910 | 117,835 | 210,879 | 547,624 | 3% |
| Crude Processing and Storage | 42 | 346,952 | 15,940 | 44,347 | 407,239 | 2% |
| Natural Gas Storage | 10 | 226,569 | 90,537 | 17,758 | 334,864 | 2% |
| PERP Equipment Owner | 58 | 148,825 | 1,960 | 4,793 | 155,577 | 1% |
| Offshore Crude Production | 16 | 104,272 | 16,708 | 19,138 | 140,118 | 1% |
| Crude Pipeline | 65 | 72,515 | 0 | 17,306 | 89,821 | 1% |
| Totals: | 1,632 | 16,398,268 | 392,563 | 895,513 | 17,686,345 | |

Total Emissions by Air District

Crude oil and natural gas operations are found in 17 air pollution control districts (APCD) and air quality management districts (AQMD) in California. Total CO₂e emissions for each air district are shown in Table 3-4. Several companies had a facility that was located in more than one air district. In those cases, the CO₂e emissions for that facility were split equally between each air district. This resulted in the total number of facilities being larger than the 1,632 facilities that reported in the survey. Nearly 80 percent of the statewide total CO₂e emissions for these operations occur in the San Joaquin Valley APCD.

Table 3-4: Total California Emissions by Air District (Metric Tons/Year)

| Air District | Number of Facilities | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|----------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| San Joaquin Valley APCD | 456 | 13,289,187 | 30,588 | 240 | 14,005,872 | 79% |
| South Coast AQMD | 265 | 1,045,442 | 6,773 | 57 | 1,205,313 | 7% |
| Santa Barbara County APCD | 63 | 890,593 | 7,458 | 5 | 1,048,824 | 6% |
| Monterey Bay Unified APCD | 19 | 494,994 | 130 | 2 | 498,249 | 3% |
| Ventura County APCD | 83 | 226,188 | 1,760 | 5 | 264,804 | 1% |
| Sacramento Metro AQMD | 155 | 71,031 | 2,933 | 1 | 133,043 | 1% |
| Yolo/Solano AQMD | 200 | 57,023 | 2,339 | 1 | 106,509 | 1% |
| Glenn County APCD | 79 | 16,989 | 3,549 | 0 | 91,584 | 1% |
| Feather River AQMD | 69 | 21,108 | 3,063 | 0 | 85,569 | 0% |
| San Luis Obispo County APCD | 4 | 63,653 | 44 | 1 | 64,785 | 0% |
| Bay Area AQMD | 68 | 19,247 | 2,090 | 0 | 63,292 | 0% |
| Colusa County APCD | 119 | 15,780 | 2,208 | 0 | 62,195 | 0% |
| Tehama County APCD | 47 | 9,753 | 853 | 0 | 27,684 | 0% |
| Butte County AQMD | PD | PD | PD | PD | PD | PD |
| North Coast Unified AQMD | PD | PD | PD | PD | PD | PD |
| No District Reported | 4 | 803 | 0 | 0 | 806 | 0% |
| San Diego County APCD | PD | PD | PD | PD | PD | PD |
| Totals: | 1,637 | 16,236,738 | 64,394 | 314 | 17,686,345 | |

Table 3-5 lists the combustion, vented, fugitive, and total CO₂e emissions by air district.

Table 3-5: Total California Combustion, Vented, and Fugitive Emissions by Air District (Metric Tons/Year)

| Air District | Number of Facilities | Combustion (CO ₂ e) | Vented (CO ₂ e) | Fugitive (CO ₂ e) | Total CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|----------------------|--------------------------------|----------------------------|------------------------------|-------------------------|------------------------------------|
| San Joaquin Valley APCD | 456 | 13,462,679 | 121,826 | 421,367 | 14,005,872 | 79% |
| South Coast AQMD | 265 | 1,077,660 | 36,196 | 91,458 | 1,205,313 | 7% |
| Santa Barbara County APCD | 63 | 852,823 | 81,107 | 114,894 | 1,048,824 | 6% |
| Monterey Bay Unified APCD | 19 | 495,724 | 437 | 2,088 | 498,249 | 3% |
| Ventura County APCD | 83 | 199,615 | 27,561 | 37,628 | 264,804 | 1% |
| Sacramento Metro AQMD | 155 | 76,125 | 22,993 | 33,925 | 133,043 | 1% |
| Yolo/Solano AQMD | 200 | 61,484 | 15,655 | 29,370 | 106,509 | 1% |
| Glenn County APCD | 79 | 17,905 | 29,372 | 44,307 | 91,584 | 1% |
| Feather River AQMD | 69 | 22,627 | 24,543 | 38,400 | 85,569 | 0% |
| San Luis Obispo County APCD | 4 | 63,946 | 0 | 838 | 64,785 | 0% |
| Bay Area AQMD | 68 | 22,505 | 8,293 | 32,494 | 63,292 | 0% |
| Colusa County APCD | 119 | 16,430 | 14,199 | 31,566 | 62,195 | 0% |
| Tehama County APCD | 47 | 9,781 | 5,546 | 12,356 | 27,684 | 0% |
| Butte County AQMD | PD | PD | PD | PD | PD | PD |
| North Coast Unified AQMD | PD | PD | PD | PD | PD | PD |
| No District Reported | 4 | 805 | 0 | 0 | 806 | 0% |
| San Diego County APCD | PD | PD | PD | PD | PD | PD |
| Totals: | 1,637 | 16,398,268 | 392,563 | 895,513 | 17,686,345 | |

Total Emissions by Combustion, Vented, and Fugitive Sources

Table 3-6 lists the total combustion emissions by source type. The majority of the CO₂e emissions are from steam generators, combined heat and power units, and turbines.

Table 3-6: Combustion Emissions by Combustion Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Steam Generator | 6,658,156 | 2,973 | 115 | 6,756,167 | 41% |
| Combined Heat and Power | 3,568,017 | 612 | 7 | 3,583,006 | 22% |
| Turbine | 2,731,036 | 835 | 153 | 2,796,035 | 17% |
| Internal Combustion Engine | 1,004,624 | 4,537 | 16 | 1,104,754 | 7% |
| Cogeneration | 930,377 | 15 | 2 | 931,185 | 6% |
| Flare | 242,454 | 812 | 0 | 259,623 | 2% |
| Microturbine | 232,240 | 581 | 17 | 249,584 | 2% |
| Thermal Oxidizer | 216,378 | 80 | 0 | 218,155 | 1% |
| Boiler | 140,240 | 245 | 0 | 145,454 | 1% |
| Heater | 116,301 | 34 | 2 | 117,584 | 1% |
| Heater/Treater | 115,607 | 47 | 2 | 117,226 | 1% |
| Incinerator | 44,846 | 49 | 0 | 45,896 | 0% |
| Drill Rig | 31,600 | 1 | 0 | 31,708 | 0% |
| Reboiler | 17,466 | 15 | 0 | 17,782 | 0% |
| Workover Rig | 13,300 | 1 | 0 | 13,345 | 0% |
| Vapor Recovery | 10,681 | 0 | 0 | 10,690 | 0% |
| Other | 72 | 0 | 0 | 73 | 0% |
| Totals: | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Table 3-7 lists the total combustion emissions by primary business type. The primary business type “crude processing” and “crude storage” were combined to protect confidential company data. Table 3-7 shows that 88 percent of the emissions are from onshore crude production and the business type “other.”

Table 3-7: Combustion Emissions by Primary Business (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Onshore Crude Production | 9,601,843 | 6,069 | 178 | 9,784,578 | 60% |
| Other | 4,579,058 | 161 | 108 | 4,616,047 | 28% |
| Natural Gas Processing | 832,060 | 2,173 | 6 | 879,601 | 5% |
| Crude Processing and Storage | 334,290 | 580 | 2 | 346,952 | 2% |
| Natural Gas Storage | 200,225 | 1,126 | 9 | 226,569 | 1% |
| Onshore Natural Gas Production | 204,801 | 620 | 4 | 218,910 | 1% |
| PERP Equipment Owner | 148,048 | 19 | 1 | 148,825 | 1% |
| Offshore Crude | 101,521 | 78 | 4 | 104,272 | 1% |
| Crude Pipeline | 71,548 | 9 | 3 | 72,515 | 0% |
| Totals: | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Table 3-8 lists the total combustion emissions by air district. Several companies had a facility that was located in more than one air district. Table 3-8 shows that 82 percent of the emissions are from the San Joaquin Valley APCD.

Table 3-8: Combustion Emissions by Air District (Metric Tons/Year)

| Air District | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| San Joaquin Valley APCD | 13,242,316 | 6,953 | 240 | 13,462,679 | 82% |
| South Coast AQMD | 1,027,580 | 1,544 | 57 | 1,077,660 | 7% |
| Santa Barbara County APCD | 829,037 | 1,056 | 5 | 852,823 | 5% |
| Monterey Bay Unified APCD | 494,952 | 12 | 2 | 495,724 | 3% |
| Ventura County APCD | 189,880 | 385 | 5 | 199,615 | 1% |
| Sacramento Metro AQMD | 70,842 | 232 | 1 | 76,125 | 0% |
| San Luis Obispo County APCD | PD | PD | PD | PD | PD |
| Yolo/Solano AQMD | 56,901 | 201 | 1 | 61,484 | 0% |
| Feather River AQMD | 21,050 | 69 | 0 | 22,627 | 0% |
| Bay Area AQMD | 19,132 | 153 | 0 | 22,505 | 0% |
| Glenn County APCD | 16,933 | 43 | 0 | 17,905 | 0% |
| Butte County AQMD | PD | PD | PD | PD | PD |
| Colusa County APCD | 15,746 | 30 | 0 | 16,430 | 0% |
| Tehama County APCD | 9,729 | 2 | 0 | 9,781 | 0% |
| North Coast Unified AQMD | PD | PD | PD | PD | PD |
| No District Reported | 803 | 0 | 0 | 805 | 0% |
| Totals: | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Table 3-9 lists the total vented emissions by source type. The type “natural gas gathering pipelines” only includes the venting from maintenance activities. These pipelines do not include natural gas transmission and distribution pipelines. Automated control devices and compressor blowdowns account for 48 percent of the total vented emissions in California.

Table 3-9: Vented Emissions by Source Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|--|-----------------|-----------------|-------------------|------------------------------------|
| Automated Control Devices | 161 | 5,727 | 120,434 | 31% |
| Compressor Blowdowns | 172 | 3,238 | 68,165 | 17% |
| Natural Gas Gathering Pipelines | 2,659 | 2,490 | 54,940 | 14% |
| Sweetening/Acid Gas Removal | 51,749 | 19 | 52,148 | 13% |
| Well Workovers | 645 | 2,116 | 45,085 | 11% |
| Dehydrators | 308 | 1,975 | 41,774 | 11% |
| Well Cleanups | 219 | 327 | 7,082 | 2% |
| Compressor Startups | 4 | 69 | 1,462 | 0% |
| Carbon Adsorbers | 0 | 54 | 1,131 | 0% |
| Natural Gas Gathering Pipeline Pigging | 104 | 5 | 211 | 0% |
| Storage Tank Degassing | 0 | 5 | 109 | 0% |
| Separator Degassing | 0 | 1 | 24 | 0% |
| New Wells Drilled | 0 | 0 | 0 | 0% |
| Totals: | 56,021 | 16,026 | 392,563 | |

Table 3-10 lists the total vented emissions by primary business type. The primary business type “crude processing” and “crude storage” were combined to protect confidential company data. Table 3-10 shows that 85 percent of the total vented emissions in California are from the primary business types “onshore crude production”, “onshore natural gas production”, and “natural gas storage”.

Table 3-10: Vented Emissions by Primary Business Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Onshore Crude Production | 18,897 | 5,073 | 125,428 | 32% |
| Onshore Natural Gas Production | 127 | 5,605 | 117,835 | 30% |
| Natural Gas Storage | 384 | 4,293 | 90,537 | 23% |
| Natural Gas Processing | 20,649 | 164 | 24,102 | 6% |
| Offshore Crude Production | 84 | 792 | 16,708 | 4% |
| Crude Processing and Storage | 15,867 | 4 | 15,940 | 4% |
| PERP Equipment Owner | 10 | 93 | 1,960 | 0% |
| Other | 2 | 2 | 53 | 0% |
| Crude Pipeline | 0 | 0 | 0 | 0% |
| Totals: | 56,021 | 16,026 | 392,563 | |

Table 3-11 lists the total vented emissions by air district. San Joaquin Valley APCD and Santa Barbara County APCD account for 52 percent of the total vented emissions in California.

Table 3-11: Vented Emissions by Air District (Metric Tons/Year)

| Air District | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------|-----------------|-----------------|-------------------|------------------------------------|
| San Joaquin Valley APCD | 5,225 | 5,552 | 121,826 | 31% |
| Santa Barbara County APCD | 19,276 | 2,944 | 81,107 | 21% |
| South Coast AQMD | 6,307 | 1,423 | 36,196 | 9% |
| Glenn County APCD | 18 | 1,398 | 29,372 | 7% |
| Ventura County APCD | 25,074 | 118 | 27,561 | 7% |
| Feather River AQMD | 11 | 1,168 | 24,543 | 6% |
| Sacramento Metro AQMD | 46 | 1,093 | 22,993 | 6% |
| Yolo/Solano AQMD | 27 | 744 | 15,655 | 4% |
| Colusa County APCD | 7 | 676 | 14,199 | 4% |
| Bay Area AQMD | 13 | 394 | 8,293 | 2% |
| Tehama County APCD | 2 | 264 | 5,546 | 1% |
| Butte County AQMD | PD | PD | PD | PD |
| Monterey Bay Unified APCD | 6 | 21 | 437 | 0% |
| North Coast Unified AQMD | PD | PD | PD | PD |
| San Diego County APCD | PD | PD | PD | PD |
| Totals: | 56,021 | 16,026 | 392,563 | |

Table 3-12 lists the total fugitive emissions by source type. The type “natural gas gathering pipeline” only includes the fugitive emissions from the gathering system pipelines. These pipelines do not include natural gas transmission and distribution pipelines. Compressor seals and storage tanks account for 69 percent of the total fugitive emissions in California that are covered by this survey.

Table 3-12: Fugitive Emissions by Source Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Compressor Seals | 2,025 | 17,679 | 373,274 | 42% |
| Storage Tanks | 1,084 | 11,501 | 242,594 | 27% |
| Sweetening/Acid Gas Removal | 61,605 | 576 | 73,694 | 8% |
| Well Cellars | 0 | 2,154 | 45,225 | 5% |
| Wellheads | 559 | 2,032 | 43,228 | 5% |
| Dehydrators | 16,567 | 1,252 | 42,866 | 5% |
| Other Natural Gas Processing | 24,888 | 228 | 29,676 | 3% |
| Natural Gas Gathering Pipelines | 327 | 867 | 18,541 | 2% |
| Components | 256 | 811 | 17,283 | 2% |
| Sumps | 0 | 264 | 5,552 | 1% |
| Separators | 11 | 170 | 3,578 | 0% |
| Totals: | 107,322 | 37,533 | 895,513 | |

Table 3-13 lists the total fugitive emissions by primary business type. The primary business type “crude processing” and “crude storage” were combined to protect confidential company data. This table shows that the primary business types “onshore crude production”, “onshore natural gas production” and “natural gas processing” account for 88 percent of the total fugitive emissions.

Table 3-13: Fugitive Emissions by Primary Business Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Onshore Crude Production | 25,151 | 19,425 | 433,082 | 48% |
| Onshore Natural Gas Production | 408 | 10,022 | 210,879 | 24% |
| Natural Gas Processing | 60,886 | 3,753 | 139,698 | 16% |
| Crude Processing and Storage | 20,509 | 1,135 | 44,347 | 5% |
| Offshore Crude Production | 202 | 902 | 19,138 | 2% |
| Natural Gas Storage | 29 | 844 | 17,758 | 2% |
| Crude Pipeline | 77 | 820 | 17,306 | 2% |
| Other | 37 | 404 | 8,512 | 1% |
| PERP Equipment Owner | 24 | 227 | 4,793 | 1% |
| Totals: | 107,322 | 37,533 | 895,513 | |

Table 3-14 lists the total fugitive emissions by air district. San Joaquin Valley APCD, Santa Barbara County APCD, and South Coast AQMD account for 70 percent of the total fugitive emissions in California.

Table 3-14: Fugitive Emissions by Air District (Metric Tons/Year)

| Air District | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|-----------------|-----------------|-------------------|------------------------------------|
| San Joaquin Valley APCD | 41,645 | 18,082 | 421,367 | 47% |
| Santa Barbara County APCD | 42,280 | 3,458 | 114,894 | 13% |
| South Coast AQMD | 11,554 | 3,805 | 91,458 | 10% |
| Glenn County APCD | 39 | 2,108 | 44,307 | 5% |
| Feather River AQMD | 47 | 1,826 | 38,400 | 4% |
| Ventura County APCD | 11,234 | 1,257 | 37,628 | 4% |
| Sacramento Metro AQMD | 143 | 1,609 | 33,925 | 4% |
| Bay Area AQMD | 102 | 1,542 | 32,494 | 4% |
| Colusa County APCD | 27 | 1,502 | 31,566 | 4% |
| Yolo/Solano AQMD | 95 | 1,394 | 29,370 | 3% |
| Tehama County APCD | 22 | 587 | 12,356 | 1% |
| Butte County AQMD | PD | PD | PD | PD |
| Monterey Bay Unified APCD | 36 | 98 | 2,088 | 0% |
| North Coast Unified AQMD | PD | PD | PD | PD |
| San Luis Obispo County APCD | 4 | 83 | 36 | 0% |
| San Diego County APCD | PD | PD | PD | PD |
| No District Reported | PD | PD | PD | PD |
| Totals: | 107,322 | 37,533 | 895,513 | |

Total Emissions by CO₂e Range

Total CO₂e emissions were calculated for each facility. All facilities were then categorized into ranges of CO₂e emissions. Table 3-15 lists the number of facilities in each range and the total CO₂e emissions for all the facilities in that range. Ninety-four percent of the facilities in this sector account for only 6 percent of the total emissions while 2 percent of the facilities account for over 80 percent of the emissions.

Table 3-15: Total California Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 10,000 | 1,537 | 983,552 | 6% |
| 10,000 to 25,000 | 28 | 451,872 | 3% |
| 25,000 to 50,000 | 19 | 679,163 | 4% |
| 50,000 to 100,000 | 12 | 815,119 | 5% |
| 100,000 to 500,000 | 27 | 5,122,394 | 29% |
| > 500,000 | 9 | 9,634,245 | 54% |
| Totals: | 1,632 | 17,686,345 | |

Tables 3-16, 3-17, and 3-18 list the number of facilities and total CO₂e emissions for combustion, vented, and fugitive sources. These tables mirror Table 19-11 in that the majority of the emissions come from a small fraction of the total number of facilities.

Table 3-16: Total California Combustion Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 10,000 | 1,549 | 544,783 | 3% |
| 10,000 to 25,000 | 25 | 398,589 | 2% |
| 25,000 to 50,000 | 17 | 629,251 | 4% |
| 50,000 to 100,000 | 7 | 547,906 | 3% |
| 100,000 to 500,000 | 25 | 4,743,074 | 29% |
| > 500,000 | 9 | 9,534,666 | 58% |
| Totals: | 1,632 | 16,398,268 | |

Table 3-17: Total California Vented Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| <1,000 | 1,587 | 101,692 | 26% |
| 1,000 to 5,000 | 34 | 68,841 | 18% |
| 5,000 to 10,000 | PD | PD | PD |
| 10,000 to 25,000 | 6 | 102,455 | 26% |
| > 25,000 | PD | PD | PD |
| Totals: | 1,632 | 392,563 | |

Table 3-18: Total California Fugitive Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 1,000 | 1,505 | 204,824 | 23% |
| 1,000 to 5,000 | 105 | 192,512 | 21% |
| 5,000 to 10,000 | 10 | 73,867 | 8% |
| 10,000 to 25,000 | 7 | 105,589 | 12% |
| > 25,000 | 5 | 318,720 | 36% |
| Totals: | 1,632 | 895,513 | |

Chapter 4 – Wells

Wells are essential to extracting crude oil and natural gas from geological formations. These wells have emissions from the site of the well as well as from maintenance activities. Table 2 of the 2007 Oil and Gas Industry Survey required companies to fill out the number of

- active wells,
- well cellars,
- new wells drilled,
- workovers that required tubing removal,
- well cleanups (also known as liquid unloading), and
- well completions.

Active wells are wells that are producing crude oil or natural gas throughout the year. Well cellars are lined or unlined pits around one or more wells that: (a) allow access to the wellhead components for servicing, or (b) contain intermittent flows of crude oil or water during an emergency or from drilling and petroleum production processes.

Well completions are the final step to bringing a newly drilled well on to production. In some cases, a new well will be completed in a different reporting period than when the well was drilled. Thus, the number of well completions for crude oil in 2007 is larger than the number of wells drilled in that same year.

Well workovers are the process of performing major maintenance or remedial treatments on an oil or gas well. This can be done with the production tubing remaining in place or being removed. The number of well workovers listed in Tables 4-3 and 4-4 only include workovers that required tubing removal.

Well cleanups are well maintenance activities that included hydraulic fracturing or removing fluids to increase production. Hydraulic fracturing uses high pressure pumps to increase fluid pressure at the bottom of the well. This fluid pressure cracks the formation and proppants such as sand or walnut hulls are injected into the newly formed crevices to keep them open when the fluid pressure is removed. This increases the flow of the crude oil or natural gas. Fluid removal is a natural gas well maintenance activity that removes built up fluids from the well to increase natural gas production.

Table 4-1 lists the number of crude oil active wells and well cellars by API range. Table 4-2 lists the number of active wells and well cellars for natural gas.

Table 4-1: Number of Crude Oil Active Wells and Well Cellars by API Range

| Type | Number of Active Wells | Number of Well Cellars |
|---------------------------|------------------------|------------------------|
| Ultra-Heavy Oil (API <10) | 47 | 22 |
| Heavy Oil (API 10 - 20) | 36,619 | 7,461 |
| Light Oil (API 20 - 30) | 14,261 | 4,998 |
| Ultra-Light Oil (API >30) | 1,323 | 2,168 |
| Totals: | 52,250 | 14,649 |

Table 4-2: Number of Natural Gas Active Wells and Well Cellars

| Type | Number of Active Wells | Number of Well Cellars |
|---------------------|------------------------|------------------------|
| Dry Gas | 1,397 | 491 |
| Natural Gas Storage | 372 | 337 |
| Totals: | 1,769 | 828 |

Table 4-3 lists the number of new wells drilled, well completions, well workovers, and well cleanups reported in the survey by API range. Table 4-4 lists the number of new wells drilled, well completions, well workovers, and well cleanups for natural gas.

Table 4-3: Number of Crude Oil New Wells Drilled, Well Completions, Well Workovers and Well Cleanups by API Range

| Type | Number of New Wells Drilled | Number of Well Completions | Number of Well Workovers | Number of Well Cleanups |
|---------------------------|-----------------------------|----------------------------|--------------------------|-------------------------|
| Ultra-Heavy Oil (API <10) | 0 | 0 | 0 | 0 |
| Heavy Oil (API 10 - 20) | 1,197 | 1,399 | 12,889 | 956 |
| Light Oil (API 20 - 30) | 763 | 732 | 5,424 | 1,977 |
| Ultra-Light Oil (API >30) | 175 | 187 | 599 | 187 |
| Totals: | 2,135 | 2,318 | 18,912 | 3,120 |

Table 4-4: Number of Natural Gas New Wells Drilled, Well Completions, Well Workovers, and Well Cleanups

| Type | Number of New Wells Drilled | Number of Well Completions | Number of Well Workovers | Number of Well Cleanups |
|---------------------|-----------------------------|----------------------------|--------------------------|-------------------------|
| Dry Gas | 162 | 142 | 304 | 86 |
| Natural Gas Storage | PD | PD | PD | PD |
| Totals: | PD | PD | PD | PD |

Emissions

Emissions for wells and their maintenance activities are detailed in this section. Emissions from active wells and well cellars are categorized as fugitive emissions. Fugitive emissions are unintentional emission leaks. Emissions from well workovers and well cleanups are vented emissions. Vented emissions are intentional emission leaks. All CO₂ and CH₄ values are multiplied by their corresponding GWP (1 for CO₂ and 21 for CH₄) to get the CO₂e number.

Active Wells

The emissions of CO₂ and CH₄ are calculated using emission factors multiplied by the number of active wells. The calculations and emission factors are detailed in Appendix B.

Table 4-5 lists the number of wells and the calculated emissions by API range. Table 4-6 lists the number of wells and calculated emissions for natural gas. In 2007, there were 59,856 wells producing crude oil and 1,540 active dry gas wells (DOGGR, 2008). Thus, 87 percent of the actively producing crude oil wells and 91 percent of the actively producing dry gas wells in California were reported in the survey.

Table 4-5: Emissions of Crude Oil Wells by API Range (Metric Tons/Year)

| Type | Number of Active Wells | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------|------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Ultra-Heavy Oil (API <10) | 47 | 0 | 0 | 4 | 0% |
| Heavy Oil (API 10 - 20) | 36,619 | 66 | 155 | 3,327 | 9% |
| Light Oil (API 20 - 30) | 14,261 | 459 | 1,415 | 30,163 | 83% |
| Ultra-Light Oil (API >30) | 1,323 | 19 | 139 | 2,932 | 8% |
| Totals: | 52,250 | 543 | 1,709 | 36,427 | |

Table 4-6: Emissions of Natural Gas Wells (Metric Tons/Year)

| Type | Number of Active Wells | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------|------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Dry Gas | 1,397 | 14 | 253 | 5,321 | 78% |
| Natural Gas Storage | 372 | 1 | 70 | 1,479 | 22% |
| Totals: | 1,769 | 16 | 323 | 6,801 | |

Well Cellars

The emissions of CO₂ and CH₄ are calculated using emission factors multiplied by the number of well cellars. The calculations and emission factors are detailed in Appendix B.

Table 4-7 lists the number of well cellars and their emissions by crude oil API. Emission factors for natural gas well cellars do not exist at this time.

Table 4-7: Emissions of Crude Oil Well Cellars by API Range (Metric Tons/Year)

| Type | Number of Well Cellars | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------|------------------------|-----------------|-------------------|------------------------------------|
| Ultra-Heavy Oil (API <10) | 22 | 3 | 58 | 0% |
| Heavy Oil (API 10 - 20) | 7,461 | 933 | 19,585 | 43% |
| Light Oil (API 20 - 30) | 4,998 | 850 | 17,843 | 39% |
| Ultra-Light Oil (API >30) | 2,168 | 369 | 7,740 | 17% |
| Totals: | 14,649 | 2,154 | 45,225 | |

Drilling and Maintenance

GHG emissions can be calculated from well drilling and maintenance activities. At this time, there are emission calculations for CO₂ and CH₄ emissions from well workovers and cleanups but not for new wells drilled and well completions. The emissions are calculated using the number of workovers or cleanups, the percent CO₂ and CH₄ in the associated or dry gas, and emission factors. These calculations are detailed in Appendix B.

Tables 4-8 through 4-11 list the calculated emissions for well workovers and well cleanups. As these tables show, well workovers account for the majority of the CO₂e emissions from well maintenance activities.

**Table 4-8: Emissions of Crude Oil Well Workovers by API Range
(Metric Tons/Year)**

| Type | Number of Well Workovers | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------|--------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Ultra-Heavy Oil (API <10) | 0 | 0 | 0 | 0 | 0% |
| Heavy Oil (API 10 - 20) | 12,889 | 405 | 1,428 | 30,403 | 69% |
| Light Oil (API 20 - 30) | 5,424 | 225 | 575 | 12,303 | 28% |
| Ultra-Light Oil (API >30) | 599 | 9 | 65 | 1,374 | 3% |
| Totals: | 18,912 | 639 | 2,069 | 44,080 | |

Table 4-9: Emissions of Natural Gas Well Workovers (Metric Tons/Year)

| Type | Number of Well Workovers | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------|--------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Dry Gas | 304 | 6 | 46 | 970 | PD |
| Natural Gas Storage | PD | PD | PD | PD | PD |
| Totals: | PD | PD | PD | PD | |

**Table 4-10: Emissions of Crude Oil Well Cleanups by API Range
(Metric Tons/Year)**

| Type | Number of Well Cleanups | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------------|-------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Ultra-Heavy Oil (API <10) | 0 | 0 | 0 | 0 | 0% |
| Heavy Oil (API 10 - 20) | 956 | 103 | 90 | 1,993 | 29% |
| Light Oil (API 20 - 30) | 1,977 | 113 | 201 | 4,327 | 64% |
| Ultra-Light Oil (API >30) | 187 | 3 | 21 | 442 | 7% |
| Totals: | 3,120 | 219 | 312 | 6,762 | |

Table 4-11: Emissions of Natural Gas Well Cleanups (Metric Tons/Year)

| Type | Number of Well Cleanups | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|---------------------|-------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Dry Gas | 86 | 0 | 14 | 292 | PD |
| Natural Gas Storage | PD | PD | PD | PD | PD |
| Totals: | PD | PD | PD | PD | |

Chapter 5 – Electricity Generation and Use

Many crude oil and natural gas facilities often produce their own electricity. This is done using generators, cogeneration units, or combined heat and power units. Many of the cogeneration units and combined heat and power units are used to generate steam as well as electricity.

Table 3 of the 2007 Oil and Gas Industry Survey required facilities to report the amount of electricity generated onsite, exported, and purchased. Table 5-1 lists the total electricity by primary business type. Twenty-four terra-watt hours (Twh) of electricity was generated by facilities through generators, cogeneration units, or combined heat and power units. Sixty percent of the generated electricity was used on site, with the remainder exported to either the grid or other facilities. Crude oil and natural gas facilities purchased 17 Twh of electricity in 2007. This is nine percent of the 200 Twh of electricity that was purchased by non-residential customers (CEC, 2007).

Table 5-1: Electricity by Primary Business (Metric Tons/Year)

| Type | Generated (MWh) | Used (MWh) | Exported (MWh) | Purchased (MWh) |
|--------------------------------|-------------------|-------------------|------------------|-------------------|
| Onshore Crude Production | 15,564,710 | 14,259,805 | 1,304,905 | 17,183,986 |
| Offshore Crude Production | 81,739 | 81,739 | 0 | 69,056 |
| Onshore Natural Gas Production | PD | PD | PD | PD |
| Natural Gas Storage | 7,729 | 7,729 | 0 | 27,976 |
| Natural Gas Processing | 49,037 | 18,078 | 30,959 | 60,393 |
| Crude Pipeline | 19,202 | 5,195 | 14,007 | 194,877 |
| Crude Processing | PD | PD | PD | PD |
| Crude Storage | 0 | 0 | 0 | 67,270 |
| PERP Equipment Owner | PD | PD | PD | PD |
| Other | 8,472,167 | 152,854 | 8,319,313 | 7,888 |
| Totals: | 24,582,599 | 14,910,228 | 9,672,371 | 17,676,795 |

The business type “other” includes the following self-reported facility types:

- CNG compression and marketing
- Cogeneration
- Combined heat and power
- Electricity generation
- Portable heating
- Water disposal
- Vapor recovery services.

References

CEC (2007). California Energy Commission. 2007 Non-Residential Electricity Consumption by County. <http://www.ecdms.energy.ca.gov/elecbycounty.aspx>. 2007.

Chapter 6 – Vapor Recovery

Vapor recovery is the process of collecting vapors so their emissions to the atmosphere are substantially reduced. Vapor recovery equipment collects or converts these vapors. Table 4 of the 2007 Oil and Gas Industry Survey collected information about four types of vapor recovery units. These include flares, incinerators, thermal oxidizers, and carbon adsorbers. Flares, incinerators, and thermal oxidizers convert vapors while carbon adsorbers collect them. In the oil and gas production sector, these units are also used to convert or collect natural gas that is not of good enough quality to enter a natural gas transmission pipeline or that is stranded, and which would otherwise be emitted to the atmosphere.

Table 4 of the Oil and Gas Industry Survey collected the following information about each facility's vapor recovery units.

- Type
 - Flare, incinerator, thermal oxidizer, or carbon adsorber
- Use
 - Vapor recovery or emergency were choices on the survey
 - Some facilities added other uses such as gas disposal and planned flaring
- For flares, incinerators, and thermal oxidizers
 - Size in btu/hr
 - Throughput in scf
 - Combustion efficiency
 - CH₄ and CO₂ content of the gas stream
 - Carbon mole ratio
- For carbon adsorbers
 - Size in cubic feet
 - Throughput in scf
 - Capture efficiency
 - CH₄ content of the gas stream

Table 6-1 lists the number of vapor recovery units by type. Flares represented the most common type. They account for 77 percent of the total number of vapor recovery units.

Table 6-1: Number of Vapor Recovery Units by Type

| Type | Number of Units |
|------------------|-----------------|
| Flare | 196 |
| Thermal Oxidizer | 19 |
| Incinerator | 23 |
| Carbon Adsorbers | 17 |
| Totals: | 255 |

Emissions

Emissions from flares, incinerators, thermal oxidizers, and carbon adsorbers are detailed in this section. Emissions from flares, incinerators, and thermal oxidizers are categorized as combustion emissions from burning fuel. Emissions from carbon adsorbers are considered vented emissions. The emissions are calculated using fuel data supplied in the survey and are detailed in Appendix B. The CO₂, CH₄, and N₂O emissions are multiplied by their corresponding GWP (1 for CO₂, 21 for CH₄, and 310 for N₂O) to get the CO₂e value.

Table 6-2 lists the combustion emissions from flares, incinerators, and thermal oxidizers. Some equipment types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. For example, incinerators, burners, and afterburners were combined into the category “incinerator.” This table shows that flares and thermal oxidizers have similar CO₂e emissions even though there are 10 times as many flares as thermal oxidizers. This is because both flares and thermal oxidizers combusted similar volumes of gas.

Table 6-2: Vapor Recovery Combustion Emissions by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|------------------|-----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Flare | 196 | 242,454 | 812 | 0.4 | 259,623 | 50% |
| Thermal Oxidizer | 19 | 216,378 | 80 | 0.3 | 218,155 | 42% |
| Incinerator | 23 | 44,846 | 49 | 0.1 | 45,896 | 9% |
| Totals: | 238 | 503,678 | 941 | 0.7 | 523,675 | |

Table 6-3 lists the vented emissions from carbon adsorbers. The CO₂e emissions from carbon adsorbers are a very small fraction of the total emissions from vapor recovery units.

Table 6-3: Carbon Adsorber Vented Emissions (Metric Tons/Year)

| Type | Number of Units | CH ₄ | CO ₂ e |
|------------------|-----------------|-----------------|-------------------|
| Carbon Adsorbers | 17 | 54 | 1,131 |
| Totals: | 17 | 54 | 1,131 |

Table 6-4 lists the uses of flares, incinerators, and thermal oxidizers. All carbon adsorbers were used for vapor recovery. Some vapor recovery uses were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar equipment uses. Below is a list of use categories and the types they represent.

- Unknown – unknown, not in use, and dormant
- Emergency – emergency, emergency and vapor recovery, planned and unplanned flaring, and standby

- o Gas Disposal – gas disposal, maintenance, tank degassing, fuel limited, and vapor recovery/gas disposal

As this table shows, vapor recovery is the dominant use. It accounts for 73 percent of the total CO₂e emissions.

Table 6-4: Vapor Recovery Combustion Emissions by Use (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Vapor Recovery | 123 | 373,813 | 475 | 0.5 | 383,949 | 73% |
| Emergency | 92 | 90,949 | 364 | 0.1 | 98,629 | 19% |
| Unknown | 11 | 29,236 | 75 | 0.1 | 30,835 | 6% |
| Gas Disposal | 12 | 9,680 | 28 | 0.0 | 10,262 | 2% |
| Totals: | 238 | 503,678 | 941 | 0.7 | 523,675 | |

Table 6-5 lists the combustion vapor recovery units by their rated size. It includes all flares, incinerators, and thermal oxidizers reported in the 2007 Oil and Gas Industry Survey.

Table 6-5: Number of Combustion Vapor Recovery Units by Size

| Range (MMBtu/Hr) | Number of Units | Percent of Total |
|------------------|-----------------|------------------|
| Unknown | 26 | 11% |
| <5 | 84 | 35% |
| 5 to 25 | 55 | 23% |
| 25 to 100 | 17 | 7% |
| 100 to 500 | 32 | 13% |
| 500 to 1000 | 9 | 4% |
| >1000 | 15 | 6% |
| Totals: | 238 | |

Chapter 7 – Combustion Equipment

Combustion equipment encompasses many different types of equipment that all burn a fuel for energy. The 2007 Oil and Gas Industry Survey collected information about two main categories of combustion equipment: external combustion units and internal combustion units.

Table 5 of the Oil and Gas Industry Survey collected the following information about each facility's combustion equipment.

- Type
 - External
 - Boiler, steam generator, heater/treater, oil heater, glycol reboiler, or amine reboiler
 - Facilities could also specify a type not listed above
 - Internal combustion
 - Reciprocating two-stroke or four-stroke and either lean or rich burn, combined heat and power, simple or combined cycle turbine, microturbine, drill rig, or workover rig,
 - Facilities could also specify a type not listed above
- Use for internal combustion equipment
 - Compressor, vapor recovery, crude oil pump, well pump, or water injection pump
 - Facilities could also specify a use not listed above
- Fuel type
 - Including volume, higher heating value (hhv), carbon weight percent, liquid fuel density, and gaseous fuel molecular weight as appropriate
- Manufacturer
- Model year
- Average load in HP, BTU, or MW
- Inspection frequency
- Permitting and PERP registration

Emissions

Emission calculations for combustion equipment are dependent on the information reported in the survey. Three methods are available to calculate CO₂, CH₄, and N₂O. The first method uses a mass balance approach, the second uses equipment-specific emission factors, and the third method uses fuel-specific emission factors. The mass balance approach is used first if fuel composition was reported. If fuel composition was not reported, the equipment-specific emission factors are used. For combustion equipment emission calculations that could not utilize either the first or second method, fuel-specific emission factors were used. These equations and emission factors are detailed in Appendix B. The CO₂, CH₄, and N₂O emissions are multiplied by their corresponding GWP numbers (1 for CO₂, 21 for CH₄, and 310 for N₂O) to get the CO₂e values.

External Combustion

An external combustion engine is an engine where an internal fluid is heated by an external heat source. The most common types of external combustion units are steam generators and boilers. Some equipment types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Boilers – boilers and locomotive boilers;
- Heaters – heaters, central process heaters, tank heaters, forced air furnaces, water heaters, hot water circulating heaters, line heaters, oil heaters, and process heaters; and
- Vapor Recovery – flares, incinerators, and thermal oxidizers that were reported on Table 5 rather than Table 4 of the Oil and Gas Industry Survey.

Steam generators create steam that is injected into the geological formation to increase crude oil production. Cogeneration units produce steam for injection and electricity generation. Heater/Treaters are oil/water separators that use heat to expedite the separation process. Reboilers include glycol and amine reboilers. These units heat glycol or amine to remove water in dehydrators and the acid gas in amine units.

Table 7-1 lists the CO₂, CH₄, and N₂O emissions from external combustion equipment. This table shows that the majority of the emissions are from steam generators.

Table 7-1: External Combustion Emissions by Equipment Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|-----------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Steam Generator | 587 | 6,658,156 | 2,973 | 115 | 6,756,167 | 83% |
| Cogeneration | 34 | 930,377 | 15 | 2 | 931,185 | 12% |
| Boiler | 132 | 140,240 | 245 | 0 | 145,454 | 2% |
| Heater | 294 | 116,301 | 34 | 2 | 117,584 | 1% |
| Heater/Treater | 371 | 115,607 | 47 | 2 | 117,226 | 1% |
| Reboiler | 201 | 17,466 | 15 | 0 | 17,782 | 0% |
| Vapor Recovery | 11 | 10,681 | 0 | 0 | 10,690 | 0% |
| Totals: | 1,630 | 7,988,827 | 3,328 | 121 | 8,096,089 | |

Table 7-2 lists the age of the external combustion equipment. The age of each unit was determined from the model year. As this table shows, 80 percent of the units did not have a reported model year. Of the remaining units, most are 5 to 10 years old.

Table 7-2: Age of External Combustion Units

| Type | < 5 Years | 5 – 10 Years | 10 – 20 Years | 20 – 30 Years | >30 Years | Unknown | Total |
|-----------------|-----------|--------------|---------------|---------------|-----------|--------------|--------------|
| Boiler | 3 | 28 | 4 | 15 | 1 | 81 | 132 |
| Cogeneration | 0 | 0 | 0 | 0 | 0 | 34 | 34 |
| Heater | 1 | 30 | 3 | 4 | 6 | 250 | 294 |
| Heater/Treater | 11 | 61 | 5 | 21 | 5 | 268 | 371 |
| Reboiler | 5 | 50 | 5 | 7 | 5 | 129 | 201 |
| Steam Generator | 10 | 11 | 1 | 25 | 0 | 540 | 587 |
| Vapor Recovery | 0 | 4 | 1 | 0 | 0 | 6 | 11 |
| Totals: | 30 | 184 | 19 | 72 | 17 | 1,308 | 1,630 |

Internal Combustion

An internal combustion engine is an engine where fuel is burned inside a combustion chamber. The expansion of the gas applies direct force to a component of the engine such as a piston or turbine blade. Some equipment types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Other – generators, pumps, accumulators, and welders; and
- Turbines – turbines, turbines – combined cycle, turbines – simple cycle, and turbines – combined heat and power.

Table 7-3 lists the combustion emissions for internal combustion engines. The type “internal combustion engines” encompasses all the general use reciprocating engines. The type “combined heat and power” and turbines together account for 82 percent of the emissions. The term “combined heat and power” is interchangeable with the term “cogeneration” listed above in “external combustion”. Such units produce electricity and useful heat. The heat is either used to create steam for injection into the geological formation or used to create more electricity. Combined heat and power units could be turbines or reciprocating engines. Facilities reported cogeneration and combined heat and power differently. Thus, they appear as both internal and external combustion.

Table 7-3: Internal Combustion Emissions by Equipment Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Combined Heat and Power | 23 | 3,568,017 | 612 | 7 | 3,583,006 | 46% |
| Turbine | 64 | 2,731,036 | 835 | 153 | 2,796,035 | 36% |
| Internal Combustion Engine | 2,698 | 1,004,624 | 4,537 | 16 | 1,104,754 | 14% |
| Microturbine | 29 | 232,240 | 581 | 17 | 249,584 | 3% |
| Drill Rig | 174 | 31,600 | 1 | 0 | 31,708 | 0% |
| Workover Rig | 225 | 13,300 | 1 | 0 | 13,345 | 0% |
| Other | 77 | 72 | 0 | 0 | 73 | 0% |
| Totals: | 3,290 | 7,580,889 | 6,567 | 193 | 7,778,505 | |

Table 7-4 lists the age of internal combustion units by type. Almost half of the units did not have a reported model year in their survey; thus, their ages are unknown.

Table 7-4: Age of Internal Combustion Units

| Type | < 5 Years | 5 – 10 Years | 10 – 20 Years | 20 – 30 Years | >30 Years | Unknown | Total |
|----------------------------|------------|--------------|---------------|---------------|------------|--------------|--------------|
| Combined Heat and Power | 0 | 4 | 13 | 1 | 5 | 0 | 23 |
| Drill Rig | 123 | 11 | 10 | 17 | 12 | 1 | 174 |
| Internal Combustion Engine | 347 | 362 | 92 | 240 | 180 | 1,477 | 2,698 |
| Microturbine | 2 | 0 | 0 | 0 | 0 | 27 | 29 |
| Other | 22 | 0 | 0 | 0 | 0 | 55 | 77 |
| Turbine | 1 | 6 | 7 | 16 | 3 | 31 | 64 |
| Workover Rig | 24 | 63 | 34 | 4 | 100 | 0 | 225 |
| Totals: | 519 | 446 | 156 | 278 | 300 | 1,591 | 3,290 |

Internal Combustion Engines

The type category “internal combustion engines” was reported on Table 5 of the 2007 Oil and Gas Industry Survey as reciprocating engines. Many internal combustion engine uses were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar equipment uses. Appendix D lists the use categories and the types they represent.

Table 7-5 lists the combustion emissions by use. The use “unknown” accounts for equipment where a use was not specified on the survey. The use “pump” is separate from “crude oil pump” and “water pump” as it was not indicated on the survey which kind of pump it is. Cogeneration is listed here as a use for a reciprocating engine. As stated above, cogeneration units can be either reciprocating engines or turbines.

Table 7-5: Combustion Emissions of Internal Combustion Engines by Use (Metric Tons/Year)

| Use | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|--------------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Compressor | 693 | 714,295 | 4,200 | 13 | 806,644 | 73% |
| Crude Oil Pump | 722 | 103,846 | 224 | 1 | 108,786 | 10% |
| Power Generation | 229 | 54,000 | 41 | 0 | 54,997 | 5% |
| Well Servicing | 297 | 53,181 | 3 | 0 | 53,360 | 5% |
| Water Pump | 49 | 27,619 | 51 | 0 | 28,778 | 3% |
| Unknown | 96 | 20,856 | 5 | 0 | 20,986 | 2% |
| Pump | 297 | 14,796 | 1 | 0 | 14,841 | 1% |
| Miscellaneous | 189 | 9,440 | 1 | 0 | 9,482 | 1% |
| Cogeneration | 17 | 5,254 | 13 | 0 | 5,534 | 1% |
| Crane | 36 | 915 | 0 | 0 | 919 | 0% |
| Air Compressor | 35 | 277 | 0 | 0 | 278 | 0% |
| Emergency Services | 38 | 145 | 0 | 0 | 149 | 0% |
| Totals: | 2,698 | 1,004,624 | 4,537 | 16 | 1,104,754 | |

Compressors account for the majority of the emissions for internal combustion engines. They emit 73 percent of the internal combustion engine CO₂e emissions. Crude oil

pumps account for the next highest percentage. The remaining 17 percent of the emissions are distributed among the remaining ten use categories.

Table 7-6 lists combustion emissions by rich burn, lean burn, two-stroke, or four-stroke. Survey respondents did not report the type for about half of the units. Of the remaining units for which a type was not specified, 66 percent are rich burn, four-stroke engines. Rich burn two-stroke engines are the least common.

Table 7-6: Combustion Emissions of Internal Combustion Engines by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Rich Burn Four-Stroke | 914 | 378,030 | 828 | 3 | 396,392 | 36% |
| Rich Burn Two-Stroke | 78 | 17,134 | 13 | 0 | 17,431 | 2% |
| Lean Burn Four-Stroke | 284 | 395,947 | 3,279 | 10 | 467,823 | 42% |
| Lean Burn Two-Stroke | 115 | 43,195 | 356 | 2 | 51,262 | 5% |
| Unknown | 1,307 | 170,318 | 62 | 1 | 171,846 | 16% |
| Totals: | 2,698 | 1,004,624 | 4,537 | 16 | 1,104,754 | |

Turbines

Turbines are a type of internal combustion engine where the force from the combustion chamber moves a blade rather than a piston. Some turbine uses were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar equipment uses. Below is a list of use categories and the types they represent:

- Cogeneration – cogeneration, electrical and steam generation, electrical and process heat generation;
- Electricity – electrical generation and power generation; and
- Other – compressors and pumps.

Table 7-7 lists the combustion emissions for turbines by use. Cogeneration accounts for 81 percent of the total emissions.

Table 7-7: Turbine Combustion Emissions by Use (Metric Tons/Year)

| Use | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Cogeneration | 46 | 2,207,183 | 791 | 125 | 2,262,524 | 81% |
| Electricity | 6 | 308,823 | 22 | 21 | 315,810 | 11% |
| Other | 12 | 215,029 | 22 | 7 | 217,701 | 8% |
| Totals: | 64 | 2,731,036 | 835 | 153 | 2,796,035 | |

Table 7-8 lists the combustion emissions from turbines by the type of cycles they use. Combined cycle turbines have a gas turbine that generates electricity, and the waste heat is used to make steam. The steam is then used to generate electricity through a

steam turbine or injected into the geological formation to increase production. Simple cycle turbines generate electricity in the same manner as combined cycle turbines. The difference is that the waste heat is not used to create steam for more electricity or useful steam.

Some turbine cycle types were combined from what was listed on individual surveys to protect confidential company data:

- Turbine Combined Cycle – turbine combine cycle and turbines-combined heat and power.

Table 7-8 shows that the majority of the emissions are from combined cycle turbines.

Table 7-8: Turbine Combustion Emissions by Cycle Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|------------------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Turbine Combined Cycle | 23 | 1,648,609 | 167 | 124 | 1,690,680 | 60% |
| Turbine | 26 | 682,553 | 640 | 1 | 696,374 | 25% |
| Turbine Simple Cycle | 15 | 399,873 | 28 | 27 | 408,981 | 15% |
| Totals: | 64 | 2,731,036 | 835 | 153 | 2,796,035 | |

Cogeneration

Cogeneration and combined heat and power are interchangeable terms. Both refer to engines that produce electricity and waste heat. In these categories, the waste heat is used to create steam. This steam is then injected into geological formations to increase crude oil production or used to create more electricity.

Cogeneration and combined heat and power units were reported in the 2007 Oil and Gas Industry Survey in many different ways. Table 7-9 lists these units together in the manner they were reported. Two turbine types were combined from what was listed on individual surveys to protect confidential company data. The type “turbines combined cycle” and “turbines-combined heat and power” were combined under the type “turbine combined cycle.”

Table 7-9: Cogeneration Combustion Emissions by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------------------|-----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Combined Heat and Power | 23 | 3,568,017 | 612 | 7 | 3,583,006 | 50% |
| Turbine Combined Cycle | 19 | 1,642,198 | 153 | 124 | 1,683,882 | 24% |
| Cogeneration | 34 | 930,377 | 15 | 2 | 931,185 | 13% |
| Turbine | 23 | 563,939 | 638 | 1 | 577,654 | 8% |
| Turbine Simple Cycle | 10 | 309,869 | 21 | 21 | 316,799 | 4% |
| Internal Combustion Engine | 54 | 36,143 | 19 | 0 | 36,633 | 1% |
| Totals: | 163 | 7,050,543 | 1,457 | 155 | 7,129,158 | |

Total Combustion Emissions

Table 7-10 lists the combustion emissions from equipment listed on both Tables 4 and 5 of the Oil and Gas Industry Survey. It shows that the majority of the emissions are from external and internal combustion engines. Vapor recovery units, which include flares, thermal oxidizers, and incinerators, only account for 3 percent of the total combustion emissions from this sector.

Table 7-10: Combustion Emissions by Combustion Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| External | 7,988,827 | 3,328 | 121 | 8,096,089 | 49% |
| Internal | 7,580,889 | 6,567 | 193 | 7,778,505 | 47% |
| Vapor Recovery | 503,678 | 941 | 1 | 523,675 | 3% |
| Totals: | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Table 7-11 lists the total combustion emissions by primary business type. This table shows that 88 percent of the emissions are from onshore crude production and the business type “other.”

The business type “other” includes the following self-reported facility types:

- CNG compression and marketing,
- Cogeneration,
- Combined heat and power,
- Electricity generation,
- Portable heating, and
- Water disposal.

Table 7-11: Combustion Emissions by Primary Business (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Onshore Crude Production | 9,601,843 | 6,069 | 178 | 9,784,578 | 60% |
| Other | 4,579,058 | 161 | 108 | 4,616,047 | 28% |
| Natural Gas Processing | 832,060 | 2,173 | 6 | 879,601 | 5% |
| Crude Processing and Storage | 334,290 | 580 | 2 | 346,952 | 2% |
| Natural Gas Storage | 200,225 | 1,126 | 9 | 226,569 | 1% |
| Onshore Natural Gas Production | 204,801 | 620 | 4 | 218,910 | 1% |
| PERP Equipment Owner | 148,048 | 19 | 1 | 148,825 | 1% |
| Offshore Crude | 101,521 | 78 | 4 | 104,272 | 1% |
| Crude Pipeline | 71,548 | 9 | 3 | 72,515 | 0% |
| Totals: | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Table 7-12 lists the total combustion emissions by fuel types. Natural gas accounts for 99 percent of the total combustion emissions. Pipeline natural gas and associated gas are the top two of all the natural gas fuels.

Table 7-12: Combustion Emissions by Fuel Type (Metric Tons/Year)

| Type | Volume Combusted (mscf or gal) | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------------|--------------------------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Pipeline Quality Gas | 202,096,976 | 11,313,493 | 3,718 | 231 | 11,463,292 | 70% |
| Associated Gas | 54,465,754 | 3,424,822 | 5,740 | 71 | 3,567,473 | 22% |
| Waste Gas | 17,656,611 | 886,192 | 619 | 5 | 900,899 | 5% |
| Dry Gas | 4,623,503 | 252,638 | 749 | 4 | 269,709 | 2% |
| Diesel | 18,195,581 | 180,052 | 8 | 2 | 180,688 | 1% |
| Landfill Gas | 332,047 | 14,007 | 0 | 0 | 14,014 | 0% |
| Propane | 419,638 | 1,748 | 0 | 0 | 1,750 | 0% |
| Gasoline | 47,081 | 433 | 0 | 0 | 435 | 0% |
| LPG | 1,400 | 8 | 0 | 0 | 8 | 0% |
| Totals: | | 16,073,395 | 10,836 | 314 | 16,398,268 | |

Chapter 8 – Components

In the 2007 Oil and Gas Industry Survey, Table 6 asked for counts of components by service type. Service type was natural gas, light crude oil (API >20), and heavy crude oil (API <20). Facilities were asked to report counts of the following component types:

- Components 1 inch and above
 - Manual valves, flanges, connectors, open-ended lines, and threaded components; and
- Other components
 - Pump seals, pressure relief valves, bursting discs, diaphragms, hatches, meters, polished rod stuffing boxes, sight glasses, loading arms, and dump lever arms.

Table 8-1 lists the number of components by service type that was reported. The service type “natural gas” includes dry gas, associated gas, and gas storage. This table shows that the total number of all components is fairly equally distributed throughout the three service types.

Table 8-1: Number of Components by Service Type

| Type | Natural Gas | Light Crude (API >20) | Heavy Crude (API <20) | Total |
|-----------------------------|------------------|-----------------------|-----------------------|------------------|
| Connectors | 1,006,166 | 963,565 | 1,401,237 | 3,370,968 |
| Threaded Components | 992,715 | 633,749 | 531,380 | 2,157,844 |
| Manual Valves | 471,916 | 244,296 | 321,321 | 1,037,533 |
| Flanges | 348,579 | 260,939 | 370,274 | 979,792 |
| Polished Rod Stuffing Boxes | 1,925 | 8,441 | 35,174 | 45,540 |
| Pressure Relief Valves | 16,754 | 7,293 | 3,614 | 27,661 |
| Meters | 8,997 | 3,687 | 5,670 | 18,354 |
| Open-ended Lines | 5,639 | 1,543 | 9,608 | 16,790 |
| Pump Seals | 8,049 | 3,327 | 3,942 | 15,318 |
| Hatches | 5,043 | 2,410 | 4,820 | 12,273 |
| Sight Glasses | 2,983 | 1,825 | 2,740 | 7,548 |
| Diaphragms | 5,142 | 995 | 1,114 | 7,251 |
| Dump Lever Arm | 2,963 | 515 | 1,337 | 4,815 |
| Bursting Discs | 1,354 | 195 | 175 | 1,724 |
| Loading Arms | 547 | 137 | 334 | 1,018 |
| Totals: | 2,878,772 | 2,132,917 | 2,692,740 | 7,704,429 |

Emissions

Components are connections from which vapors could leak. Emissions from components are considered fugitive emissions because these connections are not designed to intentionally leak. CO₂ and CH₄ emissions are calculated using emission factors and total component counts and are detailed in Appendix B. The CO₂ and CH₄ emissions are multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 8-2 lists the fugitive emissions by primary business type. The business type “other” includes the following self-reported facility types:

- CNG compression and marketing,
- Cogeneration,
- Combined heat and power,
- Electricity generation,
- Portable heating,
- Water disposal, and
- Vapor recovery services.

This table shows that the majority of the number of components and the total CO₂e are from onshore crude production. This business type includes both oil and associated natural gas components. It accounts for 76 percent of the emissions and 82 percent of the number of components.

**Table 8-2: Fugitive Emissions of Components by Primary Business Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|------------------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Onshore Crude | 6,339,732 | 232 | 617 | 13,198 | 76% |
| Natural Gas Processing | 738,279 | 8 | 69 | 1,457 | 8% |
| Onshore Natural Gas | 195,062 | 1 | 34 | 712 | 4% |
| Crude Processing | PD | PD | PD | PD | PD |
| Offshore Crude | 231,733 | 7 | 28 | 604 | 3% |
| Natural Gas Storage | 47,486 | 0 | 12 | 245 | 1% |
| Crude Pipeline | 69,612 | 1 | 10 | 216 | 1% |
| Crude Storage | 25,586 | 1 | 6 | 130 | 1% |
| Other | PD | PD | PD | PD | PD |
| Totals: | 7,704,429 | 256 | 811 | 17,283 | |

Table 8-3 lists the fugitive emissions by service type. Natural gas components account for 40 percent of the CO₂e emissions. The emissions are relatively evenly distributed among natural gas, heavy crude, and light crude service.

**Table 8-3: Fugitive Emissions of Components by Service Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Natural Gas | 2,878,772 | 68 | 324 | 6,866 | 40% |
| Heavy Crude | 2,692,740 | 160 | 263 | 5,680 | 33% |
| Light Crude | 2,132,917 | 29 | 224 | 4,737 | 27% |
| Totals: | 7,704,429 | 256 | 811 | 17,283 | |

Table 8-4 lists the fugitive emissions by type of component. Connectors, manual valves, flanges, and threaded components account for 83 percent of the emissions. They also account for 98 percent of the total number of components.

Table 8-4: Fugitive Emissions of Components by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Connectors | 3,370,968 | 44 | 239 | 5,063 | 29% |
| Manual Valves | 1,037,533 | 44 | 152 | 3,234 | 19% |
| Flanges | 979,792 | 99 | 141 | 3,057 | 18% |
| Threaded Components | 2,157,844 | 37 | 142 | 3,008 | 17% |
| Pump Seals | 15,318 | 8 | 50 | 1,060 | 6% |
| Polished Rod Stuffing Boxes | 45,540 | 10 | 26 | 561 | 3% |
| Pressure Relief Valves | 27,661 | 4 | 21 | 453 | 3% |
| Meters | 18,354 | 3 | 13 | 274 | 2% |
| Hatches | 12,273 | 2 | 8 | 180 | 1% |
| Sight Glasses | 7,548 | 1 | 6 | 117 | 1% |
| Diaphragms | 7,251 | 1 | 6 | 117 | 1% |
| Dump Lever Arm | 4,815 | 1 | 3 | 68 | 0% |
| Open-ended Lines | 16,790 | 1 | 2 | 47 | 0% |
| Bursting Discs | 1,724 | 0 | 1 | 31 | 0% |
| Loading Arms | 1,018 | 0 | 1 | 14 | 0% |
| Totals: | 7,704,429 | 256 | 811 | 17,283 | |

Tables 8-5 through 8-7 list the fugitive emissions by type of component and service type.

Table 8-5: Fugitive Emissions of Natural Gas Components by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Manual Valves | 471,916 | 21 | 81 | 1,720 | 25% |
| Connectors | 1,006,166 | 15 | 59 | 1,263 | 18% |
| Threaded Components | 992,715 | 9 | 58 | 1,237 | 18% |
| Flanges | 348,579 | 9 | 48 | 1,014 | 15% |
| Pump Seals | 8,049 | 6 | 42 | 893 | 13% |
| Pressure Relief Valves | 16,754 | 2 | 13 | 267 | 4% |
| Meters | 8,997 | 2 | 7 | 139 | 2% |
| Diaphragms | 5,142 | 1 | 4 | 87 | 1% |
| Hatches | 5,043 | 1 | 4 | 79 | 1% |
| Sight Glasses | 2,983 | 0 | 2 | 50 | 1% |
| Dump Lever Arm | 2,963 | 1 | 2 | 44 | 1% |
| Polished Rod Stuffing Boxes | 1,925 | 0 | 1 | 30 | 0% |
| Bursting Discs | 1,354 | 0 | 1 | 25 | 0% |
| Open-ended Lines | 5,639 | 1 | 1 | 13 | 0% |
| Loading Arms | 547 | 0 | 0 | 8 | 0% |
| Totals: | 2,878,772 | 68 | 324 | 6,866 | |

**Table 8-6: Fugitive Emissions of Light Crude¹ Components by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Connectors | 963,565 | 7 | 75 | 1,588 | 34% |
| Threaded Components | 633,749 | 7 | 46 | 978 | 21% |
| Flanges | 260,939 | 5 | 42 | 877 | 19% |
| Manual Valves | 244,296 | 5 | 31 | 665 | 14% |
| Polished Rod Stuffing Boxes | 8,441 | 1 | 8 | 159 | 3% |
| Pressure Relief Valves | 7,293 | 1 | 7 | 151 | 3% |
| Pump Seals | 3,327 | 1 | 6 | 123 | 3% |
| Meters | 3,687 | 1 | 3 | 73 | 2% |
| Hatches | 2,410 | 0 | 2 | 48 | 1% |
| Sight Glasses | 1,825 | 0 | 2 | 36 | 1% |
| Diaphragms | 995 | 0 | 1 | 18 | 0% |
| Dump Lever Arm | 515 | 0 | 0 | 9 | 0% |
| Open-ended Lines | 1,543 | 0 | 0 | 4 | 0% |
| Bursting Discs | 195 | 0 | 0 | 4 | 0% |
| Loading Arms | 137 | 0 | 0 | 2 | 0% |
| Totals: | 2,132,917 | 29 | 224 | 4,737 | |

1. Light Crude is crude oil with an API gravity greater than 20.

**Table 8-7: Fugitive Emissions of Heavy Crude¹ Components by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|------------------|-----------------|-----------------|-------------------|------------------------------------|
| Connectors | 1,401,237 | 22 | 104 | 2,212 | 39% |
| Flanges | 370,274 | 85 | 51 | 1,166 | 21% |
| Manual Valves | 321,321 | 18 | 40 | 849 | 15% |
| Threaded Components | 531,380 | 21 | 37 | 794 | 14% |
| Polished Rod Stuffing Boxes | 35,174 | 9 | 17 | 372 | 7% |
| Meters | 5,670 | 1 | 3 | 62 | 1% |
| Hatches | 4,820 | 1 | 3 | 53 | 1% |
| Pump Seals | 3,942 | 1 | 2 | 43 | 1% |
| Pressure Relief Valves | 3,614 | 1 | 2 | 35 | 1% |
| Sight Glasses | 2,740 | 0 | 1 | 31 | 1% |
| Open-ended Lines | 9,608 | 0 | 1 | 30 | 1% |
| Dump Lever Arm | 1,337 | 0 | 1 | 14 | 0% |
| Diaphragms | 1,114 | 0 | 1 | 12 | 0% |
| Loading Arms | 334 | 0 | 0 | 4 | 0% |
| Bursting Discs | 175 | 0 | 0 | 2 | 0% |
| Totals: | 2,692,740 | 160 | 263 | 5,680 | |

1. Heavy Crude is crude oil with an API gravity less than 20.

Chapter 9 – Automated Control Devices

Table 7 of the 2007 Oil and Gas Industry Survey asked facilities to report the number of automated control devices. Automated control devices are also commonly referred to as pneumatic devices. Facilities were asked to report the following information about their automated control devices:

- Controllers
 - Gas, electric, or air actuated
 - Continuous bleed, intermittent bleed, low bleed, or no bleed
 - Number on gas recovery, and
- Actuators
 - Gas, electric, or air actuated
 - Piston valve, hydraulic valve, or turbine valve operator
 - Number on gas recovery.

Emissions

Emissions from automated control devices are considered vented emissions as these devices are designed to leak. CO₂ and CH₄ emissions from automated control devices are calculated by multiplying the number of devices by an emission factor; those calculations are detailed in Appendix B. The number of each type of device used to calculate emissions is the total number of devices minus the number on gas recovery. Devices on gas recovery capture the gas used to actuate. The CO₂ and CH₄ emissions are multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 9-1 lists the vented emissions by primary business type. The business type “other” includes the following self-reported facility types:

- Cogeneration,
- Combined heat and power,
- Electricity generation,
- Portable heating,
- Water disposal, and
- Vapor recovery services.

This table shows that the majority of the vented emissions are from automated control devices found in onshore natural gas production facilities. However, these facilities account for only 3 percent of the total number of devices in California. Onshore crude oil production facilities have 79 percent of the number of automated control devices but account for only 4 percent of the emissions.

Table 9-1: Vented Emissions of Automated Control Devices by Primary Business Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|------------------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Onshore Natural Gas | 2,526 | 88 | 5,056 | 106,267 | 88% |
| Natural Gas Storage | 2,585 | 2 | 380 | 7,984 | 7% |
| Onshore Crude | 57,549 | 69 | 253 | 5,378 | 4% |
| Natural Gas Processing | 832 | 1 | 36 | 764 | 1% |
| Offshore Crude | 6,197 | 0 | 2 | 35 | 0% |
| Crude Storage | PD | PD | PD | PD | PD |
| Crude Pipeline | 2,517 | 0 | 0 | 0 | 0% |
| Crude Processing | PD | PD | PD | PD | PD |
| Other | 109 | 0 | 0 | 0 | 0% |
| Totals: | 72,861 | 161 | 5,727 | 120,434 | |

Table 9-2 lists the vented emissions by type of automated control device. This table also lists the total number of devices and the number on gas recovery. Several facilities listed electric and air controllers and actuators on gas recovery. We are assuming that controllers and actuators that are either air or electrically actuated do not have any emissions associated with them. Continuous bleed and intermittent bleed controllers account for 99 percent of the vented emissions from this category. However, they only account for 2 percent of the total number of devices.

Table 9-2: Vented Emissions of Automated Control Devices by Type (Metric Tons/Year)

| Type | Number of Units | Number on Gas Recovery | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|--------------------------|-----------------|------------------------|-----------------|-----------------|-------------------|------------------------------------|
| Controllers | | | | | | |
| Continuous Bleed | 1,151 | 2 | 89 | 4,915 | 103,298 | 86% |
| Intermittent Bleed | 405 | 24 | 69 | 760 | 16,019 | 13% |
| Low Bleed | 50 | 0 | 2 | 46 | 969 | 1% |
| No Bleed | 1,054 | 0 | 0 | 0 | 0 | 0% |
| Electric Controller | 6,391 | 384 | 0 | 0 | 0 | 0% |
| Air Controller | 7,995 | 599 | 0 | 0 | 0 | 0% |
| Actuators | | | | | | |
| Piston Valve Operator | 1,030 | 111 | 0 | 1 | 15 | 0% |
| Hydraulic Valve Operator | 136 | 0 | 1 | 6 | 131 | 0% |
| Turbine Valve Operator | 3 | 0 | 0 | 0 | 1 | 0% |
| Electric Actuator | 6,205 | 18 | 0 | 0 | 0 | 0% |
| Air Actuator | 48,441 | 643 | 0 | 0 | 0 | 0% |
| Totals: | 72,861 | 1,781 | 161 | 5,727 | 120,434 | |

Chapter 10 – Inspection and Maintenance

Many air districts in California require crude oil and natural gas facilities to routinely inspect their fugitive components. Table 8 of the 2007 Oil and Gas Industry Survey collected information about each facility's inspection and maintenance program (I&M). The following information were requested:

- Whether or not the facility follows an I&M program;
- District rule number governing the I&M program; and
- Leak Threshold.

An I&M program is a routine that a facility follows to inspect components for vapor leaks. Many air districts require facilities to inspect their components a specific number of times per year. They will also designate a leak threshold to test against. A component leaking above the threshold or below the threshold will determine how long the facility has to repair the leak. Components with a higher leak rate generally must be repaired sooner than ones with a lower leak rate.

Of the 1,632 facilities that completed the survey, 602 have an I&M program, 566 do not have an I&M program, and 470 did not complete Table 9 of the survey. Table 10-1 lists the number of facilities utilizing each leak threshold. Many facilities have more than one leak threshold they test against depending on the type of component. Thus, the total number of facilities listed in Table 10-1 will add up to more than the total 602 facilities with an I&M program.

Table 10-1: Number of Facilities Utilizing Each Leak Threshold

| Leak Threshold | Number of Facilities |
|---------------------|----------------------|
| 0 – 500 ppm | 247 |
| 500 – 1,000 ppm | 217 |
| 1,000 – 2,000 ppm | 146 |
| 2,000 – 10,000 ppm | 166 |
| 10,000 – 50,000 ppm | 145 |
| > 50,000 ppm | 60 |

Chapter 11 – Natural Gas Dehydrators

Natural gas dehydrators remove water from gas streams by passing natural gas through glycol or over a desiccant material. Table 9 of the 2007 Oil and Gas Industry Survey (Appendix A) collected process information about natural gas dehydrators. Facilities were asked to report the following information:

- Type
 - Glycol or desiccant
 - Facilities could also specify a type not listed above;
- Average natural gas composition
 - Percent CH₄, H₂S, CO₂ for input and output streams
 - Higher heating value (HHV) in btu for input and output streams;
- Input and output volume in standard cubic feet;
- Quantity of liquids removed in tons/year;
- For glycol units
 - Circulation rate (gal/hr)
 - Average flash tank pressure (psia)
 - Average contactor pressure (psia)
 - Whether a gas assisted pump, electric pump, stripping gas, or a flash separator was used;
- For desiccant units
 - Volume of dehydrator (ft³)
 - Pressure (psig)
 - Percent of packed vessel volume that is natural gas
 - Frequency of desiccant replacement (days); and
- For all units' vapor recovery system
 - Type
 - Flare, incinerator, collection system
 - Facilities could also specify a type not listed above
 - Control efficiency.

Emissions

Dehydrators have combustion, vented, and fugitive emissions. Combustion emissions were calculated from Table 5 of the 2007 Oil and Gas Industry Survey and are listed under “reboiler” emissions in Chapter 7 of this report. Vented and fugitive emissions are summarized here.

There are two methods for calculating vented emissions from dehydrators and one method for calculating fugitive. The first venting method is for glycol units. It uses process information to calculate venting losses. The second venting method is for desiccant units. It calculates vented emissions based on replacement of the desiccant material. The third method calculates the fugitive emissions using a mass balance approach. Appendix B details the calculations for all three methods. The CO₂ and CH₄

emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 11-1 lists the vented emissions by type of dehydrator. Some equipment types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Desiccant – desiccant and scrubber dehydrators; and
- Chiller – gas chiller, methanol chiller, low temperature separation, and refrigeration dehydrators.

Glycol dehydrators make up 85 percent of the dehydrators in California and are responsible for almost all the CO₂e emissions.

**Table 11-1: Vented Emissions of Natural Gas Dehydrators by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Glycol | 261 | 308 | 1,974 | 41,772 | 100% |
| Desiccant | 41 | 0.01 | 0.09 | 1.94 | 0% |
| Chiller | 6 | 0 | 0 | 0 | 0% |
| Totals: | 308 | 308 | 1,975 | 41,774 | |

Table 11-2 lists the fugitive emissions by type of dehydrator. Again, glycol dehydrators emit the vast majority of the CO₂e emissions reported in this survey.

**Table 11-2: Fugitive Emissions of Natural Gas Dehydrators by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Glycol | 261 | 16,567 | 718 | 31,643 | 74% |
| Chiller | 6 | 0 | 534 | 11,224 | 26% |
| Desiccant | 41 | 0 | 0 | 0 | 0% |
| Totals: | 308 | 16,567 | 1,252 | 42,866 | |

Table 11-3 lists the total input volume for each dehydrator type. This volume includes natural gas, water, and other impurities. As indicated, nearly the entire input volume is moved through glycol dehydrators.

Table 11-3: Volume of Natural Gas Dehydrators by Type

| Type | Volume (MSCF) | Percent of Total |
|----------------|--------------------|------------------|
| Glycol | 701,123,262 | 100% |
| Desiccant | 1,338,428 | 0% |
| Chiller | 1,119,742 | 0% |
| Totals: | 703,581,432 | |

Table 11-4 lists the combustion, vented, and fugitive emissions from all natural gas dehydrators. The combustion emissions are from Table 5 of the 2007 Oil and Gas Industry Survey and were calculated using the methods detailed in Chapter 7 of this report. This table shows that vented and fugitive CO₂e emissions make up the majority of the emissions from this category.

Table 11-4: Total Emissions of Natural Gas Dehydrators (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 14,093 | 14 | 0 | 14,406 | 15% |
| Vented | 308 | 1,975 | 0 | 41,774 | 42% |
| Fugitive | 16,567 | 1,252 | 0 | 42,866 | 43% |
| Totals: | 30,968 | 3,241 | 0 | 99,046 | |

Table 11-5 lists the number of dehydrators that have vapor recovery units. Less than 50 percent of the glycol dehydrators have vapor recovery units. Overall, only 44 percent of all the dehydrators reported in this survey have vapor recovery units.

Table 11-5: Natural Gas Dehydrators Percent with Vapor Recovery

| Type | Number of Units | Number on Vapor Recovery | Type-Specific Percent on Vapor Recovery |
|----------------|-----------------|--------------------------|---|
| Glycol | 261 | 125 | 48% |
| Chiller | 6 | 5 | 83% |
| Desiccant | 41 | 5 | 12% |
| Totals: | 308 | 135 | 44% |

Table 11-6 lists the types of vapor recovery units used on dehydrators. Some vapor recovery types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Flare – flares and emergency flares;
- Combustion Unit – burn lines, burners, reboilers, and turbines; and
- Collection System – compressors, collection systems, and carbon adsorbers.

Table 11-6: Natural Gas Dehydrators Types of Vapor Recovery

| Type | Number of Units | Percent of Total |
|-------------------|-----------------|------------------|
| None | 173 | 56% |
| Collection System | 77 | 25% |
| Combustion Unit | 25 | 8% |
| Incinerator | 17 | 6% |
| Flare | 11 | 4% |
| Thermal Oxidizer | 5 | 2% |
| Totals: | 308 | |

Chapter 12 – Natural Gas Sweetening and Acid Gas Removal

Natural gas sweetening and acid gas removal units (AGR) remove sulfur and CO₂ from the gas streams. Table 10 of the Oil and Gas Industry Survey collected process information about AGR units. Facilities were asked to report the following information:

- Type
 - Solid and non-solid material (Specific types listed in Appendix A)
 - Facilities could also specify a type not listed;
- Average natural gas composition
 - Percent CH₄, H₂S, CO₂ for input and output streams
 - Higher heating value (HHV) in btu for input and output streams;
- Input and output volume in standard cubic feet;
- Quantity of liquids removed in tons/year;
- CO₂ removal
 - Total CO₂ removed (tons/year)
 - Amount vented (tons/year)
 - Amount incinerated (tons/year)
 - Amount captured (tons/year);
- For solid material units
 - Volume of unit (ft³)
 - Pressure (psig)
 - Percent of packed vessel volume that is natural gas
 - Frequency of material replacement (days); and
- For all units' vapor recovery system
 - Type
 - Flare, incinerator, collection system
 - Facilities could also specify a type not listed above
 - Control efficiency.

Emissions

Natural gas sweetening and AGR units have combustion, vented, and fugitive emissions. Combustion emissions were calculated from Table 5 of the Oil and Gas Industry Survey and are listed under “reboiler” emissions in Chapter 7 of this report. Vented and fugitive emissions are summarized here.

Vented emissions are only calculated for replacing the solid material in solid material AGR units. Fugitive emissions are calculated using a mass balance approach for both solid and non-solid material units. See Appendix B for detailed calculations. The CO₂ and CH₄ emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 12-1 lists the vented emissions by type of AGR unit. These emissions contain the calculated vented emissions from solid material replacement as well as the reported

vented CO₂ values. Some equipment types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Sulfa – sulfa scrubs, sulfa treats, sulfurchecks, soluroxes, and sulfide scavengers; and
- Other – triazine, claus process, grace membrane, contactor, liquid redox, lo-cat, molecular gate.

This table shows that 63 percent of the vented CO₂e emissions are from amine AGR units.

**Table 12-1: Vented Emissions of Natural Gas AGR Units by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Amine | 19 | 32,727 | 0 | 32,727 | 63% |
| Other | 8 | 19,002 | 16 | 19,349 | 37% |
| Sulfa | 38 | 19 | 3 | 72 | 0% |
| Totals: | 65 | 51,749 | 19 | 52,148 | |

Table 12-2 lists the fugitive emissions by type of AGR unit. As listed above for Table 12-1, the same categories were combined to protect confidential company data and to aggregate similar pieces of equipment. This table shows that fugitive emissions are more spread out among the three categories. Here, 50 percent of the fugitive CO₂e emissions are from the “other” category. The remaining 50 percent is split between amine units and sulfa units.

**Table 12-2: Fugitive Emissions of Natural Gas AGR Units by Type
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Other | 8 | 27,651 | 425 | 36,578 | 50% |
| Sulfa | 38 | 22,755 | 0 | 22,756 | 31% |
| Amine | 19 | 11,199 | 151 | 14,360 | 19% |
| Totals: | 65 | 61,605 | 576 | 73,694 | |

Table 12-3 lists the combustion, vented, and fugitive emissions from all natural gas AGR units. The combustion emissions are from Table 5 of the 2007 Oil and Gas Industry Survey and were calculated using the methods detailed in Chapter 7 of this report. This table shows that vented and fugitive CO₂e emissions make up the majority of the emissions from this category.

Table 12-3: Total Emissions of Natural Gas AGR Units (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 3,373 | 0 | 0 | 3,377 | 3% |
| Vented | 51,749 | 19 | 0 | 52,148 | 40% |
| Fugitive | 61,605 | 576 | 0 | 73,694 | 57% |
| Totals: | 116,727 | 595 | 0 | 129,219 | |

Table 12-4 lists the number of AGR units that have vapor recovery units. Overall, 75 percent of all the AGR units in California have vapor recovery units.

Table 12-4: Natural Gas AGR Units Percent on Vapor Recovery

| Type | Number of Units | Number on Vapor Recovery | Type-Specific Percent on Vapor Recovery |
|----------------|-----------------|--------------------------|---|
| Amine | 19 | 11 | 58% |
| Other | 8 | 5 | 63% |
| Sulfa | 38 | 33 | 87% |
| Totals: | 65 | 49 | 75% |

Table 12-5 lists the types of vapor recovery units used on AGR units. Some vapor recovery types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Combustion Unit – boilers, heater/treaters, steam generators, and combustion equipment;
- Collection System – compressors and collection systems.

Table 12-5: Natural Gas AGR Units Types of Vapor Recovery

| Type | Number of Units | Percent of Total |
|-------------------|-----------------|------------------|
| Collection System | 30 | 46% |
| None | 16 | 25% |
| Combustion Unit | 10 | 15% |
| Flare | PD | PD |
| Incinerator | PD | PD |
| Thermal Oxidizer | PD | PD |
| Totals: | 65 | |

Chapter 13 – Other Natural Gas Processing

Other natural gas processing includes all other units that process natural gas but are not dehydrators (Chapter 10) or AGR units (Chapter 11). Table 11 of the Oil and Gas Industry Survey collected information about these units. The following information was requested from each facility:

- Type
 - Fractionation, nitrogen removal, mercury removal
 - Facilities could list a type not listed above;
- Average natural gas composition
 - Percent CH₄, H₂S, CO₂ for input and output streams
 - Higher heating value (HHV) in btu for input and output streams;
- Input and output volume in standard cubic feet;
- Quantity of liquids removed in tons/year; and
- For all units' vapor recovery system
 - Type
 - Flare, incinerator, collection system
 - Facilities could also specify a type not listed above
 - Control efficiency.

Emissions

Emissions of CO₂ and CH₄ from natural gas processing units are calculated using a mass balance approach. This calculation is detailed in Appendix B. Because a mass balance approach calculates the total vapor loss, determining whether they are vented emissions or fugitive emissions or both is not possible. Thus, emissions from these units are categorized as fugitive. The CO₂ and CH₄ emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 13-1 lists the emissions of the natural gas processing units by type. This table shows that almost all the emissions from this category come from fractionation units.

Table 13-1: Emissions of Other Natural Gas Processing Units by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|------------------------------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Fractionation | 5 | 24,888 | 225 | 29,620 | 100% |
| Liquefied Petroleum Gas Extraction | PD | PD | PD | PD | PD |
| Denitrification | PD | PD | PD | PD | PD |
| Scrubber | PD | PD | PD | PD | PD |
| Totals: | 14 | 24,888 | 228 | 29,676 | |

Table 13-2 lists the number of natural gas processing units with vapor recovery by type of unit. This table shows that nearly all fractionation units have vapor recovery and that,

overall, 93 percent of the natural gas processing units have vapor recovery. Collection systems and flares are used as vapor recovery for these natural gas processing units.

Table 13-2: Other Natural Gas Processing Units Percent on Vapor Recovery

| Type | Number of Units | Number on Vapor Recovery | Type-Specific Percent on Vapor Recovery |
|-----------------|------------------------|---------------------------------|--|
| Fractionation | 5 | 5 | 100% |
| LPG Extraction | PD | PD | PD |
| Scrubber | PD | PD | PD |
| Denitrification | PD | PD | PD |
| Totals: | 14 | 13 | 93% |

Chapter 14 – Total Natural Gas Processing Emissions

This chapter combines the emissions from the various natural gas processing equipment discussed in previous chapters. This includes dehydrators (Chapter 11), natural gas sweetening and acid gas removal units (Chapter 12), and other natural gas processing (Chapter 13).

Table 14-1 lists the total California emissions from natural gas processing. As shown, fugitive emissions account for 57 percent of the total emissions from this category while vented emissions account for 36 percent.

Table 14-1: Total California Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 17,466 | 15 | 0 | 17,782 | 7% |
| Vented | 52,056 | 1,994 | 0 | 93,922 | 36% |
| Fugitive | 103,061 | 2,056 | 0 | 146,237 | 57% |
| Totals: | 172,584 | 4,064 | 0 | 257,941 | |

Table 14-2 lists the total natural gas processing emissions by type. This table shows that 50 percent of the emissions from natural gas sweetening and acid gas removal units.

Table 14-2: Natural Gas Processing Emissions by Type (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Sweetening/Acid Gas Removal | 116,727 | 595 | 0 | 129,219 | 50% |
| Dehydration | 30,968 | 3,241 | 0 | 99,046 | 38% |
| Other Processing | 24,888 | 228 | 0 | 29,676 | 12% |
| Totals: | 172,584 | 4,064 | 0 | 257,941 | |

Chapter 15 – Natural Gas Compressors

Natural gas compressors compress natural gas to higher pressures and lower volumes. Table 12 of the 2007 Oil and Gas Industry Survey required facilities to provide the following information about their compressors:

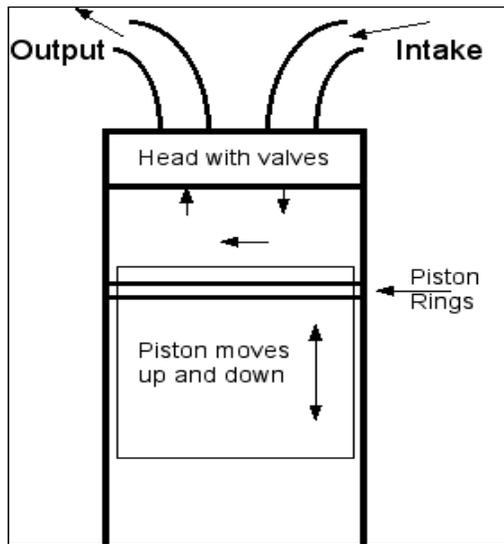
- Type
 - Centrifugal, reciprocating, rotary
 - Facilities could specify a type not listed above;
- For centrifugal
 - Number of wet seals and dry seals;
- For reciprocating
 - Number of cylinders;
- Primary driver type
 - Electric, turbine, piston engine, or integral;
- Starter type
 - Natural gas expansion, instrument air expansion, electric, or hydraulic
 - Facilities could specify a type not listed above;
- Manufacturer;
- Model year;
- Annual usage (hours);
- Inspection frequency;
- Maintenance frequency;
- Discharge pressure (psia);
- Discharge temperature (°F);
- Idle pressure (psia);
- For blowdowns
 - Number
 - Volume of natural gas vented, flared, or recovered; and
- For startups
 - Number
 - Volume of natural gas vented, flared, or recovered.

Table 15-1 lists the number of compressors by type. Some compressor types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. The compressor type “rotary” contain the types rotary, rotary vane, screw, and vane.

Table 15-1: Number of Compressors by Type

| Type | Number of Compressors |
|----------------|-----------------------|
| Centrifugal | 47 |
| Reciprocating | 911 |
| Rotary | 97 |
| Unknown | 16 |
| Totals: | 1,071 |

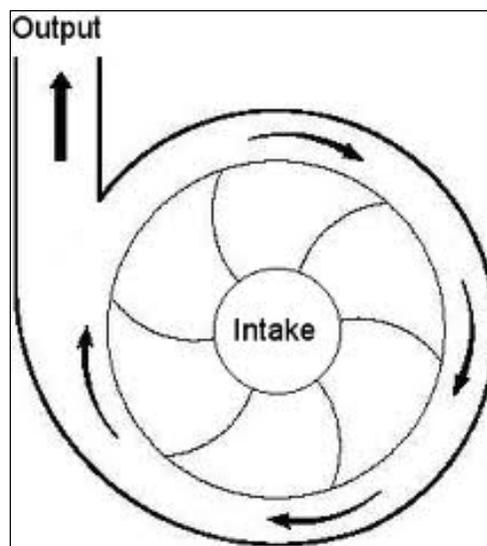
Figure 15-1: Reciprocating Compressor



Figures 15-1 through 15-3 shows the compression chambers for each type of compressor.

Reciprocating compressors increase the pressure of natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

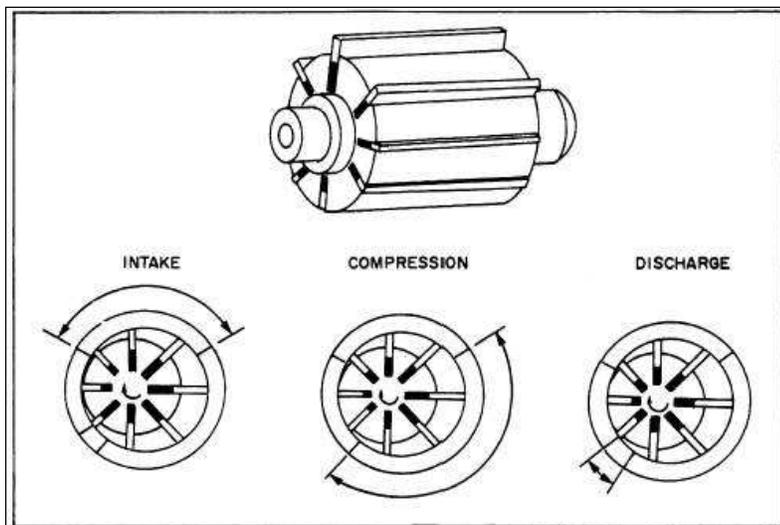
Figure 15-2: Centrifugal Compressor



Centrifugal compressors increase the pressure of natural gas by centrifugal action, employing rotating movement of the drive shaft.

Rotary and screw compressors have blades or a cylinder that rotate off center to compress the natural gas.

Figure 15-3: Rotary Compressor



Each compressor type can have a different driver, which is the engine that drives the compressor. The driver could be electric, turbine, piston engine, or integral. Integral compressors are unique in that the compressor is integrated into the engine design. Essentially the two cannot be separated. Table 15-2 lists the number of compressors by type of compressor and primary driver.

Table 15-2: Number of Primary Drivers by Type

| Type | Electric | Integral | Piston Engine | Turbine | Total |
|----------------|------------|-----------|---------------|-----------|--------------|
| Centrifugal | 18 | PD | 24 | PD | 47 |
| Reciprocating | 313 | PD | 516 | PD | 911 |
| Rotary | 83 | PD | 14 | PD | 97 |
| Unknown | 16 | PD | 0 | PD | 16 |
| Totals: | 430 | PD | 554 | PD | 1,071 |

Compressor starters also vary across the different types of compressors. Some natural gas compressor starters use natural gas expansion. These starters use high-pressure natural gas expanded across the starter to initiate the startup of the engine. The gas is then either vented to the atmosphere or recovered back into the sales line or routed to a flare. Table 15-3 lists the number of compressors by type of compressor and starters.

Table 15-3: Number of Starters by Type

| Type | Electric | Gas Expansion - Instrument Air | Gas Expansion - Natural Gas | Total |
|----------------|------------|--------------------------------|-----------------------------|--------------|
| Centrifugal | 20 | 0 | 27 | 47 |
| Reciprocating | 367 | 52 | 492 | 911 |
| Rotary | 86 | PD | PD | 97 |
| Unknown | 16 | PD | PD | 16 |
| Totals: | 489 | 54 | 528 | 1,071 |

Compressor blowdowns are the depressurization of the compressor. The natural gas in the compressor chamber is either vented to atmosphere, flared, or recovered and piped back into the system. Table 15-4 lists the volumes of natural gas that are flared, recovered, or vented for both compressor blowdowns and natural gas expansion startups.

Table 15-4: Startup and Blowdown Volumes

| Type | Flared (mcsf) | Recovered (mcsf) | Vented (mcsf) |
|----------------|---------------|------------------|----------------|
| Startup | 821 | 42 | 4,196 |
| Blowdown | 9,835 | 26,246 | 189,062 |
| Totals: | 10,657 | 26,288 | 193,259 |

Emissions

Natural gas compressors have combustion, vented, and fugitive emissions. Combustion emissions were calculated from Table 5 of the 2007 Oil and Gas Industry Survey. They are included with the types of internal combustion engines listed in Chapter 7 of this report. Vented and fugitive emissions are calculated here.

Vented emissions are calculated from the volumes of gas released from startups and blowdowns. Fugitive emissions are calculated from the number and type of compressor seals, the hours of operation and seal-specific emission factors. These calculations are detailed in Appendix B. The CO₂ and CH₄ emissions are multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 15-5 lists the vented emissions from natural gas compressor startups, and Table 15-6 lists the vented emissions from blowdowns. The majority of the emissions come from reciprocating compressors. The compressor type “unknown” encompasses survey responses where “other” was checked but the type was not specified.

Table 15-5: Natural Gas Compressor Startup Vented Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Reciprocating | 4 | 68 | 1,438 | 98% |
| Rotary | 0.08 | 0.87 | 18 | 1% |
| Centrifugal | 0.01 | 0.26 | 6 | 0% |
| Unknown | 0 | 0 | 0 | 0% |
| Totals: | 4 | 69 | 1,462 | |

Table 15-6: Natural Gas Compressor Blowdown Vented Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Reciprocating | 170 | 3,210 | 67,578 | 99% |
| Centrifugal | 0 | 17 | 358 | 1% |
| Rotary | 1 | 11 | 229 | 0% |
| Unknown | 0 | 0 | 0 | 0% |
| Totals: | 172 | 3,238 | 68,165 | |

Table 15-7 lists the fugitive emissions from compressor seals. Again, reciprocating compressors account for the majority of the CO₂e emissions for this category.

Table 15-7: Natural Gas Compressor Fugitive Seal Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Reciprocating | 1,797 | 16,871 | 356,096 | 95% |
| Rotary | 200 | 451 | 9,661 | 3% |
| Centrifugal | 28 | 357 | 7,517 | 2% |
| Unknown | 0 | 0 | 0 | 0% |
| Totals: | 2,025 | 17,679 | 373,274 | |

Table 15-8 lists the combustion, vented, and fugitive emissions from all natural gas compressor units. The combustion emissions are from Table 5 of the Oil and Gas Industry Survey (Appendix A) and are categorized under internal combustion engines and turbines in Chapter 7 of this report. This table shows that combustion CO₂e emissions make up the majority of the emissions from this category while fugitive CO₂e account for the majority of the remaining 34 percent.

Table 15-8: Total Emissions of Natural Gas Compressors (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 782,515 | 4,210 | 19 | 876,891 | 66% |
| Vented | 176 | 3,307 | 0 | 69,627 | 5% |
| Fugitive | 2,025 | 17,679 | 0 | 373,274 | 28% |
| Totals: | 784,716 | 25,196 | 19 | 1,319,792 | |

Table 15-9 shows the total compressor emissions by primary business type. These numbers include combustion, vented, and fugitive emissions. The business type “other” includes the following self-reported facility types:

- CNG compression and marketing,
- Cogeneration,
- Combined heat and power,
- Electricity generation,
- Portable heating ,
- Water disposal, and
- Vapor recovery services.

Table 15-9: Compressor Emissions by Primary Business (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|------------------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Onshore Natural Gas | 186,766 | 9,960 | 3 | 396,957 | 30% |
| Natural Gas Processing | 289,705 | 4,449 | 5 | 384,674 | 29% |
| Natural Gas Storage | 188,601 | 5,002 | 9 | 296,357 | 22% |
| Onshore Crude | 116,310 | 4,506 | 2 | 211,517 | 16% |
| Offshore Crude | 179 | 793 | 0 | 16,915 | 1% |
| PERP Equipment Owner | PD | PD | PD | PD | PD |
| Crude Processing | PD | PD | PD | PD | PD |
| Crude Pipeline | PD | PD | PD | PD | PD |
| Other | PD | PD | PD | PD | PD |
| Totals: | 784,716 | 25,196 | 19 | 1,319,792 | |

Table 15-10 lists the total compressor emissions by type of compressor. Reciprocating compressors account for 89 percent of the total CO₂e emissions as well as 85 percent of the total number of compressors.

Table 15-10: Total Emissions of Natural Gas Compressors by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Reciprocating | 911 | 664,407 | 24,168 | 13 | 1,176,006 | 89% |
| Centrifugal | 47 | 110,038 | 535 | 6 | 123,155 | 9% |
| Rotary | 97 | 10,272 | 492 | 0 | 20,631 | 2% |
| Unknown | 16 | 0 | 0 | 0 | 0 | 0% |
| Totals: | 1,071 | 784,716 | 25,196 | 19 | 1,319,792 | |

Table 15-11 lists the total compressor emissions by type of primary driver. Piston engines and integral compressors account for 85 percent of total CO₂e emissions.

**Table 15-11: Total Emissions of Natural Gas Compressors by Primary Driver
(Metric Tons/Year)**

| Type | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Piston Engine | 554 | 414,579 | 15,200 | 6 | 735,647 | 56% |
| Integral | 81 | 281,453 | 4,687 | 7 | 382,146 | 29% |
| Electric | 430 | 1,154 | 5,164 | 0 | 109,591 | 8% |
| Turbine | 6 | 87,530 | 145 | 6 | 92,408 | 7% |
| Totals: | 1,071 | 784,716 | 25,196 | 19 | 1,319,792 | |

Table 15-12 lists the total compressor emissions by type and age of the compressor. Sixty percent of the total emissions from this category are from reciprocating compressors that are over 30 years old or for which the age is unknown.

**Table 15-12: Total Emissions of Natural Gas Compressors by Age
(Metric Tons/Year)**

| Age | Number of Units | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------------|-----------------|-----------------|-----------------|------------------|-------------------|------------------------------------|
| Reciprocating | | | | | | |
| Unknown | 403 | 124,541 | 10,093 | 2 | 337,201 | 26% |
| < 5 Years | 70 | 82,080 | 1,773 | 1 | 119,592 | 9% |
| 5 - 10 Years | 61 | 53,533 | 2,040 | 1 | 96,708 | 7% |
| 10 - 20 Years | 43 | 33,173 | 986 | 0 | 53,991 | 4% |
| 20 - 30 Years | 131 | 57,271 | 2,899 | 2 | 118,655 | 9% |
| > 30 Years | 203 | 313,809 | 6,379 | 7 | 449,859 | 34% |
| Centrifugal | | | | | | |
| Unknown | 9 | 206 | 149 | 0 | 3,335 | 0% |
| < 5 Years | PD | PD | PD | PD | PD | PD |
| 5 - 10 Years | 0 | 0 | 0 | 0 | 0 | 0% |
| 10 - 20 Years | 16 | 8,407 | 155 | 0 | 11,713 | 1% |
| 20 - 30 Years | PD | PD | PD | PD | PD | PD |
| > 30 Years | PD | PD | PD | PD | PD | PD |
| Rotary | | | | | | |
| Unknown | 44 | 3,082 | 255 | 0 | 8,451 | 1% |
| < 5 Years | 34 | 6,856 | 41 | 0 | 7,733 | 1% |
| 5 - 10 Years | PD | PD | PD | PD | PD | PD |
| 10 - 20 Years | 6 | 77 | 29 | 0 | 679 | 0% |
| 20 - 30 Years | 8 | 16 | 165 | 0 | 3,491 | 0% |
| > 30 Years | PD | PD | PD | PD | PD | PD |
| Unknown | | | | | | |
| Unknown | 16 | 0 | 0 | 0 | 0 | 0% |
| Totals: | 1,071 | 784,716 | 25,196 | 19 | 1,319,792 | |

Table 15-3 lists the total number of hours and the average daily usage for each compressor type. This table shows that reciprocating compressors account for the majority of the hours of use.

Table 15-13: Usage of Natural Gas Compressors by Age

| Age | Number of Units | Total Hours | Average Daily Hours |
|----------------------|-----------------|------------------|---------------------|
| Reciprocating | | | |
| Unknown | 403 | 2,400,079 | 16 |
| < 5 Years | 70 | 399,935 | 16 |
| 5 - 10 Years | 61 | 296,475 | 13 |
| 10 - 20 Years | 43 | 292,492 | 19 |
| 20 - 30 Years | 131 | 773,125 | 16 |
| > 30 Years | 203 | 1,155,998 | 16 |
| <i>Subtotals:</i> | <i>911</i> | <i>5,318,104</i> | <i>16</i> |
| Centrifugal | | | |
| Unknown | 9 | 71,430 | 22 |
| < 5 Years | PD | PD | PD |
| 5 - 10 Years | 0 | 0 | 0 |
| 10 - 20 Years | 16 | 69,074 | 12 |
| 20 - 30 Years | PD | PD | PD |
| > 30 Years | PD | PD | PD |
| <i>Subtotals:</i> | <i>47</i> | <i>280,131</i> | <i>16</i> |
| Rotary | | | |
| Unknown | 44 | 299,080 | 19 |
| < 5 Years | 34 | 256,124 | 21 |
| 5 - 10 Years | PD | PD | PD |
| 10 - 20 Years | 6 | 51,943 | 24 |
| 20 - 30 Years | 8 | 61,320 | 21 |
| > 30 Years | PD | PD | PD |
| <i>Subtotals:</i> | <i>97</i> | <i>682,396</i> | <i>19</i> |
| Unknown | | | |
| Unknown | 16 | 140,160 | 24 |
| <i>Subtotals:</i> | <i>16</i> | <i>140,160</i> | <i>24</i> |
| Totals: | 1,062 | 6,349,360 | 16 |

Chapter 16 –Pipeline Pigging and Natural Gas Gathering Pipelines

Pipelines are used to transport crude oil and natural gas around the facility and throughout the state. This chapter only includes information about natural gas gathering system pipelines and pipeline pigging operations for both crude oil and natural gas. It does not include natural gas transmission or distribution pipelines. Table 13 of the 2007 Oil and Gas Industry Survey required facilities to provide the following information about their pipelines:

- Length of natural gas gathering system pipelines;
- Maintenance activities for natural gas gathering system pipelines;
 - Type and volume of natural gas vented, flared, or recovered; and
- Pigging operations
 - Number of crude oil and natural gas launchers and receivers
 - Number of types each launcher and receiver was opened
 - If launcher or receiver was purged with inert gas prior to being opened.

Pipelines in a natural gas gathering system are pipes of various sizes that move natural gas around the facility. They move the natural gas to combustion units, gas processing units, or to compressors to be put into transmission lines. Table 16-1 lists the number of miles of natural gas gathering system pipelines by primary business type. The business type “other” includes the following self-reported facility types:

- CNG compression and marketing,
- Cogeneration,
- Combined heat and power,
- Electricity generation,
- Portable heating ,
- Water disposal, and
- Vapor recovery services.

Table 16-1: Miles of Natural Gas Gathering System Pipelines by Primary Business Type

| Primary Business | Miles of Natural Gas Gathering System Pipeline |
|-------------------------|---|
| Natural Gas Processing | 1,124 |
| Onshore Natural Gas | 626 |
| Onshore Crude | 321 |
| Natural Gas Storage | 169 |
| Offshore Crude | 54 |
| Crude Processing | PD |
| Other | PD |
| Totals: | 2,295 |

Maintenance activities of these natural gas gathering systems encompass repairs or improvements that are done to the pipelines. These activities often result in natural gas being vented to the atmosphere. Table 16-2 lists the volumes of natural gas that were vented, recovered, or flared due to pipeline maintenance activities.

Table 16-2: Natural Gas Gathering System Pipeline Maintenance Activity Volumes

| Type | Flared (mscf) | Recovered (mscf) | Vented (mscf) |
|----------------|----------------|------------------|----------------|
| Pipeline Gas | 2,002 | 628,149 | 3,962 |
| Associated Gas | 349,193 | 1,379,138 | 180,340 |
| Dry Gas | 1,902 | 2,367,936 | 75 |
| Totals: | 353,097 | 4,375,223 | 184,377 |

Pigging refers to sending a device (a “pig”) through a pipeline to clean it. Pigging is used in both crude oil and natural gas pipelines. The natural gas pig launchers and receivers are pressurized with natural gas. This gas is either purged with an inert gas prior to opening, or the gas is vented to atmosphere. Table 16-3 lists the number of pig launchers/receivers and the number of openings.

Table 16-3: Pigging Operations

| Type | Number of Launchers/Receivers | Number of Openings |
|----------------|-------------------------------|--------------------|
| Crude Oil | 786 | 989 |
| Natural Gas | 146 | 1,417 |
| Totals: | 932 | 2,406 |

Emissions

Vented emissions are calculated from the amount of gas vented from natural gas gathering system maintenance activities, and the number of natural gas pigging operations. These are multiplied with an emission factor to yield emission estimates. No emission factor is available for crude oil pigging. Fugitive emissions are calculated from the miles of natural gas pipeline and an emission factor. These calculations are detailed in Appendix B. The CO₂ and CH₄ emissions are multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 16-4 lists the vented emissions from the natural gas gathering system maintenance activities and natural gas pigging operations. As shown, pipeline maintenance activities account for almost all of the vented emissions from pipelines.

Table 16-4: Natural Gas Vented Emissions from Gathering Pipeline Maintenance and Pigging Operations (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------|-----------------|-----------------|-------------------|------------------------------------|
| Natural Gas Pipelines | 2,659 | 2,490 | 54,940 | 100% |
| Natural Gas Pigging | 104 | 5 | 211 | 0% |
| Totals: | 2,763 | 2,495 | 55,151 | |

Table 16-5 lists the fugitive emissions from natural gas pipelines.

**Table 16-5: Natural Gas Fugitive Emissions from Gathering Pipelines
(Metric Tons/Year)**

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|-----------------------|-----------------|-----------------|-------------------|------------------------------------|
| Natural Gas Pipelines | 327 | 867 | 18,541 | 100% |
| Totals: | 327 | 867 | 18,541 | |

Chapter 17 – Separators

Separators are used to split the fluids that come out of a well. In crude oil fields, this fluid can be made of crude oil, natural gas, water, and other contaminants. In natural gas fields, this fluid can contain natural gas, water, and other contaminants. Table 14 of the 2007 Oil and Gas Industry Survey gathered information about separators. Facilities were required to submit the following information about their separators:

- Type
 - Free water knockout, heater/treater, horizontal separator, vertical separator, flow splitter, wemco, emulsion treater, or condensate tank
 - Facilities could also specify a type not listed above;
- Subtype
 - Bolted or welded;
- Size;
- Number of degassing events;
- Throughput in barrels crude oil per year or scf of natural gas per year;
- Crude oil API;
- Reactive organic gas (ROG) and total organic gas (TOG) emissions in tons/year
 - For working, breathing, and flashing losses
 - Average concentration of CH₄ and CO₂ in the vapor losses;
- Whether the separator had an access hatch or pressure relief valve
 - Were they counted in the components from Table 6 of the 2007 Oil and Gas Industry Survey;
- Vapor recovery system type
 - Flare, incinerator, collection system, or none
 - Facilities could also specify a type not listed above; and
- Vapor recovery system control efficiency.

Table 17-1 lists the number of separators by primary business type. The business type “crude processing” and “crude pipeline” were combined to protect confidential company data.

Table 17-1: Number of Separators by Primary Business Type

| Primary Business | Number of Separators |
|-------------------------------|----------------------|
| Onshore Crude | 3,228 |
| Onshore Natural Gas | 891 |
| Natural Gas Processing | 379 |
| Natural Gas Storage | 75 |
| Offshore Crude | 40 |
| Crude Processing and Pipeline | 5 |
| Totals: | 4,618 |

Emissions

Vented emissions are calculated from separator degassing events. This is where the separator is completely emptied of fluids and opened to atmosphere for cleaning or repair. Fugitive emissions are calculated from the total organic gas emissions from working, breathing, and flashing losses and the head space vapor concentrations. These equations are detailed in Appendix B. The CO₂ and CH₄ emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 17-2 lists the total vented and fugitive emissions from separators as reported in the survey. As shown, almost all of the emissions are fugitive.

Table 17-2: Total Emissions of Separators (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Vented | 0 | 1 | 24 | 1% |
| Fugitive | 11 | 170 | 3,578 | 99% |
| Totals: | 11 | 171 | 3,602 | |

Table 17-3 lists the fugitive emissions by type of separator. For approximately 90 percent of the separators reported, a value for ROG or TOG was not reported. Thus, emissions from separators are most likely underestimated. Some separator types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar equipment uses. Appendix E lists the categories and the types they represent.

Table 17-3: Fugitive Emissions of Separators by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Separator | 715 | 0 | 68 | 1,435 | 40% |
| Shipping Tank | 88 | 5 | 54 | 1,139 | 32% |
| Wash Tank | 188 | 1 | 15 | 319 | 9% |
| Vertical Separator | 604 | 1 | 14 | 288 | 8% |
| Produced Water Tank | 130 | 1 | 8 | 160 | 4% |
| Crude Oil Separator | 37 | 1 | 7 | 140 | 4% |
| Wemco | 65 | 0 | 3 | 61 | 2% |
| Free Water Knockout | 297 | 0 | 1 | 19 | 1% |
| Settling tanks | 10 | 0 | 0 | 7 | 0% |
| Heater/Treater | 309 | 0 | 0 | 5 | 0% |
| Stage Separator | 88 | 0 | 0 | 2 | 0% |
| Horizontal Separator | 1,046 | 0 | 0 | 1 | 0% |
| Condensate tank | 81 | 0 | 0 | 0 | 0% |
| Gas Separator | 102 | 0 | 0 | 0 | 0% |
| Surge Tank | 9 | 0 | 0 | 0 | 0% |
| Scrubber | 257 | 0 | 0 | 0 | 0% |
| Trap Separator | 90 | 0 | 0 | 0 | 0% |
| Well Tester | 502 | 0 | 0 | 0 | 0% |
| Totals: | 4,618 | 11 | 170 | 3,578 | |

Seventy-two percent of the emissions come from the categories “separator” and “shipping tank”. The majority of separators in the category “separator” were not reported by a specific type. Shipping tanks are tanks that should have been listed on Table 16 of the 2007 Oil and Gas Industry Survey but were instead listed on Table 15.

Table 17-4 lists the fugitive emissions by subtype of separator. Bolted separators account for 57 percent of the emissions but only 12 percent of the total number. The subtype “unknown” is the next largest contributor to the total fugitive emissions.

Table 17-4: Fugitive Emissions of Separators by Subtype (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Bolted | 537 | 9 | 97 | 2,044 | 57% |
| Unknown | 2,062 | 1 | 68 | 1,423 | 40% |
| Welded | 1,999 | 0 | 5 | 111 | 3% |
| Both | PD | PD | PD | PD | PD |
| None | PD | PD | PD | PD | PD |
| Poly | PD | PD | PD | PD | PD |
| Riveted | PD | PD | PD | PD | PD |
| Totals: | 4,618 | 11 | 170 | 3,578 | |

Table 17-5 lists the number of separator units with vapor recovery by type of separator. This table shows that, overall, 70 percent of separators have vapor recovery.

Table 17-5: Separator Units by Type Percent on Vapor Recovery

| Type | Number of Units | Number on Vapor Recovery | Percent on Vapor Recovery |
|----------------------|-----------------|--------------------------|---------------------------|
| Scrubber | 257 | 257 | 100% |
| Settling tanks | 10 | 10 | 100% |
| Well Tester | 502 | 500 | 100% |
| Surge Tank | 9 | 8 | 89% |
| Stage Separator | 88 | 78 | 89% |
| Gas Separator | 102 | 90 | 88% |
| Wemco | 65 | 56 | 86% |
| Trap Separator | 90 | 74 | 82% |
| Horizontal Separator | 1,046 | 819 | 78% |
| Free Water Knockout | 297 | 209 | 70% |
| Condensate tank | 81 | 52 | 64% |
| Heater/Treater | 309 | 196 | 63% |
| Crude Oil Separator | 37 | 23 | 62% |
| Vertical Separator | 604 | 325 | 54% |
| Produced Water Tank | 130 | 68 | 52% |
| Shipping Tank | 88 | 43 | 49% |
| Separator | 715 | 349 | 49% |
| Wash Tank | 188 | 66 | 35% |
| Totals: | 4,618 | 3,223 | 70% |

Table 17-6 lists the number of separator units with vapor recovery by subtype of separator. For both the welded and bolted subtype, about 50 percent have vapor

recovery. The subtype “unknown” has 96 percent with vapor recovery. The percentages for the remaining subtypes are not shown due to protected data.

Table 17-6: Separator Units by Subtype Percent with Vapor Recovery

| Type | Number of Units | Number with Vapor Recovery | Percent with Vapor Recovery |
|----------------|-----------------|----------------------------|-----------------------------|
| Unknown | 2,062 | 1,975 | 96% |
| Bolted | 537 | 275 | 51% |
| Welded | 1,999 | 966 | 48% |
| Both | PD | PD | PD |
| Riveted | PD | PD | PD |
| None | PD | PD | PD |
| Poly | PD | PD | PD |
| Totals: | 4,618 | 3,223 | 70% |

Table 17-7 lists the types of vapor recovery units used on separators. Some vapor recovery types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Flare – flares, flares/collection systems, flares/collection systems/combustion equipment;
- Combustion Unit – steam generators, pump engines, oil heaters, gas plants, and boilers; and
- Collection System – compressors, collection systems, disposal wells, pressure vessels, fuel gas systems, and carbon adsorbers.

This table shows that 65 percent of the total number of separators uses a collection system for vapor recovery. Four percent send the vapors directly to a flare, incinerator, or combustion unit. The remaining 30 percent have no vapor recovery unit.

Table 17-7: Separator Units by Types of Vapor Recovery

| Type | Number of Units | Percent of Total |
|-------------------|-----------------|------------------|
| Collection System | 3,019 | 65% |
| None | 1,405 | 30% |
| Flare | 105 | 2% |
| Incinerator | 55 | 1% |
| Combustion Unit | 34 | 1% |
| Totals: | 4,618 | |

Chapter 18 – Crude Oil Sumps and Pits

Crude oil sumps and pits are open pits that are used for oil/water separation or for emergency containment. Table 15 of the 2007 Oil and Gas Industry Survey gathered information about sumps and pits. Facilities were required to submit the following information about their sump/pits:

- Level
 - Primary, secondary, tertiary;
- Crude oil API;
- Number of days in use;
- Dimensions
 - Area and depth;
- Vapor recovery system type
 - Flare, incinerator, collection system, cover, or none
 - Facilities could also specify a type not listed above; and
- Vapor recovery system control efficiency.

Primary sumps/pits contain crude oil emulsions straight from the well. The liquids have not gone through any separation. Secondary sumps/pits contain emulsions that have gone through separation and thus contain mostly water and very little crude oil. Tertiary sumps/pits are primarily water.

Emissions

Fugitive emissions from sumps/pits are calculated using emission factors based on the type, area, and the days of use of the sump. These equations are detailed in Appendix B. The CO₂ and CH₄ emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 18-1 lists the fugitive emissions by type of sump/pit. About half the emissions are from primary sumps/pits. The remaining half is split between secondary and tertiary sumps/pits.

Table 18-1: Fugitive Emissions of Sumps/Pits by Type (Metric Tons/Year)

| Type | Number of Sumps | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Primary | 62 | 128 | 2,678 | 48% |
| Secondary | 94 | 80 | 1,674 | 30% |
| Tertiary | 94 | 57 | 1,200 | 22% |
| Totals: | 250 | 264 | 5,552 | |

Table 18-2 lists the fugitive emissions by type of sump/pit for each air district. Only seven air districts contain sump/pits. Most of the CO₂e emissions from sumps/pits are in the San Joaquin Valley and Santa Barbara County air districts.

Table 18-2: Fugitive Emissions of Sumps/Pits by Air District (Metric Tons/Year)

| Air District | Type | Number of Sumps | CH ₄ | CO ₂ e |
|-----------------------------|-----------|-----------------|-----------------|-------------------|
| Bay Area AQMD | Secondary | PD | PD | PD |
| Monterey Bay Unified APCD | Secondary | PD | PD | PD |
| Santa Barbara County APCD | Primary | 36 | 76 | 1,587 |
| | Secondary | 29 | 39 | 826 |
| | Tertiary | 15 | 2 | 40 |
| South Coast AQMD | Primary | PD | PD | PD |
| | Secondary | 27 | 1 | 18 |
| | Tertiary | 34 | 0 | 5 |
| San Joaquin Valley APCD | Primary | 14 | 46 | 971 |
| | Secondary | 18 | 18 | 372 |
| | Tertiary | 30 | 55 | 1,151 |
| San Luis Obispo County APCD | Tertiary | PD | PD | PD |
| Ventura County APCD | Primary | PD | PD | PD |
| | Secondary | 17 | 5 | 100 |
| | Tertiary | 14 | 0 | 4 |
| Totals: | | 250 | 264 | 5,552 |

Table 18-3 lists the number of sumps/pits with vapor recovery. Less than 20 percent of the primary sumps/pits have vapor recovery. Overall, only 50 percent of all sumps/pits have vapor recovery.

Table 18-3: Sumps/Pits by Percent on Vapor Recovery

| Type | Number of Units | Number on Vapor Recovery | Percent on Vapor Recovery |
|----------------|-----------------|--------------------------|---------------------------|
| Primary | 62 | 12 | 19% |
| Secondary | 88 | 75 | 80% |
| Tertiary | 94 | 38 | 40% |
| Totals: | 250 | 125 | 50% |

Table 18-4 lists the types of vapor recovery used on sumps/pits. Some vapor recovery types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Collection System – compressors, collection systems, tanks, and carbon adsorbers; and
- Cover – covers, covers and pressure relief devices, and covers and activated carbon.

This table shows most of the sumps/pits that have vapor recovery use either a cover or a collection system. The remaining sumps/pits have no vapor recovery.

Table 18-4: Sumps/Pits by Types of Vapor Recovery

| Type | Number of Units | Percent of Total |
|-------------------|------------------------|-------------------------|
| None | 125 | 50% |
| Cover | 73 | 29% |
| Collection System | 48 | 19% |
| Flare | PD | PD |
| Incinerator | PD | PD |
| Totals: | 250 | |

Chapter 19 – Crude Oil Storage Tanks

Crude oil storage tanks store crude oil before it's transported to a refinery for processing. They can be located on crude oil extraction sites, at tank farms, along pipelines, or at the refinery. Table 16 of the 2007 Oil and Gas Industry Survey collected information about crude oil storage tanks. Storage tanks at refineries were not included. Facilities were required to submit the following information about their tanks:

- Type
 - Fixed roof, internal floating roof, external floating roof, or open top roof;
- Subtype
 - Bolted or welded;
- Size in barrels;
- Number of degassing events;
- Average crude oil API gravity;
- Reactive organic gas (ROG) and total organic gas (TOG) emissions in tons/year
 - For working, breathing, and flashing losses
 - Average concentration of CH₄ and CO₂ in the vapor losses;
- Whether the storage tank had an access hatch or pressure relief valve
 - Were they counted in the components from Table 6 of the 2007 Oil and Gas Industry Survey;
- For floating roof tanks only
 - Deck leg height in feet
 - Tank diameter in feet
 - Primary seal type
 - Secondary seal type;
- Vapor recovery system type
 - Flare, incinerator, collection system, or none
 - Facilities could also specify a type not listed above; and
- Vapor recovery system control efficiency.

Emissions

Vented emissions are calculated from storage tank degassing events. This is where the storage tank is completely emptied of fluids and opened to atmosphere for cleaning or repair. Fugitive emissions are calculated from the total organic gas emissions from working, breathing, and flashing losses and the head space vapor concentrations. These equations are detailed in Appendix B. The CO₂ and CH₄ emissions are adjusted by the vapor recovery efficiency and then multiplied by their corresponding GWP numbers (1 for CO₂ and 21 for CH₄) to get the CO₂e values.

Table 19-1 lists the total vented and fugitive emissions from storage tanks. As shown, nearly all of the emissions are fugitive.

Table 19-1: Total Emissions of Storage Tanks (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-------------------|------------------------------------|
| Vented | 0 | 5 | 109 | 0% |
| Fugitive | 1,084 | 11,501 | 242,594 | 100% |
| Totals: | 1,084 | 11,506 | 242,703 | |

Table 19-2 lists the fugitive emissions by tank type. Most of the emissions are from fixed roof storage tanks. Fixed roof tanks also account for 94 percent of the total number of storage tanks in California. Approximately 65 percent of the storage tanks reported did not have a value reported for ROG or TOG. Thus, emissions for storage tanks are most likely underestimated.

Table 19-2: Fugitive Emissions of Storage Tanks by Type (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|------------------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Fixed Roof | 3,417 | 993 | 9,795 | 206,683 | 85% |
| Internal Floating Roof | 34 | 71 | 1,492 | 31,396 | 13% |
| External Floating Roof | 138 | 18 | 193 | 4,063 | 2% |
| Open Top Roof | 37 | 2 | 16 | 348 | 0% |
| Unknown | 13 | 0 | 5 | 105 | 0% |
| Totals: | 3,639 | 1,084 | 11,501 | 242,594 | |

Table 19-3 lists the fugitive emissions by subtype. Bolted tanks account for 80 percent of the total fugitive emissions and 61 percent of the total number of storage tanks.

Table 19-3: Fugitive Emissions of Storage Tanks by Subtype (Metric Tons/Year)

| Type | Number of Units | CO ₂ | CH ₄ | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-----------------|-----------------|-----------------|-------------------|------------------------------------|
| Bolted | 2,220 | 937 | 9,239 | 194,960 | 80% |
| Welded | 694 | 141 | 1,463 | 30,874 | 13% |
| Unknown | 653 | 5 | 785 | 16,480 | 7% |
| Riveted | PD | PD | PD | PD | PD |
| Steel | PD | PD | PD | PD | PD |
| Poly | PD | PD | PD | PD | PD |
| Open Top | PD | PD | PD | PD | PD |
| Totals: | 3,639 | 1,084 | 11,501 | 242,594 | |

Table 19-4 lists the number of storage tanks that have vapor recovery by the type of tank. As shown, less than half of the fixed roof tanks have vapor recovery. Floating roof tanks, both internal and external, are considered a type of vapor recovery system for a storage tank. They typically will not have an additional vapor recovery system. Overall, only 45 percent of all the storage tanks have vapor recovery units.

Table 19-4: Storage Tanks by Type Percent with Vapor Recovery

| Type | Number of Units | Number with Vapor Recovery | Percent with Vapor Recovery |
|------------------------|-----------------|----------------------------|-----------------------------|
| Unknown | 13 | 10 | 77% |
| Fixed Roof | 3,417 | 1,579 | 46% |
| Internal Floating Roof | 34 | 10 | 29% |
| External Floating Roof | 138 | 40 | 29% |
| Open Top Roof | 37 | 9 | 24% |
| Totals: | 3,639 | 1,648 | 45% |

Table 19-5 lists the number of storage tanks that have vapor recovery by subtype. Sixty percent of the welded tanks and 44 percent of the bolted tanks have vapor recovery units.

Table 19-5: Storage Tanks by Subtype Percent with Vapor Recovery

| Type | Number of Units | Number with Vapor Recovery | Percent with Vapor Recovery |
|----------------|-----------------|----------------------------|-----------------------------|
| Welded | 694 | 415 | 60% |
| Bolted | 2,220 | 970 | 44% |
| Unknown | 653 | 208 | 32% |
| Steel | PD | PD | PD |
| Poly | PD | PD | PD |
| Riveted | PD | PD | PD |
| Open Top | PD | PD | PD |
| Totals: | 3,639 | 1,648 | 45% |

Table 19-6 lists the type of vapor recovery systems used on storage tanks. Some vapor recovery types were combined from what was listed on individual surveys to protect confidential company data and to aggregate similar pieces of equipment. Below is a list of equipment categories and the types they represent:

- Flare – flares, flares/collection systems, flares/collection systems/combustion equipment;
- Combustion Unit – boilers, gas plants, heaters, heater/treaters, and steam generators; and
- Collection System – collection system, carbon adsorber, compressor, and disposal well.

As shown, most of the storage tanks with vapor recovery utilize collection systems.

Table 19-6: Storage Tanks by Types of Vapor Recovery

| Type | Number of Units | Percent of Total |
|-------------------|-----------------|------------------|
| None | 2,019 | 55% |
| Collection System | 1,313 | 36% |
| Flare | 131 | 4% |
| Combustion Unit | 61 | 2% |
| Incinerator | 61 | 2% |
| Unknown | 54 | 1% |
| Totals: | 3,639 | |

Chapter 20 – Overview of California Emissions from Crude Oil Production, Processing, and Storage

Total Crude Oil Emissions

This chapter gives an overview of emissions from crude oil production, processing, and storage. This encompasses the primary business types: onshore crude production, offshore crude production, crude processing, crude storage, and crude pipelines. These categories account for 62 percent of California's statewide GHG emissions from the oil and gas sector. As can be seen in Table 20-1, most of the emissions come from combustion sources.

Table 20-1: Crude Oil Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|-------------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 10,109,202 | 6,737 | 186 | 10,308,317 | 94% |
| Vented | 34,848 | 5,868 | 0 | 158,077 | 1% |
| Fugitive | 45,939 | 22,283 | 0 | 513,874 | 5% |
| Totals: | 10,189,989 | 34,888 | 186 | 10,980,268 | |

The emissions in Table 20-1 do not include 13 cogeneration units that supply steam to oil fields but do not have any production associated with them. They were listed under the primary business type "other" and their emissions are included in Chapter 8 of this report.

Table 20-2 lists the combustion, vented, and fugitive emissions for crude oil facilities by primary business type. The primary business types crude oil processing and crude oil storage were combined to protect confidential data. Most of the emissions are from onshore crude oil production facilities. The remaining 6 percent of the emissions are from offshore production, processing, storage, and pipelines.

Table 20-2: Crude Oil Emissions by Primary Business Type (Metric Tons/Year)

| Type | Number of Facilities | Combustion (CO ₂ e) | Vented (CO ₂ e) | Fugitive (CO ₂ e) | Total CO ₂ e | Percent of Total CO ₂ e |
|------------------------------|----------------------|--------------------------------|----------------------------|------------------------------|-------------------------|------------------------------------|
| Onshore Crude Production | 668 | 9,784,578 | 125,428 | 433,082 | 10,343,089 | 94% |
| Crude Processing and Storage | 42 | 346,952 | 15,940 | 44,347 | 407,239 | 4% |
| Offshore Crude Production | 16 | 104,272 | 16,708 | 19,138 | 140,118 | 1% |
| Crude Pipeline | 65 | 72,515 | 0 | 17,306 | 89,821 | 1% |
| Totals: | 791 | 10,308,317 | 158,077 | 513,874 | 10,980,268 | |

Total CO₂e emissions were calculated for each facility. The facilities were then categorized into ranges of CO₂e emissions. Table 20-3 lists the number of facilities in each range and the total CO₂e emissions for the facilities in that range. As this table shows, 83 percent of the emissions come from two percent of the facilities.

Table 20-3: Crude Oil Total Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 10,000 | 732 | 438,940 | 4% |
| 10,000 to 25,000 | 20 | 314,565 | 3% |
| 25,000 to 50,000 | 13 | 476,097 | 4% |
| 50,000 to 100,000 | 9 | 653,132 | 6% |
| 100,000 to 500,000 | 11 | 2,475,235 | 23% |
| > 500,000 | 6 | 6,622,297 | 60% |
| Totals: | 791 | 10,980,268 | |

Tables 20-4, 20-5, and 20-6 list the number of facilities and total CO₂e emissions for combustion, vented, and fugitive sources. These tables are similar to Table 20-3 in that the majority of the emissions come from a small fraction of the facilities.

Table 20-4: Crude Oil Combustion Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 10,000 | 742 | 337,672 | 3% |
| 10,000 to 25,000 | 15 | 231,994 | 2% |
| 25,000 to 50,000 | 12 | 454,116 | 4% |
| 50,000 to 100,000 | 6 | 449,261 | 4% |
| 100,000 to 500,000 | 10 | 2,254,854 | 22% |
| > 500,000 | 6 | 6,580,418 | 64% |
| Totals: | 791 | 10,308,317 | |

Tables 20-5 and 20-6 list the number of facilities and total CO₂e emissions for vented and fugitive emissions separately. With the combustion emissions removed, the range of CO₂e values is much smaller. The majority of the facilities fall in the “less than 1,000 metric ton CO₂e per year” range, while a small fraction of the facilities account for a majority of the GHG emissions.

Table 20-5: Crude Oil Vented Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| <1,000 | 776 | 17,152 | 11% |
| 1,000 to 5,000 | 9 | 20,571 | 13% |
| 5,000 to 10,000 | PD | PD | PD |
| 10,000 to 25,000 | PD | PD | PD |
| > 25,000 | PD | PD | PD |
| Totals: | 791 | 158,077 | |

Table 20-6: Crude Oil Fugitive Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 1,000 | 734 | 76,445 | 15% |
| 1,000 to 5,000 | 40 | 74,675 | 15% |
| 5,000 to 10,000 | 8 | 60,736 | 12% |
| 10,000 to 25,000 | PD | PD | PD |
| > 25,000 | PD | PD | PD |
| Totals: | 791 | 513,874 | |

Average Emissions per Barrel Produced

This section includes emissions from onshore and offshore crude production. A way to classify facilities is to determine their average total CO₂e emissions per barrel of crude oil produced. This can be calculated in two ways, as a facility average and as a production-weighted average.

Facility Average

The average CO₂e emissions per barrel of crude oil produced was calculated for each facility by dividing the facility's total CO₂e emissions by its total production. Those values were then averaged for each range of production, as a facility average and as a production-weighted average.

$$\text{Avg. CO}_2\text{e}/\text{bbl}_{\text{range}} = \sum[(\text{CO}_2\text{e}/\text{bbl}_{\text{facility}})]_{\text{range}}/\text{number facilities}_{\text{range}}$$

Production-Weighted Average

The average CO₂e emissions per barrel of crude production was calculated by summing the total CO₂e emissions for each range of production and dividing it by the total barrels produced in that range.

$$\text{Avg. CO}_2\text{e}/\text{bbl}_{\text{range}} = (\text{total CO}_2\text{e}_{\text{range}})/(\text{total bbl}_{\text{range}})$$

The above calculations were done for total emissions and combustion, vented, and fugitive emissions separately. Table 20-7 shows the average CO₂e emissions per barrel for total emissions. The range "not reported" includes facilities that listed themselves as crude production but did not fill out their crude oil production for 2007. Most of the CO₂e emissions per barrel numbers are very close with the exception of the range 10,000 to 25,000. This range is skewed upwards due to facilities generating electricity as well as producing crude oil.

**Table 20-7: Average Total CO₂e Emissions per Barrel Crude Oil Produced
(Metric Tons/Year)**

| Range (Barrels Crude Oil produced per Year) | Number of Facilities | Total Barrels of Crude Oil Produced | Total CO ₂ e | Facility Average CO ₂ e per Barrel | Production Weighted Average CO ₂ e per Barrel |
|---|-------------------------|---|-------------------------|---|---|
| Not Reported | 87 | Not Reported | 208,300 | N/A | N/A |
| < 1,000 | 87 | 42,720 | 3,444 | 0.12 | 0.08 |
| 1,000 to 10,000 | 238 | 961,326 | 36,480 | 0.04 | 0.04 |
| 10,000 to 25,000 | 84 | 1,267,662 | 273,644 | 0.31 | 0.22 |
| 25,000 to 50,000 | 57 | 2,093,042 | 72,740 | 0.04 | 0.03 |
| 50,000 to 75,000 | 21 | 1,344,532 | 101,704 | 0.07 | 0.08 |
| 75,000 to 100,000 | 11 | 896,802 | 16,528 | 0.02 | 0.02 |
| > 100,000 | 99 | 227,371,062 | 9,770,367 | 0.05 | 0.04 |
| Totals: | 684 | 233,977,146 | 10,483,207 | 0.08 | 0.04 |

Table 20-8 shows the average CO₂e emissions per barrel for combustion emissions only. Most of the ranges are relatively similar except for the 10,000 to 25,000 range. Again, this is due to facilities generating electricity as well as producing crude oil.

**Table 20-8: Average Combustion CO₂e Emissions per Barrel Crude Oil Produced
(Metric Tons/Year)**

| Range (Barrels Crude Oil produced per Year) | Number of Facilities | Total Barrels of Crude Oil Produced | Total CO ₂ e | Facility Average CO ₂ e per Barrel | Production Weighted Average CO ₂ e per Barrel |
|---|-------------------------|---|-------------------------|---|---|
| Not Reported | 87 | Not Reported | 176,148 | N/A | N/A |
| < 1,000 | 87 | 42,720 | 1,267 | 0.03 | 0.03 |
| 1,000 to 10,000 | 238 | 961,326 | 25,122 | 0.03 | 0.03 |
| 10,000 to 25,000 | 84 | 1,267,662 | 258,871 | 0.30 | 0.20 |
| 25,000 to 50,000 | 57 | 2,093,042 | 39,504 | 0.02 | 0.02 |
| 50,000 to 75,000 | 21 | 1,344,532 | 92,469 | 0.07 | 0.07 |
| 75,000 to 100,000 | 11 | 896,802 | 4,782 | 0.01 | 0.01 |
| > 100,000 | 99 | 227,371,062 | 9,290,688 | 0.03 | 0.04 |
| Totals: | 684 | 233,977,146 | 9,888,850 | 0.06 | 0.04 |

Table 20-9 shows that vented CO₂e emissions per barrel produced are relatively consistent for all ranges of production.

**Table 20-9: Average Vented CO₂e Emissions per Barrel Crude Oil Produced
(Metric Tons/Year)**

| Range (Barrels Crude Oil produced per Year) | Number of Facilities | Total Barrels of Crude Oil Produced | Total CO ₂ e | Facility Average CO ₂ e per Barrel | Production Weighted Average CO ₂ e per Barrel |
|---|----------------------------|---|----------------------------|---|---|
| Not Reported | 87 | Not Reported | 15,848 | N/A | N/A |
| < 1,000 | 87 | 42,720 | 113 | 0.0025 | 0.0027 |
| 1,000 to 10,000 | 238 | 961,326 | 1,846 | 0.0019 | 0.0019 |
| 10,000 to 25,000 | 84 | 1,267,662 | 1,312 | 0.0010 | 0.0010 |
| 25,000 to 50,000 | 57 | 2,093,042 | 2,213 | 0.0011 | 0.0011 |
| 50,000 to 75,000 | 21 | 1,344,532 | 1,616 | 0.0012 | 0.0012 |
| 75,000 to 100,000 | 11 | 896,802 | 381 | 0.0004 | 0.0004 |
| > 100,000 | 99 | 227,371,062 | 118,807 | 0.0049 | 0.0005 |
| Totals: | 684 | 233,977,146 | 142,137 | 0.0019 | 0.0006 |

Table 20-10 shows the CO₂e emissions per barrel for fugitive emissions only. The high average CO₂e emission per barrel for the < 1,000 range is due to a number of facilities that produce less than 1 barrel of crude oil per day.

**Table 20-10: Average Fugitive CO₂e Emissions per Barrel Crude Oil Produced
(Metric Tons/Year)**

| Range (Barrels Crude Oil produced per Year) | Number of Facilities | Total Barrels of Crude Oil Produced | Total CO ₂ e | Facility Average CO ₂ e per Barrel | Production Weighted Average CO ₂ e per Barrel |
|---|----------------------------|---|----------------------------|---|---|
| Not Reported | 87 | Not Reported | 16,303 | N/A | N/A |
| < 1,000 | 87 | 42,720 | 2,064 | 0.088 | 0.048 |
| 1,000 to 10,000 | 238 | 961,326 | 9,512 | 0.011 | 0.010 |
| 10,000 to 25,000 | 84 | 1,267,662 | 13,461 | 0.010 | 0.011 |
| 25,000 to 50,000 | 57 | 2,093,042 | 31,023 | 0.017 | 0.015 |
| 50,000 to 75,000 | 21 | 1,344,532 | 7,619 | 0.005 | 0.006 |
| 75,000 to 100,000 | 11 | 896,802 | 11,366 | 0.011 | 0.013 |
| > 100,000 | 99 | 227,371,062 | 360,873 | 0.010 | 0.002 |
| Totals: | 684 | 233,977,146 | 452,220 | 0.020 | 0.002 |

Chapter 21 – Overview of California Emissions from Dry Natural Gas Production, Processing, and Storage

Total Natural Gas Emissions

This chapter gives an overview of natural gas production, processing, and storage. This encompasses the primary business types: onshore natural gas production, natural gas processing, and natural gas storage. These categories account for 11 percent of California's statewide GHG emissions from the oil and gas sector. As can be seen in Table 21-1, about 70 percent of the emissions come from combustion sources and about a third come from vented and fugitive sources.

Table 21-1: Natural Gas Emissions (Metric Tons/Year)

| Type | CO ₂ | CH ₄ | N ₂ O | CO ₂ e | Percent of Total CO ₂ e |
|----------------|------------------|-----------------|------------------|-------------------|------------------------------------|
| Combustion | 1,237,087 | 3,918 | 18 | 1,325,080 | 69% |
| Vented | 21,160 | 10,063 | 0 | 232,473 | 12% |
| Fugitive | 61,322 | 14,620 | 0 | 368,335 | 19% |
| Totals: | 1,319,569 | 28,601 | 18 | 1,925,888 | |

Table 21-2 lists the combustion, vented, and fugitive emissions for natural gas facilities. About half of the emissions come from natural gas processing. The remaining emissions are split between onshore gas production and natural gas storage.

Table 21-2: Natural Gas Emissions by Primary Business Type (Metric Tons/Year)

| Type | Number of Facilities | Combustion (CO ₂ e) | Vented (CO ₂ e) | Fugitive (CO ₂ e) | Total CO ₂ e | Percent of Total CO ₂ e |
|------------------------|----------------------|--------------------------------|----------------------------|------------------------------|-------------------------|------------------------------------|
| Natural Gas Processing | 17 | 879,601 | 24,102 | 139,698 | 1,043,400 | 54% |
| Onshore Natural Gas | 703 | 218,910 | 117,835 | 210,879 | 547,624 | 28% |
| Natural Gas Storage | 10 | 226,569 | 90,537 | 17,758 | 334,864 | 17% |
| Totals: | 730 | 1,325,080 | 232,473 | 368,335 | 1,925,888 | |

“Natural gas processing” covers facilities that only process gas but do not extract gas. They are generally referred to as gas plants. Many extraction facilities have gas processing equipment onsite while others send their gas to gas plants.

The CO₂e emissions were calculated for each facility. The facilities were then categorized into ranges of CO₂e emissions. Table 21-3 lists the number of facilities in each range and the CO₂e emissions for the facilities in that range. As this table shows, about 75 percent of the emissions come from about 2 percent of the facilities.

Table 21-3: Total Natural Gas Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 1,000 | 580 | 154,516 | 8% |
| 1,000 to 5,000 | 118 | 231,265 | 12% |
| 5,000 to 10,000 | 15 | 106,265 | 6% |
| 10,000 to 25,000 | 6 | 87,945 | 5% |
| > 25,000 | 11 | 1,345,898 | 70% |
| Totals: | 730 | 1,925,888 | |

Table 21-4 lists the number of facilities in each range and the total combustion CO₂e emissions for all the facilities in that range. Again, most of the emissions come from a small fraction of the facilities. Most of the facilities fall into the < 1,000 CO₂e range.

Table 21-4: Natural Gas Combustion Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 1,000 | 679 | 70,852 | 5% |
| 1,000 to 5,000 | 31 | 67,690 | 5% |
| 5,000 to 10,000 | 5 | 31,319 | 2% |
| 10,000 to 25,000 | 8 | 117,233 | 9% |
| > 25,000 | 7 | 1,037,986 | 78% |
| Totals: | 730 | 1,325,080 | |

Tables 21-5 and 21-6 show the number of facilities and the total CO₂e emissions for vented and fugitive sources separately. Information for three ranges is listed as "PD" to protect confidential data.

Table 21-5: Natural Gas Vented Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| <1,000 | 700 | 82,528 | 35% |
| 1,000 to 5,000 | 25 | 48,270 | 21% |
| 5,000 to 10,000 | PD | PD | PD |
| 10,000 to 25,000 | PD | PD | PD |
| > 25,000 | PD | PD | PD |
| Totals: | 730 | 232,473 | |

Table 21-6: Natural Gas Fugitive Emissions by CO₂e Range (Metric Tons/Year)

| Range (CO ₂ e per Facility) | Number of Facilities | CO ₂ e | Percent of Total CO ₂ e |
|--|----------------------|-------------------|------------------------------------|
| < 1,000 | 661 | 118,093 | 32% |
| 1,000 to 5,000 | 64 | 114,820 | 31% |
| 5,000 to 10,000 | PD | PD | PD |
| 10,000 to 25,000 | PD | PD | PD |
| > 25,000 | PD | PD | PD |
| Totals: | 730 | 368,335 | |

Average Emissions per MSCF Produced

This section includes emissions from onshore and offshore natural gas production. A way to classify facilities is to determine their average total CO₂e emissions per thousand cubic feet (mscf) of natural gas produced. This can be calculated in two ways.

Facility Average

The average CO₂e emissions per mscf natural gas produced was calculated for each facility by dividing the facility's total CO₂e emissions by its total production. Those values were then averaged for each range of production.

$$\text{Avg. CO}_2\text{e/mscf}_{\text{range}} = \sum[(\text{CO}_2\text{e/mscf}_{\text{facility}})]_{\text{range}} / \text{number facilities}_{\text{range}}$$

Production – Weighted Average

The average CO₂e emissions per mscf natural gas production was calculated by summing the total CO₂e emissions for each range of production and dividing it by the total mscf produced in that range.

$$\text{Avg. CO}_2\text{e/mscf}_{\text{range}} = (\text{total CO}_2\text{e}_{\text{range}}) / (\text{total mscf}_{\text{range}})$$

The above calculations were done for total emissions and combustion, vented, and fugitive emissions separately. Table 21-7 shows the average CO₂e emissions per mscf for total emissions. The range “not reported” includes facilities that listed themselves as natural gas production but did not fill out their natural gas production for 2007.

Table 21-7 shows that most of the ranges have similar average CO₂e emissions per mscf of natural gas produced except for the two lowest ranges. The “< 1,000 mscf” range has several facilities that produce less than one mscf of natural gas. This artificially increases the CO₂e emissions per mscf. The “1,000 to 50,000 mscf” range is larger than the remaining ranges due to several facilities with compressors onsite.

Table 21-7: Average Total CO₂e Emissions per MSCF Natural Gas Produced (Metric Tons/Year)

| Range (MSCF Natural Gas Produced per Year) | Number of Facilities | Total MSCF of Natural Gas Produced | Total CO ₂ e | Facility Weighted Average CO ₂ e per MSCF | Production Weighted Average CO ₂ e per MSCF |
|--|----------------------|------------------------------------|-------------------------|--|--|
| Not Reported | 31 | Not Reported | 50,656 | N/A | N/A |
| < 1,000 | 57 | 5,196 | 1,023 | 25.438 | 0.197 |
| 1,000 to 50,000 | 329 | 9,181,032 | 202,829 | 0.052 | 0.022 |
| 50,000 to 250,000 | 242 | 34,859,306 | 252,624 | 0.007 | 0.007 |
| 250,000 to 500,000 | 35 | 10,830,889 | 27,687 | 0.003 | 0.003 |
| > 500,000 | 9 | 13,178,870 | 12,805 | 0.001 | 0.001 |
| Totals: | 703 | 68,055,293 | 547,624 | 2.090 | 0.008 |

Table 21-8 lists the average CO₂e emissions per mscf natural gas produced for combustion emissions by range of production. Here, the bottom two ranges have higher CO₂e per mscf values due to the reasons stated above for Table 21-7.

Table 21-8: Average Combustion CO₂e Emissions per MSCF Natural Gas Produced (Metric Tons/Year)

| Range (MSCF Natural Gas Produced per Year) | Number of Facilities | Total MSCF of Natural Gas Produced | Total CO ₂ e | Facility Weighted Average CO ₂ e per MSCF | Production Weighted Average CO ₂ e per MSCF |
|--|----------------------|------------------------------------|-------------------------|--|--|
| Not Reported | 31 | Not Reported | 36,316 | N/A | N/A |
| < 1,000 | 57 | 5,196 | 178 | 0.0056 | 0.0343 |
| 1,000 to 50,000 | 329 | 9,181,032 | 108,511 | 0.0227 | 0.0118 |
| 50,000 to 250,000 | 242 | 34,859,306 | 59,464 | 0.0018 | 0.0017 |
| 250,000 to 500,000 | 35 | 10,830,889 | 7,777 | 0.0008 | 0.0007 |
| > 500,000 | 9 | 13,178,870 | 6,664 | 0.0003 | 0.0005 |
| Totals: | 703 | 68,055,293 | 218,910 | 0.0118 | 0.0032 |

Tables 21-9 and 21-10 detail the average CO₂e emissions per mscf of natural gas produced for vented and fugitive emissions. In both these tables, the range “< 1,000 mscf” range is higher due to several facilities producing less than one mscf of natural gas.

Table 21-9: Average Vented CO₂e Emissions per MSCF Natural Gas Produced (Metric Tons/Year)

| Range (MSCF Natural Gas Produced per Year) | Number of Facilities | Total MSCF of Natural Gas Produced | Total CO ₂ e | Facility Weighted Average CO ₂ e per MSCF | Production Weighted Average CO ₂ e per MSCF |
|--|----------------------|------------------------------------|-------------------------|--|--|
| Not Reported | 31 | Not Reported | 4,434 | N/A | N/A |
| < 1,000 | 57 | 5,196 | 609 | 1.0773 | 0.1172 |
| 1,000 to 50,000 | 329 | 9,181,032 | 30,316 | 0.0097 | 0.0033 |
| 50,000 to 250,000 | 242 | 34,859,306 | 71,806 | 0.0020 | 0.0021 |
| 250,000 to 500,000 | 35 | 10,830,889 | 6,308 | 0.0006 | 0.0006 |
| > 500,000 | 9 | 13,178,870 | 4,361 | 0.0001 | 0.0003 |
| Totals: | 703 | 68,055,293 | 117,835 | 0.0926 | 0.0017 |

Table 21-10: Average Fugitive CO₂e Emissions per MSCF Natural Gas Produced (Metric Tons/Year)

| Range (MSCF Natural Gas Produced per Year) | Number of Facilities | Total MSCF of Natural Gas Produced | Total CO ₂ e | Facility Weighted Average CO ₂ e per MSCF | Production Weighted Average CO ₂ e per MSCF |
|--|----------------------|------------------------------------|-------------------------|--|--|
| Not Reported | 31 | Not Reported | 9,907 | N/A | N/A |
| < 1,000 | 57 | 5,196 | 236 | 24.3552 | 0.0454 |
| 1,000 to 50,000 | 329 | 9,181,032 | 64,001 | 0.0196 | 0.0070 |
| 50,000 to 250,000 | 242 | 34,859,306 | 121,354 | 0.0037 | 0.0035 |
| 250,000 to 500,000 | 35 | 10,830,889 | 13,601 | 0.0013 | 0.0013 |
| > 500,000 | 9 | 13,178,870 | 1,780 | 0.0001 | 0.0001 |
| Totals: | 703 | 68,055,293 | 210,879 | 1.9852 | 0.0031 |

Appendix A: 2007 Oil and Gas Industry Survey

**California Air Resources Board
Oil and Gas Industry Survey**

Air Resources Board

Mary D. Nichols, Chairman

1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov



Arnold Schwarzenegger
Governor

Linda S. Adams
Secretary for
Environmental Protection

February 17, 2009

Dear Sir or Madam:

The Air Resources Board (ARB) is requesting your participation in a survey of the oil and natural gas sector. This sector includes oil and gas extraction, processing, storage, and crude oil pipelines. The purpose of this survey is to improve our current estimate of greenhouse gas emissions in California. Gathering this information is part of our responsibilities under AB 32, the California Global Warming Solutions Act of 2006 (California Health and Safety Code section 38500 to 38599). Due to the wide range of operations in this sector, your participation is important to help us make accurate estimates.

We have designed the enclosed survey in a table format. We will also accept electronic data transfers and have included both Microsoft Excel and Access templates on the enclosed compact disc for your convenience. Please see the enclosed instructions for assistance and to locate staff who can answer specific questions.

Pursuant to California state law, **completion and submittal of this survey is a mandatory requirement.** The information being requested is for use by the ARB to develop a baseline greenhouse gas emissions inventory. This request for information is made pursuant to sections 39607, 39701, and 41511 of the California Health and Safety Code, and Title 17, California Code of Regulations, section 91100. These sections authorize the ARB to require the submission of information needed to estimate atmospheric emissions and to carry out its other statutory responsibilities.

All data will be protected as confidential in accordance with Title 17, California Code of Regulations, section 91000 to 91022 and the California Public Records Act (Government Code section 6250 et seq.).

We appreciate your participation and are available to provide assistance. Please submit the completed survey or electronic data transfers by **April 30, 2009**.

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website: <http://www.arb.ca.gov>.

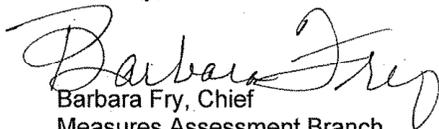
California Environmental Protection Agency

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Sir or Madam
February 17, 2009
Page 2

For general questions, please contact Joseph Fischer at (916) 445-0071 or via e-mail at joseph.fischer@arb.ca.gov. For additional information, or to sign up for our automatic e-mail notification system, please visit <http://www.arb.ca.gov/oil-gas/oil-gas.htm>.

Sincerely,



Barbara Fry, Chief
Measures Assessment Branch
Stationary Source Division

cc: Mr. Joseph Fischer
Air Resources Engineer

Enclosures

California Air Resources Board
Oil and Gas Industry Survey

**For additional information related to this survey, please see
accompanying
General Instructions.**

Reporting Year 2007

Table 1: Facility Description

| | | | |
|--|--------|--|--|
| Company Name: | | | |
| Facility Name: | | Air District: | |
| Address: | | | |
| City: | State: | Zip: | |
| Contact Person: | Phone: | Email: | |
| Type of Business (Check all that apply) | | Air District Facility ID¹: | |
| <input type="checkbox"/> Onshore Crude Oil Production | | _____ | |
| <input type="checkbox"/> Offshore Crude Oil Production | | _____ | |
| <input type="checkbox"/> Onshore Natural Gas Production | | _____ | |
| <input type="checkbox"/> Offshore Natural Gas Production | | _____ | |
| <input type="checkbox"/> Natural Gas Storage Facility | | _____ | |
| <input type="checkbox"/> Natural Gas Processing | | _____ | |
| <input type="checkbox"/> Crude Oil Pipeline | | _____ | |
| <input type="checkbox"/> Crude Oil Storage | | _____ | |
| <input type="checkbox"/> Crude Oil Processing | | _____ | |
| <input type="checkbox"/> PERP Equipment Owner ² | | _____ | |
| <input type="checkbox"/> Other (Specify): _____ | | _____ | |

1. If your facility does not have an air district facility ID, please see instructions to create one. This code will be used in the remaining tables under "Air District Facility ID".
2. Portable Equipment Registration Program (PERP).

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 2: Facility Production

| | | | | | | |
|---|---|------------------------------------|---|--|--|---|
| Facility Name: _____ | | | | | | |
| Box 1: Production | | | | | | |
| | Produced Natural Gas¹ | Natural Gas Storage | Ultra Heavy Oil API < 10° | Heavy Oil API 10° - 20° | Light Oil API 20° - 30° | Ultra Light Oil API > 30° |
| Number of: | | | | | | |
| Active Wells | _____ | _____ | _____ | _____ | _____ | _____ |
| Well Cellars | _____ | _____ | _____ | _____ | _____ | _____ |
| New Wells Drilled | _____ | _____ | _____ | _____ | _____ | _____ |
| Workovers (Tubing Removal) | _____ | _____ | _____ | _____ | _____ | _____ |
| Well Cleanups ³ | _____ | _____ | _____ | _____ | _____ | _____ |
| Well Completions | _____ | _____ | _____ | _____ | _____ | _____ |
| Volume Produced (bbl) | | _____ | _____ | _____ | _____ | _____ |
| Box 2: Associated or Produced Natural Gas Production² | | | | | | |
| | Mole % Methane | Mole % CO₂ | Mole % H₂S | Higher Heating Value (Btu) | Volume Produced (SCF) | |
| Average Raw Gas Stream | _____ | _____ | _____ | _____ | _____ | |
| Box 3: Crude Oil Transmission Pipeline (After LACT Unit) | | | | | | |
| Volume Transported _____ | | | | | | |
| Barrels Crude Oil | _____ | | Length (Miles) | _____ | | |

1. Produced Natural Gas is gas extracted from a non-oil producing gas well. This category does not include associated gas.

2. Associated Gas is gas produced with crude oil extraction. Box 2 is to be used for both associated and produced natural gas.

3. Well cleanups are maintenance activities that include fracturing or removing fluids to increase production.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 3: Facility Electrification

| | | |
|--------------------------------------|-------------------------------|--------------------------------|
| Air District Facility ID: | | |
| Onsite Generated Electricity: | | |
| Amount Generated: _____ MWh | Amount Exported: _____ MWh | Amount Purchased: _____ MWh |

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 4: Vapor Recovery and Flares
(Complete one for each piece of equipment)**

| | |
|--|---|
| Air District Facility ID: _____ | |
| Type: <input type="checkbox"/> Flare <input type="checkbox"/> Thermal Oxidizer <input type="checkbox"/> Incinerator <input type="checkbox"/> Carbon Adsorption | Use: <input type="checkbox"/> Vapor Recovery <input type="checkbox"/> Emergency |
| Flares, Thermal Oxidizers, and Incinerators Only Size (Btu/hr): _____ Throughput (SCF): _____ Combustion Efficiency: _____ Avg. Composition (Mole %): _____ % Methane _____ % CO ₂ Carbon Mole Ratio ¹ _____ | Carbon Adsorbers Only: Size (ft ³): _____ Throughput (SCF): _____ Capture Efficiency: _____ Avg. Composition (Mole %): _____ % Methane |

1. Please see instructions to calculate the carbon mole ratio.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 5: Combustion Equipment
(Complete one for each piece of equipment)**

| | | | |
|--|--|--|--|
| Air District Facility ID: _____ | | | |
| External Combustion Type: | | | |
| <input type="checkbox"/> Boiler | <input type="checkbox"/> Heater/Treater | <input type="checkbox"/> Reboiler | <input type="checkbox"/> Other (Specify) _____ |
| <input type="checkbox"/> Steam Generator | <input type="checkbox"/> Oil Heater | o Glycol | _____ |
| | | o Amine | |
| Internal Combustion Type: | | | |
| Type: | | Use: | |
| <input type="checkbox"/> Reciprocating | <input type="checkbox"/> Turbine | <input type="checkbox"/> Compressor | |
| o Rich Burn Two-Stroke | o Simple Cycle | o ID ¹ _____ | |
| o Lean Burn Two-Stroke | o Combined Cycle | <input type="checkbox"/> Vapor Recovery | |
| o Rich Burn Four-Stroke | <input type="checkbox"/> Microturbine | <input type="checkbox"/> Crude Oil Pump | |
| o Lean Burn Four-Stroke | <input type="checkbox"/> Drill Rig | <input type="checkbox"/> Well Pump | |
| <input type="checkbox"/> Combined Heat and Power | <input type="checkbox"/> Workover Rig | <input type="checkbox"/> Water Injection Pump | |
| | | <input type="checkbox"/> Other (Specify) _____ | |
| Manufacturer ² : | Fuel Type: | Primary | Secondary |
| | Diesel | <input type="checkbox"/> | <input type="checkbox"/> |
| | Pipeline Quality Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| Model Year: | Associated Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| | Produced Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| | Waste Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| Average Load (HP/BTU/MW): | Landfill Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| | Liquefied Petroleum Gas | <input type="checkbox"/> | <input type="checkbox"/> |
| | Propane | <input type="checkbox"/> | <input type="checkbox"/> |
| Avg. Thermal Efficiency: (Steam Generators and Turbine Engines) | Gasoline | <input type="checkbox"/> | <input type="checkbox"/> |
| | Other (Specify): _____ | <input type="checkbox"/> | <input type="checkbox"/> |
| | Annual Fuel Volume: (Gallons/SCF) | | |
| Inspection Frequency: | Metered | _____ | _____ |
| Instrument Test _____ | Calculated | _____ | _____ |
| Visual Inspection _____ | Avg. Higher Heating Value (Btu) | _____ | _____ |
| Third Party _____ | Carbon Weight % | _____ | _____ |
| Under Air District Permit? | Liquid Fuel Density (lb/gal) | _____ | _____ |
| <input type="checkbox"/> Yes <input type="checkbox"/> No | Gaseous Fuel Molecular Weight³ | _____ | _____ |
| PERP ⁴ Registered? | | | |
| <input type="checkbox"/> Yes <input type="checkbox"/> No | | | |

1. Create a unique ID number for each compressor engine. The number will be used in conjunction with Table 12.

2. For external combustion, list the burner manufacturer.

3. See instructions for calculation. 4. Portable Equipment Registration Program (PERP)

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 6: Component Counts¹

| | | | |
|--|--|--------------------------------------|--------------------------------------|
| Air District Facility ID: | | | |
| Type: | Number of Components by Product Type: | | |
| (1-inch and above): | Natural Gas | Light Crude (API >20°) | Heavy Crude (API <20°) |
| <input type="checkbox"/> Manual Valves | _____ | _____ | _____ |
| <input type="checkbox"/> Flanges | _____ | _____ | _____ |
| <input type="checkbox"/> Connectors | _____ | _____ | _____ |
| <input type="checkbox"/> Open-ended Lines | _____ | _____ | _____ |
| <input type="checkbox"/> Threaded Components | _____ | _____ | _____ |
| Other Components: | | | |
| <input type="checkbox"/> Pump Seals | _____ | _____ | _____ |
| <input type="checkbox"/> Pressure Relief Valves | _____ | _____ | _____ |
| <input type="checkbox"/> Bursting Discs | _____ | _____ | _____ |
| <input type="checkbox"/> Diaphragms | _____ | _____ | _____ |
| <input type="checkbox"/> Hatches | _____ | _____ | _____ |
| <input type="checkbox"/> Meters | _____ | _____ | _____ |
| <input type="checkbox"/> Polished Rod Stuffing Boxes | _____ | _____ | _____ |
| <input type="checkbox"/> Sight Glasses | _____ | _____ | _____ |
| <input type="checkbox"/> Loading Arms | _____ | _____ | _____ |
| <input type="checkbox"/> Dump Lever Arm | _____ | _____ | _____ |

1. If actual counts are not available please estimate. See instructions for details.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 7: Automated Control Devices¹

| | | |
|--------------------------------|----------------|---|
| Air District Facility ID: | | |
| Controllers: | | |
| Gas Actuated | Number: | Number on Gas Recovery² |
| Continuous Bleed | _____ | _____ |
| Intermittent Bleed | _____ | _____ |
| Low Bleed | _____ | _____ |
| No Bleed ³ | _____ | _____ |
| Electronically Actuated | _____ | _____ |
| Air Actuated | _____ | _____ |
| Actuators: | | |
| Gas Actuated | | |
| Piston Valve Operator | _____ | _____ |
| Hydraulic Valve Operator | _____ | _____ |
| Turbine Valve Operator | _____ | _____ |
| Electronically Actuated | _____ | _____ |
| Air Actuated | _____ | _____ |

1. If actual counts are unavailable, please estimate.
2. Includes units connected to a vapor recovery system or vented back into a system.
3. A "No Bleed" controller is not connected to a gas recovery system.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 8: Inspection and Maintenance Program¹
(For Table 6 and 7)

| | |
|--|-----------------------|
| Air District Facility ID: | |
| Does your facility follow an Inspection and Maintenance (I&M) Program? <input type="checkbox"/> Yes <input type="checkbox"/> No | |
| District Rule # for I&M Program (If Applicable): | |
| I&M Program Type: | |
| Stratum: | Leak Threshold (ppm): |
| <input type="checkbox"/> 0 – 500 ppm | _____ |
| <input type="checkbox"/> 500 – 1,000 ppm | _____ |
| <input type="checkbox"/> 1,000 – 2,000 ppm | _____ |
| <input type="checkbox"/> 2,000 – 10,000 ppm | _____ |
| <input type="checkbox"/> 10,000 – 50,000 ppm | _____ |
| <input type="checkbox"/> > 50,000 ppm | _____ |
| Is this test data available electronically? <input type="checkbox"/> Yes <input type="checkbox"/> No (If yes, please submit electronically) | |

1. An Inspection and Maintenance Program is where the operator of a facility inspects their facility for leaks of organic gases and repairs the leaks.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 9: Natural Gas Dehydration
(Complete one for each piece of equipment)**

| | | | |
|--|------------------------------|--|--|
| Air District Facility ID: _____ | | | |
| Type: | | | |
| <input type="checkbox"/> Glycol | | <input type="checkbox"/> Desiccant | |
| <input type="checkbox"/> Other (Specify) _____ | | | |
| Avg. Natural Gas Composition (Mole %): | | Input Volume (SCF): | |
| Input: | Output: | Output Volume (SCF): | |
| _____ % Methane | _____ % Methane | | |
| _____ % H ₂ S | _____ % H ₂ S | | |
| _____ % CO ₂ | _____ % CO ₂ | | |
| _____ HHV ¹ (Btu) | _____ HHV ¹ (Btu) | Volume of Liquids Removed (tons/year): | |
| For Glycol Units Only: | | | |
| Glycol Circulation Rate (Gallons/Hour): _____ | | Gas Assisted Pump? | <input type="checkbox"/> Yes <input type="checkbox"/> No |
| Average Flash Tank Pressure (PSIA): _____ | | Electric Pump? | <input type="checkbox"/> Yes <input type="checkbox"/> No |
| Average Contactor Pressure (PSIA): _____ | | Stripping Gas Used? | <input type="checkbox"/> Yes <input type="checkbox"/> No |
| | | Flash Separator? | <input type="checkbox"/> Yes <input type="checkbox"/> No |
| For Desiccant Units Only: | | | |
| Volume of Dehydrator (ft ³): _____ | | % of Packed Vessel Volume that is Natural Gas ² : _____ | |
| Vessel Pressure (PSIG): _____ | | Frequency of Desiccant Replacement (days): _____ | |
| Vapor Recovery System: | | | |
| <input type="checkbox"/> Flare | | <input type="checkbox"/> None | |
| <input type="checkbox"/> Incinerator | | <input type="checkbox"/> Other (Specify) _____ | |
| <input type="checkbox"/> Collection System | | Control Efficiency: _____% | |

1. HHV is Higher Heating Value.

2. See instructions.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 11: Other Natural Gas Processing
(Complete one for each piece of equipment)**

| | |
|--|--|
| Air District Facility ID: _____ | |
| Unit Type: <input type="checkbox"/> Fractionation <input type="checkbox"/> Mercury Removal <input type="checkbox"/> Nitrogen Removal <input type="checkbox"/> Other (Specify) _____ | |
| Avg. Natural Gas Composition (Mole %): | |
| Input: _____ % Methane _____ % H ₂ S _____ % CO ₂ _____ HHV ¹ (Btu) | Output: _____ % Methane _____ % H ₂ S _____ % CO ₂ _____ HHV ¹ (Btu) |
| Input Volume (SCF): _____ | |
| Output Volume (SCF): _____ | |
| Volume of Liquids Removed (tons/year): _____ | |
| Vapor Recovery System: <input type="checkbox"/> Flare <input type="checkbox"/> Other (Specify) _____ Control Efficiency: _____% <input type="checkbox"/> Incinerator <input type="checkbox"/> None <input type="checkbox"/> Collection System | |

1. HHV is Higher Heating Value.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 12: Natural Gas Compressors
(Complete one for each piece of equipment)**

| | | |
|--|---|---|
| Air District Facility ID: _____ | | |
| Type: <input type="checkbox"/> Centrifugal ○ # Wet Seals _____ ○ # Dry Seals _____ <input type="checkbox"/> Reciprocating ○ # Cylinders _____ <input type="checkbox"/> Rotary <input type="checkbox"/> Other (Specify) _____ | Primary Driver: Compressor ID ¹ _____ Type: <input type="checkbox"/> Electric <input type="checkbox"/> Turbine <input type="checkbox"/> Piston Engine <input type="checkbox"/> Integral | Starter Type (For Primary Driver): <input type="checkbox"/> Gas Expansion ○ Natural Gas ○ Instrument Air <input type="checkbox"/> Electric <input type="checkbox"/> Hydraulic <input type="checkbox"/> Other (Specify) _____ |
| Manufacturer: _____ | Model Year: _____ | Annual Usage (Hours): _____ |
| Inspection Frequency (Daily, Monthly, Annually, ect.): _____ | | Maintenance Frequency ² : _____ |
| Discharge Pressure (PSIA) _____ | Discharge Temperature (°F) _____ | Idle Pressure (PSIA) _____ |
| Blow-downs: Total Number: _____ Total Volume of Gas for Blow-downs (SCF): <input type="checkbox"/> Vented _____ <input type="checkbox"/> Flared _____ <input type="checkbox"/> Recovered _____ | | Start-ups: Total Number: _____ Total Volume of Gas for Start-ups (SCF): <input type="checkbox"/> Vented _____ <input type="checkbox"/> Flared _____ <input type="checkbox"/> Recovered _____ |

1. Enter the compressor engine ID number from Table 5. If the compressor engine is electric, leave this field blank.

2. The maintenance frequency is the number of times the unit had to be disassembled to replace valves, seals, or packing.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

Table 13: Pipelines

| | | | |
|--|-----------------|-----------------------------|---------------------------|
| Air District Facility ID: _____ | | | |
| Natural Gas: Extraction Facility Gathering System (Prior to Gas Meter) Estimated Length (miles): _____ | | | |
| Natural Gas Gathering System Maintenance Activities (SCF): | | | |
| | Pipeline Gas | Associated Gas ¹ | Produced Gas ² |
| Vented | _____ | _____ | _____ |
| Flared | _____ | _____ | _____ |
| Recovered ³ | _____ | _____ | _____ |
| Pigging Operations: | | | |
| Number of Launchers/Receivers | Crude Oil _____ | Natural Gas _____ | |
| Number of Launcher/Receiver Openings | Crude Oil _____ | Natural Gas _____ | |
| Are Launchers/Receivers Purged with Inert Gas Prior to Opening? <input type="checkbox"/> Yes <input type="checkbox"/> No | | | |

1. Associated Natural Gas is gas produced with crude oil extraction.

2. Produced Natural Gas is gas extracted from a gas well.

3. Recovered is any volume of gas that is not either vented or flared.

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 14: Crude Oil or Natural Gas Separation Units
(Complete one per piece of equipment)**

| | | | |
|--|--|--|--|
| Air District Facility ID: _____ | | | |
| Type: <input type="checkbox"/> Free Water Knockout <input type="checkbox"/> Heater/Treater <input type="checkbox"/> Horizontal Separator <input type="checkbox"/> Vertical Separator <input type="checkbox"/> Flow Splitter <input type="checkbox"/> Wemco <input type="checkbox"/> Emulsion Treater <input type="checkbox"/> Condensate Tank <input type="checkbox"/> Other (Specify) _____ | Subtype: <input type="checkbox"/> Bolted <input type="checkbox"/> Welded | | Size (Barrels/SCF): _____ |
| | | | Number of Degassing Events: _____ |
| | | | Throughput (Barrels/year or SCF/year): _____ |
| | | | Avg. Crude Oil API: _____ |
| Working Loss _____ _____ Breathing Loss _____ _____ Flashing Loss _____ _____ Avg. Methane _____ % Avg. CO₂ _____ % | Components: <input type="checkbox"/> Access Hatch <input type="checkbox"/> Pressure Relief Valve Are hatches and pressure relief valves included in Table 6? <input type="checkbox"/> Yes <input type="checkbox"/> No | | |
| Vapor Recovery System: <input type="checkbox"/> Flare <input type="checkbox"/> None Control Efficiency: _____% <input type="checkbox"/> Incinerator <input type="checkbox"/> Other (Specify) _____ <input type="checkbox"/> Collection System | | | |

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 15: Crude Oil Separation Sumps or Pits
(Complete one per piece of equipment)**

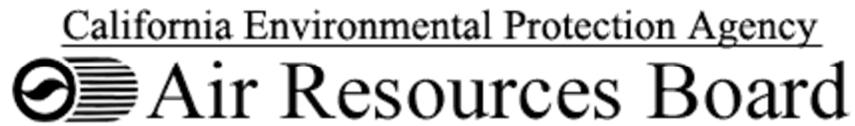
| | |
|--|--|
| Air District Facility ID: _____ | |
| Level: <input type="checkbox"/> Primary <input type="checkbox"/> Secondary <input type="checkbox"/> Tertiary | Usage: <input type="checkbox"/> Crude Oil API _____ <input type="checkbox"/> Number of Days in Use _____ |
| Dimensions: Area (Square Feet) _____ Depth (Feet) _____ | Vapor Recovery System: <input type="checkbox"/> Flare <input type="checkbox"/> Cover <input type="checkbox"/> Incinerator <input type="checkbox"/> None <input type="checkbox"/> Collection System <input type="checkbox"/> Other (Specify) _____ Control Efficiency _____% |

California Air Resources Board
Oil and Gas Industry Survey

Reporting Year 2007

**Table 16: Crude Oil Storage Tanks
(Complete one per piece of equipment)**

| | | | | | | | | | | | | | | | | | | |
|--|--|--|---|---|--------------|-------|-------|----------------|-------|-------|---------------|-------|-------|----------------------|------------------------------|--|--|--|
| Air District Facility ID: _____ | | | | | | | | | | | | | | | | | | |
| Type: <input type="checkbox"/> Fixed Roof <input type="checkbox"/> Internal Floating Roof <input type="checkbox"/> External Floating Roof <input type="checkbox"/> Open Top Roof | Subtype: <input type="checkbox"/> Bolted Tank <input type="checkbox"/> Welded Tank | Size (Barrels): _____ | | | | | | | | | | | | | | | | |
| | | Number of Degassing Events: _____ | | | | | | | | | | | | | | | | |
| | | Avg. Crude Oil API: _____ | | | | | | | | | | | | | | | | |
| <table border="0"> <tr> <td></td> <td style="text-align: center;">ROG (tons/year)</td> <td style="text-align: center;">TOG (tons/year)</td> <td rowspan="5"> Components: <input type="checkbox"/> Access Hatch <input type="checkbox"/> Pressure Relief Valve Are hatches and pressure relief valves included in Table 6? <input type="checkbox"/> Yes <input type="checkbox"/> No </td> </tr> <tr> <td>Working Loss</td> <td style="text-align: center;">_____</td> <td style="text-align: center;">_____</td> </tr> <tr> <td>Breathing Loss</td> <td style="text-align: center;">_____</td> <td style="text-align: center;">_____</td> </tr> <tr> <td>Flashing Loss</td> <td style="text-align: center;">_____</td> <td style="text-align: center;">_____</td> </tr> <tr> <td>Avg. Methane _____ %</td> <td style="text-align: center;">Avg. CO₂ _____ %</td> <td></td> </tr> </table> | | ROG (tons/year) | TOG (tons/year) | Components: <input type="checkbox"/> Access Hatch <input type="checkbox"/> Pressure Relief Valve Are hatches and pressure relief valves included in Table 6? <input type="checkbox"/> Yes <input type="checkbox"/> No | Working Loss | _____ | _____ | Breathing Loss | _____ | _____ | Flashing Loss | _____ | _____ | Avg. Methane _____ % | Avg. CO ₂ _____ % | | | |
| | ROG (tons/year) | TOG (tons/year) | Components: <input type="checkbox"/> Access Hatch <input type="checkbox"/> Pressure Relief Valve Are hatches and pressure relief valves included in Table 6? <input type="checkbox"/> Yes <input type="checkbox"/> No | | | | | | | | | | | | | | | |
| Working Loss | _____ | _____ | | | | | | | | | | | | | | | | |
| Breathing Loss | _____ | _____ | | | | | | | | | | | | | | | | |
| Flashing Loss | _____ | _____ | | | | | | | | | | | | | | | | |
| Avg. Methane _____ % | Avg. CO ₂ _____ % | | | | | | | | | | | | | | | | | |
| Floating Roof Tanks Only: | | | | | | | | | | | | | | | | | | |
| Deck Leg Height (ft): _____ Tank Diameter (ft): _____ | | | | | | | | | | | | | | | | | | |
| <table border="0"> <tr> <td> Primary Seal: <input type="checkbox"/> Metallic Shoe o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Wiper <input type="checkbox"/> Other (Specify) _____ </td> <td> Secondary Seal: <input type="checkbox"/> Wiper <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Other (Specify) _____ </td> </tr> </table> | | | Primary Seal: <input type="checkbox"/> Metallic Shoe o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Wiper <input type="checkbox"/> Other (Specify) _____ | Secondary Seal: <input type="checkbox"/> Wiper <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Other (Specify) _____ | | | | | | | | | | | | | | |
| Primary Seal: <input type="checkbox"/> Metallic Shoe o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Wiper <input type="checkbox"/> Other (Specify) _____ | Secondary Seal: <input type="checkbox"/> Wiper <input type="checkbox"/> Resilient Toroid o Liquid Mounted o Vapor Mounted <input type="checkbox"/> Other (Specify) _____ | | | | | | | | | | | | | | | | | |
| Vapor Recovery System: | | | | | | | | | | | | | | | | | | |
| <input type="checkbox"/> Flare <input type="checkbox"/> None Control Efficiency: _____% <input type="checkbox"/> Incinerator <input type="checkbox"/> Other (Specify) _____ <input type="checkbox"/> Collection System | | | | | | | | | | | | | | | | | | |



Oil & Natural Gas Industry Survey

General Instructions

Mailing Address:

California Air Resources Board
P.O. Box 2815
Sacramento, California 95812
Attention: SSD / Oil & Gas Survey

February 2009

Overview

The Oil & Natural Gas Industry Survey has been designed to improve our estimates of greenhouse gas emissions in California. We are collecting data for the 2007 calendar year in order to accurately quantify equipment and operation processes. This survey is intended to be a one-time collection of information needed to develop a statewide inventory baseline. This survey is not being used as a compliance tool nor is it part of other mandatory reporting programs. This survey pertains to all upstream oil and natural gas facilities regardless of the size of the operation.

The following instructions have been provided to answer general questions pertaining to the individual survey tables. Since this survey covers a wide range of processes and operations, some companies may not need to complete every table.

Who should fill out this survey? Any owner or operator of the following facilities:

Oil or Natural Gas Extraction Facilities: includes any facility that extracts crude oil, natural gas, or both crude oil and natural gas.

Processing Facilities: includes any facility that processes crude oil or natural gas for use or distribution. This survey does not include refineries.

Crude Oil Transmission Facilities: includes crude oil pipelines or crude oil bulk loading operations. This includes ship, truck, or rail car loading facilities.

Storage Facilities: includes any facility that stores crude oil or natural gas, including underground natural gas storage facilities. This survey excludes crude oil tank farms that are located on refinery premises.

Submission Format. Paper forms, Microsoft Excel/Access files, or a combination of both paper and electronic files are acceptable. It is preferable to have all data submitted electronically. We have staff available to provide assistance or answer questions via e-mail or telephone.

Permitted and Non-Permitted Equipment. This survey covers both air district permitted and non-permitted equipment and includes equipment that is registered under the Portable Equipment Registration Program (PERP). Therefore, this survey includes equipment that is moved more than once annually and includes non-air district permitted equipment that is below 50-horsepower in rating.

Questions? Please contact any of the following ARB staff for questions or assistance:

| | | |
|----------------|----------------|--|
| Stephanie Lee | (916) 324-8024 | sjlee@arb.ca.gov |
| Joseph Fischer | (916) 445-0071 | joseph.fischer@arb.ca.gov |
| Luis Leyva | (916) 323-1079 | lleyva@arb.ca.gov |

General Instructions

Table 1: Facility Description

This survey and the Facility Description Table are to be completed one time per geographically distinct facility (i.e., property boundary) by the entity that has operational control of the equipment. Even though a single operator may oversee operations at multiple facilities, please complete one survey per geographically distinct facility in order for us to determine the locations of equipment and processes.

PERP Equipment Owners: In the case where a company owns and operates equipment that is portable (e.g., PERP registered equipment such as drill rigs, portable gas compressors) please use the company headquarters contact information as the facility description.

Inside a facility there may be different Facility ID numbers provided by the local air district (e.g., multiple gas plants). Please provide the facility ID number where indicated. In some cases, a Facility ID number may not be available and a generic number must be created. One way to create a unique ID number is by using the first two letters of the local air district where the facility is located and a number. For example, a facility located in San Joaquin Valley APCD could use "SJ1, SJ2, etc."

Table 2: Facility Production

The Facility Production Table is designed to list active wells, production, and workover information for the 2007 calendar year. Enter information in the corresponding categories. Indicate the number of new wells drilled, completions, and workovers for the facility. For well workovers, enter the number that required tubing removal only. The number that did not require tubing removal is not required. Well cleanups (also referred to as well unloading) include fluids removal or well fracturing, where in either case fluids are removed from the well.

There is a separate column listed for underground natural gas storage facilities. Some of these facilities may intermittently produce crude oil with the natural gas. For simplification, please enter the volume of oil intermittently produced from the gas wells in Box 1 under the Natural Gas Storage Column, and enter the total volume of natural gas extracted in Box 2. For all companies, please enter the average natural gas composition and volume in Box 2.

For crude oil transmission facilities, a section has been included for length of pipeline and barrels of crude oil transported. These facilities are located after a production facility's LACT unit. A production facility does not enter information in Box 3.

Table 3: Facility Electrification

The Facility Electrification Table is designed to determine the level of electrification at crude oil and natural gas facilities. This information is important to understand the level of electrification within the sector. In some instances, a facility may generate or export its own electricity using Generators, Microturbines, Turbines, or Combined Heat and Power units. This includes electricity generated from standby or backup, on-site generators used in the event of power outages. Please indicate the amount of electricity generated, exported, and purchased. Estimated values are acceptable.

Table 4: Vapor Recovery and Flaring

Vapor recovery units consist of flares, thermal oxidizers, incinerators, and carbon adsorption units. These units control the release of hydrocarbons and may be designed for continuous or emergency operation. Table 4 is to be completed one time for each piece of equipment. In most cases, it may be easier to use one of the electronic templates.

Enter the throughput volume and rated size of the unit. For flares, enter the size in terms of btu/hour. For carbon adsorption units, enter the size in terms of the volume of the unit (height x diameter, etc.). In some cases the units are source tested for combustion or capture efficiency. If test data are available, please enter the efficiency where indicated.

For flares, thermal oxidizers, or incinerators, the average composition of the raw natural gas stream is required to enter the average gas composition and calculate the Carbon Mole Ratio. In many cases, a Gas Chromatograph (GC) analysis will have all of the values but the Carbon Mole Ratio must be calculated. If you are unsure on how to calculate these parameters, please call or submit a copy of a GC analysis and we will provide assistance. For convenience, the formula and a simplified example are shown below.

$$\text{Carbon Mole Ratio} = \sum \left[\frac{\text{mole \% hydrocarbon}}{100} \right] * \text{Number carbons in hydrocarbon}$$

The carbon mole ratio is calculated by adding up each of the mole percentages multiplied by the number of carbons in each species. The following is a simplified example:

| Species | Mole % |
|--|--------|
| Methane (CH ₄) | 80 |
| Ethane (C ₂ H ₂) | 15 |
| Propane (C ₃ H ₈) | 5 |

In this example, the carbon mole ratio would be calculated as follows:

$$\text{Carbon Mole Ratio} = (80/100)*(1) + (15/100)*(2) + (5/100)*(3) = \underline{1.25}$$

Table 5: Combustion Equipment

Table 5 is to be completed one time for each piece of combustion equipment. In most cases, it may be easier to use one of the electronic templates. This table is designed to accommodate a wide variety of external and internal combustion equipment. List both air district and nonair district permitted equipment. The table also includes a box to indicate if the equipment is included in the Portable Equipment Registration Program (PERP).

The purpose of this survey is to perform an accurate statewide inventory baseline. Therefore, this survey includes equipment that is moved more than once annually and includes non-air district permitted equipment that is below 50-horsepower in rating.

We have provided examples from which to choose and the option to specify equipment not included as an example. For engines powering compressors, enter a unique ID number that will be used with the natural gas compressor table (Table 12). This number will link the primary driver engine with the natural gas compressor.

Enter the manufacturer name where indicated. For some external combustion units (e.g., steam generators) it is acceptable to enter the name of the burner manufacturer if no other information is available. Enter the inspection frequency and indicate the frequency that involves testing with instruments, visual inspections, and the use of a third-party tester. Estimated inspection frequencies are acceptable.

Fuel Type and Fuel Properties

Under fuel type, list the primary and, if necessary, the secondary fuel type and volume as metered or calculated. The average Higher Heating Value and Liquid Fuel Density may be entered as standard values. If available, it is preferred to have actual values. A Gas Chromatograph (GC) analysis will provide the values for you.

In many cases, a GC analysis will list values or allow figures to be computed. If you are unsure on how to calculate these parameters, please call or submit a copy of a GC analysis and we will provide assistance. For convenience, the formula for Gaseous Fuel Molecular Weight is provided below.

$$\text{Gaseous Fuel MW} = \frac{1}{100} * \sum [(Mole \%_{\text{compound}}) * (MW_{\text{compound}})]$$

Where:

$Mole \%_{\text{compound}} = \text{indicated on GC analysis}$

$$MW_{\text{compound}} = \sum Weight_{\text{element}} * Coefficient_{\text{element}}$$

An example calculation for MW_{compound} : $CH_4 = (12*1) + (1*4) = \underline{16}$

Table 6: Component Counts

Table 6 provides a means of organizing components by natural gas, heavy crude, and light crude oil. If the actual number of components is unknown for a facility, it is acceptable to estimate the number using an average number of components per unit and then multiply by the total number of similar units. Table 6 has been designed similarly to local air district inspection and maintenance (I&M) programs and should be completed in conjunction with Table 8.

Table 7: Automated Control Devices

Automated Control Devices (i.e., pneumatic devices) control the flow of fluids or gases. The devices may be connected to a central vapor recovery system or plumbed back into a natural gas system (gas recovery). Table 7 has been designed similarly to local air district inspection and maintenance (I&M) programs and should be completed in conjunction with Table 8.

Typically, a single unit consists of one or more components. For example, a controller is used to control an actuator and the actuator is used to operate a block or turbine valve. Intermittent bleed devices are the actuators that only emit when actuated. Low bleed devices are the controllers that continuously emit less than 6 scfh. Figure 1 shows the common components. For additional information, please refer to the manufacturer catalogue or look at the EPA Natural Gas Star web site for topics on pneumatic devices, such as http://www.epa.gov/gasstar/documents/II_pneumatics.pdf

Due to design characteristics of the various units, indicate how many controllers and actuators are located at the facility and whether the devices are instrument air, gas, or electronically actuated. If the actual number of components is unknown for a facility, an estimated number of components are acceptable.

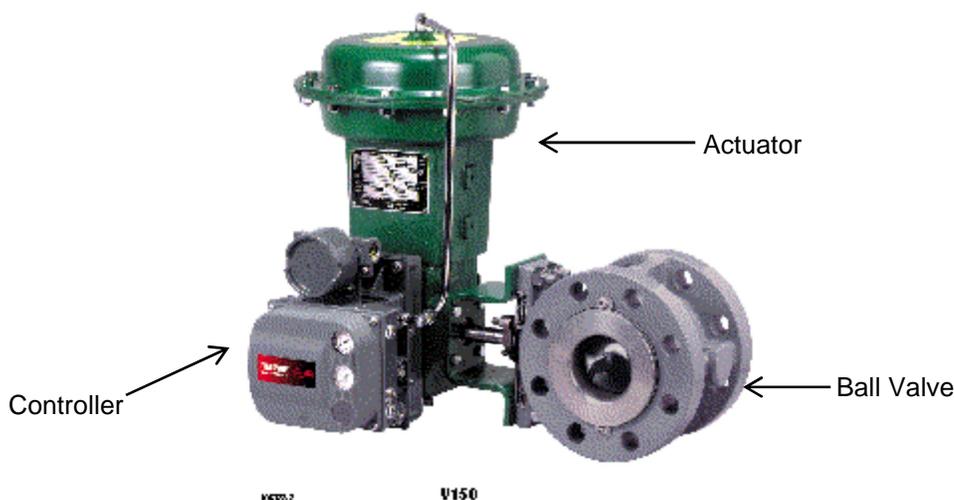


Figure 1. Typical Vee-Ball® Valves with Type 1052 Actuators and DVC6020 Digital Valve Controllers.

Table 8: Inspection and Maintenance Program

An inspection and maintenance (I&M) program requires a facility operator to routinely screen for and repair leaks from equipment at their facility. Many facilities are required to comply with local air district I&M programs. Table 8 is designed to list how companies comply with the various requirements. Check the box or boxes that indicate the stratum range that the facility tests to. Indicate a different leak threshold should the facility test to a different level within the indicated stratum range.

In many cases oil and gas facilities store I&M data electronically. This data may be provided by a third-party tester, etc. If you have I&M data available in electronic format, submittal of the information would help prevent overestimating emissions or relying on national averages. Please submit electronic I&M program data in any Microsoft Excel or Access format. Submittal of hard copy data is not required.

Table 9: Natural Gas Dehydration

Natural Gas Dehydration units are used to remove moisture from a natural gas stream. The most common types are glycol and desiccant units. Please complete one table for each unit. In some cases, it may be simpler to use one of the electronic templates.

Enter the average input and output gas composition and enter the estimated volume of liquids removed for the 2007 calendar year. Indicate if the unit is connected to a vapor recovery system and if available, enter the control efficiency of the vapor recovery system.

For glycol units, there are fields provided for average circulation rate, pump type, and stripping gas. Check each box and fill in the appropriate fields that apply. Similarly, a separate box is included for desiccant units. For desiccant units, indicate the volume of the unit (height x diameter, etc.) and indicate the average remaining volume that exists after the unit is packed with desiccant (a typical value is 45 percent). If you can estimate a more precise percent packed volume value, please provide where indicated.

Table 10: Natural Gas Sweetening or Acid Gas Removal

Natural gas sweetening and acid gas removal units are used to condition gas for combustion or resale. Table 10 is designed to accommodate a large variety of units. In some cases all fields may not need to be completed. Please complete one table for each particular unit. It may be convenient to use one of the electronic templates.

Enter the average input and output gas composition. Enter the Higher Heating Value of the input and output gas streams (average values are acceptable).

In some units CO₂ is mixed with waste gas and sent to an incinerator or vented. Indicate the method of CO₂ disposal. For units that require regular solid material replacement, indicate the average remaining volume that exists after the unit is packed with material

(a typical value is 45 percent). If you can estimate a more precise percent packed volume value, please enter the value where indicated.

Table 11: Other Natural Gas Processing

Table 11 is for listing other processing units used for removing natural gas liquids other than CO₂, H₂S, and water. Please complete one table for each particular unit. It may be convenient to use one of the electronic templates.

Enter the average input and output gas composition and average volume of liquids removed. Indicate if the unit is connected to a vapor recovery system and list the estimated control efficiency of the vapor recovery system where indicated. In some cases it may be necessary to estimate total throughput.

Table 12: Natural Gas Compressors

Table 12 is designed to cover a variety of natural gas compressors. Please complete one table for each individual unit. This table should be completed using the unique compressor ID number from Table 5. This will link the compressor with the primary driver engine.

The primary types of compressors are reciprocating, centrifugal, rotary, and integral. In an integral unit, the primary driver engine and compressor are combined into a single unit. In other cases, the primary driver engine (internal combustion or turbine engine) are separated by a drive shaft.

For centrifugal units, indicate the type and number of wet or dry seals under the corresponding seal type. Wet seals, also known as lubricated seals, use oil as a means to retain internal compressor pressure. Wet seal units may be identified as having a separate "seal oil" pump used to maintain seal pressure. Dry seal compressors may be identified as having a separate "seal gas" outlet for gas to escape the compressor. Both wet and dry seal compressors will have a lube oil pump.

Indicate the primary driver and starter type. Enter the average discharge and idle pressure in units of pounds per square inch and the discharge temperature in degrees F. The discharge pressure is the average pressure inside the unit during operation. The idle pressure is the average pressure when the unit is idle.

Indicate the hours of usage, number of start-ups and blowdowns, and the inspection frequency. The maintenance frequency is the number of times the unit had to be disassembled to replace valves, seals, or packing. If actual numbers are not available, estimated values are acceptable.

Table 13: Pipelines

Table 13 pertains to natural gas gathering systems found within an extraction or underground natural gas storage facility (prior to a gas meter). Enter, or estimate, the length of the natural gas pipeline gathering system where indicated. Enter estimated volumes depicting how gas is handled for system maintenance or modification activities.

Table 13 also pertains to crude oil transmission and natural gas pipeline pigging operations conducted at the facility. Enter, or estimate how many times a pig was sent or received for the 2007 calendar year. Please indicate whether the operations were for crude oil or natural gas pipeline.

Table 14: Crude Oil or Natural Gas Separation Units

Table 14 is designed to accommodate a variety of crude oil and natural gas separation units. There are a variety of units in this category. We have included a list of some examples and an option to specify units at the facility that may go by a different name. Please complete one table per individual unit. In some cases, it may be more convenient to use one of the electronic templates provided.

Enter the Working, Breathing, and Flashing Losses as calculated with *TANKS* (US Environmental Protection Agency) or similar software or calculation, or enter the values as listed on the district permit. If the calculations have not been performed and are not required by the local air district, please leave these fields blank.

In order to prevent double counting of components, indicate if the separation unit components were included in Table 6 and indicate if the unit is controlled by a vapor recovery system.

Table 15: Crude Oil Separation Units Sumps or Pits

Crude oil separation sumps or pits are used to separate water from crude oil and may be used for permanent or emergency purposes. Indicate whether the sump is primary, secondary, or tertiary and list the average crude oil API number and number of days the sump or pit was in use. In some cases, a sump may be used in conjunction with a cover or a vapor collection system. Please indicate if either type of system is used.

Table 16: Crude Oil Storage Tanks

Table 16 is designed to accommodate fixed roof and floating roof crude oil storage tanks. Please complete one table per storage tank. In some cases, it may be convenient to use one of the electronic templates.

Enter the tank type, size, and average crude oil API number. Enter the number of degassing events that required the tank to be completely emptied of liquid and vapor.

For fixed roof and floating roof tanks, enter the Working, Breathing, and Flashing Losses as reported to the local air district. If available, enter the average methane and carbon dioxide values as depicted in a Gas Chromatograph analysis. If information is not available for methane or carbon dioxide concentration, please leave those fields blank.

Appendix B: Emission Calculation Methodologies and Corresponding Emission Factors

**California Air Resources Board
Oil and Gas Industry Survey**

**Emission Calculation Methodologies
and
Corresponding Emission Factors**

Appendix B details the individual equations and emission factors used to calculate greenhouse gas emissions. Default mole percent of CH₄ and CO₂ are 78.8 percent and 3 percent, respectively (API, 2004). For equipment that has vapor recovery, CO₂ and CH₄ emissions are reduced by the vapor recovery efficiency before conversion to CO₂e. All CO₂, CH₄, and N₂O values are multiplied by their corresponding GWP (1 for CO₂, 21 for CH₄, and 310 for N₂O) to get the CO₂e number.

Method 1 – Active Wells

The 2007 Industry survey separates crude oil into four categories: ultra-heavy, heavy, light, and ultra-light. It also separates gas wells by dry gas fields and gas storage fields. When calculating GHG emissions from active wells, the categories ultra-heavy and heavy crude use the emission factor “heavy crude”, light and ultra-light crude use the emission factor “light crude”, and dry gas and gas storage use the emission factor “natural gas”.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{CO}_2 \text{ EF}) * (\text{Number}) * (\text{CO}_2 \text{ Mole Fraction} \backslash 0.03)$$

Where

CO₂ EF = See Table 1

Number = Number of active wells

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

Data Requirements

1. Number of active wells
2. Mole % CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Number}) * (\text{CH}_4 \text{ Mole Fraction} \backslash 0.788)$$

Where

CH₄ EF = See Table 1

Number = Number of active wells

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

Data Requirements

1. Number of active wells
2. Mole % CH₄

Table 1: Wellheads

| Type | CH ₄ (tonnes/well-year) | % Methane Assumption | CO ₂ (tonnes/well-year) | % CO ₂ Assumption |
|-------------|---------------------------------------|-------------------------|---------------------------------------|---------------------------------|
| Natural Gas | 0.157 ¹ | 78.8 | 1.644E-02 ¹ | 3 |
| Light Crude | 0.108 ¹ | 78.8 | 1.128E-02 ¹ | 3 |
| Heavy Crude | 4.568E-03 ¹ | 78.8 | 4.782E-04 | 3 |

1. API (2004)

Method 2 – Well Cellars

The 2007 Industry survey separates crude oil into four categories: ultra-heavy, heavy, light, and ultra-light. When calculating GHG emissions from well cellars, an average dimension of 6 feet by 6 feet is used (Kern County APCD,1990). Additionally, the categories ultra-heavy and heavy crude use the emission factor “heavy crude”, light and ultra-light crude use the emission factor “light crude”.

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Number})$$

Where

CH₄ EF = See Table 2

Number = number of well cellars

Data Requirements

1. Number of well cellars

Table 2: Well Cellars

| Type | CH ₄ (tonnes/well cellar-year) |
|-------------|--|
| Light Crude | 0.170 ¹ |
| Heavy Crude | 0.125 ¹ |

1. Kern County APCD (1990)

Method 3 – New Wells Drilled

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Number})$$

Where

CH₄ EF = See Table 3

Number = Number of wells drilled

Data Requirements

1. Number of wells drilled

Table 3: New Wells Drilled

| Type | CH ₄ (tonnes/well-year) |
|-------------|---------------------------------------|
| Natural Gas | |
| Light Crude | |
| Heavy Crude | |

Method 4 – Well Workovers and Cleanups

The calculations for well workovers and cleanups assume an average well depth, casing diameter, and tubing diameter and that only one well volume is released. For crude oil wells, the volume of gas released is assumed to be the space between the casing and tubing. For natural gas wells, the volume of gas released is assumed to be the entire volume of the casing.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CO}_2 \text{ Mole Fraction}) * (\text{D}) * (\text{Events})$$

Where

EF = See Table 4

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

D = (molar volume)*(Molecular Weight CO₂)*(tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Events = Number of well workovers and cleanups

Data Requirement

1. Number of well workovers and cleanups
2. Mole % CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CH}_4 \text{ Mole Fraction}) * (\text{D}) * (\text{Events})$$

Where

EF = See Table 4

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

D = (molar volume)*(Molecular Weight CH₄)*(tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Events = Number of well workovers and cleanups

Data Requirement

1. Number of well workovers and cleanups
2. Mole % CH₄

Emission Factor Calculation (Listed in Table 4)

$$\text{Equation} = [(V) * (P_1) * (T_2)] / [(P_2) * (T_1)]$$

Where

V = volume of well

P₁ = shut-in pressure (psia) of well

P₂ = 14.7 psia (standard surface pressure)

T₁ = temperature in well at shut-in pressure

T₂ = 60°F (standard surface temperature)

Assumptions

Depth = 5000 ft

Casing Diameter = 7 in

Tubing Diameter = 2.875 in

P₁ = 100 psia

T₁ = 60°F

Table 4: Well Workovers and Cleanups

| Type | CH ₄ /CO ₂ (scf/event) |
|-------------|---|
| Natural Gas | 9090.256 |
| Light Crude | 7556.855 |
| Heavy Crude | 7556.855 |

Method 5 – Well Completions

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Number})$$

Where

CH₄ EF = See Table 5

Number = Number of wells completed

Data Requirements

1. Number of wells completed

Table 5: Well Completions

| Type | CH ₄ (tonnes/well) |
|-------------|----------------------------------|
| Natural Gas | |
| Light Crude | |
| Heavy Crude | |

Method 6 – Flares, Incinerators, Thermal Oxidizers

CO₂ and CH₄ emission calculations based on the following mass balance equations (API, 2004).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Combustion Emissions}) + (\text{Vented Emissions})$$

$$\text{Combustion emissions (tonnes/year)} = (\text{Throughput}) * (\text{Carbon Mole Ratio}) * (\text{Combustion Efficiency}) * (D)$$

Where

Throughput = volume of gas flared (scf gas/year)

Carbon Mole Ratio = $\sum[(\text{mole \% hydrocarbon}/100) * (\# \text{ carbons in hydrocarbon})]$

D = (molar volume) * (Molecular Weight CO₂) * (tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CO₂ = (44 lb CO₂)/(lb mole CO₂)

Data Requirements

1. Throughput (scf gas/year)
2. Combustion Efficiency (98% will be assumed if no combustion efficiency is supplied)
3. Carbon Mole Ratio of gas

$$\text{Vented emissions (tonnes/year)} = (\text{Throughput}) * (\text{CO}_2 \text{ Mole Fraction}) * (D)$$

Where

Throughput = volume of gas flared (scf/year)

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

D = (molar volume) * (Molecular Weight CO₂) * (tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CO₂ = (44 lb CO₂)/(lb mole CO₂)

Data Requirements

1. Throughput (scf/year)
2. Mole % CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Throughput}) * (\text{CH}_4 \text{ Mole Fraction}) * (\% \text{ Residual CH}_4) * (D)$$

Where

$$\begin{aligned} \text{Throughput} &= \text{volume of gas flared (scf gas/year)} \\ \text{CH}_4 \text{ Mole Fraction} &= (\text{lbmole CH}_4) / (\text{lbmole gas}) \\ \% \text{ Residual CH}_4 &= 100 - (\text{Combustion Efficiency}) \\ D &= (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb}) \\ \text{Molar Volume} &= (1 \text{ lbmole gas}) / (379.3 \text{ scf gas}) \\ \text{Molecular Weight CH}_4 &= (16 \text{ lb CH}_4) / (\text{lb mole CH}_4) \end{aligned}$$

Data Requirements

1. Throughput (scf gas/year)
2. Combustion Efficiency (98% will be assumed if no combustion efficiency is supplied)
3. Mole % CH₄

$$\text{N}_2\text{O emissions (tonnes/year)} = (\text{Throughput}) * (\text{N}_2\text{O Emission Factor})$$

Where

$$\begin{aligned} \text{Throughput} &= \text{volume of gas flared (scf gas/year)} \\ \text{N}_2\text{O Emission Factor} &= 1\text{E-}10 \text{ tonnes/scf gas (INGAA, 2005)} \end{aligned}$$

Data Requirements

1. Throughput (scf/year)

Method 7 – Carbon Adsorbers

The vented emission calculation for carbon adsorbers assumes that 100% of the methane in the gas stream passes through the adsorber.

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Throughput}) * (\text{CH}_4 \text{ Mole Fraction}) * (D)$$

Where

$$\begin{aligned} \text{Throughput} &= \text{volume of gas (scf gas/year)} \\ \text{CH}_4 \text{ Mole Fraction} &= (\text{lbmole CH}_4) / (\text{lbmole gas}) \\ D &= (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb}) \\ \text{Molar Volume} &= (1 \text{ lbmole gas}) / (379.3 \text{ scf gas}) \\ \text{Molecular Weight CH}_4 &= (16 \text{ lb CH}_4) / (\text{lbmole CH}_4) \end{aligned}$$

Data Requirements

1. Throughput (scf gas/year)
2. Mole % CH₄

Method 8 – Mass Balance Fuel Consumption

CO₂ and CH₄ combustion calculations for all combustion equipment (except flares, incinerators, and thermal oxidizers) are based on the following mass balance equations (INGAA, 2005).

Gaseous Fuels

CO₂ emissions (tonnes/year) = (Combustion Emissions) + (Vented Emissions)

Combustion Emissions (tonnes/year) = (Fuel Use)*(MW_{fuel})*(Carbon Weight %)*(COX)*(D)

Where

Fuel Use = fuel use (scf/year)

MW_{fuel} = molecular weight of fuel (lb fuel/lbmole fuel)

Carbon Weight % = (lb C/lb fuel)

COX = fraction of fuel oxidized (assumed to be 99%)

D = (molar volume)*(1/MW_C)*(lbmole CO₂/lbmole C)*(MW_{CO₂})*(tonne/2204.6 lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

MW_C = (12 lb C)/(lb mole C)

MW_{CO₂} = (44 lb CO₂)/(lb mole CO₂)

Data Requirements

1. Fuel Use (scf gas/year)
2. Molecular Weight of fuel
3. Carbon Weight % of fuel
4. COX (if different from assumed value of 99%)

Vented Emissions (tonnes/year) = (Fuel Use)*(1-COX)*(CO₂ Mole Fraction)*(D)

Where

Fuel Use = fuel use (scf/year)

COX = fraction of fuel oxidized (assumed to be 99%)

D = (molar volume)*(MW_{CO₂})*(tonne/2204.6 lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

MW_{CO₂} = (44 lb CO₂)/(lb mole CO₂)

Data Requirements

1. Fuel Use (scf gas/year)
2. COX (if different from assumed value of 99%)
3. Mole % CO₂

CH₄ emissions (tonnes/year) = (Fuel Use)*(CH₄ Mole Fraction)*(1-COX)*(D)

Where

Fuel Use = fuel use (scf/year)

COX = fraction of fuel oxidized (assumed to be 99%)

D = (molar volume)*(MW_{CH₄})*(tonne/2204.6 lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

MW_{CH₄} = (16 lb CH₄)/(lb mole CH₄)

Data Requirements

1. Fuel Use (scf gas/year)
2. COX (if different from assumed value of 99%)
3. Mole % CH₄

Liquid Fuels

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{Fuel Density}) * (\text{Carbon Weight \%}) * (\text{COX}) * (\text{D})$$

Where

Fuel Use = fuel use (gal/year)

Fuel Density = density of fuel (lb fuel/gal fuel)

Carbon Weight % = (lb C/lb fuel)

COX = fraction of fuel oxidized (assumed to be 99%)

$D = (1/MW_C) * (\text{lbmole CO}_2/\text{lbmole C}) * (MW_{\text{CO}_2}) * (\text{tonne}/2204.6 \text{ lb})$

$MW_C = (12 \text{ lb C})/(\text{lb mole C})$

$MW_{\text{CO}_2} = (44 \text{ lb CO}_2)/(\text{lb mole CO}_2)$

Data Requirements

1. Fuel Use (gal fuel/year)
2. Fuel Density
3. Carbon Weight % of fuel
4. COX (if different from assumed value of 99%)

Method 9 - Equipment Specific

Combustion calculations for equipment with equipment specific emission factors. This method is used only for those equipment that have emission factors listed in Table 6.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{CO}_2 \text{ Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)

HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)

CO₂ Emission Factor = See Table 6

Data Requirement

1. Type of equipment
2. Fuel Use (scf/year or gal/year)
3. HHV of fuel (Btu/scf or Btu/gal)

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{CH}_4 \text{ Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)

HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)

CH₄ Emission Factor = See Table 6

Data Requirement

1. Type of equipment
2. Fuel Use (scf/year or gal/year)
3. HHV of fuel (Btu/scf or Btu/gal)

$$\text{N}_2\text{O emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{N}_2\text{O Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)

HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)

N₂O Emission Factor = See Table 6

Data Requirement

1. Type of equipment
2. Fuel Use (scf/year or gal/year)
3. HHV of fuel (Btu/scf or Btu/gal)

Table 6: Combustion Equipment

| Equipment Type | CO ₂ (tonnes/MMBtu) | CH ₄ (tonnes/MMBtu) | N ₂ O (tonnes/MMBtu) |
|---------------------------|-----------------------------------|-----------------------------------|------------------------------------|
| Natural Gas Fired | | | |
| Boilers | 0.0534 ² | 1.023E-06 ⁴ | 9.8E-07 ⁵ |
| Steam Generators | 0.0534 ² | 1.023E-06 ⁴ | 9.8E-07 ⁵ |
| Heaters | 0.0534 ² | 1.023E-06 ⁴ | 9.8E-07 ⁵ |
| Reciprocating Engine | | | |
| Two – Stroke Lean | 0.0499 ³ | 6.577E-04 ⁴ | 2.3E-06 ⁵ |
| Four – Stroke Lean | 0.0499 ³ | 5.670E-04 ⁴ | 1.4E-06 ⁵ |
| Four – Stroke Rich | 0.0499 ³ | 1.043E-04 ⁴ | 4.5E-07 ⁵ |
| Turbine | 0.0499 ³ | 3.901E-06 ⁴ | 3.8E-06 ⁵ |
| Diesel Fired | | | |
| Reciprocating Engine | | | |
| Two – Stroke Lean | 0.0744 ¹ | 4E-06 ⁵ | |
| Two – Stroke Rich | 0.0744 ¹ | 4E-06 ⁵ | |
| Four – Stroke Lean | 0.0744 ¹ | 4E-06 ⁵ | |
| Four – Stroke Rich | 0.0744 ¹ | 4E-06 ⁵ | |
| Gasoline Fired | | | |
| Reciprocating Engine | | | |
| Two – Stroke Lean | 0.0699 ¹ | 1.2E-04 ⁵ | |
| Two – Stroke Rich | 0.0699 ¹ | 1.2E-04 ⁵ | |
| Four – Stroke Lean | 0.0699 ¹ | 3.9-05 ⁵ | |
| Four – Stroke Rich | 0.0699 ¹ | 3.9-05 ⁵ | |
| Landfill Gas Fired | | | |
| Turbine | 0.0227 ³ | | |

1. EPA (1996b); 2. EPA (1998); 3. EPA (2000); 4. API (2004); 5. INGAA (2005)

Method 10 – Fuel Based

Combustion calculations for equipment using fuel based emission factors listed in Table 7.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{CO}_2 \text{ Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)
 HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)
 CO₂ Emission Factor = See Table 7

Data Requirement

1. Fuel Use (scf/year or gal/year)
2. HHV of fuel (Btu/scf or Btu/gal)

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{CH}_4 \text{ Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)
 HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)
 CH₄ Emission Factor = See Table 7

Data Requirement

1. Fuel Use (scf/year or gal/year)
2. HHV of fuel (Btu/scf or Btu/gal)

$$\text{N}_2\text{O emissions (tonnes/year)} = (\text{Fuel Use}) * (\text{HHV}) * (\text{N}_2\text{O Emission Factor}) * (10^{-6})$$

Where

Fuel Use = volume of fuel used (scf/year or gal/year)
 HHV = Higher Heating Value of fuel (Btu/scf or Btu/gal)
 N₂O Emission Factor = See Table 7

Data Requirement

1. Fuel Use (scf/year or gal/year)
2. HHV of fuel (Btu/scf or Btu/gal)

Table 7: Fuels

| Fuel Type | CO ₂ (tonnes/MMBtu) | CH ₄ (tonnes/MMBtu) | N ₂ O (tonnes/MMBtu) |
|---------------------------|-----------------------------------|-----------------------------------|------------------------------------|
| Natural Gas | | | |
| Unspecified | 0.05302 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| 975 to 1,000 Btu/scf | 0.05397 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| 1,000 to 1,025 Btu/scf | 0.05287 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| 1,025 to 1,050 Btu/scf | 0.05302 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| 1,050 to 1,075 Btu/scf | 0.05342 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| 1,075 to 1,100 Btu/scf | 0.05368 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| > 1,100 Btu/scf | 0.05467 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| Landfill Gas | 0.05203 ¹ | 9E-07 ¹ | 1E-07 ¹ |
| Diesel | 0.0731 ² | 3E-06 ¹ | 6E-07 ¹ |
| Liquidified Petroleum Gas | 0.06298 ¹ | 1E-06 ¹ | 1E-07 ¹ |
| Propane | 0.06302 ¹ | 1E-06 ¹ | 1E-07 ¹ |
| Gasoline | 0.07083 ¹ | 3E-06 ¹ | 6E-07 ¹ |

1. ARB Mandatory Reporting (2008)

2. ARB Mandatory Reporting (2008) Distillate Fuel Oil #1, #2, #4

Method 11 – Components

Components for other equipment (e.g. storage tanks) will be backed out of this calculation.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{CO}_2 \text{ EF}) * (\text{Number}) * (\text{CO}_2 \text{ Mole Fraction}/0.03)$$

Where

CO₂ EF = See Table 8

Number = Number of components

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

Data Requirements

1. Mole % CO₂
2. Number of components

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Number}) * (\text{CH}_4 \text{ Mole Fraction}/0.788)$$

Where

CH₄ EF = See Table 8

Number = Number of components

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

Data Requirements

1. Mole % CH₄
2. Number of components

Table 8: Components

| Component Type | Natural Gas ¹ | Light Crude ² (tonnes/component-year) | Heavy Crude ³ |
|--|--------------------------|---|--------------------------|
| CH₄ (78.8% Methane Assumption) | | | |
| Manual Valves | 1.759E-04 ⁴ | 1.348E-04 ⁴ | 1.341E-04 ⁴ |
| Flanges | 1.407E-04 ⁴ | 1.703E-04 ⁴ | 2.203E-04 ⁴ |
| Connectors | 6.029E-05 ⁴ | 7.095E-05 ⁴ | 7.661E-05 ⁴ |
| Open-ended Lines | 1.206E-04 ⁴ | 1.277E-04 ⁴ | 1.436E-04 ⁴ |
| Threaded Components | 6.029E-05 ⁴ | 7.095E-05 ⁴ | 7.661E-05 ⁴ |
| Pump Seals | 5.004E-03 ⁴ | 1.880E-03 ⁴ | 5.458E-04 ⁴ |
| Pressure Relief Valves | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Bursting Discs | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Diaphragms | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Drains | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Hatches | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Instruments | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Meters | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Polished Rod Stuffing Boxes | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Sight Glasses | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Loading Arms | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| Dump Lever Arm | 7.386E-04 ⁴ | 9.294E-04 ⁴ | 5.458E-04 ⁴ |
| CO₂ (3% CO₂ Assumption) | | | |
| Manual Valves | 2.247E-05 ⁴ | 1.411E-05 ⁴ | 1.404E-05 ⁴ |
| Flanges | 1.473E-05 ⁴ | 1.783E-05 ⁴ | 2.306E-05 ⁴ |
| Connectors | 6.312E-06 ⁴ | 7.428E-06 ⁴ | 8.021E-06 ⁴ |
| Open-ended Lines | 1.263E-05 ⁴ | 1.337E-05 ⁴ | 1.504E-05 ⁴ |
| Threaded Components | 6.312E-06 ⁴ | 7.428E-06 ⁴ | 8.021E-06 ⁴ |
| Pump Seals | 5.239E-04 ⁴ | 1.968E-04 ⁴ | 5.715E-05 ⁴ |
| Pressure Relief Valves | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Bursting Discs | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Diaphragms | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Drains | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Hatches | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Instruments | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Meters | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Polished Rod Stuffing Boxes | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Sight Glasses | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Loading Arms | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |
| Dump Lever Arm | 7.733E-05 ⁴ | 9.730E-05 ⁴ | 5.715E-05 ⁴ |

1. Assume THC is 70% CH₄; 2. Assume THC is 74% CH₄; 3. Assume THC is 72% CH₄; 4. CAPCOA (1999)

Method 12 – Automated Control Devices

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{CO}_2 \text{ Emission Factor}) * (\text{CO}_2 \text{ Mole Fraction}/0.03) * (\# \text{ Devices})$$

Where

CO₂ Emission Factor = See Table 9

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

Devices = Number of automated control devices

Data Requirements

1. Mole % CO₂
2. Number of automated control devices

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ Emission Factor}) * (\text{CH}_4 \text{ Mole Fraction}/0.788) * (\# \text{ Devices})$$

Where

CH₄ Emission Factor = See Table 9

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

Devices = Number of automated control devices

Data Requirements

1. Mole % CH₄
2. Number of automated control devices

Table 9: Automated Control Devices

| Device Type | CH ₄ (tonnes/device-year) | % Methane Assumption | CO ₂ (tonnes/device-year) | % CO ₂ Assumption |
|-------------------------------|---|-------------------------|---|---------------------------------|
| Controllers | | | | |
| Continuous Bleed | 3.599 ¹ | 78.8 | 0.377 ¹ | 3 |
| Intermittent Bleed | 1.778 ¹ | 78.8 | 0.186 ¹ | 3 |
| Low Bleed | 0.792 ² | 78.8 | 0.083 ² | 3 |
| Actuators - Production | | | | |
| Piston Valve Operator | 7.237E-04 ³ | 78.8 | 7.577E-05 | 3 |
| Hydraulic Valve Operator | 4.095E-02 ³ | 78.8 | 4.287E-03 | 3 |
| Turbine Valve Operator | 1.086E-02 ³ | 78.8 | 1.137E-03 | 3 |

1. API (2004); 2. EPA (2003a); 3. EPA (1996a)

Method 13 – Natural Gas Dehydration (Glycol Units)

Vented emissions from glycol dehydrators (CEC 2006).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Throughput}) * (\text{EF} \setminus 0.90) * (\text{CO}_2 \text{ Mole Fraction}) * D$$

Where

$$\text{EF} = [(0.0066) * (\text{GCR}) * (\text{P}) * (\text{GAP})] + (\text{SG})$$

$$\text{EF units} = (\text{Mcf CH}_4/\text{year per MMcf gas throughput/day})$$

$$\text{EF conversion} = [(1 \text{ year}) / (365 \text{ days})] * [(1 \text{ MMcf gas}) / (10^6 \text{ scf gas})] * [(1000 \text{ scf CH}_4) / (1 \text{ Mcf CH}_4)]$$

$$0.90 = \% \text{ methane used to create EF (lbmole CH}_4) / (\text{lbmole gas})$$

$$\text{GCR} = \text{glycol circulation rate (gph)}$$

$$\text{P} = \text{flash tank or contactor pressure (psia)}$$

$$\text{GAP} = 2.5 \text{ if a gas assist pump is installed or } 1.0 \text{ if there is no gas assist pump}$$

$$\text{SG} = 0.245 \text{ if stripping gas is used or } 0 \text{ if no stripping gas is used}$$

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{CH}_4 \text{ Density}) * (\text{lb}/453.5 \text{ grams}) * (1/\text{MW}_{\text{CH}_4}) * (\text{MW}_{\text{CO}_2}) * (\text{tonne}/2204.6\text{lb}) * (\text{EF conversion})$$

$$\text{CH}_4 \text{ Density} = (19.2 \text{ grams}) / (\text{scf CH}_4)$$

$$\text{MW}_{\text{CH}_4} = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

$$\text{MW}_{\text{CO}_2} = (44 \text{ lb CO}_2) / (\text{lbmole CO}_2)$$

Data Requirements

1. Throughput (scf/year)
2. Input Mole % CO₂
3. Glycol circulation rate (gallons/hour)
4. Flash tank pressure (psia)
5. Contactor pressure (psia)
6. Gas assist pump installation
7. Stripping gas use

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Throughput}) * (\text{EF} \setminus 0.90) * (\text{CH}_4 \text{ Mole Fraction}) * D$$

Where

$$\text{EF} = [(0.0066) * (\text{GCR}) * (\text{P}) * (\text{GAP})] + (\text{SG})$$

$$\text{EF units} = (\text{Mcf CH}_4/\text{year per MMcf gas throughput/day})$$

$$\text{EF conversion} = [(1 \text{ year}) / (365 \text{ days})] * [(1 \text{ MMcf gas}) / (10^6 \text{ scf gas})] * [(1000 \text{ scf CH}_4) / (1 \text{ Mcf CH}_4)]$$

$$0.90 = \% \text{ methane used to create EF (lbmole CH}_4) / (\text{lbmole gas})$$

$$\text{GCR} = \text{glycol circulation rate (gph)}$$

$$\text{P} = \text{flash tank or contactor pressure (psia)}$$

$$\text{GAP} = 2.5 \text{ if a gas assist pump is installed or } 1.0 \text{ if there is no gas assist pump}$$

$$\text{SG} = 0.245 \text{ if stripping gas is used or } 0 \text{ if no stripping gas is used}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{CH}_4 \text{ Density}) * (\text{lb}/453.5 \text{ grams}) * (\text{tonne}/2204.6\text{lb}) * (\text{EF conversion})$$

$$\text{CH}_4 \text{ Density} = (19.2 \text{ grams}) / (\text{scf CH}_4)$$

Data Requirements

1. Throughput (scf/year)
2. Input Mole % CH₄
3. Glycol circulation rate (gallons/hour)
4. Flash tank pressure (psia)
5. Contactor pressure (psia)
6. Gas assist pump installation
7. Stripping gas use

Method 14 – Natural Gas Dehydration (Desiccant Units)

Vented emissions from refilling desiccant (EPA 2003b).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CO}_2 \text{ Mole Fraction}) * \text{D}$$

Where

$$\text{EF} = [(P_2) * (G) * (365 \text{ days/yr}) * (V)] / [(P_1) * (T)]$$

$$P_1 = 14.7 \text{ psia (atmospheric pressure)}$$

$$P_2 = (\text{Pressure of Gas (psig)}) + 14.7$$

$$G = \% \text{ of Packed Vessel Volume that is Natural Gas}$$

$$V = \text{Volume of Dehydrator (ft}^3\text{)}$$

$$T = \text{Frequency of Desiccant Replacement (days)}$$

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CO}_2) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CO}_2 = (44 \text{ lb CO}_2) / (\text{lbmole CO}_2)$$

Data Requirements

1. Mole % CO₂
2. Volume of Dehydrator
3. Pressure of Natural Gas
4. Frequency of Desiccant Replacement
5. % of Packed Vessel Volume that is Natural Gas (45% will be assumed if no value is provided)

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CH}_4 \text{ Mole Fraction}) * \text{D}$$

Where

$$\text{EF} = [(P_2) * (G) * (365 \text{ days/yr}) * (V)] / [(P_1) * (T)]$$

$$P_1 = 14.7 \text{ psia (atmospheric pressure)}$$

$$P_2 = (\text{Pressure of Gas (psig)}) + 14.7$$

$$G = \% \text{ of Packed Vessel Volume that is Natural Gas}$$

$$V = \text{Volume of Dehydrator (ft}^3\text{)}$$

$$T = \text{Frequency of Desiccant Replacement (days)}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CH}_4 = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

Data Requirements

1. Mole % CH₄
2. Volume of Dehydrator
3. Pressure of Natural Gas
4. Frequency of Desiccant Replacement
5. % of Packed Vessel Volume that is Natural Gas (45% will be assumed if no value is provided)

Method 15 – Natural Gas Dehydration Fugitive Emissions

Fugitive emission calculations using mass balance.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Mass Balance}) - (\text{Vented Emissions})$$

Where

$$\text{Mass Balance} = D * [(\text{Input}) * (\text{In CO}_2 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CO}_2 \text{ Mole Fraction})]$$

$$\text{Vented Emissions} = \text{Method 13 or Method 14}$$

$$\text{Input} = \text{Input volume (scf/year)}$$

$$\text{Output} = \text{Output volume (scf/year)}$$

$$\text{In CO}_2 \text{ Mole Fraction} = \text{Input CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$\text{Out CO}_2 \text{ Mole Fraction} = \text{Output CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CO}_2) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CO}_2 = (44 \text{ lb CO}_2) / (\text{lbmole CO}_2)$$

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CO₂
4. Output Mole % CO₂
5. Vented Emissions

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Mass Balance}) - (\text{Vented Emissions})$$

Where

$$\text{Mass Balance} = D * [(\text{Input}) * (\text{In CH}_4 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CH}_4 \text{ Mole Fraction})]$$

$$\text{Vented Emissions} = \text{Method 13 or Method 14}$$

$$\text{Input} = \text{Input volume (scf/year)}$$

$$\text{Output} = \text{Output volume (scf/year)}$$

$$\text{In CH}_4 \text{ Mole Fraction} = \text{Input CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$\text{Out CH}_4 \text{ Mole Fraction} = \text{Output CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CH}_4 = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CH₄
4. Output Mole % CH₄
5. Vented Emissions

Method 16 –Natural Gas Sweetening/Acid Gas Removal (Solid Material Units)

Vented emissions from refilling solid material (EPA 2003b).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CO}_2 \text{ Mole Fraction}) * \text{D}$$

Where

$$\text{EF} = [(P_2) * (G) * (365 \text{ days/yr}) * (V)] / [(P_1) * (T)]$$

$$P_1 = 14.7 \text{ psia (atmospheric pressure)}$$

$$P_2 = (\text{Pressure of Gas (psig)}) + 14.7$$

$$G = \% \text{ of Packed Vessel Volume that is Natural Gas}$$

$$V = \text{Volume of Unit (ft}^3\text{)}$$

$$T = \text{Frequency of Solid Material Replacement (days)}$$

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CO}_2) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CO}_2 = (44 \text{ lb CO}_2) / (\text{lbmole CO}_2)$$

Data Requirements

1. Input Mole % CO₂
2. Volume of unit
3. Pressure of Natural Gas
4. Frequency of solid material replacement
5. % of Packed Vessel Volume that is Natural Gas (45% will be assumed if no value is provided)

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{EF}) * (\text{CH}_4 \text{ Mole Fraction}) * \text{D}$$

Where

$$\text{EF} = [(P_2) * (G) * (365 \text{ days/yr}) * (V)] / [(P_1) * (T)]$$

$$P_1 = 14.7 \text{ psia (atmospheric pressure)}$$

$$P_2 = (\text{Pressure of Gas (psig)}) + 14.7$$

$$G = \% \text{ of Packed Vessel Volume that is Natural Gas}$$

$$V = \text{Volume of Unit (ft}^3\text{)}$$

$$T = \text{Frequency of Solid Material Replacement (days)}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CH}_4 = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

Data Requirements

1. Input Mole % CH₄
2. Volume of unit
3. Pressure of Natural Gas
4. Frequency of solid material replacement
5. % of Packed Vessel Volume that is Natural Gas (45% will be assumed if no value is provided)

Method 17 – Natural Gas Sweetening/Acid Gas Removal Fugitive Emissions (Solid Material Units)

Fugitive emission calculations using mass balance.

CO₂ emissions (tonnes/year) = (Mass Balance) – (Vented Emissions)

Where

Mass Balance = $D * [(Input) * (In\ CO_2\ Mole\ Fraction) - (Output) * (Out\ CO_2\ Mole\ Fraction)]$

Vented Emissions = Method 16

Input = Input volume (scf/year)

Output = Output volume (scf/year)

In CO₂ Mole Fraction = Input CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

Out CO₂ Mole Fraction = Output CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

D = (molar volume) * (Molecular Weight CO₂) * (tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CO₂
4. Output Mole % CO₂
5. Vented Emissions

CH₄ emissions (tonnes/year) = (Mass Balance) – (Vented Emissions)

Where

Mass Balance = $D * [(Input) * (In\ CH_4\ Mole\ Fraction) - (Output) * (Out\ CH_4\ Mole\ Fraction)]$

Vented Emissions = Method 16

Input = Input volume (scf/year)

Output = Output volume (scf/year)

In CH₄ Mole Fraction = Input CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

Out CH₄ Mole Fraction = Output CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

D = (molar volume) * (Molecular Weight CH₄) * (tonne/2204.6lb)

Molar Volume = (1 lbmole gas)/(379.3 scf gas)

Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CH₄
4. Output Mole % CH₄
5. Vented Emissions

Method 18 – Natural Gas Sweetening/Acid Gas Removal Mass Balance (Non-solid Material Units)

Fugitive emissions from natural gas sweetening or acid gas removal.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = D * [(\text{Input}) * (\text{In CO}_2 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CO}_2 \text{ Mole Fraction})]$$

Where

Input = Input volume (scf/year)
 Output = Output volume (scf/year)
 In CO₂ Mole Fraction = Input CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 Out CO₂ Mole Fraction = Output CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CO₂)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CO₂
4. Output Mole % CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = D * [(\text{Input}) * (\text{In CH}_4 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CH}_4 \text{ Mole Fraction})]$$

Where

Input = Input volume (scf/year)
 Output = Output volume (scf/year)
 In CH₄ Mole Fraction = Input CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 Out CH₄ Mole Fraction = Output CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CH₄)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CH₄
4. Output Mole % CH₄

Method 19 – Other Natural Gas Processing

Vented and fugitive emissions from other natural gas processing.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = D * [(\text{Input}) * (\text{In CO}_2 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CO}_2 \text{ Mole Fraction})]$$

Where

Input = Input volume (scf/year)
 Output = Output volume (scf/year)
 In CO₂ Mole Fraction = Input CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 Out CO₂ Mole Fraction = Output CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CO₂)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CO₂
4. Output Mole % CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = D * [(\text{Input}) * (\text{In CH}_4 \text{ Mole Fraction}) - (\text{Output}) * (\text{Out CH}_4 \text{ Mole Fraction})]$$

Where

Input = Input volume (scf/year)
 Output = Output volume (scf/year)
 In CH₄ Mole Fraction = Input CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 Out CH₄ Mole Fraction = Output CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CH₄)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Data Requirements

1. Input volume (scf/year)
2. Output volume (scf/year)
3. Input Mole % CH₄
4. Output Mole % CH₄

Method 20 – Natural Gas Compressor Startups

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Total Volume of Gas Vented}) * (\text{CO}_2 \text{ Mole Fraction}) * D$$

Where

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CO₂)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Data Requirements

1. Total volume of gas vented (scf)
2. Mole %CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Total Volume of Gas Vented}) * (\text{CH}_4 \text{ Mole Fraction}) * D$$

Where

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CH₄)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Data Requirements

1. Total volume of gas vented (scf)
2. Mole %CH₄

Method 21 – Natural Gas Compressor Blowdowns

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{Total Volume of Gas Vented}) * (\text{CO}_2 \text{ Mole Fraction}) * D$$

Where

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CO}_2) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CO}_2 = (44 \text{ lb CO}_2) / (\text{lbmole CO}_2)$$

Data Requirements

1. Total volume of gas vented (scf)
2. Mole %CO₂

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{Total Volume of Gas Vented}) * (\text{CH}_4 \text{ Mole Fraction}) * D$$

Where

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CH}_4 = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

Data Requirements

1. Total volume of gas vented (scf)
2. Mole %CH₄

Method 22 – Natural Gas Compressor Seals

Fugitive emission calculations for natural gas compressor seals.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{CO}_2 \text{ EF}) * (\text{CO}_2 \text{ Mole Fraction} \setminus 0.03) * (\text{Seals}) * (\text{Usage})$$

Where

$$\text{CO}_2 \text{ EF} = \text{See Table 10}$$

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$\text{Seals} = \text{Number seals}$$

$$\text{Usage} = \text{Annual Usage (hours/year)}$$

Data Requirements

1. Mole % CO₂
2. Number of compressor seals
3. Annual usage (hours/year)

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{CH}_4 \text{ Mole Fraction} \setminus 0.788) * (\text{Seals}) * (\text{Usage})$$

Where

$$\text{CH}_4 \text{ EF} = \text{See Table 10}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$\text{Seals} = \text{Number of seals}$$

$$\text{Usage} = \text{Annual Usage (hours/year)}$$

Data Requirements

1. Mole % CH₄
2. Number of compressor seals
3. Annual usage (hours/year)

Table 10: Compressor Seals

| Device Type | CH ₄ (tonnes/component ¹ -hr) | % Methane Assumption | CO ₂ (tonnes/component ¹ -hr) | % CO ₂ Assumption |
|--------------------------|--|-------------------------|--|---------------------------------|
| Reciprocating Seal | 9.925E-04 ² | 78.8 | 1.039E-04 ² | 3 |
| Centrifugal Seal | 1.035E-03 ² | 78.8 | 1.083E-04 ² | 3 |
| Rotary Seal ³ | 1.035E-03 ² | 78.8 | 1.083E-04 ² | 3 |
| Screw Seal ³ | 1.035E-03 ² | 78.8 | 1.083E-04 ² | 3 |
| Vane Seal ³ | 1.035E-03 ² | 78.8 | 1.083E-04 ² | 3 |

1. Leak rate for when the compressor is pressurized.

2. EPA (1996a)

3. Assumed Rotary, Screw, and Vane seals emit at the same rate as Centrifugal seals.

Method 23 – Natural Gas Gathering System Pipelines

Fugitive emission calculations for natural gas gathering system pipelines (before the gas meter).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{CO}_2 \text{ EF}) * (\text{CO}_2 \text{ Mole Fraction} \backslash 0.03) * (\text{Miles}) + (\text{Oxidation CO}_2 \text{ EF}) * (\text{Miles})$$

Where

CO₂ EF = See Table 11

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)

Oxidation CO₂ EF = See Table 10

Miles = miles of natural gas pipeline

Data Requirement

1. Mole % CO₂
2. Mile of natural gas pipeline

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{CH}_4 \text{ Mole Fraction} \backslash 0.788) * (\text{Miles})$$

Where

CH₄ EF = See Table 11

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)

Miles = miles of natural gas pipeline

Data Requirements

1. Mole % CH₄
2. Miles of natural gas pipeline

Table 11: Natural Gas Gathering Pipelines

| Type | CH ₄ (tonnes/mile-yr) | % Methane Assumption | CO ₂ (tonnes/mile-yr) | % CO ₂ Assumption | Oxidation CO ₂ (tonnes/mile-yr) |
|--------------------|-------------------------------------|-------------------------|-------------------------------------|---------------------------------|---|
| Gathering Pipeline | 0.374 ¹ | 78.8 | 7.682E-02 ¹ | 3 | 3.833E-02 ¹ |

1. API (2004)

Method 24 – Natural Gas Gathering System Maintenance Activities

CO₂ emissions (tonnes/year) = (Total Volume of Gas Vented)*(CO₂ Mole Fraction)*D

Where

CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CO₂)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CO₂ = (44 lb CO₂)/(lbmole CO₂)

Data Requirements

1. Total volume of gas vented (scf/year)
2. Mole % CO₂

CH₄ emissions (tonnes/year) = (Total Volume of Gas Vented)*(CH₄ Mole Fraction)*D

Where

CH₄ Mole Fraction = (lbmole CH₄)/(lbmole gas)
 D = (molar volume)*(Molecular Weight CH₄)*(tonne/2204.6lb)
 Molar Volume = (1 lbmole gas)/(379.3 scf gas)
 Molecular Weight CH₄ = (16 lb CH₄)/(lbmole CH₄)

Data Requirements

1. Total volume of gas vented (scf/year)
2. Mole % CH₄

Method 25 – Pipeline Pigging

Vented emission calculations for natural gas pipeline pigging (EPA 2005).

CO₂ emissions (tonnes/year) = (CO₂ EF)*(CO₂ Mole Fraction\0.03)*(Openings)

Where

CO₂ EF = See Table 12
 CO₂ Mole Fraction = (lbmole CO₂)/(lbmole gas)
 Openings = Number of time launcher/receiver is opened

Data Requirements

1. Mole % CO₂
2. Number of launcher/receiver openings

Emission Factor Calculation

$$\text{Equation} = V * [(P_1) * (T_2)] / [(P_2) * (T_1)]$$

Where

V = pig launcher/receiver volume
 P₁ = gathering line pressure (psia)
 P₂ = 14.7 psia (standard surface pressure)
 T₁ = temperature of the pig launcher/receiver
 T₂ = 60°F (standard surface temperature)

Assumptions (from EPA 2005)

$$V = 11.5 \text{ ft}^3 \text{ (for an 18 in line)}$$

$$P_1 = 315 \text{ psia}$$

$$T_1 = 60^\circ\text{F}$$

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{CH}_4 \text{ Mole Fraction} \backslash 0.788) * (\text{Openings})$$

Where

$$\text{CH}_4 \text{ EF} = \text{See Table 12}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$\text{Openings} = \text{Number of time launcher/receiver is opened}$$

Data Requirements

1. Mole %CH₄
2. Number of launcher/receiver openings

Table 12: Pigging

| Device Type | CH ₄ (tonnes/opening) | % Methane Assumption | CO ₂ (tonnes/opening) | % CO ₂ Assumption |
|-------------|-------------------------------------|-------------------------|-------------------------------------|---------------------------------|
| Pigging | 3.716E-03 ¹ | 78.8 | 3.89E-04 ¹ | 3 |

1. EPA (2005)

Method 26 – Tank Cleaning (Separators and Storage Tanks)

Vented emission calculations for the cleaning of crude oil storage tanks or separation units.

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (V) * (\text{CO}_2 \text{ Mole Fraction}) * (0.1) * (\text{Events}) * D$$

Where

$$V = \text{Volume of tank (ft}^3\text{)}$$

$$0.1 = \text{Common air district rule that vapors must be reduced at least 90\% before opening}$$

$$\text{CO}_2 \text{ Mole Fraction} = (\text{lbmole CO}_2) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CO}_2) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CO}_2 = (44 \text{ lb CH}_4) / (\text{lbmole CO}_2)$$

$$\text{Events} = \text{Number of degassing events}$$

Data Requirements

1. Size of tank (bbl/ft³)
2. Mole % CO₂ in vapor head space
3. Number of degassing events

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (V) * (\text{CH}_4 \text{ Mole Fraction}) * (0.1) * (\text{Events}) * D$$

Where

$$V = \text{Volume of tank (ft}^3\text{)}$$

$$0.1 = \text{Common air district rule that vapors must be reduced at least 90\% before opening}$$

$$\text{CH}_4 \text{ Mole Fraction} = (\text{lbmole CH}_4) / (\text{lbmole gas})$$

$$D = (\text{molar volume}) * (\text{Molecular Weight CH}_4) * (\text{tonne}/2204.6\text{lb})$$

$$\text{Molar Volume} = (1 \text{ lbmole gas}) / (379.3 \text{ scf gas})$$

$$\text{Molecular Weight CH}_4 = (16 \text{ lb CH}_4) / (\text{lbmole CH}_4)$$

$$\text{Events} = \text{Number of degassing events}$$

Data Requirements

1. Size of tank (bbl/ft³)
2. Mole % CH₄ in vapor head space
3. Number of degassing events

Method 27 – Crude Oil Separation and Storage Tanks

Fugitive emission calculations for crude oil separation and storage tanks. Default CH₄ and CO₂ mole percents are 43% and 4% respectively (HARC, 2006).

$$\text{CO}_2 \text{ emissions (tonnes/year)} = (\text{TOG}) * (\% \text{ CO}_2)$$

Where

TOG = (Working Loss TOG)+(Breathing Loss TOG)+(Flashing Loss TOG)
 % CO₂ = percent CO₂ in the head space vapor concentration

Data Requirements

1. Working Losses (tons/year)
2. Breathing Losses (tons/year)
3. Flashing Losses (tons/year)
4. % CO₂ in the head space vapor concentration

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{TOG}) * (\% \text{ CH}_4)$$

Where

TOG = (Working Loss TOG)+(Breathing Loss TOG)+(Flashing Loss TOG)
 % CH₄ = percent CH₄ in the head space vapor concentration

Data Requirements

1. Working Losses (tons/year)
2. Breathing Losses (tons/year)
3. Flashing Losses (tons/year)
4. % CH₄ in the head space vapor concentration

Method 28 – Sumps and Pits

Fugitive emission calculations for sumps and pits.

$$\text{CH}_4 \text{ emissions (tonnes/year)} = (\text{CH}_4 \text{ EF}) * (\text{Area}) * (\text{Days})$$

Where

CH₄ EF = See Table 13
 Area = area of the sump or pit
 Days = Number of Days in Use

Data Requirements

1. Area of sump or pit
2. Sump or pit level (primary, secondary, tertiary)
3. Crude Oil API
4. Number of days sump is in use

Table 13: Sumps

| Type | CH ₄ (tonnes/ft ² -day) |
|--------------------|--|
| Light Crude | |
| Primary Sump | 1.297E-05 ¹ |
| Secondary Sump | 1.814E-06 ¹ |
| Tertiary Sump | 9.070E-07 ¹ |
| Heavy Crude | |
| Primary Sump | 9.480E-06 ¹ |
| Secondary Sump | 4.672E-06 ¹ |
| Tertiary Sump | 5.90E-07 ¹ |

1. Kern County APCD (1990)

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Appendix C: Site Visits and Meetings

**California Air Resources Board
Oil and Gas Industry Survey**

Site Visits and Meetings

| Date | Action |
|----------------|---|
| April 2008 | <ul style="list-style-type: none"> • Staff held preliminary public workshop. • Industry and district working groups created. |
| May 2008 | <ul style="list-style-type: none"> • Staff met with the Western States Petroleum Association (WSPA) and several large crude oil production companies. Staff explained to WSPA our intention to survey the sector and asked for contacts for potential site visits. |
| June 2008 | <ul style="list-style-type: none"> • Staff met with the California Independent Petroleum Association (CIPA). CIPA was asked for contacts for site visits and staff explained our intention for a survey to create an accurate baseline inventory for regulatory development. |
| July 2008 | <ul style="list-style-type: none"> • Staff traveled to Bakersfield to tour two large crude oil production fields and several small independent producers. • Staff met with the Independent Oil Producers' Agency (IOPA) to hear their concerns about potential regulation and to inform them of our intention to survey the sector. • Staff toured a large Northern California dry gas field. |
| August 2008 | <ul style="list-style-type: none"> • Staff toured a natural gas storage field. • Staff traveled to Santa Barbara to tour an onshore processing plant for offshore platforms. • Staff met with Santa Barbara and Ventura air district personnel responsible for permitting oil and gas production facilities. • Staff travelled to Los Angeles to tour two large crude oil producers and to meet with South Coast air district staff. • A draft version of the survey was sent to the industry workgroup for review. |
| September 2008 | <ul style="list-style-type: none"> • A conference call with the industry workgroup was held to discuss the draft survey. Attendees of the call gave detailed feedback to staff. • A revised version of the survey was then sent out to the industry working group for review and comments. • Staff travelled to the Los Angeles area to tour several oil terminals and to meet with the South Coast air district staff again. • Staff and the industry working group met to discuss the revised draft survey. Staff took detailed comments from the industry and incorporated them into another |

| | |
|---------------|--|
| | revised draft survey. |
| October 2008 | <ul style="list-style-type: none"> • Staff travelled to the Santa Barbara area to tour an offshore platform and an onshore processing plant. Staff also toured a large natural gas storage facility in the northern Los Angeles area during that trip. • Staff sent a portion of the revised survey out to the industry working group for their review and comments. • Staff traveled to Bakersfield to attend the Oil and Gas Conference put on by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources. During that trip, a crude oil pipeline storage and heating station was also toured. |
| November 2008 | <ul style="list-style-type: none"> • Staff received supporting information from the industry working group for changes they had requested of the draft survey. Staff made the appropriate changes to the draft survey. • Staff travelled to Bakersfield to tour a small crude oil production field using a microturbine to generate electricity. Staff also toured a crude oil pipeline processing station. |
| December 2008 | <ul style="list-style-type: none"> • Staff sent out the draft survey with general instructions for completing the survey and electronic templates to two companies for a pilot survey. • Staff conducted a conference call with our district working group to discuss comments on the draft survey. • Staff toured a natural gas storage field north of Sacramento. • Staff conducted a meeting with the industry working group to discuss emission factors ARB would be using to calculate the baseline GHG emissions inventory for the oil and gas production sector. • Staff continued working with the companies performing the pilot survey and incorporated changes to the draft survey based on comments from the industry and district working group. |
| January 2009 | <ul style="list-style-type: none"> • Comments from the pilot group were received. Staff revised the draft survey and general instructions based on those comments and sent out a revised version of both to the industry working group. • Staff conducted a conference call with the industry working group. Comments were incorporated where appropriate and staff sent a revised draft survey and general instructions to the industry working group for review and comment. |

| | |
|----------------------------|---|
| February 2009 | <ul style="list-style-type: none"> • Staff toured a large natural gas extraction facility just north of Sacramento. • ARB staff mailed out the Oil and Gas Industry Survey on February 19. |
| March 2009 | <ul style="list-style-type: none"> • On March 26, 2009 staff traveled to Bakersfield to conduct a training seminar for filling out the survey. |
| April 2009 | <ul style="list-style-type: none"> • Staff answered questions from the industry about the survey. • The Oil and Gas Industry Survey was due on April 30. • Extensive follow-up with facilities started. |
| May to August 2009 | <ul style="list-style-type: none"> • Staff toured crude oil facilities in the Los Angeles area. • Majority of surveys received. • Staff continued to follow up with facilities with questions on surveys received. • Surveys uploaded to survey database. |
| September to December 2009 | <ul style="list-style-type: none"> • Staff contacted non-respondents for the survey. • Remaining surveys received and uploaded. • On December 8, 2009 staff conducted a workshop detailing preliminary results from the survey. |
| January to March 2010 | <ul style="list-style-type: none"> • Staff worked with industry to answer questions about facility emissions. • Staff QA'd and QC'd data and followed up with facilities. |
| March 18, 2010 | <ul style="list-style-type: none"> • Survey data was frozen. |
| April to May 2010 | <ul style="list-style-type: none"> • Staff developed survey data and emission summaries. • Staff worked with industry working group on emission summaries. |
| June 2010 to January 2011 | <ul style="list-style-type: none"> • Draft survey report developed. |
| April 2011 to June 2011 | <ul style="list-style-type: none"> • Draft survey report review by district and industry working groups. |
| August 2011 | <ul style="list-style-type: none"> • Draft survey report released for public comment. |

Appendix D: Internal Combustion Engine Use Categories

**California Air Resources Board
Oil and Gas Industry Survey**

Internal Combustion Engine Use Categories

| | | |
|---|--|---|
| <u>Air Compressor</u> Air Compressor Emergency Instrument Air Compressor | <u>Cogeneration</u> Cogen Start Co-generation Co-generation plant Cogeneration Starter | <u>Compressor</u> Compressor Portable Compressor |
| <u>Crane</u> 30 ton Crane Crane Crane Engine East Crane Pedestal crane east West Crane | <u>Crude Oil Pump</u> Crude Oil Prod Crude Oil Pump Oil Pump Well Pump Well Pumps Crude Oil Pump/Charge Pump | <u>Emergency Services</u> Emergency Fire pump Emergency Firewater Pump Emergency Flood Control Emergency Freshwater Fire Pump Emergency Well Kill Pump Fire Pump Fire Water Pump Firewater Pump |
| <u>Miscellaneous</u> Acid pump A-Frame Backhoe Blower Broadbill - auxiliary engine Broadbill - main engine Building Heater Concrete saw Crew Boat - auxiliary engine Crew boat - auxiliary engines DPV Crew Boat - main engine Crew boat - main engine DPV Crew boat - main engine spot charter Crew Boat - spot charter Crew Boat -Auxiliary engines DPV Crew Boat -Auxiliary engines DPV Broadbill Crew Boat -Main engines Crew Boat -Main engines DPV Broadbill Crew Boat -Main engines spot charter Dozer E-line unit Forklift Gas Disposal Hydroblaster | Hyperclean Large Forklift LIGHT PLANT Light Tower Loader Engine Manlift Nitrogen Pump Paint Sprayer Pipe Threader Plate compactor Poly Tank Pump motor Portable Welder Portable Wood Grinder Pump Skid Road Grader Engine Roller Single Drum Roller Skip Loader Small Forklift Spare Sprayer STARTING AIR Steam Cleaner Sub-Base Supply boat - Auxiliary engines | Supply boat - main engine Supply boat - main engine (Spot charter) Supply boat - main engine DPV Supply boat - main engine spot charter Supply Boat -Bow thruster and auxiliary engines Supply Boat -Main engines spot charter SupplyBoat -Main engines Survival capsule Survival Capsule #1 Survival Capsule #2 Top Drive Tractor Engine Tractor Loader TRANSFER PUMP Truck Engine Vibe Weed Eater Welder Welding Machine |

| | | |
|---|--|--|
| <p><u>Power Generation</u> Backup Generator Electric Generator Electrical Generator Emergency Emergency drilling generator Emergency Generator emergency power Emergency Power Generator Emergency production generator Emergency response - main and auxiliary Gen House</p> | <p>Gen Set Generator Generators Hydraulic Power Unit Portable Generator Power Generation Power Generator Power Unit Standby Generator starter engine Turbine Starter</p> | <p><u>Pump</u> Hydraulic Pump Lift Pump Pump Pump Unit Test Pump Wash Pump</p> |
| <p><u>Water Pump</u> Water Injection Pump Water Pump Engine Water Transfer Pump</p> | <p><u>Well Servicing</u> Baker/Apollo Injecting Unit BJ Cement Unit Blackstart Engine Cement Pump Circulating Pump Circulation pump Cmt. Bulk Trailer Coiled Tubing Powerpack CTU Draw Works Drum Vibratory Roller Emergency drilling engine Fluid Pump Foam unit</p> | <p>Foamer Mud Pump Mud Pump Driver Portable Mud Pump Portable Power Swivel Power Pumping Unit Power Swivel Produced Water Production Rig Rig Engine Rig Power Stang Pump Well Kill Pump Engine Workover Rig</p> |

Appendix E: Separator Type Categories

California Air Resources Board Oil and Gas Industry Survey

Separator Type Categories

| | | |
|--|--|--|
| <u>Condensate tank</u> Condensate Accumulator Condensate tank Condensate vessel Condensate | <u>Free Water Knockout</u> Free Water Knockout | <u>Heater/Treater</u> Boiler Heat Exchanger Heater/Treater Heater-PU |
| <u>Crude Oil Separator</u> Clean Out Tank Clean Up Tank Crude Oil Tank Crude Stock Tank Crude Tank Dirty Oil Tank Disc Pot | Discharge Drip Pot Vessel Drip Vessel Oil Water Separator overflow drain tank Skim oil tank skim tank Skim Water Tank | Skimmer skims tank Stand-by Surge/Skim oil tank Wet oil reject tank Wet oil tank Production Unit |
| <u>Gas Separator</u> Absorber Casing Collection Separator Casing Gas Scrubber Casing Gas Separator Contactor Dehydrator Flare Knock Out Drum Flare Separator Vessel | Gas Scrubber Flash Drum Flow Splitter Flowsplitter Fuel Gas Scrubber Gas Knockout Gas Oil Separator | Gas Separator Gas Trap Vessel Glycol Catch Trap Glycol separator Inlet Scrubber Reboiler Spherical Separator |
| <u>Horizontal Separator</u> Horizontal Horizontal Separator Horizontal Separators Horizontal test trap Horizontal Vessel | <u>Scrubber</u> Loading Rack Vapor Recovery Suction Scrubber Sales gas scrubber Scrubber | Suction Bottle Suction Drip Pot Suction Pot Suction Scrubber |
| <u>Produced Water Tank</u> Clarification Tank Clarifier Clarifier Tank Depurator Flotation Unit Flotation Cell Induced Static Flotation | Induced Static Flotation Produced Water Produced Water Clarifier Produced Water Tank Production Inlet Drum Reject oil / produced water Reject tank | Waste Water Tank Wastewater Surge Tank Wastewater Tank Water Mixing Tank Water Tank Water |
| <u>Separator</u> Cone bottom tank Methanol Tank Natural Gasoline Bullet Other - No Production Equipment POT Pressure Vessel | Rerun Tanks Separator Stripper Feed Separator Tank Test Tank Tote Tank | Treater, unheated Vapor Recovery Vapor Recovery Unit Vaporizer Vessel Blow Tank |
| <u>Settling tanks</u> Sand Water Tank Settling tanks Slop Tank Sludge Collection Tank Sludge Tank Slug Catcher solids tank | <u>Shipping Tank</u> Shipping Tank Stock Tank Storage Tank | <u>Surge Tank</u> Injection Surge Tank Surge Drum surge tank |

| | | | |
|---|--|--|--|
| <u>Stage Separator</u> 1st Stage Discharge 1st Stage Discharge Bottle 1st Stage Suction Bottle 1st Stage Suction Scrubber 2nd Stage Discharge 2nd Stage Suction 2nd Stage Suction Bottle 2nd Stage Suction Scrubber 3-Phase 3rd Stage Discharge Bottle | | 3rd Stage Discharge Scrubber 3rd Stage Suc Drum 3rd Stage Suction Bottle 3rd Stage Suction Scrubber 4th Stage Discharge Drum 4th Stage Suc Drum Compressor Interstage Scrubber Compressor Interstage Separator Three stage clarifier | <u>Trap Separator</u> Ball Separator Ball Trap DBL Ball Trap Gage Trap Inlet Gas Trap Master Trap Master Trap / Scrubber |
| <u>Vertical Separator</u> Vertical Vertical Separator Vertical Vessel | <u>Wemco</u> Wemco Wemco Flotation cell Wemco holding tank Wemco surge tank | <u>Wash Tank</u> Wash Tank <u>Well Tester</u> Automatic Well Tester Well Test separator | |

CARBON LIMITS

Zero emission technologies for pneumatic controllers in the USA

Applicability and cost effectiveness



CARBON LIMITS

This report was prepared by Carbon Limits AS.

Project title:

Zero emission technologies for pneumatic controllers in the USA

| | |
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Carbon Limits is a consulting company with long standing experience in supporting energy efficiency measures in the petroleum industry. In particular, our team works in close collaboration with industries, government, and public bodies to identify and address inefficiencies in the use of natural gas and through this to achieve reductions in greenhouse gas emissions and other air pollutants.

Table of contents

| | |
|--|----|
| Executive Summary..... | 3 |
| Abbreviations and Notes on Units..... | 5 |
| 1. Introduction | 6 |
| 1.1 What is the problem? | 6 |
| 1.2 Objective of this project | 6 |
| 1.3 Approach and methodology..... | 7 |
| 2. Gas Driven Pneumatic controllers – What are we talking about?..... | 7 |
| 2.1 Definition..... | 7 |
| 2.2 Typology of controllers | 8 |
| 2.3 Number of controllers and emission factors – Brief literature review..... | 9 |
| 3. Zero emission technologies – Description and technical applicability..... | 12 |
| 3.1 Overview of the zero emission technology presented. | 12 |
| 3.2 Electronic controllers (solar powered and grid powered) | 13 |
| 3.3 Instrument air | 16 |
| 3.4 Other technologies | 18 |
| 4. Cost effectiveness of electronic controllers and instrument air..... | 20 |
| 4.1 Analytical approach..... | 20 |
| 4.2 Main findings – electronic controllers | 23 |
| 4.3 Main findings – Instrument air..... | 28 |
| 4.4 Summary of the analysis | 32 |
| 5. Reference list | 35 |
| 6. Appendix | 36 |
| 6.1 Quantitative assumptions for the model..... | 36 |
| 6.2 Other assumptions for the model..... | 37 |
| 6.3 Detailed sensitivity analysis | 38 |
| 6.4 List of site configurations with abatement cost superior to the social cost of methane | 40 |

Executive Summary

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices release methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory.

US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than six standard cubic feet/hour) at production sites and compressor stations and be *zero-bleed* at processing plants. Unfortunately, recent measurements have demonstrated that many controllers currently in field use are emitting more than would be expected based on design specifications.

This study was undertaken to determine whether cost-effective non-emitting technologies are available to eliminate this major emissions source. We find that these technologies have evolved considerably over the past decade and are now available and actively in use in oil and gas fields in the United States and Canada. Two technologies are mature, proven, and in relatively wide use, and as we discuss in this report, these technologies provide a cost-effective way to eliminate emissions of methane and other pollutants from pneumatic controllers.

Major findings include:

- Zero emission technologies can virtually eliminate emissions from pneumatic devices.
- A number of technologies are available. The two most promising, which this report focuses on, are electronic controllers – both solar and grid powered – and instrument air.

Electronic controllers can be installed both at sites connected to the electric grid and at sites isolated from the grid.

Instrument air technology is a well-established, mature solution to run pneumatic control systems and is widely applied globally. The technology requires a reliable power supply, either from the grid or from generators on the site.

- Currently, electronic controllers are generally used at smaller sites while instrument air is used at larger sites, due to the technical limitations of air compressors. These two technologies are on the market today, from multiple suppliers.
- Due to the market conditions, providers of electronic controllers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.
- A number of other zero emission solutions are available today with more limited applicability (e.g. self-contained devices) or fewer documented implementations (e.g. solar-powered instrument air). Depending on the site specificities, these options can represent useful alternatives to instrument air or electronic controllers.
- Operators have successfully installed hundreds of systems. They report positive experiences on both new and retrofit sites, valuing zero emission solutions for their low maintenance costs and reliability.
- An economic analysis, assuming conservative average emission factors for pneumatic controllers, was performed for 2032 site configurations with 1 to 40 controllers (excluding emergency

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shutdown devices). Both retrofit and new installations, with and without electricity on-site, were considered.

- Zero emission solutions have abatement costs below the social cost of methane used by US EPA (\$1354/tCH₄, mean value calculated for 2020 with a 3% discount rate in 2016 USD) in the vast majority of the site configurations considered (2008 out of 2032 site configurations).
- The abatement costs, calculated as described above, exceed the social cost of methane used by US EPA primarily at very small sites – those with less than three controllers (excluding emergency shutdown devices). However, if higher emission factors, as reported from recent field measurements, are used, the abatement costs at even the very small sites will fall below the social cost of methane.

Overall, we find that zero emission solutions are available today and are cost effective to implement in nearly every situation.

The following table presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the below categories, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

| Type of site | | Both retrofit and new sites | | | | | | |
|--|---|--|---|---|---|---|--------------|---|
| | | Number of controllers (excl. ESDs) | | 4-20 | | 21-40 | | |
| | | 1-3 | | Yes | No | Yes | No | |
| Electricity on-site? | | Yes | No | Yes | No | Yes | No | |
| Main options: Electric controller Instrument air | Description (of the most economic option which is technically feasible) | Grid connected electric controller | Solar powered electric controller | Grid connected electric controller | Solar powered electric controller | Instrument air | | |
| | Number of cases not cost effective (i.e. abatement cost > social cost of methane) under central assumptions | 6 / 36 | 11 / 36 | 0 / 308 | 2 / 308 | 5/ 328 | | |
| | Cost effective for every site configuration if emissions factors are: [*] | > 5.6 scfh for retrofit > 2.8 scfh for new sites | > 7.2 scfh for retrofit > 4.4 scfh for new sites | > 3.6 scfh for retrofit > 1.4 scfh for new sites | > 4.2 scfh for retrofit > 1.8 scfh for new sites | > 4.5 scfh for retrofit > 1.8 scfh for new sites | | |
| Other options potentially applicable depending on the local conditions | Limited applicability | Vent gas recovery | ✓ | ✓ | ✓ | ✓ | ✓ | |
| | | Instrument air powered by gas | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant | ✓ |
| | | Self contained controllers | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | Limited known implementations | Solar powered instrument air | Not relevant | ✓ | Not relevant | ✓ | X | X |
| | | Electric controllers powered by other power sources (TEG, fuel cell) | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant | ✓ |
| | | Large solar powered electric controller (no known implementations) | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant | Potential solution, ^{**} but no example known. |

^{*}Emissions factors threshold listed are determined for the site configuration with the highest abatement cost within the category.

^{**}Based on other solar applications. No fundamental barrier identified.

Abbreviations and Notes on Units

| | |
|--------------------|---|
| CAPEX | Capital Expenditure |
| CH ₄ | Methane |
| CO ₂ eq | Carbon dioxide equivalent |
| EF | Emission Factor |
| ESD | Emergency shut down |
| GHGRP | Greenhouse Gas Reporting Program – US EPA |
| GOR | Gas/oil ratio |
| Mscf | Thousands standard cubic feet |
| MMscf | Million standard cubic feet |
| MMscfd | Million standard cubic feet per day |
| MMT | Million tons |
| OPEX | Operational expenditure |
| SCADA | Supervisory Control and Data Acquisition |
| Scfh | Standard cubic feet/hour |
| USD | US dollars |
| VOC | Volatile Organic compound |
| VRU | Vapor Recovery Unit |

Notes on units:

All the data are presented in metric tons

All monetary figures are presented in US dollars, denoted as \$

Social Cost of Methane: This report uses the social cost of methane, as reported by US EPA in recent regulatory analyses, as a benchmark for the cost-effectiveness of measures to abate methane emissions. We use the mean value calculated at the 3% discount rate for emissions in year 2020. EPA calculates this as \$1300 per metric ton in 2012 USD. We have converted this to \$1354 per metric ton in 2016 USD, using a cumulative rate of inflation of 4.2%.

1. Introduction

1.1 What is the problem?

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices vent methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory [1].

Over the last few years, regulators have worked to reduce the emission of methane and volatile organic compounds (VOCs) from pneumatic controllers. US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than 6 scfh) at production sites and compressor stations and *zero-bleed* at processing plants. Wyoming goes further to include intermittent-vent controllers in its requirement that *all* new controllers are designed to emit less than 6 scfh. It also requires the replacement of existing high-emitting controllers in some areas and caps allowable emissions in other areas. Recently Colorado required that existing high-continuous-bleed controllers be replaced with low-bleed controllers statewide, and other states are currently considering similar measures. Finally, some operators have reported voluntary replacements of high-bleed controllers with low-bleed controllers to programs such as US EPA's Natural Gas STAR.

Unfortunately, recent measurement studies [2,3,4] have reported higher emissions from low-bleed controllers than expected. Some controllers that are considered low-bleed according to manufacturer specifications actually bleed above the low-bleed threshold of 6 scfh. Indeed, a number of controllers appear to malfunction, emitting significantly more than they are designed to emit.

Moreover, as a class, intermittent-vent controllers, which are largely unregulated, far outnumber continuous-bleed controllers, and EPA estimates that emissions from intermittent-vent controllers are considerably higher than emissions from continuous-bleed controllers [1]. Recent work has demonstrated that some controllers designed to emit intermittently fail and begin leaking natural gas continually [2,5].

Given the wide range of applications of pneumatic controllers, their typical installation in remote, unmanned sites, and the limited resources of air quality regulators, it is very challenging for air quality regulators to ensure compliance to emissions standards for pneumatic controllers. Currently, new continuous-bleed controllers are in compliance with EPA rules, if they are designed to emit below the EPA threshold of six cubic feet per hour. In practice, they may emit more depending on installation parameters (such as the pressure of the supply-gas), malfunctions, or even tampering, e.g. production workers modify controllers bleed rates when they believe that it will improve reliability [9]. Finally, it is inherently difficult to quantify the emissions from intermittent-vent controllers, as their actuation frequency is variable and may change over time.

1.2 Objective of this project

Zero emission technologies have the potential to virtually eliminate this emission source. They have evolved extensively over the last few years, as operators have gained experience using them. Yet, although zero emission technologies are often mentioned in best practices documentation and reports, there is very limited information on overall applicability and costs (with the exception of instrument air).

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This report documents how zero emission technologies are being used in gas and oil fields, and discusses the zero emissions technologies that are suitable for wide usage in common applications at oil and gas production facilities and compressor stations. The main objectives include:

- Presentation of zero emission technologies that are currently available on the market.
- Discussion of the applicability and the technical barriers to the implementation of these technologies.
- Estimates of implementation and methane abatement costs of these technologies for new installations and retrofits.

1.3 Approach and methodology

In addition to a comprehensive literature review, this report relies on interviews with a number of relevant stakeholders and a detailed cost-benefit analysis.

Interviews: Seventeen interviews were conducted. Nine were with technology providers, and eight with both small and large oil and gas companies. The interviews gathered information on field experience with the implementation of zero emission technologies, in particular on their applicability, technical barriers experienced, and actual costs and benefits.

Cost-benefit analysis of zero emission technology implementation: Based on the information gathered during the interviews, literature reviews, and online equipment quotes, a cost-benefit analysis was performed covering a wide range of possible site configurations.

The cost-benefit analysis is presented in section 4 of this report. Prior to that, section 2 includes an introduction to controller typologies, followed by a brief literature review of emissions from controllers. Section 3 presents the different zero emission controller technologies and includes a description of field experiences with these technologies. The report concludes with a brief overview of existing applicability and costs under a range of circumstances.

2. Gas Driven Pneumatic controllers – What are we talking about?

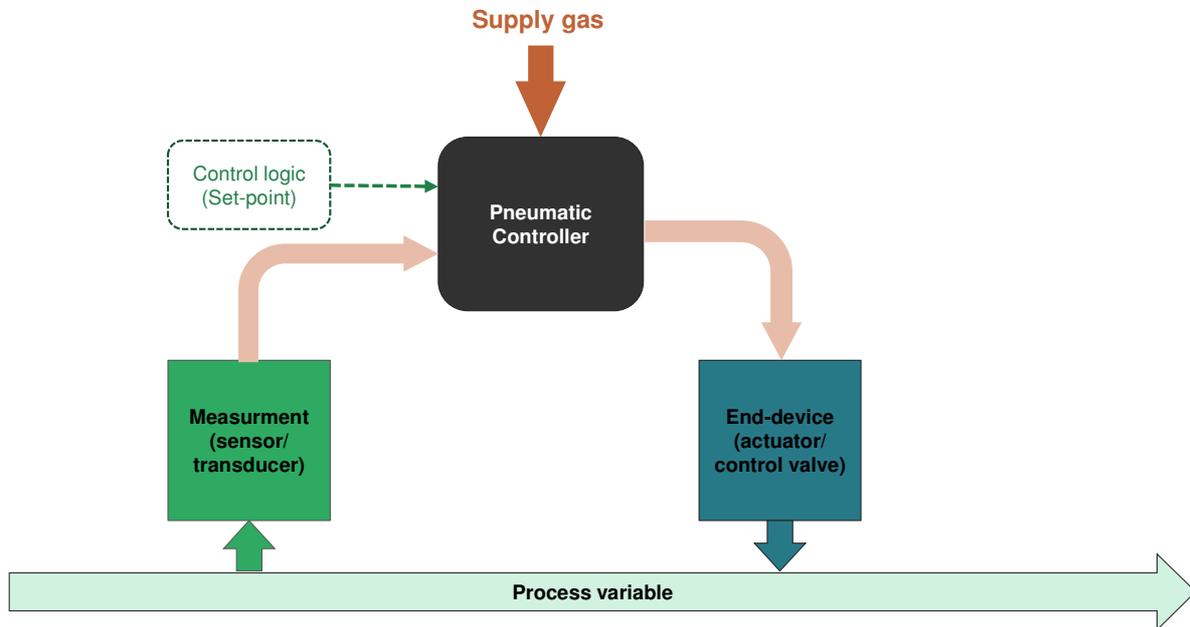
2.1 Definition

A process controller is a device that senses a physical state and then operates automatically to regulate that state¹, based on an established set-point in its control logic. Process controllers can regulate a variety of physical parameters – or *process variables* – including fluid pressure, liquid level, fluid temperature, and differential pressure. An example of a common type is a separator dump valve controller, which operates when it senses that liquid has reached a certain level. Process controllers can be electric, hydraulic, pneumatic or a combination of them. An example of a combination controller would be an electrohydraulic controller operating an electric valve to send liquid pressure to a hydraulic end-device.

Pneumatic controllers convert an input signal to a pneumatic pressure output using gas pressure. The end-device, i.e. the control valve, is adjusted by the actuator in response to signal from the controller. A pneumatic controller uses gas pressure to open or close a mechanical device, such as a valve, when it senses the need to regulate a process condition such as liquid level, pressure, temperature, or flow.

¹ In complex control systems, other process control variables might be modulated to regulate the *state* of that process variable.

Figure 1: Pneumatic Controller - concept sketch



2.2 Typology of controllers

Different typologies have been used in the literature to classify controllers, based on:

- The controller application (i.e. what the controller is used for, such as to control liquid level, pressure, or temperature)
- The emission pattern of the controller (continuous-bleed or intermittent vent)
- The end service (i.e. the way the controller regulate the parameter, such as *on/off* service or *throttle* service)

Controller application

Pneumatic controllers are widely used in upstream oil and gas operations, most commonly to regulate fluid level in separators and tanks, temperature of heaters and fans, pressure of vessels, and differential pressure of lines.

Emission pattern of the controllers

Pneumatic controllers can be designed to release supply-gas continuously or intermittently. Pneumatic controllers are thus classified as **continuous-bleed** or **intermittent-vent** (equivalent to intermittent bleed in all EPA documents), depending on whether or not they are *designed* to emit continuously.

In this study,

- emissions occurring from intermittent-vent controllers, where there is a physical barrier between the supply-gas and the end-device, are referred to as **vent**; and
- emissions from continuous-bleed controllers, where the supply-gas provides required pressure to the end-device while the excess amount of gas is emitted, are referred to as **bleed**.

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The continuous-bleed controllers are classified into high-bleed and low-bleed in this report, depending on whether or not the controller is deemed to have a bleed rate above or below 6 scfh, in line with EPA regulations.²

The typology used in this report differs from the one presented in Allen et al. [2] where controllers are classified depending on their measured emissions pattern as opposed to their designed emissions pattern.

End-service typology

The end-device can be in *on/off* service or *throttle* service, depending on the process requirements. An example of on/off service is a dump-valve that controls the level of a vessel. In the “on” state, the valve is completely open to “dump” liquid. When the desired level has been achieved, the valve completely closes to its “off” state. An example of throttle service is a pressure control valve, which increases or decreases the flow of gas as needed to maintain line pressure at a fixed value. Both continuous-bleed and intermittent-vent controllers are commonly used to perform both on/off and throttling services.

A summary of pneumatic controller typology is presented in the table below. As this study focuses on eliminating emissions from these devices, only the emission pattern typology is used in the rest of the report.

Table 1: Summary of controller typology (mainly based on [6])

| | | Type of Service | |
|--------------------------|---|---|--|
| | | On/Off | Throttling |
| Emission characteristics | Intermittent-vent | <ul style="list-style-type: none"> - Gas vented at de-actuation - Designed to emit no gas between de-actuation instances - De-actuation frequency depends on process variability | <ul style="list-style-type: none"> - Gas vented when end-device needs to throttle-off - Designed to emit no gas between throttle-off instances - Throttling frequency depends on process fluctuations |
| | High-bleed continuous controller | <ul style="list-style-type: none"> - Gas emitted continuously with higher bleed rates when end-device needs “off” service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh | <ul style="list-style-type: none"> - Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh |
| | Low-bleed continuous controller | <ul style="list-style-type: none"> - Gas emitted continuously with higher bleed rates when end-device needs “off” service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh | <ul style="list-style-type: none"> - Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh |

2.3 Number of controllers and emission factors – Brief literature review.

Important work has been taking place over the last few years to measure and understand methane and VOC emissions from pneumatic controllers. This work includes measurement surveys [2,3,4,7], count of controllers per facility [1,2,8], and engineering calculations [8]. The methodology and the sampling approach vary significantly between different sources of information; thus comparisons should be made with particular care [8].

² It should be noted that the bleed rate is not a specification of the controller only, but also depends on the pressure and flow-rate of the supply-gas in addition to the size of the restriction orifice.

How many controllers per site?

The number of controllers per site varies depending on the number of wells and more generally the number and type of equipment used. Recent studies have demonstrated that the vast majority of sites have less than 20 controllers.

Most of the existing studies have focused only on emitting controllers [3,5,7], thus underestimating the number of controllers reported for each site, since some intermittent-bleed controllers actuate infrequently (e.g., controllers for emergency shut-down valves) and are unlikely to do so while a site is being surveyed. Two studies have performed a thorough count of the number of controllers per site [2,8]. The distribution of controller functions reported by these studies varied, perhaps due to differences in the types of sites sampled in the studies, but the overall distribution of controller counts at production sites were quite similar (Figures 2 and 3):

- Very small and medium sites (with less than 20 controllers) account for the vast majority (97%) of the sites evaluated in both studies (Figure 2)
- These sites represent 85% of the controllers (Figure 3)

Figure 2: Share of the sites depending on the total number of controllers per site

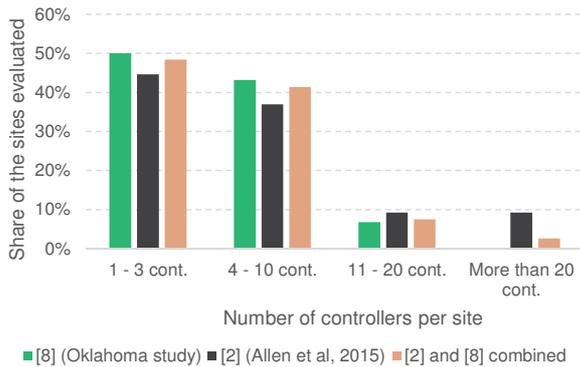
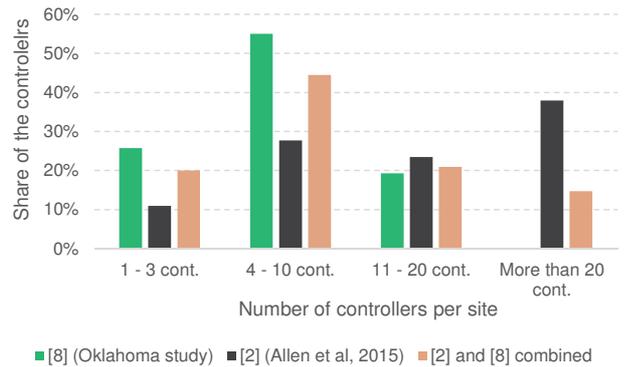


Figure 3: Share of the controllers depending on the total number of controllers per site

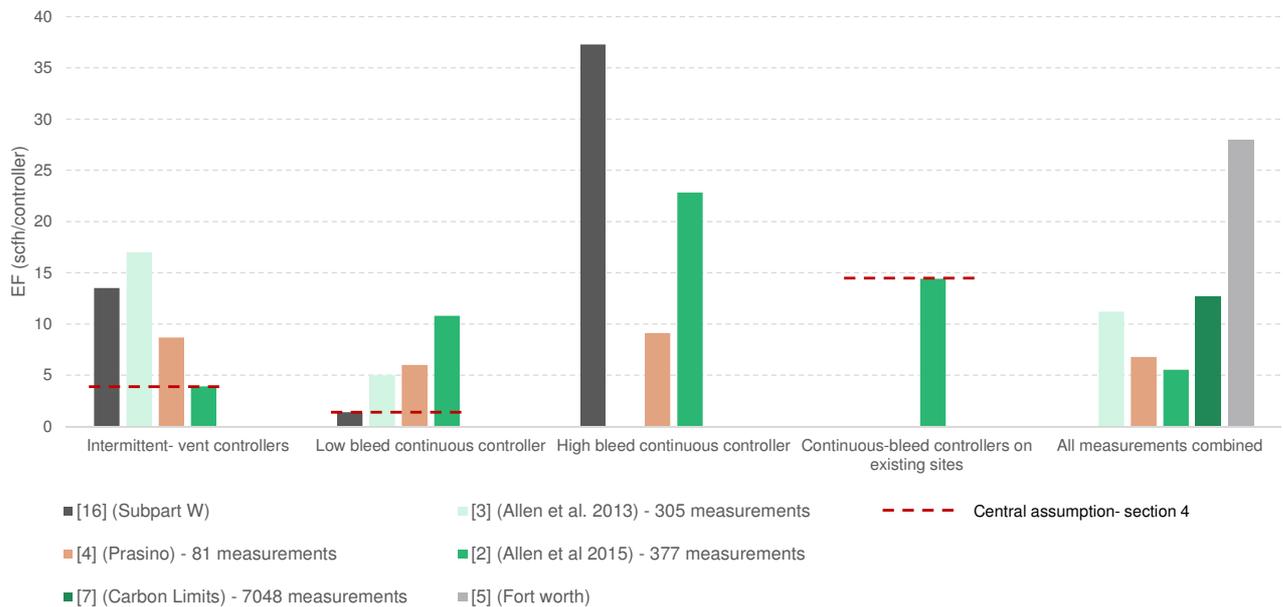


How much do controllers emit?

Despite the important work performed over the last few years, there is still significant uncertainty regarding emissions factors from controllers. The following figure summarizes the current emission estimates available for the different categories of controllers.

CARBON LIMITS

Figure 4: Emissions factors by controller category from different information sources³



A number of important conclusions can be drawn from the review of existing publications:

- Emissions from controllers vary between controller models and, for some models, for the same controller model between sites [2,4,7]
- A small subset of the controllers account for the vast majority of the emissions [2,7]
- Overall, recent research has demonstrated that a number of controllers behave differently than originally designed. In particular,
 - Average emission rates exceed the manufacturers' specifications [4], including some controllers designated low-bleed which emit above the threshold rate of 6 scfh [4,7]
 - Some controllers designed to emit intermittently fail and begin emitting natural gas continually [2,5]

In the analysis presented in the report, we have very conservatively adopted the lowest of the above average EFs for low-bleed in new installations and for intermittent-vent controllers. For continuous bleed controllers at existing sites, we have used the results of the recent measurement [2]. This average is consistent with a mix of low- and high-bleed in the field. The EFs are illustrated in Figure 4 and are described further in Section 4.1.

Do controllers from smaller sites emit more?

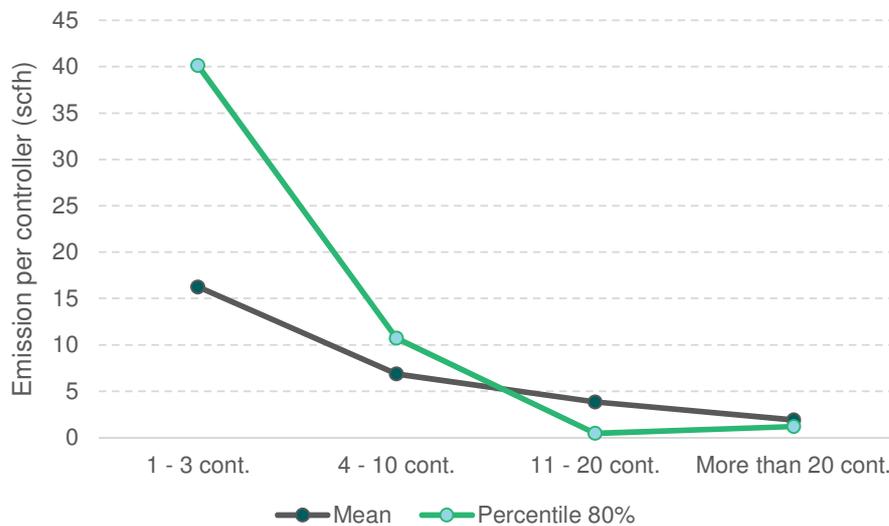
There is very little information available on how emission factors vary depending on the site's size. Analysis of recent measurements [2] suggests, however, that controllers are likely to emit much more in small than in large sites.

The following graph, plotting the mean and the eightieth percentile emission factors, shows a clear downward trend as the number of controllers per site increases. This trend could potentially be explained by the difference in terms of maintenance practices for small sites (typically unmanned and in remote area) and larger sites. In the follow-up analysis, a constant emission factor is assumed for both small and large sites.

³ The data from [3] and [4] have been categorized and presented as described in [8]. The data from [2] have been categorized based on the "company classification into EPA category" (excluding ESD) and not based on the measured emission typology.

CARBON LIMITS

Figure 5: Average emission factors depending on the number of controllers per site [2]



3. Zero emission technologies – Description and technical applicability

This section provides an overview of a number of zero emission technologies available as an alternative to gas driven pneumatic controllers, based primarily on interviews and on a general literature review. A technology is considered “zero emission” if there is no methane or VOC emissions associated with its utilization.

3.1 Overview of the zero emission technology presented.

Five different technologies have been reviewed: Electronic controllers, instrument air provided by compressors (with electric power from the grid or existing on-site generation), solar-powered instrument air, vent recovery, and self-contained pneumatic controllers. Of these five different zero emission technologies, two – electronic controllers and instrument air – have reached a reliable level of maturity and are widely applicable. The remaining three technologies are either less mature (solar-powered instrument) or are applicable only in certain circumstances (self-contained pneumatic controllers and vent recovery).

The economic feasibility of the two mature and widely applicable technologies, electronic controllers and instrument air, is evaluated in detail in section 4 of this report.

The following table presents a brief summary of the different technologies evaluated.

Table 2: overview of the zero emission technologies presented

| Technology | Maturity of the technology | Technical applicability limitations | Main strengths |
|---|---|--|--|
| Electronic controllers (ref section 3.2) | The technology has reached a reliable level of maturity, with hundreds of installations identified throughout this study. | Operators interviewed continue to use pneumatic ESDs. Some limitations with large numbers of controllers or high power demand chemical injection pumps. | <ul style="list-style-type: none"> • Can operate off grid • Reduced maintenance costs, in particular compared to wet gas driven controllers • Enables or simplifies automation of systems |

CARBON LIMITS

| | | | |
|--|--|--|--|
| Instrument air (ref section 3.3) | Extensive global experience for many years | Requires a reliable source of power Limited to installations with an air compressor > 5 HP | <ul style="list-style-type: none"> Reliability Reduced maintenance costs, in particular compared to wet gas driven controllers |
| Solar-powered Instrument air (ref section 3.4) | Less than 100 installations identified | Compressor up to ~20 scfh | <ul style="list-style-type: none"> Operates off grid Reduced maintenance costs, in particular compared to wet gas driven controllers |
| Vent Recovery (ref section 3.4) | The study identified less than 100 installations, with uncertain performance | Requires the presence of a VRU or a gas engine on site | <ul style="list-style-type: none"> Reliability |
| Self-contained pneumatic controllers (aka “Bleed to Pressure” or integral controllers) (ref section 3.4) | Although this solution has been deployed since early 2000s and is considered a relatively well-developed technology, controllers of this type are only available for certain specific applications | Applicability is limited by a number of conditions (e.g. pressure differential, downstream pressure, etc.) | <ul style="list-style-type: none"> Low-cost solution |

3.2 Electronic controllers (solar powered and grid powered)

Electronic controllers adjust the position of the end-device by sending an electric signal to an electric actuator or positioner (as compared to pneumatic controllers which send a pneumatic signal to a pneumatic actuator or positioner). A motor powers the electric actuator to adjust the control valve to the desired position.

This section provides a description of the benefits, costs, and applicability of electronic controllers to both new sites and existing sites, where retrofits would be required. The description is based mainly on interviews with four oil and gas production companies that have installed these systems in their operations (from 3 to 40 installations per operator interviewed), complemented by interviews with technology providers.

Description of the technology

Electronic controllers can be installed both at sites connected to the electric grid, and at remote sites isolated from the grid. These systems typically include a control panel, electric actuators, electronic controllers, control valves, relevant switches (e.g. pressure, level or temperature switch) and a power source – connection to the grid, solar panels and batteries, or power generation on site. An electronic control system is generally designed to completely replace all pneumatically powered devices with electronic controls (with the exception of ESD, see below).

Electrically powered sites: Electronic controllers can be powered using 120 VAC or 220 VAC input from the grid or from on-site generation (three-phase power is not needed).

Remote sites: Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. Systems can be customized for every application; those installed to date include up to three solar panels and eight batteries [9]. Use of solar-powered chemical injection pumps has become widespread over the past years.

CARBON LIMITS

Rationale for the use of electronic controllers:

For the operators interviewed, the two main drivers for project implementation were (i) to reduce methane and VOC emissions and conserve gas otherwise emitted and (ii) to reduce maintenance costs. Electronic systems have much lower maintenance costs than traditional gas-driven controller systems [10], in particular if the gas used is not perfectly dry and sweet.

Higher operating costs are also experienced for gas driven controller systems on sites where there is a need to purchase fuel gas from another source or use imported propane. These include sites with overly sour or wet gas, or with drastic drop in gas supply due to low gas/oil ratio (GOR) /low production.

Investment Costs

Each electronic control system is designed on a case-by-case basis. The investment costs depend on the number of controllers/pumps, but also on other factors such as pressure differential, pipeline diameter, and methanol volume requirement, which varies according to such factors as climate and production patterns⁴. The following table summarizes typical equipment costs for the cases evaluated:

Figure 6- Calscan pictures- Bear solar control system: Top: solar panel and control panel, bottom: Electric Actuator



Table 3: Electronic controllers – Typical investment costs for main equipment

| Main items | Approximate unit costs USD |
|--|----------------------------|
| Level Controller & Level Control Valve | 4000 |
| Pressure Controller & Control Valve | 4000 |
| Chemical injection Pump | 6000 |
| Control panel | 4000 |
| Solar panel (140W unit) | 500 |
| Battery (100 Ah unit) | 500 |

The operators interviewed experienced fairly smooth installations, with installation costs decreasing as they gained experience with the technology⁵. The installation costs vary by site, estimated at between \$5000 and \$8000 per well site. For a retrofit project, the well needs to be shut in for one or two days; retrofit will generally take place when other maintenance is scheduled, to take advantage of that shut-down time.

⁴ Chemical injection pumps (e.g. methanol pumps) usually are the most important power consumer. Sites requiring high volumes of methanol volume injection would cause higher costs for scaled-up solar panel and batteries.

⁵ After the first few sites installations.

CARBON LIMITS

Maintenance costs

The major maintenance costs include the replacement of batteries and panels. Most batteries last three to six years, while solar panels last twenty to thirty years. The operators interviewed highlighted that they experienced minimal maintenance costs on the sites converted to electronic controllers over the last five years.

Benefits of electronic controllers

Operators highlighted a number of benefits:

- Revenue from the sale of gas: Electronic controllers eliminate methane and VOC emissions and thus increase the volume of gas available for sale.
- Automation: Electronic control systems can provide additional benefits by enabling or simplifying the installation of automation systems (SCADA, Supervisory Control and Data Acquisition), though these systems are not required in order to use electronic controllers. This can potentially reduce the need for site inspections, reducing those costs for operators. For example, an alarm can be programmed to warn the operator if the dump has been open for more than 10 min. The system can be as sophisticated or as simple as required. (Note that we have not included any estimate of these cost reductions in the calculations of cost-effectiveness discussed in Section 4.)
- Reliability: As highlighted above, operators report that the electronic system is more reliable than a gas driven pneumatic control system, as operation of the latter with even slightly wet gas can lead to condensation issues, which over time will impact the performance of the system. One operator reported corrosion issues with sour gas used for pneumatic controllers and pumps.

Technical challenges with electronic controllers

- Snow: One operator reported that snow can be a problem with solar panel and battery lifetime.
- Theft or damage: Solar panels have reportedly been stolen or used as targets for shooting.
- Chemical injection pumps: Pumps consume far more energy than controllers/actuators. Sites with a large number of pumps or with pumps with high energy or power demand may represent a challenge for 100% solar powered electric systems. In addition, shortly after completion, some wells may require high volumes of methanol injection, and powering pumps to inject this high volume can strain these systems. Some of the operators interviewed reported that this technical barrier can be solved by bringing a portable stand-alone generator to the site for a few weeks to ensure that the power requirement is met.
- Safety considerations: Due to the very low voltage of the system, the safety risks are considered acceptable by the operator who evaluated this risk.

Applicability of electronic controllers

According to interviews with operators, this solution can technically be implemented on any well site. Generally, for the sites with these systems in place, the pressure differential is up to 2000 psi and the pipe diameters are between 2- 3 inches, but the system can be designed for larger pressure drops and larger diameters as required.

The only general limitation is the incremental costs. According to the operators, given the current gas prices, implementation costs are not compensated by the value of the gas saved. The project can be economical when other factors such as lower maintenance costs improve the return on investment.

Note on Emergency Shut-Down Valves (ESD): As a rule, electric controllers/actuators will stay in position if the system fails and power is lost, wires are cut, or other failures occur. This differs from some other solutions that can be designed so that valves close (or open) if the system fails (for example if the supply gas pressure is lost). Although Calscan is developing a “fail safe” electric ESD, operators have reportedly been using pneumatic or hydraulic ESD valves, as they are “fail-safe”.

CARBON LIMITS

Sunlight: In northern latitudes (e.g. northern Alberta) and when the energy demand is high (e.g. several pumps), solar panels may not generate enough power, in particular for chemical injection pumps. Other power sources such as thermal electric generators or methanol fuel cells have been used in pilot implementations.

Electronic controllers at medium and large sites: Due to the market conditions, providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites. No technical barriers were identified for the installation of electronic controllers in sites with available electricity. Given the recent progress in both solar panel technologies and large battery solutions, solar-powered solutions may also be appropriate for large sites without available power. However, we are not aware of any such installations. Therefore, to be conservative, we do not examine the use of electronic controllers at large sites without electricity available.

Medium or large sites may also be the result of a combination of a number of small sites (e.g. several well pads). In practice, several small independent electronic controller installations can thus be installed on one medium to large site.

Suppliers

The following table presents a non-exhaustive list of relevant providers:

Table 4: Non-exhaustive list of relevant providers:

| Name of the suppliers | Website | Offer | Comments |
|----------------------------|---|---|---|
| Calscan | http://www.calscan.net/products_bearcontrol.html | Provide full customized system | Calscan's Bear Solar Electric Control System is designed mainly for well head separators, but it can also be used in other applications. It includes solar panels, batteries, electric actuators, control valves, switches, control panels and other control equipment. |
| Spartan | http://www.spartancontrols.com/ | Provide full customized system | Spartan designs electronic control systems assembling a number of components including Emerson/Fisher electronic controllers and actuators. |
| Ameresco | http://www.amerescosolar.com/solar-power-solutions-oil-and-gas-industry | Provide full customized systems | Ameresco Solar designs customized off-grid solar power systems. |
| Emerson/ Fisher | | Manufacture elec. controllers and actuators | Different brands under Emerson Process Management (including Fisher, EIM) supply electronic and electro-pneumatic control components (controllers, positioners, actuators, control valves, transducers, etc.) |
| Exlar | http://exlar.com/ | Manufacture elec. actuators | Exlar currently offer electric actuators that can replace pneumatic actuators. |

3.3 Instrument air

Instrument air controllers are systems where pressurized natural gas is replaced with compressed air as a source of energy and signaling medium for pneumatic controllers and pneumatic actuators. Since controllers use air, instead of natural gas, they only vent air to the atmosphere, eliminating emissions from pneumatic controllers. Instrument air controllers are applicable to both new sites and existing sites; however, the technology can only be implemented when a reliable power supply is available.

CARBON LIMITS

This section provides a description of the benefits, the costs, and the applicability of instrument air controllers and is mainly based on interviews with oil companies, reviewing their recent experience installing instrument air systems.

Description of the technology

Instrument air technology is a well-established mature solution to run pneumatic control systems and is widely applied globally. In many countries (e.g. Norway, Iran, Kazakhstan [11]), the majority of the pneumatic control systems run on instrument air.

Systems typically include:

- Heavy-duty industrial air compressors. Two compressors are generally installed for redundancy, but for cost reasons, an operator has reported using only one.
- Air dryers - part of the air compressor package.
- Wet air receiver tank - part of the air compressor package.
- Dry air receiver tank - helps provide a buffer to secure longer system autonomy in the event of a power outage or demand surge.

Investment costs

Interviewers highlighted that the investment costs for instrument air installation vary significantly from site to site, depending on the layout and the type of equipment already on site. Investment costs can be classified as follows:

- Air compressor package: This includes the purchase of the main equipment (compressors, dryers and air receiver tanks). The size of compressors, dryers, and other equipment depends on the number of pneumatic controllers to be supplied with compressed air, and on their specifications (i.e., their demand for compressed air). A small compressor station would require around 5 HP of air compression capacity, while a larger facility would require up to 20 HP. This system can be purchased as individual components or as a package, for between \$20,000 and \$70,000 [12].
- Mechanical & installation costs: Mechanical and civil work may be required, depending on the layout of the existing facility. These costs are often higher for older facilities and can include:
 - Pipe cleaning and upgrades.
 - Trenching and tubing installation, since large sites may have several independent natural gas supply systems for controllers and pumps, and air would need to be piped through the full site.
- Electrical/instrumentation equipment and supplies: Depending on the site and the specific project requirement, this category may include:
 - Remote terminal unit or SCADA system installation or upgrade. The control system for some plants (e.g. shutdown/start-up, safety systems etc.) may have to be upgraded to accommodate the air compressor package.
 - Upgrades and wiring needed to add the additional electrical loads from the air compressor motors.
 - Repair/replacement of a controller in case of malfunctioning controller.
- Engineering/consulting: The site might require additional expenditures for electrical engineering and consulting.

Although air compressors and their auxiliary equipment represent a large part of the CAPEX, the engineering, preparation and installation costs can comprise up to 70% of the total upfront investment. Installation and preparation costs may include electrical and instrumentation supplies, mechanical and civil works, additional wiring, piping, valves and fittings. These costs are higher for older facilities that are not capable of handling the extra power, or don't have a suitable layout for utilities. Overall, the total cost for a project varies between \$50,000 and \$250,000 [10].

CARBON LIMITS

Maintenance costs

Maintenance costs typically include:

- Power consumption
- Air compressor servicing, generally every 6 months.

Benefits of instrument air controllers

Operators highlight a number of benefits:

- Revenue from the sale of gas: Instrument air eliminates methane and VOC emissions and thus increases the volume of gas available for sale.
- Reliability: The instrument air system is a highly reliable alternative to a natural gas driven pneumatic system for grid-connected facilities.
- Reduced maintenance costs: Although there are some additional operating costs with the deployment of air systems, some maintenance expenses are cut as a result of stopping the use of natural gas, particularly wellhead gas (or separator gas). Due to fluctuations in the GOR, some operators reported gas shortages on-site and thus they had to use other sources, such as propane, or to purchase gas from an adjacent field. Maintenance costs due to liquids condensing in the system or sour gas damage are also avoided by replacing untreated natural gas with air.

Applicability of instrument air controllers

Two main applicability limitations were identified during the interviews:

Size of the installation:

Instrument air controllers require heavy duty industrial air compressor packages designed for continuous duty (24/7). This in effect precludes the use of air compressors smaller than 5 HP, since available 2-3 HP air compressor packages present reliability problems. One operator reported that the one-year lifetime of a smaller compressors makes them unacceptable, so a minimum of 5 HP is assumed.

Access to power

Instrument air systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Operators have used instrument air at:

- Grid connected sites.
- Sites with onsite power generation. Many sites (e.g. compressor plants) have power generation for other purposes: lighting, automation and control systems, etc. The same system can also be used for instrument air if generation capacity is available. We note that a sufficient, reliable, good quality gas stream is required for power generation. Wet or sour gas may not always be used for on-site power generation, depending on the specification of generator engines, etc.

In theory, diesel powered instrument air could be installed; however, this project identified no concrete examples of this technology. One operator stated he considered, and then rejected, the use of diesel to run air compressors, due to the high costs and low perceived environmental benefits.

3.4 Other technologies

This section reviews other “zero emission” technologies at various stages of maturity. In general these technical options are either (i) not widely applicable (such as self-contained controllers and vent gas recovery) or (ii) fewer than 100 installations were identified as part of this project (such as solar powered instrument air).

CARBON LIMITS

Solar powered instrument air

This study identified about 40 installations of small, energy efficient motor-compressors powered by solar panels/batteries, to replace natural gas with instrument air as the pneumatic medium. TRIDO industries, the technology provider interviewed as part of this study, indicated that these systems have a maximum capacity of ~20 scfh, making them suitable for some small to medium sites which use a few low-emitting controllers. High-bleed controllers have to be retrofitted to reduce air consumption in order to reach the feasible level. Despite the lack of extensive deployment so far, an attraction of this solution lies in the fact that controllers and actuators do not need to be replaced.

Instrument air powered by other power sources

Other power sources, such as thermal electric generators or methanol fuel cells, have been used in pilot implementations to power traditional instrument air systems.

Vent Gas Recovery

Re-routing to VRU

Vapor Recovery Units (VRUs) have a long, well-established track record in the upstream oil and gas industry to recover VOCs and methane from vented sources. Typically, they consist of capturing and piping equipment, a de-liquefaction drum, and compressor(s) to inject the recovered gas into pipelines. In theory, all vent lines can be connected to the VRU, including pneumatic controllers' lines.

Nevertheless, there have been limited implementations (only one example identified in this study) of well-site vent gas recovery projects using the recovered gas from pneumatic controllers in non-engine applications. SlipStream®, as further presented below, is a technology that facilitates recovery of the gas and use of it in gas-fired engines. Another technology, Cata-Dyne™, utilizes the recovered gas as a feed to a small, flameless appliance that converts natural gas or propane into infrared radiant heat that is usable if industrial heating is required.

SlipStream®

Spartan's SlipStream® system captures vented hydrocarbons and uses them as a supplementary fuel source for natural gas-fired engines, reducing fuel consumption. This technology can thus be applied only to sites with gas-fired engines, e.g. compressor engines. Despite concerns about costs, one operator emphasized specifically the reliability of the technology, as it reportedly does not interfere with normal operations. Nevertheless, if the volume of gas emitted by the combined vents (including the controllers) exceeds the engine fuel requirements, natural gas would still be vented or otherwise controlled.

Self-contained (aka Bleed-to-Pressure or Integral Pneumatic Controllers)

Self-contained systems are designed to contain the gas typically vented from controllers and then discharge it to the control valve's downstream piping, thus resulting in zero emission.

A number of operational requirements limit the applicability of self-contained systems, the most important of which is the need for a high differential pressure across the control valve [6,13]. For instance, GE's Bleed-to-Pressure system requires more than 80 psi, and both GE and VRG Controls require a downstream pressure of maximum 300 psi [13]. Also, sour or untreated gas could cause disturbances in the operation of self-contained controllers. Nevertheless, if applicable, the technology may be cost-effective or economical in cases where the total baseline emissions are high.⁶

Due to the limited applicability or the lack of widespread field experience, the technologies described above are not further analyzed in this report. However, depending on the site specifics, these options may

⁶ A technology provider [reports](#) an average of less than \$3000 per Bleed-to-Pressure control system, leading to a payback period of less than 2 years for replacing 8 controllers.

CARBON LIMITS

be applicable and cost-effective, and can represent useful alternatives to instrument air or electronic controllers; thus they are presented as potential alternative options in section 4.4.

4. Cost effectiveness of electronic controllers and instrument air

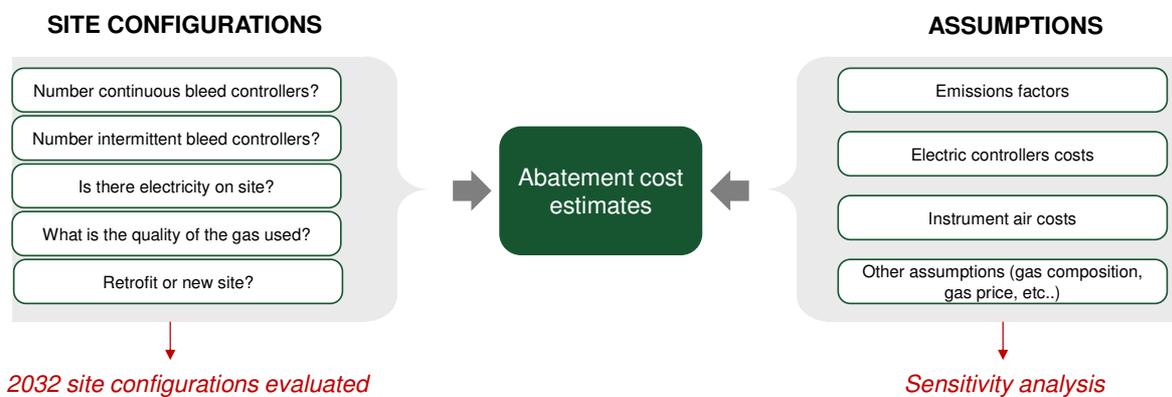
This section presents an analysis of the *cost-effectiveness* – net cost in USD per ton of avoided pollution – of employing the two main zero emission technologies, air-driven pneumatic controllers and electronic controllers, instead of natural gas-driven pneumatic controllers at new and existing sites. These results are applicable at both oil and gas production sites (well pads) and compressor stations.

4.1 Analytical approach

The cost-effectiveness of zero emission technologies will vary with the number and type of controllers at a site, in addition to many other factors, as we discuss below. Given the variety of site configurations (number and type of controllers per site, connection to the grid, type of gas handled) across the US, and the lack of information on the frequency of occurrence of these configurations, we opted to carry out cost-effectiveness assessments for both electronic and instrument air controllers for a broad spectrum of permutations of those site configuration parameters.

A number of assumptions have been made for the analysis. Key assumptions are discussed in the section below; all assumptions are detailed in the Appendix.

Figure 7: Overview of the methodology



For each permutation of the site configuration parameters, a CH₄ abatement cost (cost per metric ton of avoided pollution) was estimated.

For this analysis, a zero emission technology implementation is considered

- “economical” if the CH₄ abatement cost is negative (i.e. if the project NPV is positive)
- “cost effective” if the CH₄ abatement cost (net cost per ton of abated pollution) is lower than the social cost of methane that EPA has used in recent regulatory analyses [19] (Social cost of methane for 2020, calculated with a 3% discount rate, \$1354 (2016 USD)).⁷

⁷ EPA reports that the 2020 social cost of methane (mean value at 3% discount rate) is \$1300 / metric ton of methane in 2012 USD; this is adjusted to \$1354 / metric ton of methane in 2016 USD using a 4.2% cumulative inflation rate.

CARBON LIMITS

The following sections provide more insight on:

- The abatement cost calculation
- The main assumptions
- The site configurations evaluated.

Abatement cost calculation – methodology

For each site configuration, the following were estimated:

- The CAPEX and OPEX of the zero emission technology implementation (either electronic controllers or instrument air)
- The CAPEX and OPEX of the baseline scenario (i.e. the cost incurred by the operator if the conventional pneumatic technology had been used instead of zero emission systems)
- The emissions of CH₄ and VOC under the baseline scenario

Since methane and VOC emissions will be zero if the zero emission technology is used, the abatement cost (in \$/t CH₄) is then estimated as follows:

$$\text{Abatement cost} = - \frac{NPV(\text{Cash flow}_{\text{zero emission project}} - \text{Cash flow}_{\text{baseline scenario}})}{NPV(\text{Emission}_{\text{baseline scenario}})}$$

This approach, and its underlying assumptions, is compared to the annualized cost approach typically used by EPA in the appendix.

Main assumptions

The following table provides a list of the main assumptions applied. A full list of assumptions is available in the Appendix.

Table 5: Central assumptions

| Description | Central Assumption | Comment |
|---|-------------------------------|--|
| Gas price | 2 \$/Mscf | The value of recovered gas has been assumed to be similar for all emission sources, independent of the composition of the gas. Gas values from 1 to 3 \$/Mcf have been assessed in sensitivity analyses. |
| Discount rate | 7% | A 7% per year real term discount rate has been assumed. A sensitivity is presented for a 3% per year real term discount rate. This approach is consistent with EPA/BLM practice. |
| Remaining lifetime for a new project | 15 years | The lifetime for new controller installation is assumed to be 15 years in line with EPA practice. |
| Remaining lifetime for retrofit project | 10 years | The remaining lifetime for existing sites is assumed to be 10 years. A sensitivity is presented for a 5 years remaining lifetime. |
| Gas composition | 0.0167 tCH ₄ /Mscf | Gas composition assumptions for dry gas (wet gas assumptions are presented in the Appendix) |
| | 0.0046 tVOC/Mscf | |

Average emissions factors assumptions

The emission factors used for this analysis are conservative averages based on the literature review (See section 2.3). The following table presents the emission factors used and the rationale for each value.

Table 6: Emission factors assumptions – central assumptions

| Description | Central Assumption | Comment |
|--|--------------------|---|
| Continuous-bleed controller(s) – retrofit sites only | 14.4 scfh | This emission factor is applied for all the continuous bleed controllers on retrofit sites. |

CARBON LIMITS

| | | |
|--|-----------|---|
| | | Assumption based on [2] (Company classification into EPA categories excluding ESD) |
| Low bleed continuous controller (s) | 1.39 scfh | This emission factor is applied for all the continuous bleed controllers on new sites. Current federal regulation (OOOO) requires that new continuous bleed controllers be low bleed. Assumption based on [16], most conservative average value between [16], [3], [4] and [2] |
| Intermittent-vent controller(s) | 4.4 scfh | Assumption based on [2], most conservative average value between [16], [3], [4] and [2] |
| Chemical injection Pumps | 13.3 scfh | Assumption based on [16], most conservative average value between [4], [7] and [16] |
| ESD | 0.41 scfh | Assumption based on [2], average of the controllers classified as ESD |

While measurements show that emission factors vary widely in the field, using conservative average emission factors, we are able to calculate conservative (i.e. high) abatement costs for widespread adoption of zero-emitting technologies. Sensitivity analyses are presented in the section 4.2 to reflect the field variability, which impact the site specific abatement costs.

Site configurations evaluated

As described above, we performed economic modeling on a total of 2032 permutations of site configuration parameters, covering a wide range of possible combinations of site parameters.

The following parameter inputs were used to construct the site configurations:

- Total number of controllers – from 1 to 40 controllers.
- A varying mix of continuous-bleed and intermittent-vent controllers (from 0% to 100% of intermittent-vent controllers).
- One emergency device (ESD) was added for every five controllers⁸ (rounded up).
- New site (construction of new facilities) or retrofit (upgrade of existing facilities).
- Access to electricity or not.
- Whether pneumatic driven controllers currently operate on dry gas or wet gas.

To simplify the presentation of the results, the 2032 possible site configurations were then grouped into 20 larger categories depending on the total number of controllers, the presence of electricity on site, and whether the site is new or would need to be retrofit with zero emission controllers. The following table presents a matrix of the 20 different categories of site configurations evaluated, with the number of sites in each category presented in green. Each cell of this table includes a number of site configurations depending on the number of intermittent-vent or continuous-bleed controllers and the type of gas used to power the controllers.

⁸ This number of ESDs has no impact on the final conclusion. Operators do not currently replace ESDs with electric controllers, so number and the emission factor of ESD have no effect on the cost-effectiveness of electric controllers. On the other hand, ESDs will generally be converted to instrument air, but the effect of including reasonable numbers of ESDs on the final cost-effectiveness is small due to the small air consumption of ESD. In this context, the assumption on the number of ESD did not affect the final number of sites with an abatement cost higher than the social cost of methane.

CARBON LIMITS

Table 7: Site configurations categories (number of site configurations presented in green)

| Number of Pumps | Number of controllers (excluding ESD) | New sites | | Retrofit | |
|-----------------|---------------------------------------|------------------|---------------|------------------|---------------|
| | | No elec. on site | Elec. on site | No elec. on site | Elec. on site |
| 0 | 1 to 3 controllers | 18 | 18 | 18 | 18 |
| | 4 to 10 controllers | 56 | 56 | 56 | 56 |
| | 11 to 20 controllers* | 98 | 98 | 98 | 98 |
| | 21 to 40 controllers* | | 164 | | 164 |
| 1 | 1 to 20 controllers* | 172 | 172 | 172 | 172 |
| | 21 to 40 controllers* | | 164 | | 164 |

* Based on the analysis presented in section 3, we did not model either technology for larger sites (≥21 controller excluding ESD) without electricity on-site

- Electronic controllers were modeled at sites of all sizes with electricity available, and smaller to medium sites (up to 20 controllers) with no electricity available. Medium and large sites with electricity on-site are presented, as no technical barriers were identified for the installation of electronic controllers in such installations. However, there seems to be much less field experience for these types of installations compared to smaller sites.
- Instrument air was presented at larger sites with electricity available. For sites smaller than 20 controllers, electronic controllers were always more cost efficient than instrument air (see below).

This approach reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an **illustrative** threshold based on information available.

4.2 Main findings – electronic controllers

The findings of the cost-benefit analysis for electronic controllers are presented in four different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to illustrate the methodology by exploring one example in detail.
- Second, a sensitivity analysis is performed for the same site configuration to show the impact of the main assumptions.
- An overview of the results for all the site configurations evaluated is then presented.
- Finally, the impact of the emission factors assumptions is described.

Example of abatement cost estimate for one example site configuration

The following table presents a full analysis for an example site configuration. The project is the retrofit of an existing site with four different controllers (one continuous-bleed, two intermittent-vent, one ESD and no pump) which represents the most common number of controllers in [8,2]. The site is not connected to the grid and currently uses dry supply gas for the controllers.

Table 8 presents the CAPEX estimate for the conversion to electronic controllers. As the project is a retrofit project, the baseline CAPEX is zero.

The detailed assumptions for the size of the electronic system (such as number of solar panels and battery requirements) are presented in the appendix. Overall, the system is oversized and always includes, for example, 10 days of energy storage.

CARBON LIMITS

Table 8: CAPEX estimates for electronic controller implementation (central assumptions)

| Item | Assumption | # | Total USD |
|------------------------------------|------------------------|----|---------------|
| Controllers | \$ 4000/unit | 3 | 12 000 |
| Control Panel | \$ 4000/unit | 1 | 4 000 |
| 140 W Solar Panel | \$500 /Unit | 1 | 500 |
| 100 Amh battery | \$400 /Unit | 3 | 1 200 |
| Installation and engineering costs | 20% of equipment costs | NA | 3 540 |
| Total CAPEX | | | 21 240 |

Table 9: Emissions estimates (central assumptions, new sites)

| Whole gas emissions in scfh | EF assumption | # | Total |
|---------------------------------|---------------|---|-------------|
| Intermittent – vent controllers | 4.43 | 2 | 8.9 |
| Continuous –bleed controller | 14.4 | 1 | 14.4 |
| Total gas emissions | | | 23.3 |

In terms of OPEX, it is assumed that batteries are replaced every 4 years and solar panels every 10 years. Given the operators' reports of minimal maintenance for electronic controllers, it has thus been assumed, conservatively, that general maintenance costs for are similar to those for continuous-bleed controllers functioning properly⁹. We do not include any estimate of savings in inspection costs due to automation (conservative assumption). Table 9 above presents emission estimates for the baseline scenario and finally Table 10 includes the abatement costs estimated.

Table 10: Final results – central assumptions

| Item | Unit | Value USD |
|------------------------|---------------------------|------------|
| CAPEX | \$ | 21 240 |
| Value of the gas saved | \$/year | 408 |
| NPV of the OPEX | \$ | 1 672 |
| NPV | \$ | -19 266 |
| ABATEMENT COSTS | \$/tCH₄ | 751 |

As presented in Table 10, for the small and remote site configuration presented, the abatement costs is well below the social cost of methane as defined above. The abatement cost for same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be \$847/ton CH₄. The difference is due to the difference in baseline costs and baseline emissions between new and retrofit sites (see below).

Info Box 1: Electric conversion of pneumatic pumps

Pumps at well sites and well pads are typically used for methanol, corrosion inhibitor, de-waxing agents, or soap injection. Federal regulation (OOOOa) rules already require that emissions from new and modified chemical injection pumps be controlled in a number of circumstances.

As highlighted in Section 3, conversion of chemical injection pumps to electric is both a mature and a cost effective technology.

In the analysis presented in this section, the conversion of one chemical injection pump per site is presented as a potential added benefit for the project developer. In cases with many pumps, or of major energy requirements for the pumps, the conversion of pumps to zero emission technologies could be assessed as a separate emission reduction project.

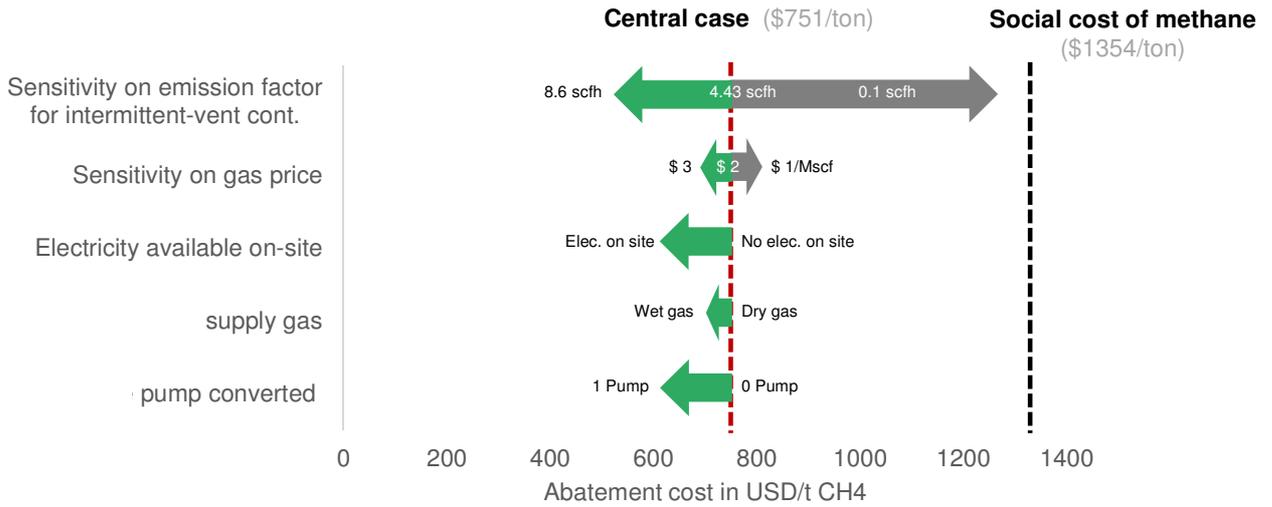
⁹ Which is lower than the maintenance costs for continuous bleed controllers operating with wet supply gas.

CARBON LIMITS

Sensitivity analysis for one example site configuration

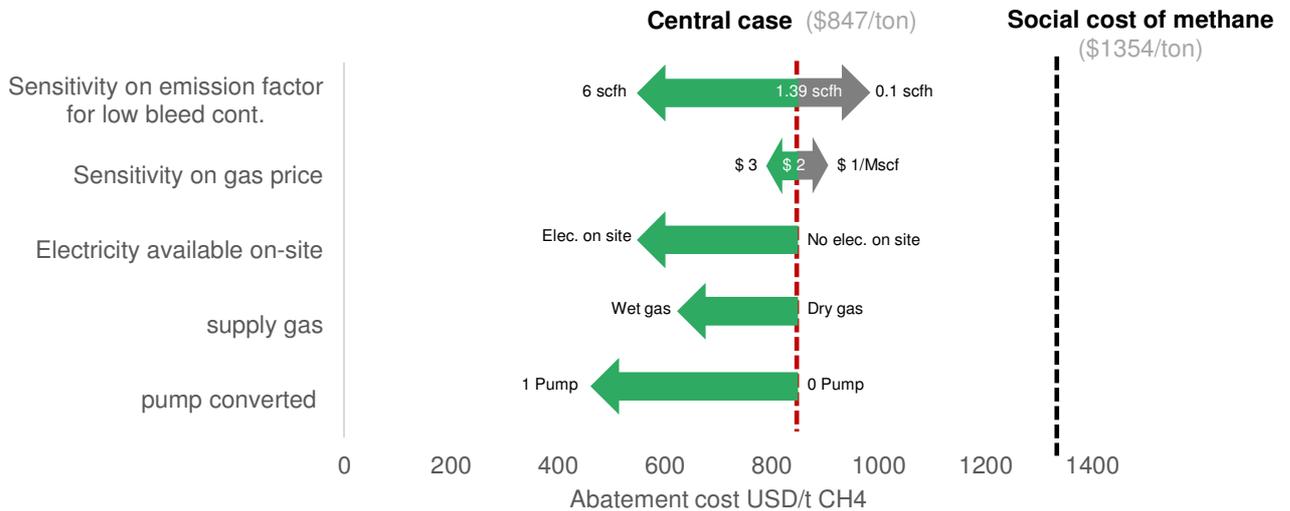
In this analysis, a number of assumptions have been made which impact the abatement cost. The following figures present sensitivity analyses for the site configuration described in the previous section, for both the retrofit case and the new site case. We examine the sensitivity of the abatement cost to changes to a few key sensitivities. A more exhaustive sensitivity analysis is presented in the appendix.

Figure 8: sensitivity analysis – electronic controllers - retrofit



The next figure presents a similar sensitivity for the same site configuration, but at a new facility as opposed to a retrofit.

Figure 9: sensitivity analysis – electronic controllers - new



The emission factor has by far the largest impact on the abatement cost and clearly heavily impacts the cost effectiveness of the option for retrofit sites. Excluding the emission factors, the other assumptions impact up to +33% of the abatement costs and no sensitivity leads to an abatement cost higher than the social cost of methane (see appendix).

CARBON LIMITS

In general terms, the abatement cost is more sensitive to changes for new sites than for retrofit sites. This is due to the fact that both the incremental costs and the emissions reductions are much smaller for new sites than for retrofit sites. A small change in either of these is thus relatively larger for new sites than for retrofit sites.

The following few paragraphs describes in more detail the impact of the main assumptions:

Electricity on site

The investment costs for sites without an electricity supply are higher than for sites with electricity due to the need to install solar panels and batteries. As a result, the abatement cost for site configurations with electricity is generally ten to one hundred percent lower than for site configurations without power. In a few site configurations the abatement cost is negative (i.e. NPV>0).

Wet versus dry supply gas

Operators have reported that the quality of the supply gas affects maintenance costs. Even slightly wet (or sour) gas can lead to condensation (or corrosion) issues, which over time will impact the performance of the system. The maintenance cost for sites with wet supply gas is estimated at \$200/year/controller [10] compared to \$80/year/controller for dry supply gas [18]. As a result, sites with wet gas have an abatement cost generally 5 to 100 % lower than sites with dry gas, and, in a few site configurations, the abatement cost is negative (i.e. NPV>0). Gas quality is also likely to impact the average emission rate. Due to the lack of quantitative data on this impact, however, this factor has not been taken into consideration during the analysis, but it would reduce the abatement costs of sites with wet gas even lower.

Chemical injection pumps

As pumps have high emissions factors, sites where one pump (or several) can be converted to electric power have much lower abatement costs than sites without. All the sites with one pump have an abatement cost lower than the social cost of methane.

New versus retrofit sites

The costs and the emissions abatement structures differ greatly for new and for retrofit sites. The main differences include:

- The incremental CAPEX (i.e. the difference between the zero emission technology CAPEX and the baseline CAPEX) for a retrofit site is usually much higher than for a new site.
- Given the current regulatory framework, it is assumed that new sites use low-bleed continuous controllers as a default, and we conservatively use the EPA emissions factor [1] for these controllers, despite measurements showing higher emissions for low-bleed controllers [3,4]. The emissions reduction for retrofit sites is higher than for new sites, as we use an emissions factor based on actual measurement [2] for continuous-bleed controllers at existing sites.

The first difference makes the abatement cost higher for retrofit sites than new sites, while the second difference has the opposite effect. Overall, in the vast majority of the site configurations evaluated, the abatement cost for new sites is higher than for the equivalent retrofit site configuration.

Overview of the results for all the site configurations

Overall, the abatement costs for electronic controller installations at 2032 site configurations were estimated during this project. Under the central assumptions, 20 of the 2032 site configurations evaluated have abatement costs higher than the social cost of methane, \$1354/t. The following table shows in red the number of site configurations with abatement costs higher than that figure for each category.

CARBON LIMITS

Table 11: Number of site configurations with abatement costs superior to the social cost of methane – central assumptions

| Number of Pumps | Number of controllers (excluding ESD) | New sites | | Retrofit | |
|-----------------|---------------------------------------|------------------|----------------|------------------|----------------|
| | | No elec. on site | Elec. On site | No elec. on site | Elec. On site |
| 0 | 1 to 3 controllers | 6 / 18 | 4 / 18 | 5 / 18 | 2 / 18 |
| | 4 to 10 controllers | 2 / 56 | 0 / 56 | 0 / 56 | 0 / 56 |
| | 11 to 20 controllers* | 0 / 98 | 0 / 98 | 0 / 98 | 0 / 98 |
| | 21 to 40 controllers* | | 0 / 164 | | 0 / 164 |
| 1 | 1 to 20 controllers* | 0 / 172 | 0 / 172 | 0 / 172 | 0 / 172 |
| | 21 to 40 controllers* | | 0 / 164 | | 0 / 164 |

* Sites with more than 10 controllers were presented for the installation of electronic controllers. However, there seems to be much less field experience for this type of installation, compared to smaller sites. Sites with more than 20 controllers and without electricity on-site were not modelled. Though no major technical barriers were identified, we could identify no examples of installations of solar powered electronic controllers on very large sites.

A number of conclusions can be drawn from this analysis. Under the central assumptions:

- For almost all the site configurations evaluated with four or more controllers (excluding ESDs), it is cost-effective to install electronic controllers.
- For all site configurations evaluated with one chemical injection pump, it is cost effective to install electronic controllers.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. In general, for a given type of site configuration (wet/dry, on or off grid, new or existing, share of intermittent controllers), the cost-effectiveness improves (fewer \$/ton) with the number of controllers.

In addition, we can highlight the following patterns for the site configurations with abatement costs higher than the social cost of methane:

- For new facilities, these sites have only low-bleed continuous controllers (5 or fewer). The low bleed emission factor assumption has an important impact on the conclusion (see below).
- For retrofit facilities, these sites have only intermittent-vent controllers (3 or fewer). For retrofit sites, the emissions factor used for intermittent-vent controllers is less than that used for continuous bleed controllers (see section 4.1)

The full list of site configurations with an abatement cost higher than the social cost of methane is presented in the appendix.

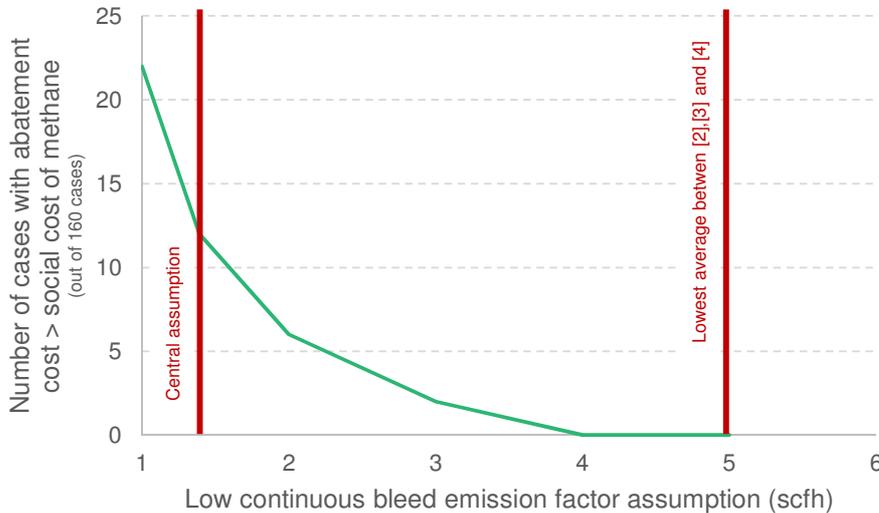
Impact of the emission factors assumptions

The results of the analysis are quite dependent on the emissions factors used for the various types of pneumatic controllers.

The following graph illustrates the impact of the continuous low-bleed emission factor on the cost effectiveness of new sites with at least one continuous low-bleed device. This represents 12 of the 19 site configurations deemed not cost effective. The central assumption for the low-bleed emission factor is 1.39 scfh. But an emission factor of 4 scfh would make all sites with at least one continuous bleed controller cost effective. It is interesting to compare this figure to the results of past measurement campaigns presented in the Figure 4, which suggest that average emission factors for low-bleed devices are likely higher than 5 scfh.

CARBON LIMITS

Figure 10: Impact of the continuous low bleed emission factor on the cost effectiveness of new sites with at least one continuous low bleed device.



In a site without an electricity supply and with just a single controller, an electronic controller is cost-effective if the emissions from that single controller are more than 4.4 scfh for a new site and more than 7.2 scfh for a retrofit site. The point of cost-effectiveness is lower for sites with 2 or more controllers, for sites using wet supply gas, or for sites with on-site electricity. These thresholds should be compared with emissions factors observed in Figure 5 for small and very small sites.

As mentioned above, while emissions from pneumatic controllers vary widely from device to device, this analysis uses average emissions factors based on recent measurements, aiming at evaluating the cost-effectiveness of using electronic controllers on a widespread basis.

To conclude, the analysis shows that conversion to electronic controllers would be cost effective in most site configurations even using conservative average emissions assumptions. If higher emissions assumptions are considered -- as reflected in recent field measurements -- virtually all site configurations evaluated would be fall below the social cost of methane

4.3 Main findings – Instrument air

As in the previous section, the finding of the analysis for instrument air is presented in three different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to explain the methodology applied to one example.
- Secondly, a sensitivity analysis is performed for the same site configuration to illustrate the impact of the main assumptions.
- Finally, an overview of the results for all the site configurations evaluated is presented.

Contrary to electronic controllers, instrument air installation is only presented for site configurations with electricity available on-site.

Example of abatement cost estimate for one example site configuration

The following tables present a full analysis for an example site configuration. The project is retrofit of an existing site with 20 different controllers (5 continuous-bleed, 11 intermittent-vent, and 4 ESD). This configuration is illustrative; it is not known how representative it would be of larger sites. The site is

CARBON LIMITS

connected to the grid or has power already generated on site, and currently uses dry gas for the controllers.

The first table presents the CAPEX estimate for the instrument air project. The detailed assumptions for the size of the instrument air system (share of the air bypassed in dryer, share of the utility air supply,¹⁰ size of compressor, load of the compressor) are presented in the appendix. The approach in terms of system sizing proposed by Natural gas star has been applied [14], after having been quality checked against nine recently implemented projects. Overall, the system is oversized (as per the industry standard) and always includes, for example, one spare compressor. Equipment costs (including industrial grade compressors designed for 24/7 duty) have been assumed using online quotes.

As highlighted previously, installation costs for instrument air are highly site specific. Interviews have reported very low installation costs in particular when retrofitting many sites with similar designs. On the other side of the spectrum, operators have also reported high installation costs in cases where important investments, such as electric system upgrades and trenching between building or clusters of equipment, were required on the installations. The investment cost estimates presented below include some relatively conservative assumptions (i.e., high cost) in terms of equipment and installation costs. Some sensitivities are presented (appendix) to reflect the variability of the local circumstances.

Table 12: CAPEX estimates for instrument air controller implementation – central assumptions

| Item | Assumption | Sizing /# | Value USD |
|---|---|--|----------------|
| Controllers and installation costs for the controllers | NA | retrofit projects (it is assumed that controller can be re-used) | 0 |
| Compressor package (Assuming 2 compressors, air drying unit and wet air receiver unit) | See list of assumption in the appendix [12] | 10 HP | 32 000 |
| Other supplies costs (Instrumentation Supplies & Pipe/Valve/Fittings, electrical supplies, etc..) | 1400 \$/cont | 20 | 28 000 |
| Electrical, mechanical & civil Installation Costs, engineering | Retrofit: 100% New: 50% of equipment costs | NA | 60 000 |
| Total CAPEX | | | 120 000 |

In terms of OPEX, it is assumed that compressors are replaced every 6 years. In addition, 4% of the equipment costs are accounted for normal compressor maintenance (typically every 6 months). Other OPEX costs include, for example, electricity costs.

Table 13 presents the emissions estimates while Table 14 present the final results.

¹⁰ Because it is useful to have compressed air at a site for a variety of tasks and uses, operators typically oversize compressed air systems installed to drive pneumatic controllers. In this analysis, we assume that operators will do so, and consider the costs of the oversized system but do not make any estimate of the value of having compressed air available onsite. This approach is conservative (since operators do not strictly need oversize compression capacity for this purpose to use instrument air for pneumatic controllers), though the effect is not large.

CARBON LIMITS

Table 13: Emission estimates – central assumptions

| Emissions is scfh | EF assumption | # | total |
|-------------------------------|---------------|----|-------|
| Intermittent-vent Controllers | 4.43 | 11 | 48.7 |
| Continuous-bleed controllers | 14.43 | 5 | 72.1 |
| ESD | 0.41 | 4 | 1.64 |
| Total gas emissions | | | 122.5 |

Table 14: Final results for the site configuration analyzed – central assumptions

| Item | Unit | Value USD |
|------------------------|---------------------|-----------|
| CAPEX | \$ | 120 000 |
| Value of the gas saved | \$/year | 1073 |
| NPV (Opex) | \$ | 24 683 |
| NPV | \$ | -121 652 |
| ABATEMENT COSTS | \$/tCH ₄ | 972 |

The abatement cost for the same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be \$886/ton CH₄. The difference is because the baseline costs are higher and the baseline emissions are lower for new sites than for retrofits.

Info Box 2: Conversion of pneumatic pumps to instrument air

Pneumatic pumps typically emit more per device than pneumatic controllers, so converting pumps to air can represent a large emission reduction and potentially reduce significantly the abatement cost of conversion. However converting pumps to instrument air is not always technically and/or economically feasible. For sites with access to reliable source of electricity, conversion to air is applicable and cost-effective for the majority of chemical injection pumps. However, even for grid-connected sites, conversion to instrument air is not always the preferred option, as electric pumps are proven effective and low-cost.

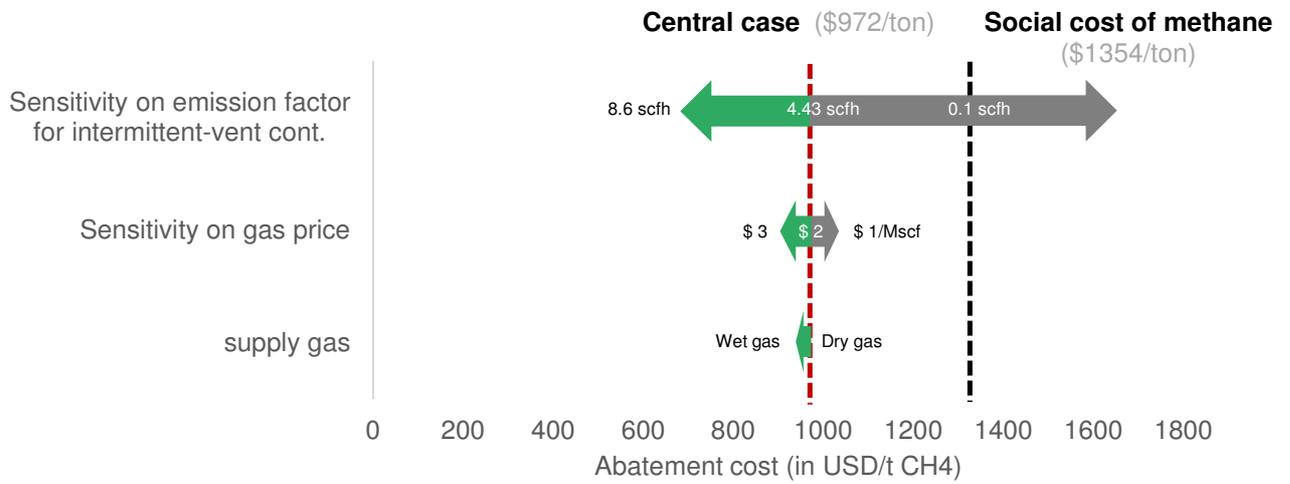
In summary, in a number of cases, emissions reduction for pumps could be considered as a separate project from controllers. In the follow up analysis, conversion of 1 pump to instrument air is only presented as part of the sensitivity analysis.

Sensitivity analysis for one example site configuration

The following figures present a sensitivity analysis for the same site configuration as in the section above. The CH₄ abatement cost for a few key sensitivities is compared to the abatement cost with the central assumptions. A more detailed sensitivity assessment is presented in the appendix.

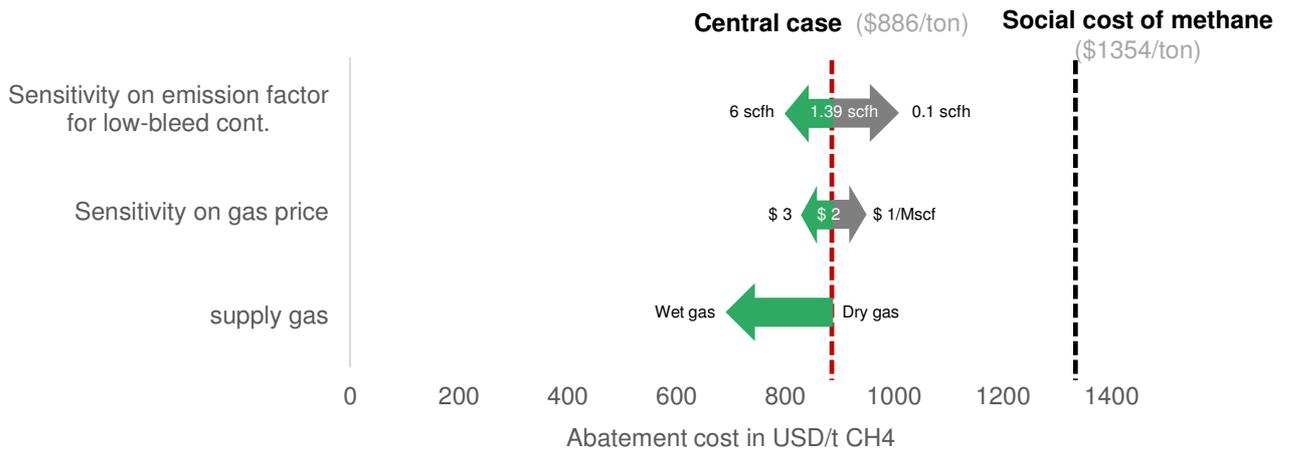
CARBON LIMITS

Figure 11: Sensitivity analysis – instrument air - retrofit



The next figure presents a similar sensitivity for the same site configuration but at a new facility.

Figure 12: Sensitivity analysis – instrument air - new site



As with the electronic controllers, the emission factor heavily impacts the attractiveness of the option. Excluding the emission factor, no other assumption affects the abatement cost per ton by more than 30% (see appendix).

Wet versus dry supply gas

As with electronic controllers, sites with wet gas have an abatement cost generally 5% to 50 % lower than sites with dry gas due to the difference in maintenance costs.

Overview of the results for all the site configurations

The overall abatement costs for about 328 site configurations, all with an electricity supply and no pneumatic pump conversions, were estimated, with a total number of controllers ranging from 21 to 50 (in various permutations of intermittent-vent and continuous-bleed controllers). Sites with fewer than 20 controllers are not presented, as conversion to electric is cheaper (on a per ton basis) in most of the site configurations with fewer than 20 controllers.

CARBON LIMITS

In terms of CAPEX, the total investment for retrofit sites varies between \$90,000 and \$230,000, while the investment (excluding controllers and their installation) for new sites varies between \$60,000 and \$120,000.

Under the central assumptions, 5 of the 328 site configurations evaluated have abatement costs higher than the social cost of methane. The following table shows in red the number of sites with abatement costs higher than \$1354 /tCH₄ for each category of sites.

Table 15: Number of site configurations with abatement costs higher than the social cost of methane – central assumptions

| Number of Pumps | Number of controllers (Excluding ESD) | New Sites | Retrofit |
|-----------------|---------------------------------------|-----------|----------|
| | | | |
| 0 | 21 to 25 controllers | 3 / 42 | 0 / 42 |
| | 26 to 30 controllers | 2 / 40 | 0 / 40 |
| | 31 to 40 controllers | 0 / 82 | 0 / 82 |

A number of conclusions can be drawn from this analysis. Under the central assumptions:

- For almost all the site configurations evaluated with more than 21 controllers (excluding ESDs), it is cost effective to install instrument air.
- For all the retrofit site configurations evaluated, it is cost effective to install instrument air.
- In a few of the new site configurations considered, it is not cost effective to install instrument air.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. The new site configurations with abatement costs greater than the social cost of methane have a vast majority of low bleed continuous controllers, which we have conservatively assumed have very low emissions (1.39 scfh emission factor, see Section 4.1).

The full list of site configurations with abatement costs higher than the social cost of methane is presented in the appendix.

4.4 Summary of the analysis

As described in the section above, an economic analysis assuming conservative average emission factors was performed for 2032 permutations of site configurations with 1 to 50 controllers. Both retrofit and new installations, with or without electricity, were considered. A number of key conclusions can be drawn:

- Zero emission solutions had abatement costs below the social cost of methane (for 2020) described in the EPA 2015 Regulatory Impact Analysis in the vast majority of site configurations considered.
- The abatement costs exceeded the social cost of methane mostly for small sites – those with less than three controllers (excluding ESDs). If higher emission factors, as reflected in field measurements, are used, the abatement costs at even the very small sites fall below the social cost of methane.

The following figure presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the categories below, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

CARBON LIMITS

Table 16: Summary table

| Type of site | | Both retrofit and new sites | | | | | | |
|--|---|--|---|---|---|---|--------------|---|
| | | Number of controllers (excl. ESDs) | | 4-20 | | 21-40 | | |
| | | Yes | No | Yes | No | Yes | No | |
| Main options: Electric controller Instrument air | Description (of the most economic option which is technically feasible) | Grid connected electric controller | Solar powered electric controller | Grid connected electric controller | Solar powered electric controller | Instrument air | | |
| | Number of cases not cost effective (i.e. abatement cost > social cost of methane) under central assumptions | 6 / 36 | 11 / 36 | 0 / 308 | 2 / 308 | 5 / 328 | | |
| | Cost effective for every site configuration if emissions factors are: [*] | > 5.6 scfh for retrofit > 2.8 scfh for new sites | > 7.2 scfh for retrofit > 4.4 scfh for new sites | > 3.6 scfh for retrofit > 1.4 scfh for new sites | > 4.2 scfh for retrofit > 1.8 scfh for new sites | > 4.5 scfh for retrofit > 1.8 scfh for new sites | | |
| Other options potentially applicable depending on the local conditions | Limited applicability | Vent gas recovery | ✓ | ✓ | ✓ | ✓ | ✓ | |
| | | Instrument air powered by gas | Not relevant | Not relevant | Not relevant | Not relevant | ✓ | |
| | | Self contained controllers | ✓ | ✓ | ✓ | ✓ | ✓ | |
| | Limited known implementations | Solar powered instrument air | Not relevant | ✓ | Not relevant | ✓ | X | |
| | | Electric controllers powered by other power sources (TEG, fuel cell) | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant | ✓ |
| | | Large solar powered electric controller (no known implementations) | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant | Potential solution,** but no example known. |

^{*} Emissions factors thresholds listed are determined for the site configuration with the highest abatement cost within the category.

^{**} Based on other solar applications.

The applicability of electronic controllers for small sites and instrument air for large sites reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an illustrative threshold based on information available.

Due to the market conditions, electronic controller providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.

These analyses indicate that the widespread adoption of zero-emitting technologies is cost effective in the vast majority of the site configurations considered. Furthermore, several factors listed should be considered:

- Conservative (low) average emissions factors have been used for low-bleed pneumatic controllers, even though recent research indicates that actual average emissions from those pneumatic controllers may be higher.
- Some of the important benefits of switching to zero-emitting technology, such as the ease of automation or remote operations associated with electrifying pneumatic controllers, are not included in our analysis of the cost-effectiveness of using zero emission technologies.
- Finally, pneumatic controllers emit natural gas, which includes (in varying amounts) other pollutants aside from methane, such as volatile organic compounds (VOCs), which are precursors to ground level smog, and toxic hazardous air pollutants (HAPs). Replacing natural-gas driven pneumatic controllers with zero-emitting technologies will eliminate emissions of these other

CARBON LIMITS

pollutants, in addition to emissions of methane, but we have not included the benefits of VOC or HAP abatement in our calculation of abatement costs for methane.

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| | |
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6. Appendix

6.1 Quantitative assumptions for the model

Table 17: Quantative assumptions for the model

| Description | Central Assumption | Unit | Source |
|---|--------------------|------------------------|--|
| GENERAL ASSUMPTIONS | | | |
| Gas price | 2 | \$/Mscf | [15] |
| Interest Rate | 7% | % | NA |
| Share methane in the gas – Dry gas | 0.0167 | tCH ₄ /Mscf | [15] |
| Share of VOC in the gas – Dry gas | 0.0046 | tVOC/Mscf | [15] |
| Share methane in the gas – wet gas | 0.0150 | tCH ₄ /Mscf | [15] |
| Share of VOC in the gas – wet gas | 0.0050 | tVOC/Mscf | [15] |
| Remaining lifetime for retrofit | 10 | years | [15] |
| Remaining lifetime for new site | 15 | years | [15] |
| EMISSION FACTORS | | | |
| Continuous Controller (s) | 14.43 | cf/h | [2] (Company classification into EPA categories excluding ESD) |
| Intermittent Controller (s) | 4.43 | cf/h | [2] (Company classification into EPA categories excluding ESD) |
| Chemical Pumps | 13.3 | cf/h | [16] |
| ESD | 0.41 | cf/h | [2] |
| Continuous Controller (s) | 1.39 | cf/h | [16] |
| Intermittent Controller (s) | 4.43 | cf/h | [2] |
| Chemical Pumps | 13.3 | cf/h | NA |
| ESD | 0.41 | cf/h | [2] |
| INSTRUMENT AIR – ENGINEERING ASSUMPTIONS | | | |
| Share of the air bypassed in dryer | 17% | % | [14,10] |
| Share of the utility air supply | 200% | % | [14,10] |
| Sizing of compressor - variable component | 0.2026 | HP/cfm | [14,10] |
| Sizing of compressor - constant component | 4.2356 | HP | [14,10] |
| Load of the compressor (main) | 50% | % | [14,10] |
| Sizing of the tank | 6 | gallon/cfm | [10] |
| Lifetime of the compressors | 6 | years | [10,14] |
| ELEC CONTROLLER - COST ASSUMPTIONS | | | |
| Continuous Controller (s) + control valve | 4000 | \$/unit | [9,10] |
| Intermittent Controller (s) + control valve | 4000 | \$/unit | [9,10] |
| Chemical injection pump | 6000 | \$/unit | [9,10] |
| Control Panel | 4000 | \$/unit | [9,10] |
| Solar Panel | 500 | \$/unit | [9,12] |
| Battery | 400 | \$/unit | [9,12] |
| Installation Costs | 20% | of Equipment costs | [9,10] |
| Annual check up | 80 | \$/controller/year | [15] |

CARBON LIMITS

| ELEC CONTROLLER - ENGINEERING ASSUMPTIONS | | | |
|---|-------|---------------|------------------------------|
| Battery replacement frequency | 4 | years | [9,10] |
| Solar Panel replacement frequency | 10 | years | [9,10] |
| Continuous Controller (s) | 0.08 | Amps/unit | [9] |
| Chemical injection pumps | 0.17 | Amps/pump | [9] |
| ESD | 0.16 | Amps/unit | [9] |
| Other systems | 0.29 | Amps/site | [9] |
| System Voltage | 12 | V | [9,12] |
| Battery Average Efficiency | 85% | % | [9,12] |
| Avg. Peak Sun | 4 | h/days | [9,10] (Confirmed with NREL) |
| Battery - At Maximum Depth of Discharge | 80% | % | [9] |
| Days of Energy Storage | 10 | days | [9] |
| Rating of the solar panel | 140 | W | [9,12] |
| Rating of the battery | 100 | Ah | [9,12] |
| Oversizing of the solar panel | 50% | % | [9,10] |
| INSTRUMENT AIR - COST ASSUMPTION | | | |
| Compressor Package – Main -5 HP | 22000 | \$ | [12,10] |
| Compressor Package – Main -10 HP | 32000 | \$ | [12,10] |
| Compressor Package – Main -15 HP | 48000 | \$ | [12,10] |
| Compressor Package – Main -20 HP | 70000 | \$ | [12,10] |
| Compressor - Unit cost - 5 HP | 7000 | \$ | [12] |
| Compressor - Unit cost - 10HP | 10000 | \$ | [12] |
| Compressor - Unit cost - 15 HP | 15000 | \$ | [12] |
| Compressor - Unit cost - 20 HP | 23000 | \$ | [12] |
| Other supply | 1400 | \$/controller | [10] |
| Other supply | 1000 | \$/controller | [10] |
| Installation | 100% | % | [10] |
| Installation | 50% | % | [10] |
| Compressor maintenance | 4% | % of Capex | [10,15] |
| BASELINE - COST ASSUMPTION | | | |
| Continuous Controller (s) + control valve | 2698 | \$/cont. | [17] |
| Intermittent Controller (s) + control valve | 2471 | \$/cont. | [17] |
| Labor - installation - Controller | 387 | \$/unit | [18] |
| Maintenance costs - Controller- wet gas sites | 200 | \$/cont./year | [10] |
| Maintenance costs - Controller- dry gas sites | 80 | \$/cont./year | [18] |

6.2 Other assumptions for the model

- General assumptions
 - Retrofitting is assumed to be performed during a planned maintenance, hence retrofit activities do not cause production losses; thus, no potential revenue losses are accounted for in the estimates presented.

CARBON LIMITS

- Electronic controllers:
 - In all the site configurations, it is assumed that ESDs are gas driven pneumatic controllers.
 - Electronic controllers can reduce the need for site inspections. The subsequent reduced labour costs have not, however, been taken into consideration in the analysis. (conservative assumption)
- Instrument air
 - CO₂ emissions from power consumption (for non-solar powered options) have been neglected; this represents a very small volume of emissions compared to the CH₄ emissions (typically a few per cent, assuming a GWP of methane of 21).

6.3 Detailed sensitivity analysis

In the analysis presented, a number of assumptions have been made which affect the abatement cost. The following sections present the detailed sensitivity analysis performed.

Electronic controller – Retrofit

The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH₄ abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$751/t CH₄. The abatement cost under all the sensitivities is below the social cost of methane.

Table 18: Sensitivity analysis – retrofit site with 4 controllers– results

| Name of the parameter | Central assumption | Sensitivity value | Abatement cost in \$/t CH ₄ |
|--|------------------------|------------------------|--|
| Number of pumps | 0 pump | 1 pump | 614 |
| Type of supply gas | Dry supply gas | Wet supply gas | 702 |
| Power on-site | No power on-site | Power on-site | 611 |
| Gas price | 2 \$/Mscf | 1 \$/Mscf | 811 |
| Gas price | | 3 \$/Mscf | 692 |
| Discount rate | 7% | 3% | 635 |
| Emission factors intermittent-vent cont. | 4.43 scfh | 8.6 scfh | 522 |
| | | 0.1 scfh | 1267 |
| Control Panel equipment cost | \$4000 | \$6000 | 845 |
| Installation Costs | 20% of Equipment Costs | 40% of Equipment Costs | 889 |
| Battery replacement freq. | 4 years | 2 years | 823 |
| Average peak sun | 4 hours | 2 hours | 775 |

Electronic controller – New

The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH₄ abatement cost for a few key sensitivities should be compared to the abatement costs under the central assumption: \$847/t CH₄. The abatement costs for all the sensitivities are below the social cost of methane.

CARBON LIMITS

Table 19: Sensitivity analysis – New site with 4 controllers– results

| Name of the parameter | Central assumption | Sensitivity value | Abatement cost in \$/t CH ₄ |
|--|------------------------|------------------------|--|
| Number of pumps | 0 pump | 1 pump | 459 |
| Type of supply gas | Dry supply gas | Wet supply gas | 624 |
| Power on-site | No power on-site | Power on-site | 548 |
| Gas price | 2 \$/Mscf | 1 \$/Mscf | 906 |
| Gas price | | 3 \$/Mscf | 787 |
| Discount rate | 7% | 3% | 680 |
| Emission factors low bleed controllers | 1.39 scfh | 6 scfh | 547 |
| | | 0.1 scfh | 986 |
| Control Panel equipment cost | \$4000 | \$6000 | 1011 |
| Installation Costs | 20% of Equipment Costs | 40% of Equipment Costs | 1089 |
| Battery replacement freq. | 4 years | 2 years | 1046 |
| Average peak sun | 4 hours | 2 hours | 905 |
| Low Bleed Cont. - Equipment cost | \$2698 per controller | \$554 per controller | 993 |
| Intermittent Cont. - Equipment cost | \$2471 per controller | \$387 per controller | 1131 |

Instrument air – Retrofit

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH₄ abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$972/t CH₄.

Table 20: Sensitivity analysis – retrofit site with 4 controllers– results

| Name of the parameter | Central assumption | Sensitivity value | Abatement cost in \$/t CH ₄ |
|---|--------------------------------------|--------------------------------------|--|
| Type of supply gas | Dry supply gas | Wet supply gas | 945 |
| Gas price | 2 \$/Mscf | 1 \$/Mscf | 1037 |
| Gas price | | 3 \$/Mscf | 908 |
| Discount rate | 7% | 3% | 848 |
| Emission factors intermittent-vent cont. | 4.43 scfh | 8.6 scfh | 679 |
| | | 0.1 scfh | 1656 |
| Other supplies costs | \$1400/controller | \$1800 /controller | 1100 |
| | | \$1000 /controller | 844 |
| Electrical, mechanical & civil installation costs | 100% of equipment and supplies costs | 150% of equipment and supplies costs | 1212 |
| | | 50% of equipment and supplies costs | 732 |

CARBON LIMITS

Instrument air – New site

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH₄ abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$886/t CH₄.

Table 21: Sensitivity analysis – retrofit site with 4 controllers– results

| Name of the parameter | Central assumption | Sensitivity value | Abatement cost in \$/t CH ₄ |
|---|-------------------------------------|--------------------------------------|--|
| Type of supply gas | Dry supply gas | Wet supply gas | 690 |
| Gas price | 2 \$/Mscf | 1 \$/Mscf | 949 |
| Gas price | | 3 \$/Mscf | 824 |
| Discount rate | 7% | 3% | 734 |
| Other supplies costs | \$1000/controller | \$1200 /controller | 963 |
| Electrical, mechanical & civil installation costs | 50% of equipment and supplies costs | 100% of equipment and supplies costs | 1154 |
| Emission factors low bleed controllers | 1.39 scfh | 6 scfh | 800 |
| | | 0.1 scfh | 1011 |

6.4 List of site configurations with abatement cost superior to the social cost of methane

The following table presents a complete list of all the site configurations with an abatement cost higher than the social cost of methane.

Electronic controller – New sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 22: Site configurations with abatement cost superior to \$1354/ton - Electric controller – New sites

| Site configuration ID | New/retrofit | Electricity on site? | Supply gas | Pump # | Continuous Cont. # | Intermittent Cont. # | ESD # | Abatement costs – central assumptions | Abatement costs – Higher EF assumption |
|-----------------------|--------------|----------------------|------------|--------|--------------------|----------------------|-------|---------------------------------------|--|
| 13 | New | Electricity | Wet | 0 | 1 | 0 | 1 | 1985 | 456 |
| 349 | New | Electricity | Dry | 0 | 1 | 0 | 1 | 2838 | 703 |
| 355 | New | Electricity | Dry | 0 | 2 | 0 | 1 | 1793 | 412 |
| 361 | New | Electricity | Dry | 0 | 3 | 0 | 1 | 1445 | 315 |
| 685 | New | No electricity | Wet | 0 | 1 | 0 | 1 | 3777 | 954 |
| 691 | New | No electricity | Wet | 0 | 2 | 0 | 1 | 2009 | 462 |
| 697 | New | No electricity | Wet | 0 | 3 | 0 | 1 | 1643 | 361 |
| 1021 | New | No electricity | Dry | 0 | 1 | 0 | 1 | 4446 | 1150 |
| 1027 | New | No electricity | Dry | 0 | 2 | 0 | 1 | 2595 | 635 |
| 1033 | New | No electricity | Dry | 0 | 3 | 0 | 1 | 2179 | 520 |
| 1039 | New | No electricity | Dry | 0 | 4 | 0 | 1 | 1820 | 420 |
| 1045 | New | No electricity | Dry | 0 | 5 | 0 | 1 | 1605 | 360 |

Electronic controller – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for an intermittent-vent controller emission factor of 7 scfh (compared to 4.43 in the central assumption).

CARBON LIMITS

Table 23: Site configurations with abatement cost superior to \$1354/ton - Electric controller – Retrofit

| Site configuration ID | New/ retrofit | Electricity on site? | Supply gas | Pump # | Continuous Cont. # | Intermittent Cont. # | ESD # | Abatement costs – central assumptions | Abatement costs – Higher EF assumption |
|-----------------------|---------------|----------------------|------------|--------|--------------------|----------------------|-------|---------------------------------------|--|
| 1345 | Retrofit | Electricity | Wet | 0 | 0 | 1 | 1 | 1593 | 960 |
| 1681 | Retrofit | Electricity | Dry | 0 | 0 | 1 | 1 | 1750 | 1064 |
| 2017 | Retrofit | No electricity | Dry | 0 | 0 | 1 | 1 | 2282 | 1400 |
| 2018 | Retrofit | No electricity | Dry | 0 | 0 | 2 | 1 | 1573 | 952 |
| 2019 | Retrofit | No electricity | Dry | 0 | 0 | 3 | 1 | 1406 | 846 |
| 2353 | Retrofit | No electricity | Wet | 0 | 0 | 1 | 1 | 2186 | 1335 |
| 2354 | Retrofit | No electricity | Wet | 0 | 0 | 2 | 1 | 1486 | 891 |

Instrument air – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 24: Site configurations with abatement cost superior to \$1354/ton – Instrument air – Retrofit

| Site configuration ID | New/ retrofit | Electricity on site? | Supply gas | Pump # | Continuous Cont. # | Intermittent Cont. # | ESD # | Abatement costs – central assumptions | Abatement costs – Higher EF assumption |
|-----------------------|---------------|----------------------|------------|--------|--------------------|----------------------|-------|---------------------------------------|--|
| 437 | New | Electricity | Dry | 0 | 20 | 1 | 5 | 1651 | 612 |
| 438 | New | Electricity | Dry | 0 | 20 | 2 | 5 | 1466 | 589 |
| 447 | New | Electricity | Dry | 0 | 25 | 0 | 5 | 1595 | 515 |
| 448 | New | Electricity | Dry | 0 | 25 | 1 | 6 | 1426 | 501 |
| 457 | New | Electricity | Dry | 0 | 30 | 0 | 6 | 1392 | 436 |



Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

**Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas
Production, Transmission, and Distribution.**

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DISCLAIMER

This report has been reviewed by EPA's Office of Air Quality Planning and Standards and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO₂, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

TABLE OF CONTENTS

| | |
|---|------|
| 1.0 NEW SOURCE PERFORMANCE BACKGROUND | 1-1 |
| 1.1 Statutory Authority | 1-1 |
| 1.2 History of Oil and Gas Source Category | 1-2 |
| 1.3 NSPS Review Process..... | 1-2 |
| 2.0 SECTOR DESCRIPTION | 2-1 |
| 3.0 NEW SOURCE PERFORMANCE REVIEW PROCESS | 3-1 |
| 3.1 Evaluation of BSER for Existing NSPS | 3-1 |
| 3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants | 3-1 |
| 3.1.2 BSER for SO ₂ Emissions from Sweetening Units at Natural Gas Processing Plants | 3-3 |
| 3.2 Additional Pollutants | 3-5 |
| 3.3 Additional Processes | 3-6 |
| 4.0 WELL COMPLETIONS AND RECOMPLETIONS | 4-1 |
| 4.1 Process Description..... | 4-1 |
| 4.1.1 Oil and Gas Well Completions | 4-1 |
| 4.1.2 Oil and Gas Well Recompletions..... | 4-2 |
| 4.2 Emission Data and Emissions Factors | 4-3 |
| 4.2.1 Summary of Major Studies and Emission Factors..... | 4-3 |
| 4.2.2 Representative Completion and Recompletion Emissions | 4-6 |
| 4.3 Nationwide Emissions from New Sources..... | 4-8 |
| 4.3.1 Overview of Approach..... | 4-8 |
| 4.3.2 Number of Completions and Recompletions | 4-8 |
| 4.3.3 Level of Controlled Sources in Absence of Federal Regulation..... | 4-10 |
| 4.3.4 Emission Estimates | 4-12 |
| 4.4 Control Techniques | 4-12 |
| 4.4.1 Potential Control Techniques..... | 4-12 |
| 4.4.2 Reduced Emission Completions and Recompletions..... | 4-14 |
| 4.4.2.1 Description..... | 4-14 |
| 4.4.2.2 Effectiveness..... | 4-15 |
| 4.4.2.3 Cost Impacts..... | 4-15 |
| 4.4.2.4 Secondary Impacts | 4-18 |
| 4.4.3 Completion Combustion Devices | 4-18 |
| 4.4.3.1 Description..... | 4-18 |
| 4.4.3.2 Effectiveness..... | 4-19 |
| 4.4.3.3 Cost Impacts..... | 4-19 |
| 4.4.3.4 Secondary Impacts | 4-20 |
| 4.5 Regulatory Options | 4-22 |
| 4.5.1 Evaluation of Regulatory Options..... | 4-24 |
| 4.5.2 Nationwide Impacts of Regulatory Options..... | 4-27 |
| 4.5.2.1 Primary Environmental Impacts of Regulatory Options..... | 4-27 |
| 4.5.2.2 Cost Impacts..... | 4-28 |
| 4.5.2.3 Secondary Impacts | 4-30 |
| 4.6 References..... | 4-32 |

| | |
|--|------|
| 5.0 PNEUMATIC CONTROLLERS | 5-1 |
| 5.1 Process Description..... | 5-1 |
| 5.2. Emission Data and Emissions Factors | 5-3 |
| 5.2.1 Summary of Major Studies and Emission Factors..... | 5-3 |
| 5.2.2 Representative Controller Emissions..... | 5-3 |
| 5.3 Nationwide Emissions from New Sources..... | 5-5 |
| 5.3.1 Overview of Approach..... | 5-5 |
| 5.3.2 Population of Devices Installed Annually..... | 5-5 |
| 5.3.3 Emission Estimates | 5-9 |
| 5.4 Control Techniques..... | 5-9 |
| 5.4.1 Potential Control Techniques..... | 5-9 |
| 5.4.2 Low Bleed Controllers | 5-12 |
| 5.4.2.1 Emission Reduction Potential | 5-12 |
| 5.4.2.2 Effectiveness | 5-12 |
| 5.4.2.3 Cost Impacts..... | 5-14 |
| 5.4.2.4 Secondary Impacts | 5-16 |
| 5.4.3 Instrument Air Systems..... | 5-16 |
| 5.4.3.1 Description | 5-16 |
| 5.4.3.2 Effectiveness | 5-18 |
| 5.4.3.3 Cost Impacts..... | 5-19 |
| 5.4.3.4 Secondary Impacts | 5-22 |
| 5.5 Regulatory Option..... | 5-22 |
| 5.5.1 Evaluation of Regulatory Options..... | 5-22 |
| 5.5.2 Nationwide Impacts of Regulatory Options..... | 5-24 |
| 5.6 References..... | 5-26 |
| | |
| 6.0 COMPRESSORS | 6-1 |
| 6.1 Process Description..... | 6-1 |
| 6.1.1 Reciprocating Compressors | 6-1 |
| 6.1.2 Centrifugal Compressors | 6-2 |
| 6.2. Emission Data and Emissions Factors | 6-2 |
| 6.2.1 Summary of Major Studies and Emission Factors..... | 6-2 |
| 6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions..... | 6-2 |
| 6.3 Nationwide Emissions from New Sources..... | 6-6 |
| 6.3.1 Overview of Approach..... | 6-6 |
| 6.3.2 Activity Data for Reciprocating Compressors | 6-6 |
| 6.3.2.1 Wellhead Reciprocating Compressors | 6-6 |
| 6.3.2.2 Gathering and Boosting Reciprocating Compressors | 6-8 |
| 6.3.2.3 Processing Reciprocating Compressors | 6-8 |
| 6.3.2.4 Transmission and Storage Reciprocating Compressors | 6-9 |
| 6.3.3 Level of Controlled Sources in Absence of Federal Regulation..... | 6-9 |
| 6.3.4 Emission Estimates | 6-9 |
| 6.4 Control Techniques..... | 6-11 |
| 6.4.1 Potential Control Techniques..... | 6-11 |
| 6.4.2 Reciprocating Compressor Rod Packing Replacement..... | 6-12 |
| 6.4.2.1 Description | 6-12 |
| 6.4.2.2 Effectiveness | 6-12 |
| 6.4.2.3 Cost Impacts..... | 6-16 |
| 6.4.2.4 Secondary Impacts | 6-18 |
| 6.4.3 Centrifugal Compressor Dry Seals | 6-18 |

| | | |
|------------|---|------------|
| 6.4.3.1 | Description | 6-18 |
| 6.4.3.2 | Effectiveness | 6-19 |
| 6.4.3.3 | Cost Impacts..... | 6-19 |
| 6.4.3.4 | Secondary Impacts | 6-21 |
| 6.4.4 | Centrifugal Compressor Wet Seals with a Flare | 6-21 |
| 6.4.4.1 | Description | 6-21 |
| 6.4.4.2 | Effectiveness | 6-23 |
| 6.4.4.3 | Cost Impacts..... | 6-23 |
| 6.4.4.4 | Secondary Impacts | 6-23 |
| 6.5 | Regulatory Options | 6-23 |
| 6.5.1 | Evaluation of Regulatory Options..... | 6-27 |
| 6.5.2 | Nationwide Impacts of Regulatory Options..... | 6-28 |
| 6.6 | References..... | 6-31 |
| 7.0 | STORAGE VESSELS | 7-1 |
| 7.1 | Process Description..... | 7-2 |
| 7.2 | Emission Data | 7-2 |
| 7.2.1 | Summary of Major Studies and Emission Factors..... | 7-2 |
| 7.2.2 | Representative Storage Vessel Emissions..... | 7-2 |
| 7.2.2.1 | Model Condensate Tank Batteries | 7-2 |
| 7.2.2.2 | Model Crude Oil Tank Batteries | 7-4 |
| 7.2.2.3 | VOC Emissions from Model Condensate and Crude Oil Storage Vessels | 7-4 |
| 7.3 | Nationwide Emissions from New Sources..... | 7-10 |
| 7.3.1 | Overview of Approach..... | 7-10 |
| 7.3.2 | Number of New Storage Vessels Expected to be Constructed or Reconstructed | 7-10 |
| 7.3.3 | Level of Controlled Sources in Absence of Federal Regulation..... | 7-10 |
| 7.3.4 | Nationwide Emission Estimates for New or Modified Storage Vessels..... | 7-12 |
| 7.4 | Control Techniques | 7-12 |
| 7.4.1 | Potential Control Techniques..... | 7-12 |
| 7.4.2 | Vapor Recovery Units..... | 7-12 |
| 7.4.2.1 | Description | 7-12 |
| 7.4.2.2 | Effectiveness | 7-13 |
| 7.4.2.3 | Cost Impacts..... | 7-13 |
| 7.4.2.4 | Secondary Impacts | 7-13 |
| 7.4.3 | Combustors | 7-15 |
| 7.4.3.1 | Description and Effectiveness..... | 7-15 |
| 7.4.3.2 | Cost Impacts..... | 7-15 |
| 7.4.3.3 | Secondary Impacts | 7-15 |
| 7.5 | Regulatory Options | 7-18 |
| 7.5.1 | Evaluation of Regulatory Options..... | 7-18 |
| 7.5.2 | Nationwide Impacts of Regulatory Options..... | 7-22 |
| 7.5.3 | Primary Environmental Impacts of Regulatory Options Impacts | 7-22 |
| 7.5.4 | Cost Impacts..... | 7-24 |
| 7.6 | References..... | 7-26 |
| 8.0 | EQUIPMENT LEAKS | 8-1 |
| 8.1 | Process Description..... | 8-1 |
| 8.2 | Emission Data and Emissions Factors | 8-1 |
| 8.2.1 | Summary of Major Studies and Emission Factors..... | 8-1 |
| 8.2.2 | Model Plant..... | 8-2 |

| | |
|--|------|
| 8.2.2.1 Oil and Natural Gas Production | 8-2 |
| 8.2.2.2 Oil and Natural Gas Processing | 8-9 |
| 8.2.2.3 Natural Gas Transmission | 8-9 |
| 8.3 Nationwide Emissions from New Sources..... | 8-9 |
| 8.3.1 Overview of Approach..... | 8-9 |
| 8.3.2 Activity Data..... | 8-13 |
| 8.3.2.1 Well Pads | 8-13 |
| 8.3.2.2 Gathering and Boosting | 8-13 |
| 8.3.2.3 Processing Facilities..... | 8-16 |
| 8.3.2.4 Transmission and Storage Facilities..... | 8-16 |
| 8.3.4 Emission Estimates | 8-16 |
| 8.4 Control Techniques | 8-18 |
| 8.4.1 Potential Control Techniques..... | 8-18 |
| 8.4.2 Subpart VVa LDAR Program | 8-21 |
| 8.4.2.1 Description | 8-21 |
| 8.4.2.2 Effectiveness | 8-21 |
| 8.4.2.3 Cost Impacts..... | 8-23 |
| 8.4.2.4 Secondary Impacts | 8-26 |
| 8.4.3 LDAR with Optical Gas Imaging | 8-31 |
| 8.4.3.1 Description | 8-31 |
| 8.4.3.2 Effectiveness | 8-31 |
| 8.4.3.3 Cost Impacts..... | 8-31 |
| 8.4.3.4 Secondary Impacts | 8-34 |
| 8.4.4 Modified Alternative Work Practice with Optical Gas Imaging..... | 8-34 |
| 8.4.4.1 Description | 8-34 |
| 8.4.4.2 Effectiveness | 8-34 |
| 8.4.4.3 Cost Impacts..... | 8-35 |
| 8.4.4.4 Secondary Impacts | 8-35 |
| 8.5 Regulatory Options | 8-37 |
| 8.5.1 Evaluation of Regulatory Options for Equipment Leaks | 8-37 |
| 8.5.1.1 Well Pads | 8-37 |
| 8.5.1.2 Gathering and Boosting | 8-38 |
| 8.5.1.3 Processing Facilities..... | 8-39 |
| 8.5.1.4 Transmission and Storage Facilities..... | 8-39 |
| 8.5.2 Nationwide Impacts of Regulatory Options..... | 8-40 |
| 8.6 References..... | 8-42 |

APPENDIX A

1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "...causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO₂) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any

non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO₂) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO₂ emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether

these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO₂, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have “associated” natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered

separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H₂S), carbon dioxide (CO₂), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce “pipeline quality” dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO₂ removal, fractionation of natural gas liquid and other processes, such as the capture of CO₂ separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

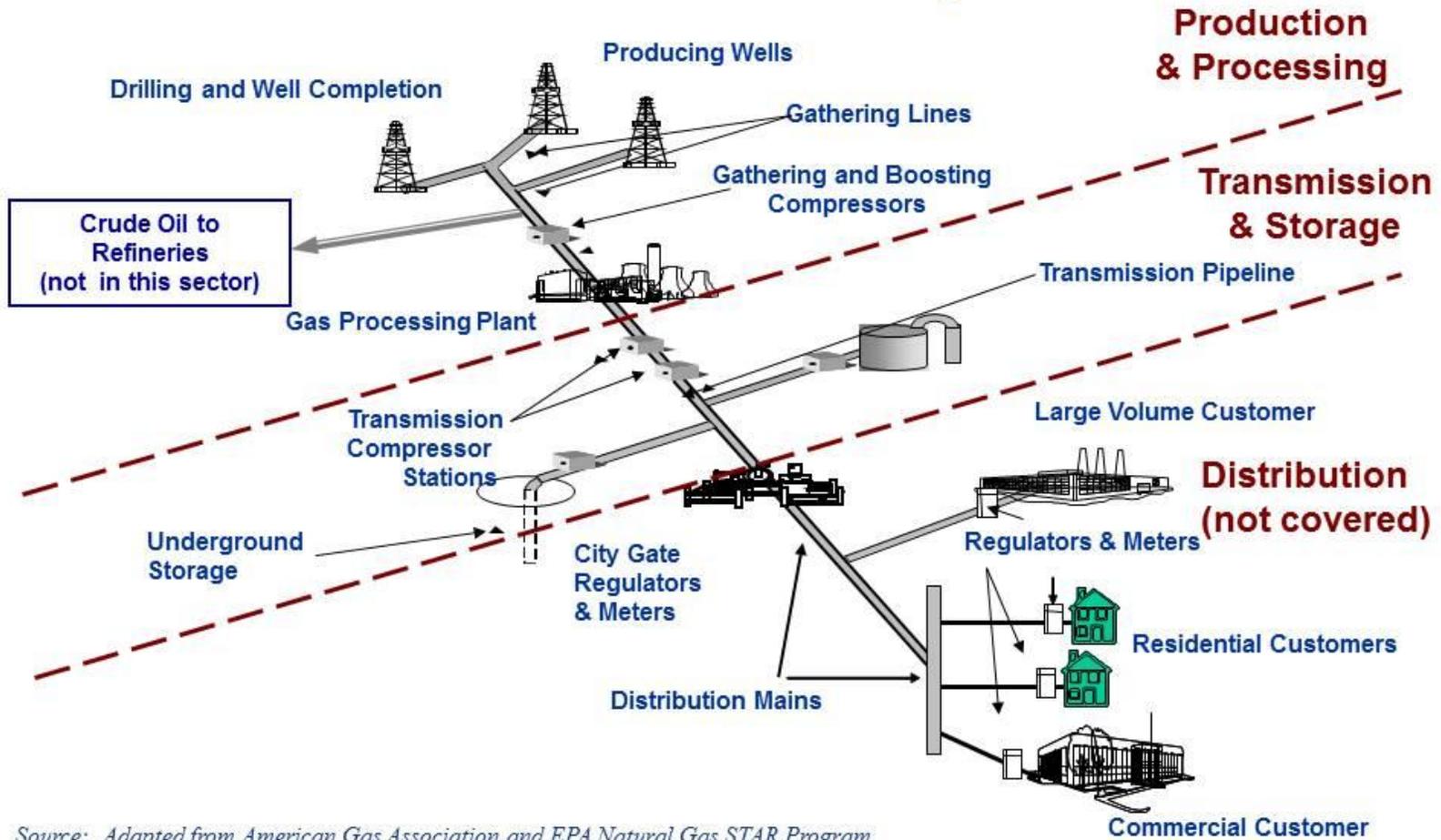
The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the “citygate.” Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO₂ are emitted from production and processing operations that handle and treat sour gasⁱ

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

ⁱ Sour gas is defined as natural gas with a maximum H₂S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO₂

Oil and Natural Gas Operations



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO₂ emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.¹

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR

program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is \$3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from \$144 per ton of VOC (for valves) to \$4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be \$6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing \$85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for \$3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is \$4,638 per ton of VOC reduction.ⁱ

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be \$76,581 based on camera purchase, or \$51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be \$43,851, based on camera purchase, or \$18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO₂ Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO₂ emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

ⁱ Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO₂ emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H₂S in acid gases (i.e., H₂S and CO₂) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H₂S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H₂S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.ⁱⁱ As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H₂S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H₂S and CO₂ in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.ⁱⁱⁱ The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H₂S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H₂S content below 10 percent to 99.8 percent for H₂S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database¹ and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO₂

ⁱⁱ 49 FR 2656, 2659-2660 (1984).

ⁱⁱⁱ 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H₂S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H₂S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H₂S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H₂S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H₂S content less than 5 long tons per day and 50 percent, respectively.¹

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO₂. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO₂e (million metric tons of CO₂-equivalents (CO₂e)).^{iv} The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

^{iv} U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009.
http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO₂e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO₂e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO₂ from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO₂ is expected to be emitted directly; although H₂S contained in sour gas^v forms SO₂ as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

^v Sour gas is defined as natural gas with a maximum H₂S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO₂.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

- 1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be “completed” after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.¹

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.²

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as “wildcat”) wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in “tight” formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.ⁱ

“Energized fractures” are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

ⁱ A darcy (or darcy unit) and millidarcies (mD) are units of permeability. Converted to SI units, 1 darcy is equivalent to $9.869233 \times 10^{-13} \text{ m}^2$ or $0.9869233 \text{ (}\mu\text{m)}^2$. This conversion is usually approximated as $1 \text{ (}\mu\text{m)}^2$.

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

| Report Name | Affiliation | Year of Report | Activity Factor(s) | Emission Information | Control Information |
|--|--|-----------------------|---------------------------|-----------------------------|----------------------------|
| Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents ³ | EPA | 2010 | Nationwide | X | |
| Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 ^{4,5} | EPA | 2010 | Nationwide | X | |
| Methane Emissions from the Natural Gas Industry ^{6, 7, 8, 9} | Gas Research Institute /US Environmental Protection Agency | 1996 | Nationwide | X | X |
| Methane Emissions from the US Petroleum Industry (Draft) ¹⁰ | EPA | 1996 | Nationwide | X | |
| Methane Emissions from the US Petroleum Industry ¹¹ | EPA | 1999 | Nationwide | X | |
| Oil and Gas Emission Inventories for Western States ¹² | Western Regional Air Partnership | 2005 | Regional | X | X |
| Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories ¹³ | Central States Regional Air Partnership | 2008 | Regional | X | X |
| Oil and Gas Producing Industry in Your State ¹⁴ | Independent Petroleum Association of America | 2009 | Nationwide | | |
| Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements ¹⁵ | Environmental Defense Fund | 2009 | Regional | X | X |
| Emissions from Oil and Natural Gas Production Facilities ¹⁶ | Texas Commission for Environmental Quality | 2007 | Regional | X | X |
| Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1 | Interstate Natural Gas Association of America | 2008 | Nationwide | | |

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

| Report Name | Affiliation | Year of Report | Activity Factor(s) | Emission Information | Control Information |
|--|---|-----------------------|---------------------------|-----------------------------|----------------------------|
| Petroleum and Natural Gas Statistical Data ¹⁷ | U.S. Energy Information Administration | 2007-2009 | Nationwide | | |
| Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations ¹⁸ | EPA | 1999 | | X | |
| Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program ¹⁹ | New York State Department of Environmental Conservation | 2009 | Regional | X | X |
| Natural Gas STAR Program ^{20, 21, 22, 23, 24, 25} | EPA | 2000-2010 | Nationwide/ Regional | X | X |

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.²⁶ The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).⁴ A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

| Well Completion Category | Emissions (Mcf/event) | Emissions (tons/event) | | |
|--|-----------------------|------------------------|------------------|------------------|
| | Methane | Methane ^a | VOC ^b | HAP ^c |
| Natural Gas Well Completion without Hydraulic Fracturing | 38.6 | 0.8038 | 0.12 | 0.009 |
| Natural Gas Well Completion with Hydraulic Fracturing | 7,623 | 158.55 | 23.13 | 1.68 |
| Oil Well Completions | 0.34 | 0.0076 | 0.00071 | 0.0000006 |
| Natural Gas Well Recompletion without Hydraulic Fracturing | 2.59 | 0.0538 | 0.0079 | 0.0006 |
| Natural Gas Well Recompletion with Hydraulic Fracturing | 7,623 | 158.55 | 23.13 | 1.68 |
| Oil Well Recompletions | 0.057 | 0.00126 | 0.001 | 0.0000001 |

Minor discrepancies may exist due to rounding.

- a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.
- b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.
- c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. EIA is legally required to make the NEMS source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI[®] database.^{ii, iii} The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI[®] collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

ⁱⁱ HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.

ⁱⁱⁱ For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From

<<http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx>

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

4.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.^{iv} Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared.²⁷ The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COGCC) requires REC for both oil and natural gas wells.²⁸ It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

^{iv} See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

| Well Completion Category | Estimated Number of Total Completions and Recompletions^a | Estimated Number of Controlled Completions and Recompletions | Estimated Number of Uncontrolled Completions and Recompletions^b |
|---|--|---|---|
| Natural Gas Well Completions without Hydraulic Fracturing [*] | 7,694 | | 7,694 |
| Exploratory Natural Gas Well Completions with Hydraulic Fracturing ^{**} | 446 | | 446 |
| Developmental Natural Gas Well Completions with Hydraulic Fracturing ^c | 10,957 | 1,644 | 9,313 |
| Oil Well Completions ^d | 12,193 | | 12,193 |
| Natural Gas Well Recompletions without Hydraulic Fracturing | 42,342 | | 42,342 |
| Natural Gas Well Recompletions with Hydraulic Fracturing ^{††} | 14,177 | 2,127 | 12,050 |
| Oil Well Recompletions [†] | 39,375 | | 39,375 |

- a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.
- b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.
- c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.
- d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.^v The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

^v Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

| Well Completion Category | Uncontrolled Methane Emissions per event (tpy) | Number of Uncontrolled Wells ^a | Baseline Nationwide Emissions (tons/year) ^a | | |
|--|--|---|--|------------------|------------------|
| | | | Methane ^b | VOC ^c | HAP ^d |
| Natural Gas Well Completions without Hydraulic Fracturing | 0.8038 | 7,694 | 6,185 | 902 | 66 |
| Exploratory Natural Gas Well Completions with Hydraulic Fracturing | 158.55 | 446 | 70,714 | 10,317 | 750 |
| Developmental Natural Gas Well Completions with Hydraulic Fracturing | 158.55 | 9,313 | 1,476,664 | 215,445 | 15,653 |
| Oil Well Completions | 0.0076 | 12,193 | 93 | 87 | .008 |
| Natural Gas Well Recompletions without Hydraulic Fracturing | 0.0538 | 42,342 | 2,279 | 332 | 24 |
| Natural Gas Well Recompletions with Hydraulic Fracturing | 158.55 | 12,050 | 1,910,549 | 278,749 | 20,252 |
| Oil Well Recompletions | 0.00126 | 39,375 | 50 | 47 | .004 |

Minor discrepancies may be due to rounding.

- a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
- b. The number of controlled and uncontrolled wells estimated based on State regulations.
- c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
- d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as “green” or “flareless” completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.²⁹ In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).³⁰ In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.
- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well

casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.³¹ Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between \$700 and \$6,500 per day, with representative well completion flowback lasting 3 to 10 days.² This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars).^{vi} Cost data used in this analysis are qualified below:

- \$700 per day (equivalent to \$806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.
- \$6,500 per day (equivalent to \$7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of \$4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of \$29,022 for a REC versus an uncontrolled completion. An additional \$691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at \$29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is \$1,429 per ton, with a methane co-benefit of \$208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of \$4.00^{vii} per thousand cubic feet (Mcf).³² It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

^{vi} The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

^{vii} The average market price for natural gas in 2010 was approximately \$4.16 per Mcf. This is much less compared to the average price in 2008 of \$7.96 per Mcf. Due to the volatility in the price, a conservative savings of \$4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

| Well Completion Category | Emission Reduction Per Completion/Recompletion (tons/year) ^a | | | Total Cost Per Completion/Recompletion ^b (\$/event) | VOC Cost Effectiveness (\$/ton) ^c | | Methane Cost Effectiveness (\$/ton) | |
|---|---|---------|-----|--|--|--------------|-------------------------------------|--------------|
| | VOC | Methane | HAP | | without savings | with savings | without savings | with savings |
| Natural Gas Completions and Recompletions with Hydraulic Fracturing | 20.8 | 142.7 | 1.5 | 29,713 | 1,429 | net savings | 208 | net savings |

Minor discrepancies may be due to rounding.

- a. This represents a ninety percent reduction from baseline for the average well.
- b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of \$4,146 per day for an average length of completion flowback lasting 7 days and an additional \$691 for transportation and set up.
- c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately \$33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of \$70 per barrel (bbl), this result is an income due to condensate sales around \$2,380.³³ When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of \$5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.³⁴ Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.³⁵ Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.^{30, 36, 37} The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC)³⁸ in 2009 by N.L. Fisher Supervision and Engineering, Ltd.^{viii} The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

^{viii} It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as \$0 and as high as \$56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately \$3,523 (2008 dollars).^{ix} As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of \$161 per ton VOC and a co-benefit of \$23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x), carbon dioxide (CO₂), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.³⁴ Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.³⁴

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

^{ix} The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is \$3,195.

**Table 4-6. Emission Reduction and Cost-effectiveness Summary
for Completion Combustion Devices**

| Well Completion Category | Emission Reduction Per Completion/Workover (tons/year) ^a | | | Total Capital Cost Per Completion Event (\$)* | VOC Cost Effectiveness | Methane Cost Effectiveness |
|--|---|---------|-----------|---|------------------------|----------------------------|
| | VOC | Methane | HAP | | (\$/ton) ^b | (\$/ton) |
| Natural Gas Well Completions without Hydraulic Fracturing | 0.11 | 0.76 | 0.0081 | 3,523 | 31,619 | 4,613 |
| Natural Gas Well Completions with Hydraulic Fracturing | 21.9 | 150.6 | 1.597 | | 160 | 23 |
| Oil Well Completions | 0.01 | 0.007 | 0.0000007 | | 520,580 | 488,557 |
| Natural Gas Well Re Completions without Hydraulic Fracturing | 0.007 | 0.051 | 0.0005 | | 472,227 | 68,889 |
| Natural Gas Well Re Completions with Hydraulic Fracturing | 21.9 | 150.6 | 1.597 | | 160 | 23 |
| Oil Well Re Completions | 0.00 | 0.001 | 0.0000001 | | 3,134,431 | 2,941,615 |

Minor discrepancies may be due to rounding.

- a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.³⁴ These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1^a

| Pollutant | Emission Factor (lb/10⁶ Btu) |
|--------------------------------|--|
| Total Hydrocarbon ^b | 0.14 |
| Carbon Monoxide | 0.37 |
| Nitrogen Oxides | 0.068 |
| Particular Matter ^c | 0-274 |
| Carbon Dioxide ^d | 60 |

- a. Based on combustion efficiency of 98 percent.
- b. Measured as methane equivalent.
- c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
- d. Carbon dioxide is measured in kg CO₂/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from \$31,600 per ton VOC to over \$3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

“(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or

(B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.”

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to “...distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing...” performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different “type” of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or
- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term “modification” means:

“any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.”

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth’s surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.
- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.^x

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be \$3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be \$1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

^x The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

| Well Completion Category | Number of Sources subject to NSPS ^a | Annual Cost Per Completion Event (\$) ^b | Nationwide Emission Reductions (tpy) ^c | | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | | Total Nationwide Costs (million \$/year) | | |
|--|--|--|---|-----------|--------|---------------------------------|--------------|-------------------------------------|--------------|--|------------------------|---------------------|
| | | | VOC | Methane | HAP | without savings | with savings | without savings | with savings | Capital Cost | Annual without savings | Annual with savings |
| Regulatory Option 5 (operational standard for REC and combustion) | | | | | | | | | | | | |
| Subcategory 1: Natural gas Completions with Hydraulic Fracturing | 9,313 | 33,237 | 204,134 | 1,399,139 | 14,831 | 1,516 | net savings | 221 | net savings | 309.5 | 309.5 | (20.24) |
| Regulatory Option 6 (operational standard for combustion) | | | | | | | | | | | | |
| Subcategory 2: Natural gas Completions with Hydraulic Fracturing | 446 | 3,523 | 9,801 | 67,178 | 712 | 160 | 160 | 23 | 23 | 1.57 | 1.57 | 1.57 |
| Regulatory Option 7 (operational standard for REC and combustion) | | | | | | | | | | | | |
| Natural Gas Well Recompletions with Hydraulic Fracturing | 12,050 | 33,237 | 264,115 | 1,810,245 | 19,189 | 1,516 | net savings | 221 | net savings | 400.5 | 400.5 | (26.18) |

Minor discrepancies may be due to rounding.

- a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
- b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
- c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around \$33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be \$309.5 million, with a net annual savings estimated around \$20 million when natural gas savings are considered. A cost of \$400.5 million was estimated for recompletions, with an overall savings of around \$26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around \$1,516 per ton, with a methane co-benefit of \$221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options^a

| Pollutant | Regulatory Options 5 ^b | | Regulatory Option 6 ^c | | Regulatory Options 7 ^b | |
|--------------------|--|---|--|---|--|---|
| | Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing | | Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing | | Natural Gas Well Recompletions with Hydraulic Fracturing | |
| | tons per event ^d | Nationwide Annual Secondary Emissions (tons/year) | tons per event ^d | Nationwide Annual Secondary Emissions (tons/year) | tons per event ^d | Nationwide Annual Secondary Emissions (tons/year) |
| Total Hydrocarbons | 0.03 | 326 | 0.66 | 296 | 0.03 | 422 |
| Carbon Monoxide | 0.09 | 861 | 1.76 | 783 | 0.09 | 1,114 |
| Nitrogen Oxides | 0.02 | 158 | 0.32 | 144 | 0.02 | 205 |
| Particulate Matter | 0.00000002 | 0.0002 | 0.011 | 5 | 0.00000002 | 0.0003 |
| Carbon Dioxide | 33.06 | 307,863 | 628 | 280,128 | 33.06 | 398,341 |

- a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.
- b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.
- c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.
- d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.¹

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-

acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized “closed loop” systems are applicable only in instances with very low pressure² and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device’s bleed stream. Since actuation emissions serve the device’s functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These “non-gas driven” pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.⁹ The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.ⁱ

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.^{3,ii} While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

ⁱ The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

ⁱⁱ All rates are listed at an assumed supply gas pressure of 20 psig.

**Table 5-1. Major Studies Reviewed for Consideration
of Emissions and Activity Data**

| Report Name | Affiliation | Year of Report | Number of Devices | Emissions Information | Control Information |
|--|----------------------------------|-----------------------|--------------------------|------------------------------|----------------------------|
| Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document ³ | EPA | 2010 | Nationwide | X | |
| Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 ^{4,5} | EPA | 2011 | Nationwide/ Regional | X | |
| Methane Emissions from the Natural Gas Industry ^{6,7,8,9} | Gas Research Institute / EPA | 1996 | Nationwide | X | |
| Methane Emissions from the Petroleum Industry (draft) ¹⁰ | EPA | 1996 | Nationwide | X | |
| Methane Emissions from the Petroleum Industry ¹¹ | EPA | 1999 | Nationwide | X | |
| Oil and Gas Emission Inventories for Western States ¹² | Western Regional Air Partnership | 2005 | Regional | X | |
| Natural Gas STAR Program ¹ | EPA | 2000-2010 | | X | X |

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI reportⁱⁱⁱ was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.¹³ The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

ⁱⁱⁱ Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)^a

| Industry Segment | High-Bleed | | | Low-Bleed | | |
|---|------------|-------|-------|-----------|-------|--------|
| | Methane | VOC | HAP | Methane | VOC | HAP |
| Natural Gas Production ^b | 6.91 | 1.92 | 0.073 | 0.26 | 0.072 | 0.003 |
| Natural Gas Transmission and Storage ^c | 3.20 | 0.089 | 0.003 | 0.24 | 0.007 | 0.0002 |
| Oil Production ^d | 6.91 | 1.92 | 0.073 | 0.26 | 0.072 | 0.003 |
| Natural Gas Processing ^e | 1.00 | 0.28 | 0.01 | 1.00 | 0.28 | 0.01 |

Minor discrepancies may be due to rounding.

- a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
- b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
- c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
- d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
- e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.⁹ Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year's total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.⁹ The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

| Industry Segment | Number of New Devices Estimated for a Typical Year ^a | | |
|---|---|---------------|--------|
| | Snap-Acting | Bleed-Devices | Total |
| Natural Gas and Oil Production ^b | 16,371 | 17,040 | 33,411 |
| Natural Gas Transmission and Storage ^c | 178 | 84 | 262 |

- a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.
- b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.
- c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)^a

| Industry Segment | Baseline Emissions from Representative New Unit (tpy) | | | Number of New Bleed Devices Expected Per Year | Nationwide Baseline Emissions from Bleeding Pneumatic (tpy) ^b | | |
|--------------------------------------|---|---------|--------|---|--|---------|-------|
| | VOC | Methane | HAP | | VOC | Methane | HAP |
| Oil and Gas Production | 1.9213 | 6.9112 | 0.0725 | 17,040 | 32,739 | 117,766 | 1,237 |
| Natural Gas Transmission and Storage | 0.09523 | 3.423 | 0.003 | 84 | 8 | 288 | 0.2 |

Minor discrepancies may be due to rounding.

- a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.
- b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

| Option | Description | Applicability/Effectiveness | Estimated Cost Range |
|---|--|--|---|
| Install Low Bleed Device in Place of High Bleed Device | Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions. | Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. | Low-bleed devices are, on average, around \$165 more than high bleed versions. |
| Convert to Instrument Air ¹⁴ | Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel. | Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions. | A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment. |
| Mechanical and Solar Powered Systems in place of Bleed device ¹⁵ | Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability. | Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable. | Depending on supply of power, costs can range from below \$1,000 to \$10,000 for entire systems. |
| Enhanced Maintenance ¹⁶ | Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions. | Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs. | Variable based on labor, time, and fuel required to travel to many remote locations. |

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.¹ This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

| Segment/Device Type | Emissions (tons/year) ^a | | |
|--------------------------------------|------------------------------------|-------|-------|
| | Methane | VOC | HAP |
| Oil and Natural Gas Production | 6.65 | 1.85 | 0.07 |
| Natural Gas Transmission and Storage | 2.96 | 0.082 | 0.002 |

Minor discrepancies may be due to rounding.

- a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,^{iv} the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.¹ As Table 5-7 indicates, the average cost for a low bleed pneumatic is \$2,553, while the average cost for a high bleed is \$2,338.^v Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of \$165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

^{iv} ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

^v Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices^a

| Device | Minimum cost (\$) | Maximum cost (\$) | Average cost (\$) | Low-Bleed Incremental Cost (\$) |
|-----------------------|--------------------------|--------------------------|--------------------------|--|
| High-bleed controller | 366 | 7,000 | 2,388 | \$165 |
| Low-bleed controller | 524 | 8,852 | 2,553 | |

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around \$23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of \$4.00 per Mcf.^{vi,17} The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately \$1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*:

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

^{vi} The average market price for natural gas in 2010 was approximately \$4.16 per Mcf. This is much less compared to the average price in 2008 of \$7.96 per Mcf. Due to the volatility in the value, a conservative savings of \$4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

**Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices
versus High Bleed Pneumatics**

| Segment | Incremental Capital Cost Per Unit (\$) ^a | Total Annual Cost Per Unit (\$/yr) ^b | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | |
|--|---|---|-----------------|---------------------------------------|-----------------|---|-----------------|
| | | without savings | with savings | without savings | with savings | without savings | with savings |
| Oil and Natural Gas Production | 165 | 23.50 | -1,519 | 13 | net savings | 4 | net savings |
| Natural Gas Transmission and Storage | 165 | 23.50 | 23.50 | 286 | 286 | 8 | 8 |

- a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
- b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.
- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.¹⁴

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent

supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.¹⁴

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.¹⁴ As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air”¹⁴ and summarized in Table 5-10.^{vii}

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

^{vii} Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems^a

| Compressor Power Requirements ^b | | | Flow Rate | Control Loops |
|--|----|------|-----------|------------------|
| Size of Unit | hp | kW | (cfm) | Loops/Compressor |
| small | 10 | 13.3 | 30 | 15 |
| medium | 30 | 40 | 125 | 63 |
| large | 75 | 100 | 350 | 175 |

- a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*¹⁴
- b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

| Instrument Air System Size | Compressor | Tank | Air Dryer | Total Capital^a | Annualized Capital^b | Labor Cost | Total Annual Costs^c | Annualized Cost of Instrument Air System |
|-----------------------------------|-------------------|-------------|------------------|----------------------------------|---------------------------------------|-------------------|---------------------------------------|---|
| Small | \$3,772 | \$754 | \$2,262 | \$16,972 | \$2,416 | \$1,334 | \$8,674 | \$11,090 |
| Medium | \$18,855 | \$2,262 | \$6,787 | \$73,531 | \$10,469 | \$4,333 | \$26,408 | \$36,877 |
| Large | \$33,183 | \$4,525 | \$15,083 | \$135,750 | \$19,328 | \$5,999 | \$61,187 | \$80,515 |

- a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.
- b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.
- c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.⁹ Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

| System Size | Number of Control Loops | Annual Emissions Reduction ^a (tons/year) | | | Value of Product Recovered (\$/year) ^b | Annualized Cost of System | | VOC Cost-effectiveness (\$/ton) | | Methane Cost-effectiveness (\$/ton) | |
|-------------|-------------------------|---|-----------------|------|---|---------------------------|--------------|---------------------------------|--------------|-------------------------------------|--------------|
| | | VOC | CH ₄ | HAP | | without savings | with savings | without savings | with savings | without savings | with savings |
| Small | 15 | 4.18 | 15 | 0.16 | 3,484 | 11,090 | 7,606 | 2,656 | 1,822 | 738 | 506 |
| Medium | 63 | 17.5 | 63 | 0.66 | 14,632 | 36,877 | 22,245 | 2,103 | 1,269 | 585 | 353 |
| Large | 175 | 48.7 | 175 | 1.84 | 40,644 | 80,515 | 39,871 | 1,653 | 819 | 460 | 228 |

Minor discrepancies may be due to rounding.

- a. Based on the emissions mitigated from the entire system, which includes multiple control loops.
- b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of \$4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of \$166,000. When savings are realized the net annual cost is reduced to around \$114,000. Regulatory Option 2 has nationwide annual costs of \$320,000 for the production segment and around \$1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of \$20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

| Industry Segment | Number of Sources subject to NSPS* | Capital Cost Per Device/IAS (\$)** | Annual Costs (\$/year) | | Nationwide Emission Reductions (tpy)† | | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | | Total Nationwide Costs (\$/year) | | |
|---|------------------------------------|------------------------------------|------------------------|--------------|---------------------------------------|---------|-----|---------------------------------|--------------|-------------------------------------|--------------|----------------------------------|------------------------|---------------------|
| | | | without savings | with savings | VOC | Methane | HAP | without savings | with savings | without savings | with savings | Capital Cost | Annual without savings | Annual with savings |
| Regulatory Option 1 (emission threshold equal to 0 scfh) | | | | | | | | | | | | | | |
| Natural Gas Processing | 15 | 16,972 | 11,090 | 7,606 | 63 | 225 | 2 | 2,656 | 1,822 | 738 | 506 | 254,576 | 166,351 | 114,094 |
| Regulatory Option 2 (emission threshold equal to 6 scfh) | | | | | | | | | | | | | | |
| Oil and Natural Gas Production | 13,632 | 165 | 23 | (1,519) | 25,210 | 90,685 | 952 | 13 | net savings | 4 | net savings | 2,249,221 | 320,071 | (20,699,918) |
| Natural Gas Transmission and Storage | 67 | 165 | 23 | 23 | 6 | 212 | 0.2 | 262 | 262 | 7 | 7 | 11,039 | 1,539 | 1,539 |

Minor discrepancies may be due to rounding.

- a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).
- b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.
- c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

- 1 U.S. Environmental Protection Agency. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004
- 2 Memorandum to Bruce Moore from Denise Grubert. Meeting Minutes from EPA Meeting with the American Petroleum Institute. October 2011
- 3 U.S. Environmental Protection Agency. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC. November 2010.
- 4 U.S. Environmental Protection Agency. Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.
- 5 U.S. Environmental Protection Agency. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.
- 6 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.
- 7 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080c. June 1996.
- 8 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080e. June 1996.
- 9 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.
- 10 Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. Environmental Protection Agency, June 14, 1996.
- 11 ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. Environmental Protection Agency. 1999.
- 12 ENVIRON International Corporation. Oil and Gas Emission Inventories for the Western States. Prepared for Western Governors' Association. December 27, 2005.
- 13 Memorandum to Bruce Moore from Heather Brown. Gas Composition Methodology. July 2011

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- 14 U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004
 - 15 U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.
 - 16 CETAC WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.
 - 17 U.S. Energy Information Administration. Annual U.S. Natural Gas Wellhead Price. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <<http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>>

6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the

atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs. The opposing forces create a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study¹ and use the methane to pollutant ratios developed in the gas composition memorandum.² The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

**Table 6-1. Major Studies Reviewed for Consideration
Of Emissions and Activity Data**

| Report Name | Affiliation | Year of Report | Activity Information | Emissions Information | Control Information |
|--|----------------------------|-----------------------|-----------------------------|------------------------------|----------------------------|
| Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 ¹ | EPA | 2010 | Nationwide | X | |
| Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document ² | EPA | 2010 | Nationwide | X | |
| Methane Emissions from the Natural Gas Industry ³ | Gas Research Institute/EPA | 1996 | Nationwide | X | |
| Natural Gas STAR Program ^{4,5} | EPA | 1993-2010 | Nationwide | X | X |

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

| Oil and Gas Industry Segment | Reciprocating Compressors | | | Centrifugal Compressors | |
|------------------------------|---|-----------------------------|--|---|--|
| | Methane Emission Factor (scf/hr-cylinder) | Average Number of Cylinders | Pressurized Factor (% of hour/year Compressor Pressurized) | Wet Seal Methane Emission Factor (scf/minute) | Dry Seals Methane Emission Factor (scf/minute) |
| Production (Well Pads) | 0.271 ^a | 4 | 100% | N/A ^f | N/A ^f |
| Gathering & Boosting | 25.9 ^b | 3.3 | 79.1% | N/A ^f | N/A ^f |
| Processing | 57 ^c | 2.5 | 89.7% | 47.7 ^g | 6 ^g |
| Transmission | 57 ^d | 3.3 | 79.1% | 47.7 ^g | 6 ^g |
| Storage | 51 ^e | 4.5 | 67.5% | 47.7 ^g | 6 ^g |

- a. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-8.
- b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. (Draft): 2006.
- c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
- d. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.
- e. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.
- f. The 1996 EPA/GRI Study Volume 11³, does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
- g. U.S Environmental Protection Agency. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3. Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

| Industry Segment/ Compressor Type | Baseline Emission Estimates (tons/year) | | |
|--|--|--------|---------|
| | Methane | VOC | HAP |
| <i>Reciprocating Compressors</i> | | | |
| Production (Well Pads) | 0.198 | 0.0549 | 0.00207 |
| Gathering & Boosting | 12.3 | 3.42 | 0.129 |
| Processing | 23.3 | 6.48 | 0.244 |
| Transmission | 27.1 | 0.751 | 0.0223 |
| Storage | 28.2 | 0.782 | 0.0232 |
| <i>Centrifugal Compressors (Wet seals)</i> | | | |
| Processing | 228 | 20.5 | 0.736 |
| Transmission | 126 | 3.50 | 0.104 |
| Storage | 126 | 3.50 | 0.104 |
| <i>Centrifugal Compressors (Dry seals)</i> | | | |
| Processing | 28.6 | 2.58 | 0.0926 |
| Transmission | 15.9 | 0.440 | 0.0131 |
| Storage | 15.9 | 0.440 | 0.0131 |

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.⁴ A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,^{5,6} with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.⁷ The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,⁸ the

Table 6-4. Approximate Number of New Sources in the Oil and Gas Industry in 2008

| Industry Segment | Number of New Reciprocating Compressors | Number of New Centrifugal Compressors |
|-------------------------|--|--|
| Wellheads | 6,000 | 0 |
| Gathering and Boosting | 210 | 0 |
| Processing | 209 | 16 |
| Transmission | 20 | 14 |
| Storage | 4 | |

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database⁹ between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S. Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.^{10,11} The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory^{12,13} data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory. For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5. Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

| Industry Segment/ Compressor Type | Nationwide baseline Emissions (tons/year) | | |
|--------------------------------------|--|-------|--------|
| | Methane | VOC | HAP |
| <i>Reciprocating Compressors</i> | | | |
| Production (Well Pads) | 1,186 | 330 | 12.4 |
| Gathering & Boosting | 2,587 | 719 | 27.1 |
| Processing | 4,871 | 1,354 | 51.0 |
| Transmission | 529 | 14.6 | 0.435 |
| Storage | 113 | 3.13 | 0.0929 |
| <i>Centrifugal Compressors</i> | | | |
| Processing | 3,640 | 329 | 11.8 |
| Transmission/Storage | 1,768 | 48.9 | 1.45 |

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate option for reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.¹⁴ Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. “Beam” type compressors have two seals, one on each end of the compressor, while “over-hung” compressors have a seal on only the “inboard” (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes “O-ring” rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the “inboard” (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering

and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6} \quad \text{Equation 1}$$

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);

$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors in Table 6-2, in cubic feet per hour per cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder¹⁵ for this analysis;

C = Average number of cylinders for gathering and boosting compressors in Table 6-2;

O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;

8760 = Number of days in a year;

10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well} (E_{Well}) \times C \times O \times 8760}{10^6} \left(\frac{E_{Trans} - E_{New}}{E_{Trans}} \right) \quad \text{Equation 2}$$

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);

$Comp_{New}^{Well}$ = Number of new wellhead compressors;

E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;

C = Average number of cylinders for wellhead compressors in Table 6-2;

O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder¹⁶ for this analysis;

8760 = Number of days in a year;

10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6} \quad \text{Equation 3}$$

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);

$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;

$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder¹⁷ for this analysis;

C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;

O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;

8760 = Number of days in a year;

10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition¹⁸ for each of the segments.

Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6. Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

| Oil & Gas Segment | Number of New Sources Per Year | Individual Compressor Emission Reductions (tons/compressor-year) | | | Nationwide Emission Reductions (tons/year) | | |
|------------------------|--------------------------------|--|--------|---------|--|-------|--------|
| | | Methane | VOC | HAP | Methane | VOC | HAP |
| Production (Well Pads) | 6,000 | 0.158 | 0.0439 | 0.00165 | 947 | 263 | 9.91 |
| Gathering & Boosting | 210 | 6.84 | 1.90 | 0.0717 | 1,437 | 400 | 15.1 |
| Processing | 375 | 18.6 | 5.18 | 0.195 | 3,892 | 1,082 | 40.8 |
| Transmission | 199 | 21.7 | 0.600 | 0.0178 | 423 | 11.7 | 0.348 |
| Storage | 9 | 21.8 | 0.604 | 0.0179 | 87.3 | 2.42 | 0.0718 |

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document¹⁹ which estimated the cost to replace the packing rings to be \$1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing placement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program.²⁰ The cost impacts are based on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of \$1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of \$4.00 per Mcf.²¹ This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

| Oil and Gas Segment | Capital Cost (\$2008) | Annual Cost per Compressor (\$/compressor-year) | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | |
|----------------------|-----------------------|---|--------------|---------------------------------|--------------|-------------------------------------|--------------|
| | | Without savings | With savings | Without savings | With savings | Without savings | With savings |
| Production | \$6,480 | \$2,493 | \$2,457 | \$56,847 | \$56,013 | \$15,802 | \$15,570 |
| Gathering & Boosting | \$5,346 | \$1,669 | \$83 | \$877 | \$43 | \$244 | \$12 |
| Processing | \$4,050 | \$1,413 | -\$2,903 | \$273 | -\$561 | \$76 | -\$156 |
| Transmission | \$5,346 | \$1,669 | N/A | \$2,782 | N/A | \$77 | N/A |
| Storage | \$7,290 | \$2,276 | N/A | \$3,766 | N/A | \$104 | N/A |

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- **Gas Leak Rates.** During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.²² While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.^{23,24}
- **Mechanically Simpler.** Dry seal systems do not require additional oil circulation components and treatment facilities.

- **Reduced Power Consumption.** Because dry seals have no accessory oil circulation pumps and systems, they avoid “parasitic” equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- **Improved Reliability.** The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- **Lower Maintenance.** Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- **Elimination of Oil Leakage from Wet Seals.** Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.²⁵ Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.²⁶ The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.²⁷ A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between \$50,000 and \$100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

| Oil & Gas Segment | Number of New Sources Per Year | Individual Compressor Emission Reductions (ton/compressor-year) | | | Nationwide Emission Reductions (ton/year) | | |
|----------------------|--------------------------------|---|------|--------|---|------|------|
| | | Methane | VOC | HAP | Methane | VOC | HAP |
| Transmission/Storage | 16 | 199 | 18.0 | 0.643 | 3,183 | 287 | 10.3 |
| Storage | 14 | 110 | 3.06 | 0.0908 | 1,546 | 42.8 | 1.27 |

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000. The annual cost was calculated as the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to \$10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is \$88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of \$4.00 per Mcf.²⁸ This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped with wet seals is to route the emissions to a combustion device or capture the emissions and route them to a fuel system. A wet seal system uses oil that is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

| Oil and Gas Segment | Capital Cost (\$2008) | Annual Cost per Compressor (\$/compressor-yr) | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | |
|----------------------|-----------------------|---|--------------------------|---------------------------------|--------------------------|-------------------------------------|--------------------------|
| | | without savings | with O&M and gas savings | without savings | with O&M and gas savings | without savings | with O&M and gas savings |
| Processing | \$75,000 | \$10,678 | -\$123,730 | \$595 | -\$6,892 | \$54 | -\$622 |
| Transmission/Storage | \$75,000 | \$10,678 | -\$77,622 | \$3,495 | -\$25,405 | \$97 | -\$703 |

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.²⁹ The heat content of the gas stream was calculated using information from the gas composition memorandum.³⁰ A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_x), carbon dioxide (CO₂), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

| Oil & Gas Segment | Number of New Sources Per Year | Individual Compressor Emission Reductions (tons/compressor-year) | | | Nationwide Emission Reductions (tons/year) | | |
|----------------------|--------------------------------|--|------|--------|--|------|------|
| | | Methane | VOC | HAP | Methane | VOC | HAP |
| Processing | 16 | 216 | 19.5 | 0.699 | 3,283 | 296 | 10.6 |
| Transmission/Storage | 14 | 120 | 3.32 | 0.0986 | 1,596 | 44.2 | 1.31 |

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

| Industry Segment | Secondary Impacts from Wet Seals Equipped with a Flare (tons/year) | | | | |
|-------------------------|---|------------------------|-----------------------|------------------------|---------------------------|
| | Total Hydrocarbons | Carbon Monoxide | Carbon Dioxide | Nitrogen Oxides | Particulate Matter |
| Processing | 0.0289 | 0.0205 | 7.33 | 0.00377 | Negligible |
| Transmission/Storage | 0.00960 | 0.00889 | 3.18 | 0.00163 | Negligible |

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

| Oil and Gas Segment | Capital Cost (\$2008) | Annual Cost per Compressor (\$/compressor-year) | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | |
|----------------------|-----------------------|---|------------------|---------------------------------|------------------|-------------------------------------|------------------|
| | | without savings | with gas savings | without savings | with gas savings | without savings | with gas savings |
| Processing | \$67,918 | \$103,371 | N/A | \$5,299 | N/A | \$478 | N/A |
| Transmission/Storage | \$67,918 | \$103,371 | N/A | \$31,133 | N/A | \$862 | N/A |

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on 26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from \$56,847 for reciprocating compressors located at production pads to \$273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were \$877, \$2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be \$595 for centrifugal compressors located at processing plants, and \$3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these

pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were \$5,299 and \$31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

| Oil & Gas Segment | Number of New Sources Per Year | Nationwide Emission Reductions (tons/year) | | | Total Nationwide Costs | | |
|----------------------|--------------------------------|--|---------|--------|------------------------|-------------------------------------|----------------------------------|
| | | VOC | Methane | HAP | Capital Cost (\$) | Annual Cost without savings (\$/yr) | Annual Cost with savings (\$/yr) |
| Gathering & Boosting | 210 | 400 | 1,437 | 15.1 | \$1,122,660 | \$350,503 | \$17,337 |
| Processing | 209 | 1,082 | 3,892 | 40.8 | \$846,450 | \$295,397 | -\$606,763 |
| Transmission | 20 | 11.7 | 423 | 0.348 | \$104,247 | \$32,547 | \$32,547 |
| Storage | 4 | 2.42 | 87.3 | 0.0718 | \$29,160 | \$9,104 | \$9,104 |

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

| Oil & Gas Segment | Number of New Sources Per Year | Nationwide Emission Reductions ¹ (tons/year) | | | Total Nationwide Costs ^a | | |
|------------------------|--------------------------------|--|---------|--------|-------------------------------------|-----------------------------------|----------------------------------|
| | | VOC | Methane | HAP | Capital Cost (\$) | Annual Cost w/o Savings (\$/year) | Annual Cost w/ Savings (\$/year) |
| Production (Well Pads) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gathering & Boosting | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Processing | 16 | 118 | 422 | 4.42 | \$100,196 | \$14,266 | -\$120,144 |
| Transmission/Storage | 14 | 3.24 | 117 | 0.0962 | \$50,098 | \$7,133 | -\$37,017 |

- a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located at a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directed to a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage vessel from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located at tank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.¹ For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.^{2,3} Therefore, 2008 was chosen to represent the base year for this impacts analysis. To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

| Report Name | Affiliation | Year of Report | Activity Factors | Emission Figures | Control Information |
|---|---|-----------------------|-------------------------|-------------------------|----------------------------|
| VOC Emissions from Oil and Condensate Storage Tanks ⁴ | Texas Environmental Research Consortium | 2009 | Regional | X | X |
| Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks ⁵ | EPA | 2003 | National | | X |
| Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report ⁶ | Texas Commission on Environmental Quality | 2009 | Regional | X | |
| Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission’s Regulation Number ⁷ | Colorado | 2008 | n/a | | X |
| E&P TANKS ⁸ | American Petroleum Institute | | National | X | |
| Inventory of U.S. Greenhouse Gas Emissions and Sinks ^{2,3} | EPA | 2008 and 2009 | National | X | |

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992 to 124 MMbbl/yr in 2008. This increase in condensate production was then distributed across the model condensate tank batteries in the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 *Model Crude Oil Tank Batteries*

According to the Natural Gas STAR program,⁵ there were 573,000 crude oil storage tanks in 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries. Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 *VOC Emissions from Condensate and Crude Oil Storage Vessels*

Once the model condensate and crude oil tank battery distributions were developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.⁸ A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

| Parameter | Model Condensate Tank Battery | | | |
|---|--------------------------------------|----------|----------|-----------|
| | E | F | G | H |
| Condensate throughput (bbl/day) ^a | 15 | 100 | 1,000 | 5,000 |
| Condensate throughput (bbl/yr) ^a | 5,475 | 36,500 | 365,000 | 1,825,000 |
| Number of fixed-roof product storage vessels ^a | | | | |
| 210 barrel capacity | 4 | 2 | | |
| 500 barrel capacity | | 2 | 2 | |
| 1,000 barrel capacity | | | 2 | 4 |
| Estimated tank battery population (1992) ^a | 12,000 | 500 | 100 | 70 |
| Estimated tank battery population (2008) ^b | 14,038 | 585 | 117 | 82 |
| Total number of storage vessels (2008) ^b | 56,151 | 2,340 | 468 | 328 |
| Percent of number of storage vessels in model condensate tank battery | 94.7% | 3.95% | 0.789% | 0.552% |
| Percent of throughput per model condensate tank battery ^a | 26% | 7% | 15% | 51% |
| Total tank battery condensate throughput (MMbbl/yr) ^c | 32.8 | 9.11 | 18.2 | 63.8 |
| Condensate throughput per model condensate battery (bbl/day) | 6.41 | 42.7 | 427 | 2,135 |
| Condensate throughput per storage vessel (bbl/day) | 1.60 | 10.7 | 106.8 | 534 |

Minor discrepancies may be due to rounding.

- a. Developed for NESHAP (Reference 1).
- b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References 2,3).
- c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

| Parameter | Model Crude Oil Tank Battery | | | |
|--|-------------------------------------|----------|----------|----------|
| | E | F | G | H |
| Percent of number of condensate storage vessels in model size range ^a | 94.7% | 3.95% | 0.789% | 0.552% |
| Number of storage vessels ^b | 491,707 | 20,488 | 4,098 | 2,868 |
| Percent of throughput across condensate tank batteries | 26% | 7% | 15% | 51% |
| Crude oil throughput per model plant category (MMbbl/yr) | 351 | 97.5 | 195 | 683 |
| Crude oil throughput per storage vessel (bbl/day) | 1.96 | 13.0 | 130 | 652 |

Minor discrepancies may be due to rounding.

- a. Same relative percent of storage vessel population developed for model condensate tank batteries. Refer to Table 7-2.
- b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).
- c. Same relative percent of throughput developed for model condensate tank batteries. Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.⁹

The more than 100 storage vessels provided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissions was studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.ⁱ While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A. Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.ⁱⁱ An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

ⁱ The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.

ⁱⁱ This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

| Parameter^a | | Average of Dataset | Average of Storage Vessels with API Gravity > 40 degrees | Average of Storage Vessels with API Gravity ≤ 40 degrees |
|------------------------------|--------------------------|---------------------------|--|---|
| Throughput Rate (bbl) | | 500 | 500 | 500 |
| API Gravity | | 40.6 | 52.8 | 30.6 |
| VOC | Emissions (tons/year) | 531 | 1046 | 107 |
| | Emission factor (lb/bbl) | 5.8 | 11.5 | 1.18 |

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

| Parameter | Model Tank Battery | | | |
|--|--------------------|------|-----|------|
| | E | F | G | H |
| Model Condensate Tank Batteries | | | | |
| Condensate throughput per storage vessel (bbl/day) | 1.60 | 10.7 | 107 | 534 |
| VOC Emissions (tons/year) ^b | 3.35 | 22.3 | 223 | 1117 |
| Model Crude Oil Tank Batteries | | | | |
| Crude Oil throughput per storage vessel (bbl/day) ^c | 2.0 | 13 | 130 | 652 |
| VOC Emissions (tons/year) ^d | 0.4 | 2.80 | 28 | 140 |

- a. Condensate throughput per storage vessel from table 7-2.
- b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.
- c. Crude oil throughput per storage vessel from table 7-3.
- d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.¹⁰ Therefore, using the forecast function in Microsoft Excel®, crude oil production was predicted for the year 2015.ⁱⁱⁱ From 2009 to 2015,^{iv} the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

ⁱⁱⁱ The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.

^{iv} For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

| | Model Tank Battery | | | | |
|--|---------------------------|----------|----------|----------|--------------|
| | E | F | G | H | Total |
| Model Condensate Tank Batteries | | | | | |
| Total number of storage vessels (2008) | 56,151 | 2,340 | 468 | 328 | 59,286 |
| Total projected number of new or modified storage vessels (2015) ^a | 4,630 | 193 | 39 | 27 | 4,889 |
| Number of uncontrolled storage vessels in absence of federal regulation ^b | 1,688 | 70 | 14 | 10 | 1,782 |
| Uncontrolled VOC Emissions from storage vessel at model tank battery ^c | 3.35 | 22.3 | 223 | 1,117 | 1,366 |
| Total Nationwide Uncontrolled VOC Emissions | 5,657 | 1,572 | 3,143 | 11,001 | 21,373 |
| Model Crude Oil Tank Batteries | | | | | |
| Total number of storage vessels (2008) | 491,707 | 20,488 | 4,098 | 2,868 | 519,161 |
| Total projected number of new or modified storage vessels (2015) ^a | 40,548 | 1,689 | 338 | 237 | 42,812 |
| Number of uncontrolled storage vessels in absence of federal regulation ^b | 14,782 | 616 | 123 | 86 | 15,607 |
| Uncontrolled VOC Emissions from storage vessel at model tank battery ^c | 0.4 | 2.80 | 28 | 140 | 171 |
| Total Nationwide Uncontrolled VOC Emissions | 6,200 | 1,722 | 3,444 | 12,055 | 23,421 |

Minor discrepancies may be due to rounding

- a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
- b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
- c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used. Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.¹¹ There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels. These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation. As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically

recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.⁵

7.4.2.2 *Effectiveness*

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.**Error! Bookmark not defined.**A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 *Cost Impacts*

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.⁷Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).¹² According to the EIA, the purchased equipment cost of a VRU was estimated to be \$85,423 (escalated to 2008 dollars from \$75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be \$98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be \$18,983/year.

7.4.2.4 *Secondary Impacts*

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

| Cost Item^a | Capital Costs (\$) | Non-Recurring, One-time Costs (\$) | Total Capital Investment (\$)^b | O&M Costs (\$) | Savings due to Fuel Sales (\$/yr) | Annualized Total Cost (\$/yr)^c |
|--|---------------------------|---|--|---------------------------|--|--|
| VRU | \$78,000 | | | | | |
| Freight and Design | | \$1,500 | | | | |
| VRU Installation | | \$10,154 | | | | |
| Maintenance | | | | \$8,553 | | |
| Recovered natural gas | | | | | (\$1,063) | |
| Subtotal Costs (2007) | \$78,000 | \$11,654 | | \$8,553 | (\$1,063) | |
| Subtotal Costs (2008) ^d | \$85,423 | \$12,763 | \$98,186 | \$9,367 | (\$1,164) | |
| Annualized costs (using 7% interest, 15 year equipment life) | \$9,379 | \$1,401 | | n/a | n/a | \$18,983 |

Minor discrepancies may be due to rounding

- a. Assume cost data provided is for the year 2007. Reference 7.
- b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
- c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
- d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels. The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.¹³ Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.¹⁴ For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.⁷ Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.⁷ As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).¹² According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be \$23,699 (escalated to 2008 dollars from \$21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be \$32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be \$8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.¹³ These emissions factors, however, are the best indication for secondary pollutants from combustors currently available. The secondary emissions per storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

| Cost Item^a | Capital Costs (\$) | Non-Recurring, One-time Costs (\$) | Total Capital Investment (\$)^b | O&M Costs (\$) | Annualized Total Cost (\$/yr)^c |
|--|---------------------------|---|--|---------------------------|--|
| Combustor | \$16,540 | | | | |
| Freight and Design | | \$1,500 | | | |
| Combustor Installation | | \$6,354 | | | |
| Auto Igniter | \$1,500 | | | | |
| Surveillance System ^d | \$3,600 | | | | |
| Pilot Fuel | | | | \$1,897 | |
| Maintenance | | | | \$2,000 | |
| Data Management | | | | \$1,000 | |
| Subtotal Costs (2007) | \$21,640 | \$7,854 | | \$4,897 | |
| Subtotal Costs (2008) ^e | \$23,699 | \$8,601 | \$32,301 | \$5,363 | |
| Annualized costs (using 7% interest, 15 year equipment life) | \$2,602 | \$944 | | n/a | \$8,909 |

Minor discrepancies may be due to rounding

- a. Assume cost data provided is for the year 2007. Reference 7.
- b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
- c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
- d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
- e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

| Pollutant | Emission Factor | Units | Emissions per Storage Vessel (tons/year)^a |
|------------------|------------------------|--|---|
| THC | 0.14 | lb/MMBtu | 0.0061 |
| CO | 0.37 | lb/MMBtu | 0.0160 |
| CO ₂ | 60 | Kg/MMBtu ^b | 5.62 |
| NO _x | 0.068 | lb/MMBtu | 2.95E-03 |
| PM | 40 | µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke) | 5.51E-05 |

- a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.
- b. CO₂ emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustor is an option for tank batteries because of the operational issues associated with a VRU as discussed above. However the use of a VRU is preferable to a combustor because a combustor destroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium¹⁵ was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used. Using the throughput for each control option, an equivalent emissions limit was determined. Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

| Regulatory Option | Throughput Cutoff (bbl/day) | Equivalent Emissions Cutoff (tons/year)^a | Emission Reduction (tons/year)^b | Annual Costs for VRU (\$/yr)^c | Cost Effectiveness (\$/ton) | Number of impacted units^d |
|--------------------------|------------------------------------|--|---|---|------------------------------------|---|
| 1 | 0.5 | 3.0 | 2.89 | \$18,983 | \$6,576 | 1782 |
| 2 | 1 | 6.1 | 5.77 | \$18,983 | \$3,288 | 94 |
| 3 | 2 | 12.2 | 11.55 | \$18,983 | \$1,644 | 94 |
| 4 | 5 | 30.4 | 28.87 | \$18,983 | \$658 | 24 |

Minor discrepancies may be due to rounding

- a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
- b. Calculated using 95 percent reduction
- c. Refer to Table 7-7 for VRU Annual Costs.
- d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day. Therefore Regulatory Option 1 is rejected. Since the cost effectiveness associated with Regulatory Option 2 is acceptable (\$3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);
- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected. Since the cost effectiveness associated with Regulatory Option 3 is acceptable (\$3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel Categories G and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

| Regulatory Option | Throughput Cutoff (bbl/day) | Equivalent Emissions Cutoff (tons/year)^a | Emission Reduction (tons/year)^b | Annual Costs for VRU (\$/yr)^c | Cost Effectiveness (\$/ton) | Number of impacted units^d |
|--------------------------|------------------------------------|--|---|---|------------------------------------|---|
| 1 | 1 | 0.3 | 0.28 | \$18,983 | \$68,432 | 15607 |
| 2 | 5 | 1.5 | 1.4 | \$18,983 | \$13,686 | 825 |
| 3 | 20 | 5.8 | 5.55 | \$18,983 | \$3,422 | 209 |
| 4 | 50 | 14.6 | 13.87 | \$18,983 | \$1,369 | 209 |

Minor discrepancies may be due to rounding

- a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
- b. Calculated using 95 percent reduction
- c. Refer to Table 7-7 for VRU Annual Costs.
- d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels. In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option 2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.
- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables 7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulations and impacted by Regulatory Option 2 (condensate storage vessels). As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

| Model Tank Battery | Number of Sources subject to Regulatory Option ^a | VOC Emissions for a Typical Storage Vessel (tons/year) | Capital Cost for Typical Storage Vessel ^b (\$) | Annual Cost for a Typical Storage Vessel ^b (\$/yr) | | Nationwide Emission Reductions (tons/year) ^c | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | | Total Nationwide Costs (million \$/year) | | |
|--|---|--|---|---|---------------|---|----------------------|---------------------------------|--------------|-------------------------------------|--------------|--|------------------------|---------------------|
| | | | | without savings | with savings | VOC | Methane ^d | without savings | with savings | without savings | with savings | Capital Cost | Annual without savings | Annual with savings |
| Regulatory Option 2: Condensate Storage Vessels | | | | | | | | | | | | | | |
| F | 70 | 22.3 | 65,243 | 14,528 | 13,946 | 1,483 | 325 | 685 | 658 | 3129 | 3004 | 4.57 | 1.02 | 0.98 |
| G | 14 | 223 | 65,243 | 14,528 | 13,946 | 2,966 | 649 | 68 | 66 | 313 | 301 | 0.913 | 0.203 | 0.195 |
| H | 10 | 1117 | 65,243 | 14,528 | 13,946 | 10,612 | 2,322 | 14 | 13 | 62.6 | 60.1 | 0.652 | 0.145 | 0.139 |
| Total for Regulatory Option 2 | | | | | | 15,061 | 3,296 | | | | | 6.14 | 1.37 | 1.31 |
| Regulatory Option 3: Crude Oil Storage Vessels | | | | | | | | | | | | | | |
| G | 123 | 28 | 65,243 | 14,528 | 13,946 | 3,272 | 716 | 546 | 524 | 2496 | 2396 | 8.02 | 1.79 | 1.71 |
| H | 86 | 140 | 65,243 | 14,528 | 13,946 | 11,438 | 2,503 | 109 | 104 | 499 | 479 | 5.61 | 1.25 | 1.20 |
| Total for Regulatory Option 3 | | | | | | 14,710 | 3,219 | | | | | 13.6 | 3.04 | 2.91 |
| Combined Impacts^e | | | | | | | | | | | | | | |
| Typical Storage Vessel | 304 | 103 | 65,243 | 14,528 | 13,946 | 29,746 | 6,490 | 149 | 143 | 680 | 652 | 19.8 | 4.41 | 4.24 |

Minor discrepancies may be due to rounding

- a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.
- b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.
- c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.
- d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A). Methane:VOC = 0.219
- e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be \$65,243 (the average of the total capital investment for a VRU of \$98,186 and \$32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be \$14,528/yr (average of the total annual cost for a VRU of \$20,147/yr and \$8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and \$13,946/yr (average of the total annual cost for a VRU of \$18,983/yr and \$8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be \$6.14 million and for Regulatory Option 3 (crude oil storage vessels) nationwide capital cost was estimated to be \$13.6 million. Total annual costs without fuel savings were estimated to be \$1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and \$3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be \$1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and \$2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year). Therefore, the nationwide annual costs were estimated to be \$4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of \$149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

| Pollutant | Emissions per Storage Vessel (tons/year)^a | Nationwide Emissions (tons/year)^b |
|------------------|---|---|
| THC | 0.0061 | 0.927 |
| CO | 0.0160 | 2.43 |
| CO ₂ | 5.62 | 854 |
| NO _x | 2.95E-03 | 0.448 |
| PM | 5.51E-05 | 0.0084 |

- a. Emissions per storage vessel presented in Table 7-9.
- b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

7.6 References

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for “model” facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.^{1,2,3} In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA’s analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458). These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

| Report Name | Affiliation | Year of Report | Activity Factor (s) | Emissions Data | Control Options |
|--|--|-----------------------|----------------------------|-----------------------|------------------------|
| Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents | EPA | 2010 | Nationwide | X | X |
| Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 ⁴ | EPA | 2010 | Nationwide | X | |
| Methane Emissions from the Natural Gas Industry ^{5,6,7} | Gas Research Institute / EPA | 1996 | Nationwide | X | X |
| Methane Emissions from the US Petroleum Industry (Draft) ⁸ | EPA | 1996 | Nationwide | X | |
| Methane Emissions from the US Petroleum Industry ⁹ | EPA | 1999 | Nationwide | X | |
| Oil and Gas Emission Inventories for Western States ¹⁰ | Western Regional Air Partnership | 2005 | Regional | X | X |
| Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories ¹¹ | Central States Regional Air Partnership | 2008 | Regional | X | X |
| Oil and Gas Producing Industry in Your State ¹² | Independent Petroleum Association of America | 2009 | Nationwide | | |
| Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements ¹³ | Environmental Defense Fund | 2009 | Regional | X | X |
| Emissions from oil and Natural Gas Production Facilities ¹⁴ | Texas Commission for Environmental Quality | 2007 | Regional | X | X |
| Petroleum and Natural Gas Statistical Data ¹⁵ | U.S. Energy Information Administration | 2007-2009 | Nationwide | | |
| Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations ¹⁶ | EPA | 1999 | | X | X |
| Protocol for Equipment Leak Emission Estimates ¹⁷ | EPA | 1995 | Nationwide | X | X |

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.⁴The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average number of other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI document. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressor seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2. Average Equipment Count for Oil and Gas Production Well Pad Model Plants

| Equipment | Model Plant 1 | Model Plant 2 | Model Plant 3 |
|------------------|----------------------|----------------------|----------------------|
| Gas Wellheads | 1 | 5 | 48 |
| Separators | --- | 4 | 40 |
| Meter/Piping | --- | 2 | 24 |
| In-Line Heaters | --- | 2 | 26 |
| Dehydrators | --- | 2 | 19 |

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3. Average Component Count for Oil and Gas Production Well Pad Model Plants

| Component | Model Plant 1 | Model Plant 2 | Model Plant 3 | Model Plant 4 |
|-----------------------|----------------------|----------------------|----------------------|----------------------|
| Valve | 9 | 122 | 235 | 348 |
| Connectors | 37 | 450 | 863 | 1,276 |
| Open-Ended Line | 1 | 15 | 29 | 43 |
| Pressure Relief Valve | 0 | 5 | 10 | 15 |

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4. Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

| Equipment | Model Plant 1 | Model Plant 2 | Model Plant 3 |
|-----------------------|----------------------|----------------------|----------------------|
| Separators | 7 | 11 | 15 |
| Meter/Piping | 4 | 7 | 10 |
| Gathering Compressors | 3 | 5 | 7 |
| In-Line Heaters | 4 | 7 | 10 |
| Dehydrators | 3 | 5 | 7 |

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

| Component | Model Plant 1 | Model Plant 2 | Model Plant 3 |
|-----------------------|----------------------|----------------------|----------------------|
| Valve | 547 | 906 | 1,265 |
| Connectors | 1,723 | 2,864 | 4,005 |
| Open-Ended Line | 51 | 83 | 115 |
| Pressure Relief Valve | 29 | 48 | 67 |

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 *Oil and Natural Gas Processing*

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 *Natural Gas Transmission/Storage*

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.⁵ Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6. Average Component Count for Oil and Gas Processing Model Plant

| Component | Gas Plant (non-compressor components) |
|-----------------------|--|
| Valve | 1,392 |
| Connectors | 4,392 |
| Open-Ended Line | 134 |
| Pressure Relief Valve | 29 |

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7. Average Component Count for a Gas Transmission Facility

| Component | Processing Plant Component Count |
|-----------------------|---|
| Valve | 704 |
| Connection | 3,068 |
| Open-Ended Line | 55 |
| Pressure Relief Valve | 14 |

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

| Component Type | Component Service | Emission Factor (kg/hr/source) |
|-----------------------|--------------------------|---|
| Valves | Gas | 4.5E-03 |
| Connectors | Gas | 2.0E-04 |
| Open-Ended Line | Gas | 2.0E-03 |
| Pressure Relief Valve | Gas | 8.8E-03 |

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995.
(EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.⁶ A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

| Component Type | Component Service | Emission Factor (kg/hr/source) |
|-----------------------|--------------------------|---|
| Valves | Gas | 5.5E-03 |
| Connectors | Gas | 9.3E-04 |
| Open-Ended Line | Gas | 7.1E-02 |
| Pressure Relief Valve | Gas | 3.98E-02 |

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

| Oil and Gas Sector | Model Plant | TOC Emissions (Tons/yr) | Methane Emissions (Tons/yr) | VOC Emissions (Tons/yr) | HAP Emissions (Tons/yr) |
|---------------------------|--------------------|------------------------------------|--|------------------------------------|------------------------------------|
| Well Pads | 1 | 0.482 | 0.335 | 0.0930 | 0.00351 |
| | 2 | 13.3 | 9.24 | 2.56 | 0.0967 |
| | 3 | 139 | 96.5 | 26.8 | 1.01 |
| Gathering & Boosting | 1 | 30.5 | 21.2 | 5.90 | 0.222 |
| | 2 | 50.6 | 35.2 | 9.76 | 0.368 |
| | 3 | 70.6 | 49.1 | 13.6 | 0.514 |
| Processing | 1 | 74.0 | 51.4 | 14.3 | 0.539 |
| Transmission/Storage | 1 | 108.1 | 98.1 | 2.71 | 0.0806 |

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIA predicts a 1.03 tcf/year increase in natural gas processing from 21.07 to 22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

| Oil and Gas Sector | Model Plant | Number of New Facilities | TOC Emissions (tons/yr) | Methane Emissions (tons/yr) | VOC Emissions (tons/yr) | HAP Emissions (tons/yr) |
|---------------------------|--------------------|---------------------------------|--------------------------------|------------------------------------|--------------------------------|--------------------------------|
| Well Pads | 1 | 605 | 292 | 203 | 56.3 | 2.12 |
| | 2 | 2,610 | 34,687 | 24,116 | 6,682 | 252 |
| | 3 | 605 | 84,035 | 58,389 | 16,214 | 612 |
| | Total | 3,820 | 119,014 | 82,708 | 22,952 | 866 |
| Gathering & Boosting | 1 | 44 | 1,312 | 912 | 254 | 9.55 |
| | 2 | 187 | 9,513 | 6,618 | 1,835 | 69.2 |
| | 3 | 44 | 3,106 | 2,160 | 598 | 22.6 |
| | Total | 275 | 13,931 | 9,690 | 2,687 | 101 |
| Processing | 1 | 29 | 2,146 | 1,490 | 415 | 15.6 |
| Transmission/Storage | 1 | 107 | 11,567 | 10,497 | 290 | 8.62 |

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with “leakless” or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The third option that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an

annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart A alternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

Monitoring Frequency: The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

| Equipment Type and Service | Control Effectiveness (% Reduction) | | |
|--|--|---|---|
| | Monthly Monitoring 10,000 ppmv Leak Definition | Quarterly Monitoring 10,000 ppmv Leak Definition | 500 ppm Leak Definition ^a |
| Chemical Process Unit | | | |
| Valves – Gas Service ^b | 87 | 67 | 92 |
| Valves – Light Liquid Service ^c | 84 | 61 | 88 |
| Pumps – Light Liquid Service ^c | 69 | 45 | 75 |
| Connectors – All Services | --- | --- | 93 |
| Petroleum Refinery | | | |
| Valves – Gas Service ^b | 88 | 70 | 96 |
| Valves – Light Liquid Service ^c | 76 | 61 | 95 |
| Pumps – Light Liquid Service ^c | 68 | 45 | 88 |
| Connectors – All Services | --- | --- | 81 |

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

- a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.
- b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.
- c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

Leak Definition: The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.⁷ This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.⁸ The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developed for estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Subsequent monitoring costs are \$1.50 for valves and connectors, \$2.00 for pressure relief valve disks, and \$5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at \$48.04 per hour.
- The capital cost also includes \$14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of \$4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device (\$6,500) was divided by 20 to get a shared capital cost of \$325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be \$929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

| Model Plant | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/year) | | Cost Effectiveness (\$/ton) | | |
|--|---|---------|---------|----------------------|--------------------------|--------------|--------------------------------|-------------|----------|
| | VOC | HAP | Methane | | without savings | with savings | VOC | HAP | Methane |
| <i>Well Pads</i> | | | | | | | | | |
| 1 | 0.0876 | 0.00330 | 0.315 | \$15,418 | \$23,423 | \$23,350 | \$267,386 | \$7,088,667 | \$74,253 |
| 2 | 2.43 | 0.0915 | 8.73 | \$69,179 | \$37,711 | \$35,687 | \$15,549 | \$412,226 | \$4,318 |
| 3 | 25.3 | 0.956 | 91.3 | \$584,763 | \$175,753 | \$154,595 | \$6,934 | \$183,835 | \$1,926 |
| <i>Gathering and Boosting Stations</i> | | | | | | | | | |
| 1 | 5.58 | 0.210 | 20.1 | \$148,885 | \$57,575 | \$52,921 | \$10,327 | \$273,769 | \$2,868 |
| 2 | 9.23 | 0.348 | 33.2 | \$255,344 | \$84,966 | \$77,259 | \$9,203 | \$243,987 | \$2,556 |
| 3 | 12.9 | 0.486 | 46.4 | \$321,203 | \$105,350 | \$94,591 | \$8,174 | \$216,692 | \$2,270 |
| <i>Processing Plants</i> | | | | | | | | | |
| 1 | 13.5 | 0.508 | 48.5 | \$7,522 | \$45,160 | \$33,915 | \$3,352 | \$88,870 | \$931 |
| <i>Transmission/Storage Facilities</i> | | | | | | | | | |
| 1 | 2.62 | 0.0780 | 94.9 | \$94,482 | \$51,875 | N/A | \$19,769 | \$665,155 | \$546 |

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developed for estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Subsequent monitoring costs are \$1.50 for valves and connectors, \$2.00 for pressure relief valve disks, and \$5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at \$48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be \$6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness's that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a $1/x$ relationship with the monitoring frequency. Using this assumption the component cost effectiveness's were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

| Component | Average Number of Components | Monitoring Frequency (Times/yr) | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/yr) | Cost-effectiveness (\$/ton) | | |
|--|------------------------------|---------------------------------|--|---------|---------|-------------------|---------------------|-----------------------------|-------------|----------|
| | | | VOC | HAP | Methane | | | VOC | HAP | Methane |
| <i>Subpart VVa Option</i> | | | | | | | | | | |
| Valves | 235 | 12 | 1.84 | 0.0696 | 6.64 | \$11,175 | \$27,786 | \$15,063 | \$399,331 | \$4,183 |
| Connectors | 863 | 1/0.25 ^a | 0.308 | 0.0116 | 1.11 | \$7,830 | \$22,915 | \$74,283 | \$1,969,328 | \$20,628 |
| PRD | 10 | 0 | 0.164 | 0.00619 | 0.591 | \$48,800 | \$29,609 | \$180,537 | \$4,786,215 | \$50,135 |
| OEL | 29 | 0 | 0.108 | 0.00408 | 0.389 | \$9,458 | \$22,915 | \$211,992 | \$5,620,108 | \$58,870 |
| <i>Modified Subpart VVa– Less Frequent Monitoring</i> | | | | | | | | | | |
| Valves | 235 | 1 | 1.31 | 0.0496 | 4.73 | \$11,175 | \$23,436 | \$17,828 | \$472,640 | \$4,951 |
| Connectors | 863 | 1/0.125 ^b | 0.261 | 0.00983 | 0.938 | \$7,830 | \$22,740 | \$87,277 | \$2,313,795 | \$24,237 |
| PRD | 5 | 0 | 0.164 | 0.00619 | 0.591 | \$48,800 | \$29,609 | \$180,537 | \$4,786,215 | \$50,135 |
| OEL | 29 | 0 | 0.108 | 0.00408 | 0.389 | \$9,458 | \$22,915 | \$211,992 | \$5,620,108 | \$58,870 |

Minor discrepancies may be due to rounding.

- a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
- b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

| Component | Average Number of Components | Monitoring Frequency (Times/yr) | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/yr) | Cost-effectiveness (\$/ton) | | |
|--|------------------------------|---------------------------------|--|--------|---------|-------------------|---------------------|-----------------------------|-------------|----------|
| | | | VOC | HAP | Methane | | | VOC | HAP | Methane |
| <i>Subpart VVa Option</i> | | | | | | | | | | |
| Valves | 906 | 12 | 7.11 | 0.268 | 25.6 | \$24,524 | \$43,234 | \$6,079 | \$161,162 | \$1,688 |
| Connectors | 2,864 | 1/0.25 ^a | 1.02 | 0.0386 | 3.69 | \$10,914 | \$24,164 | \$23,603 | \$625,752 | \$6,555 |
| PRD | 48 | 0 | 0.787 | 0.0297 | 2.83 | \$195,140 | \$57,091 | \$72,523 | \$1,922,648 | \$20,139 |
| OEL | 83 | 0 | 0.309 | 0.0117 | 1.11 | \$14,966 | \$23,917 | \$77,310 | \$2,049,557 | \$21,469 |
| <i>Modified Subpart VVa – Less Frequent Monitoring</i> | | | | | | | | | | |
| Valves | 906 | 1 | 5.07 | 0.191 | 18.2 | \$24,524 | \$24,461 | \$5,221 | \$138,417 | \$1,450 |
| Connectors | 2,864 | 1/0.125 ^b | 0.865 | 0.0326 | 3.11 | \$10,914 | \$23,584 | \$27,274 | \$723,067 | \$7,574 |
| PRD | 48 | 0 | 0.787 | 0.0297 | 2.83 | \$195,140 | \$57,091 | \$72,523 | \$1,922,648 | \$20,139 |
| OEL | 83 | 0 | 0.309 | 0.0117 | 1.11 | \$14,966 | \$23,917 | \$77,310 | \$2,049,557 | \$21,469 |

Minor discrepancies may be due to rounding.

- a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
- b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

| Component | Average Number of Components | Monitoring Frequency (Times/yr) | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/yr) | Cost-effectiveness (\$/ton) | | |
|--|------------------------------|---------------------------------|--|--------|---------|-------------------|---------------------|-----------------------------|-----------|---------|
| | | | VOC | HAP | Methane | | | VOC | HAP | Methane |
| <i>Incremental Component Cost for Subpart VV to Subpart VVa Option</i> | | | | | | | | | | |
| Valves | 1,392 | 12 | 10.9 | 0.412 | 39.3 | \$6,680 | \$1,576 | \$144 | \$3,824 | \$40 |
| Connectors | 4,392 | 1/0.25 ^a | 1.57 | 0.0592 | 5.65 | \$2,559 | \$6,845 | \$4,360 | \$115,585 | \$1,211 |
| PRD | 29 | 0 | 0.499 | 0.0188 | 1.80 | \$0 | \$0 | \$0 | \$0 | \$0 |
| OEL | 134 | 0 | 0.476 | 0.0179 | 1.71 | \$0 | \$0 | \$0 | \$0 | \$0 |

Minor discrepancies may be due to rounding.

- a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

| Component | Average Number of Components | Monitoring Frequency (Times/yr) | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/yr) | Cost-effectiveness (\$/ton) | | |
|---|------------------------------|---------------------------------|--|---------|---------|-------------------|---------------------|-----------------------------|-------------|---------|
| | | | VOC | HAP | Methane | | | VOC | HAP | Methane |
| <i>Subpart VVa Option</i> | | | | | | | | | | |
| Valves | 673 | 12 | 0.878 | 0.0261 | 31.8 | \$19,888 | \$37,870 | \$43,111 | \$1,450,510 | \$1,192 |
| Connectors | 3,068 | 1/0.25 ^a | 0.665 | 0.0198 | 24.1 | \$11,229 | \$24,291 | \$36,527 | \$1,229,005 | \$1,010 |
| PRD | 14 | 0 | 0.133 | 0.00397 | 4.83 | \$61,520 | \$32,501 | \$243,525 | \$8,193,684 | \$6,732 |
| OEL | 58 | 0 | 0.947 | 0.0282 | 34.3 | \$12,416 | \$23,453 | \$24,762 | \$833,137 | \$684 |
| <i>Modified Subpart VVa – Less Frequent Monitoring</i> | | | | | | | | | | |
| Valves | 673 | 1 | 0.626 | 0.0186 | 22.6 | \$19,888 | \$25,410 | \$40,593 | \$1,365,801 | \$1,122 |
| Connectors | 3,068 | 1/0.125 ^b | 0.562 | 0.0167 | 20.3 | \$11,229 | \$23,669 | \$42,140 | \$1,417,844 | \$1,165 |
| PRD | 14 | 0 | 0.133 | 0.00397 | 4.83 | \$61,520 | \$32,501 | \$243,525 | \$8,193,684 | \$6,732 |
| OEL | 58 | 0 | 0.947 | 0.0282 | 34.3 | \$12,416 | \$23,453 | \$24,762 | \$833,137 | \$684 |

Minor discrepancies may be due to rounding.

- a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
- b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are discussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developed for estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be \$0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be \$1.50 for valves and connectors, \$2.00 for pressure relief valve disks, and \$5.00 for pressure relief devices and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at \$48.04 per hour.
- The capital cost also includes \$14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of \$4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, \$85,000) and the Method 21 device (\$6,500) was divided by 173 to get a shared capital cost of \$529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be \$1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sector using the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

| Model Plant | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/year) | | Cost Effectiveness (\$/ton) | | |
|--|--|---------|---------|-------------------|-----------------------|--------------|-----------------------------|-------------|----------|
| | VOC | HAP | Methane | | without savings | with savings | VOC | HAP | Methane |
| Well Pads | | | | | | | | | |
| 1 | 0.0876 | 0.00330 | 0.315 | \$15,428 | \$21,464 | \$21,391 | \$245,024 | \$6,495,835 | \$68,043 |
| 2 | 2.43 | 0.0915 | 8.73 | \$64,858 | \$39,112 | \$37,088 | \$16,127 | \$427,540 | \$4,478 |
| 3 | 25.3 | 0.956 | 91.3 | \$132,891 | \$135,964 | \$114,807 | \$5,364 | \$142,216 | \$1,490 |
| Gathering and Boosting Stations | | | | | | | | | |
| 1 | 5.58 | 0.210 | 20.1 | \$149,089 | \$63,949 | \$59,295 | \$11,470 | \$304,078 | \$3,185 |
| 2 | 9.23 | 0.348 | 33.2 | \$240,529 | \$93,210 | \$85,503 | \$10,096 | \$267,659 | \$2,804 |
| 3 | 12.9 | 0.486 | 46.4 | \$329,725 | \$121,820 | \$111,060 | \$9,451 | \$250,567 | \$2,625 |
| Processing Plants | | | | | | | | | |
| 1 | 13.5 | 0.508 | 48.5 | \$92,522 | \$87,059 | \$75,813 | \$6,462 | \$171,321 | \$1,795 |
| Transmission/Storage Facilities | | | | | | | | | |
| 1 | 2.62 | 0.0780 | 94.9 | \$20,898 | \$51,753 | N/A | \$19,723 | \$663,591 | \$545 |

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developed for estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be \$0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at \$48.04 per hour.
- The shared capital cost for optical gas imaging system is \$491 for production and gathering and boosting, \$85,000 for processing, and \$1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes \$14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of \$4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

| Model Plant | Annual Emission Reductions (tons/year) | | | Capital Cost (\$) | Annual Cost (\$/year) | | Cost Effectiveness (\$/ton) | | |
|---|--|-----|---------|-------------------|-----------------------|--------------|-----------------------------|-----|---------|
| | VOC | HAP | Methane | | without savings | with savings | VOC | HAP | Methane |
| <i>Well Pads</i> | | | | | | | | | |
| 1 | N/A | N/A | N/A | \$15,390 | \$21,373 | N/A | N/A | N/A | N/A |
| 2 | N/A | N/A | N/A | \$64,820 | \$37,049 | N/A | N/A | N/A | N/A |
| 3 | N/A | N/A | N/A | \$537,313 | \$189,174 | N/A | N/A | N/A | N/A |
| <i>Gathering and Boosting Stations</i> | | | | | | | | | |
| 1 | N/A | N/A | N/A | \$149,051 | \$59,790 | N/A | N/A | N/A | N/A |
| 2 | N/A | N/A | N/A | \$240,491 | \$86,135 | N/A | N/A | N/A | N/A |
| 3 | N/A | N/A | N/A | \$329,687 | \$11,940 | N/A | N/A | N/A | N/A |
| <i>Processing Plants</i> | | | | | | | | | |
| 1 | N/A | N/A | N/A | \$92,522 | \$76,581 | N/A | N/A | N/A | N/A |
| <i>Transmission/Storage Facilities</i> | | | | | | | | | |
| 1 | N/A | N/A | N/A | \$20,817 | \$45,080 | N/A | N/A | N/A | N/A |

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from \$267,386 per ton of VOC for a single well head facility to \$6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from \$15,063 for valves to \$211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from \$5,364 per ton of VOC for Model Plant 3 to \$245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from \$10,327 per ton of VOC for

Model Plant 1 to \$8,174 per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from \$6,079 for valves to \$77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be \$10,724 per ton of VOC for Model Plant 1 and \$8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be \$3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from \$0 for open-ended lined and pressure relief devices to \$4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be \$6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was \$19,769 per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from \$24,762 for open-ended lined to \$243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be \$19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

| Category | Estimated Number of Sources subject to NSPS | Facility Capital Cost (\$) | Nationwide Emission Reductions (tpy) | | | VOC Cost Effectiveness (\$/ton) | | Methane Cost Effectiveness (\$/ton) | | Total Nationwide Costs (million \$/year) | | |
|---|---|----------------------------|--------------------------------------|---------|------|---------------------------------|--------------|-------------------------------------|--------------|--|------------------------|---------------------|
| | | | VOC | Methane | HAP | without savings | with savings | without savings | with savings | Capital Cost | Annual without savings | Annual with savings |
| Regulatory Option 2 (Subpart VVa LDAR Program) | | | | | | | | | | | | |
| Processing Plants | 29 | \$7,522 | 392 | 1,407 | 14.7 | \$3,352 | \$2,517 | \$931 | \$699 | 0.218 | 1.31 | 0.984 |

8.6 References

- 1 Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards. September 2, 2008.
- 2 Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOCOMI. October 30, 2007.
- 3 Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries. October 30, 2007.
- 4 U.S. Environmental Protection Agency. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.
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- 6 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080c. June 1996.
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 - 14 Independent Petroleum Association of America. Oil and Gas Producing Industry in Your State.
 - 15 Armendariz, Al. Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements. Prepared for Environmental Defense Fund. January 2009.
 - 16 Eastern Research Group, Inc. Emissions from Oil and Gas Production Facilities. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
 - 17 U.S. Energy Information Administration. Annual U.S. Natural Gas Wellhead Price. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <<http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>>
 - 18 Eastern Research Group, Inc. Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation. Prepared for the U.S. Environmental Protection Agency. September 1999.

APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

| Tank ID | Sample Tank No. 100 | Sample Tank No. 101 | Sample Tank No. 102 | Sample Tank No. 103 |
|--------------------------------|---------------------|---------------------|---------------------|---------------------|
| E&P Tank Number | Tank No. 54 | Tank No. 55 | Tank No. 56 | Tank No. 57 |
| Total Emissions (tpy) | 173.095 | 363.718 | 391.465 | 274.631 |
| VOC Emissions (tpy) | 97.629 | 237.995 | 191.567 | 204.825 |
| Methane Emissions (tpy) | 52.151 | 56.163 | 3.830 | 22.453 |
| HAP Emissions (tpy) | 4.410 | 2.820 | 5.090 | 19.640 |
| <i>Benzene</i> | 0.242 | 0.369 | 0.970 | 5.674 |
| <i>Toluene</i> | 0.281 | 0.045 | 0.836 | 4.267 |
| <i>E-Benzene</i> | 0.031 | 0.026 | 0.019 | 0.070 |
| <i>Xylenes</i> | 0.164 | 0.129 | 0.135 | 0.436 |
| <i>n-C6</i> | 3.689 | 2.253 | 3.127 | 9.194 |
| <i>224Trimethylp</i> | 0.000 | 0.000 | 0.000 | 0.000 |
| Separator Pressure (psig) | 60 | 60 | 33 | 42 |
| Separator Temperature (F) | 80 | 58 | 60 | 110 |
| Ambient Pressure (psia) | 14.7 | 14.7 | 14.7 | 14.7 |
| Ambient Temperature (F) | 60 | 58 | 60 | 110 |
| C10+ SG | 0.891 | 0.877 | 0.907 | 0.879 |
| C10+ MW | 265 | 309 | 295 | 283 |
| API Gravity | 39.0 | 39.0 | 39.0 | 39.0 |
| Production Rate (bbl/day) | 500 | 500 | 500 | 500 |
| Reid Vapor Pressure (psia) | 5.60 | 6.80 | 6.40 | 5.40 |
| GOR (scf/bbl) | 23.36 | 43.14 | 36.04 | 26.60 |
| Heating Value of Vapor (Btu/s) | 1766.66 | 2016.56 | 1509.76 | 2428.31 |
| LP Oil Component | | | | |
| H2S | 0.0000 | 0.0000 | 0.1100 | 0.0000 |
| O2 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| CO2 | 0.0500 | 0.0300 | 2.4000 | 0.0100 |
| N2 | 0.0100 | 0.0100 | 0.0000 | 0.0000 |
| C1 | 2.3200 | 2.6700 | 0.1600 | 1.0900 |
| C2 | 0.7200 | 1.7300 | 0.7600 | 1.5000 |
| C3 | 1.1900 | 3.6000 | 2.6400 | 2.1200 |
| i-C4 | 0.8900 | 1.8800 | 0.9100 | 0.8400 |
| n-C4 | 1.8300 | 3.2300 | 3.5800 | 2.2800 |
| i-C5 | 2.3500 | 2.4900 | 2.6500 | 1.6400 |
| n-C5 | 3.2400 | 2.1100 | 3.4400 | 2.5200 |
| C6 | 3.9900 | 2.7200 | 3.7800 | 2.6100 |
| C7 | 9.9400 | 8.1600 | 10.7700 | 9.7300 |
| C8 | 11.5600 | 11.9800 | 11.8300 | 8.9300 |
| C9 | 6.0600 | 4.9500 | 6.1900 | 5.8900 |
| C10+ | 48.9900 | 50.3400 | 40.8600 | 47.7300 |
| Benzene | 0.3000 | 0.3800 | 1.2700 | 2.7500 |
| Toluene | 1.0300 | 0.1500 | 3.4900 | 5.3000 |
| E-Benzene | 0.2900 | 0.2400 | 0.2200 | 0.2000 |
| Xylenes | 1.7800 | 1.3700 | 1.8000 | 1.3900 |
| n-C6 | 3.4600 | 1.9600 | 3.1400 | 3.4700 |
| 224Trimethylp | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | 100.0000 | 100.0000 | 100.0000 | 100.0000 |

| Tank ID | | | | | API > 40 | | |
|--------------------------------|-----------------------|--------------------|---------------|--------------|----------------|--------------|---------------|
| E&P Tank Number | | Average | ratios to HAP | Ratio to VOC | Maximum | Minimum | Average |
| Total Emissions (tpy) | Total | 785.812 | | | 8152.118 | 129.419 | 1530.229 |
| VOC Emissions (tpy) | VOC | 530.750 | 33.837 | | 5678.554 | 43.734 | 1046.343 |
| Methane Emissions (tpy) | Methane | 116.167 | 7.406 | 0.219 | 1206.981 | 0.197 | 230.569 |
| HAP Emissions (tpy) | HAP | 15.685 | | 0.030 | 101.610 | 2.680 | 30.684 |
| Benzene | | | | | | | |
| Toluene | | | | | | | |
| E-Benzene | | | | | | | |
| Xylenes | | | | | | | |
| n-C6 | | | | | | | |
| 224Trimethylp | | | | | | | |
| Separator Pressure (psig) | Separator Pressure | 126.451 | | | 870.000 | 13.000 | 231.870 |
| Separator Temperature (F) | Separator Temperature | 88.657 | | | 140.000 | 40.000 | 82.500 |
| Ambient Pressure (psia) | | | | | | | |
| Ambient Temperature (F) | | | | | | | |
| C10+ SG | | 0.893 | | | 0.929 | 0.801 | 0.873 |
| C10+ MW | | 292.72 | | | 375.000 | 162.000 | 241.304 |
| API Gravity | API Gravity | 40.6 | | | 68.0 | 40.0 | 52.8 |
| Production Rate (bbl/day) | | | | | | | |
| Reid Vapor Pressure (psia) | RVP | 5.691 | | | 13.100 | 3.000 | 7.983 |
| GOR (scf/bbl) | GOR | 88.149 | | | 924.960 | 12.300 | 172.479 |
| Heating Value of Vapor (Btu/s) | Heating value | 1968.085 | | | | | |
| LP Oil Component | | Composition | | | | | |
| H2S | | 0.0679 | | | | | |
| O2 | | 0.0000 | | | | | |
| CO2 | | 0.3661 | | | | | |
| N2 | | 0.0360 | | | | | |
| C1 | | 2.9248 | | | | | |
| C2 | | 1.6262 | | | | | |
| C3 | | 2.7564 | | | | | |
| i-C4 | | 1.3958 | | | | | |
| n-C4 | | 2.9738 | | | | | |
| i-C5 | | 2.4711 | | | | | |
| n-C5 | | 2.7194 | | | | | |
| C6 | | 3.2723 | | | | | |
| C7 | | 8.5230 | | | | | |
| C8 | | 10.3202 | | | | | |
| C9 | | 5.6686 | | | | | |
| C10+ | | 48.1339 | | | | | |
| Benzene | | 0.6044 | | | | | |
| Toluene | | 1.6882 | | | | | |
| E-Benzene | | 0.1797 | | | | | |
| Xylenes | | 1.4353 | | | | | |
| n-C6 | | 2.8369 | | | | | |
| 224Trimethylp | | 0.0000 | | | | | |
| | | 100.0000 | | | | | |

| Tank ID E&P Tank Number | API <40 | | |
|--------------------------------|---------------|--------------|--------------|
| | Maximum | Minimum | Average |
| Total Emissions (tpy) | 746.422 | 13.397 | 174.327 |
| VOC Emissions (tpy) | 598.797 | 3.087 | 107.227 |
| Methane Emissions (tpy) | 124.465 | 0.115 | 22.193 |
| HAP Emissions (tpy) | 19.640 | 0.070 | 3.366 |
| <i>Benzene</i> | 5.674 | 0.003 | 0.445 |
| <i>Toluene</i> | 6.120 | 0.003 | 0.431 |
| <i>E-Benzene</i> | 0.086 | 0.000 | 0.019 |
| <i>Xylenes</i> | 0.732 | 0.001 | 0.120 |
| <i>n-C6</i> | 16.032 | 0.052 | 2.449 |
| <i>224Trimethylp</i> | 0.000 | 0.000 | 0.000 |
| Separator Pressure (psig) | 280.000 | 4.000 | 39.857 |
| Separator Temperature (F) | | | |
| Ambient Pressure (psia) | | | |
| Ambient Temperature (F) | | | |
| C10+ SG | 0.984 | 0.861 | 0.910 |
| C10+ MW | 551.000 | 239.000 | 334.946 |
| API Gravity | 39.0 | 15.0 | 30.6 |
| Production Rate (bbl/day) | | | |
| Reid Vapor Pressure (psia) | 7.400 | 0.600 | 3.809 |
| GOR (scf/bbl) | 67.220 | 2.340 | 18.878 |
| Heating Value of Vapor (Btu/s) | | | |
| LP Oil Component | | | |
| H2S | | | |
| O2 | | | |
| CO2 | | | |
| N2 | | | |
| C1 | | | |
| C2 | | | |
| C3 | | | |
| i-C4 | | | |
| n-C4 | | | |
| i-C5 | | | |
| n-C5 | | | |
| C6 | | | |
| C7 | | | |
| C8 | | | |
| C9 | | | |
| C10+ | | | |
| Benzene | | | |
| Toluene | | | |
| E-Benzene | | | |
| Xylenes | | | |
| n-C6 | | | |
| 224Trimethylp | | | |

API Gravity >40**VOC Emissions (tpy)**

| | |
|-------------------------|-------------|
| Mean | 1046.343 |
| Standard Error | 188.1410357 |
| Median | 530.989 |
| Mode | #N/A |
| Standard Deviation | 1276.034588 |
| Sample Variance | 1628264.269 |
| Kurtosis | 3.35522263 |
| Skewness | 1.864492873 |
| Range | 5634.82 |
| Minimum | 43.734 |
| Maximum | 5678.554 |
| Sum | 48131.778 |
| Count | 46 |
| Largest(1) | 5678.554 |
| Confidence Level(95.0%) | 378.9354921 |

| | |
|-----|-------------|
| | 667.4075079 |
| VOC | 1046.343 |
| | 1425.278492 |

API Gravity <40**VOC Emissions (tpy)**

| | |
|-------------------------|----------|
| Mean | 107.2265 |
| Standard Error | 15.51304 |
| Median | 72.87 |
| Mode | #N/A |
| Standard Deviation | 116.0889 |
| Sample Variance | 13476.64 |
| Kurtosis | 9.02191 |
| Skewness | 2.680349 |
| Range | 595.71 |
| Minimum | 3.087 |
| Maximum | 598.797 |
| Sum | 6004.685 |
| Count | 56 |
| Largest(1) | 598.797 |
| Confidence Level(95.0%) | 31.08882 |

| | |
|-----|----------|
| | 76.1377 |
| VOC | 107.2265 |
| | 138.3153 |

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Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned

G.V. Chilingar · B. Endres

Abstract Urban encroachment into areas historically reserved for oil and gas field operations is an ever-present problem within the Los Angeles Basin. The recent frenzy in real estate development has only intensified what can be characterized as a conflict in land usage. Subsurface mineral rights are severed from surface ownership, often resulting in developments being approved without adequate consideration of the underlying oil and gas field consequences. Also, surface operations are frequently co-located within residential areas without consideration of the health and safety consequences of emissions of toxics to air. This paper presents a review of the environmental, health and safety hazards posed by urban oilfield operations, with an emphasis upon the lessons learned from the “L.A. Basin: Original Urban Oilfield Legend” (see Castle and Yerkes 1976; Denton and others 2001; Endres and others 2002; Kouznetsov and others 1994; Katz and others 1994; Schumacher and Abrams 1994; and Schoell 1983). The Los Angeles Basin has provided the authors with one of the largest natural laboratories in the world for studying the consequences of these issues. The results presented are part of a long-term research program based upon the application of geoscience and petroleum engineering principles in obtaining a fundamental understanding of the root causes of the environmental hazards posed. Topics addressed include: (1) vertical migration of gas to the surface along faults and improperly completed or abandoned wellbores (e.g., due to poor cementing practices), (2) subsidence caused by the fluid

production and declining reservoir pressures, (3) soil and groundwater contamination resulting from historic oil and gas field operations, and (4) air toxics resulting from surface operations. A number of case histories are discussed that illustrate the seriousness of the problem. A clear case is made for the urgent need for closer coordination and education by the petroleum industry of the local government planning departments. These departments have the principal role in determining land use policies, acting as the lead agency in performing environmental site assessments (e.g., under the California Environmental Quality Act), and in establishing mitigation measures for dealing with the long-term environmental hazards. This paper establishes prudent practices on the part of oilfield operators for the monitoring and mitigation of these hazards.

Keywords Los Angeles oilfields · Gas migration · Toxic gases (hazard) · Subsidence-earthquakes · Methane

Introduction

The environmental hazards posed to the urban development by oil and gas field operations are numerous. These hazards must be properly evaluated and mitigation measures implemented in order to protect public safety. These hazards are caused by gas migration along faults, subsidence caused by the fluid removal with consequent formation of faults and fractures, and by improperly maintained wellbores.

The Los Angeles Basin, California, has over seventy oilfields that underlie extensive urban development. This setting has provided the authors an opportunity to study the long-term environment consequences of this mixed usage. These environmental hazards are not unique to the Los Angeles Basin, but relate to fundamental principles of gas migration, along faults and fracture zones, subsidence, and outgassing of oilfield gases that must be properly evaluated. This paper provides a detailed insight into these hazards, as well as lessons learned from the numerous

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disasters that were not properly planned for. Methods for reducing risks and mitigation of hazards are discussed. Four aspects of these environment hazards are presented:

1. Oilfield gas migration into the near-surface deposits and aquifers.
2. Soil and groundwater contamination from upward migration of oilfields fluids, mainly gases.
3. Subsidence caused by oilfield fluid withdrawal and declining reservoir pressures.
4. Outgassing and release of air toxics from the oil- and gas-field operations.

These issues are interactive and must be evaluated in combination. Ignoring these issues could result in substantial legal liability upon the oilfield operator and upon those responsible for the public safety. Subsidence also results in the formation of faults and fracture zones, which are avenues for the migration of gases.

Gas migration in oilfield settings

The Los Angeles Basin has been plagued with numerous oilfield gas seeps that continue to present serious explosion and health risks to the residents. Oilfield gases have a propensity to migrate to the surface along faults and poorly completed and/or abandoned wellbores. Furthermore, the upward migrating gases will accumulate in the near-surface collector zones, often trapped and concealed within the permeable gravel and sand lenses.

The lower explosive limit (LEL) of the oilfield gases (composed primarily of methane) is approximately 5% by volume when mixed with 95% by volume of air. This translates into a serious explosion and fire hazard, especially where the gas is capable of migrating into a confined space such as a room or an electrical vault. In the Los Angeles Basin many homes and commercial structures have been constructed directly over old oil wells that have not been properly sealed, and no mitigation measures have been taken to seal out the seeping gases.

The March 24, 1985, Ross Department Store explosion

The first clear recognition of a very serious problem with oilfield gases migrating to the surface and causing an explosion hazard was the March 24, 1985, incident in the Fairfax area of Los Angeles which demolished the Ross Department Store and injured over 23 people (Cobarrubias 1985). Escaping oilfield gases burned for days through cracks in the sidewalks and within the parking lot surrounding the store located at 3rd Street and Ogden Drive, directly across the street from the Farmer's Market. Also, large quantities of gas were detected migrating to the surface under the Hancock Park Elementary School located on Fairfax Street near 3rd Street.

Near-surface soil gas studies revealed that the highest concentrations of gases were aligned in an elliptical pattern with the semi-major axis having an exact alignment with the Metropolitan Number 5 Slant Well operated from a nearby drilling island. A review of production records revealed that this well consistently produced the largest gas volumes of any operational well from the underlying Salt Lake Oilfield. Eventually, well records were obtained that revealed that the well casing had developed leaks as a result of corrosion holes located at a depth beginning at approximately 366 m, and extending deeper (Endres and others 1991; Khilyuk and others 2000).

Gas pathways to the surface included the 3rd Street Fault, that surfaced at the Ross Store location, and an old abandoned vertical well identified on the Division of Oil and Gas map for the area as Well Number 99. A vent well drilled into the parking lot of the Ross Store discovered a large pocket (collector zone) of trapped oilfield gas at a depth of approximately 15 m (Fig. 1). This collector zone had sufficient porosity and permeability to serve as a temporary trapping mechanism for the large quantities of upward migrating gases from the leaking wells to build to pressures of approximately 1.8 kg/cm². A clay layer served as a trapping mechanism until its threshold pressure was exceeded. Permanent soil gas probes were installed to a depth of approximately 4.6 m in order to perform ongoing monitoring of the upward migrating gases (Fig. 2).

Detailed gas fingerprinting, primarily utilizing isotopic gas characterization, was instrumental in providing 100% scientific proof (Fig. 3) that the explosion and fire were caused by the underlying Salt Lake Oilfield operations (Schoell and others 1993). Also, further investigation revealed that the gas seeps at the nearby La Brea Tar Pits result from upward migration of gases from the Salt Lake Oilfield along the 6th Street Fault (Jenden 1985). The 6th Street Fault slopes downward to the north and intercepts the oilfield reservoir at the location of the Metropolitan Number 5 well. Production Zone (viz., a very prolific gas zone). Gas fingerprinting has confirmed that the gas seeps at the La Brea Tar Pits match the leaking gases that caused the Ross Department Store explosion (Jenden 1985).

The City of Los Angeles methane ordinance

Following the Fairfax explosion and fires in 1985, the City of Los Angeles adopted a methane ordinance that was incorporated into the City of Los Angeles Building Code, Chapter 15, titled "Methane Seepage District Regulations." The stated purpose is for the control of methane intrusion emanating from petroliferous formations. These regulations apply largely to new construction, the boundaries of which are defined in the code, but are coincident with the boundaries of the Salt Lake Oilfield.

Existing commercial structures, including the Hancock Park Elementary School, were required to install gas detectors. These requirements for gas detection in existing buildings, however, were limited to the commercial

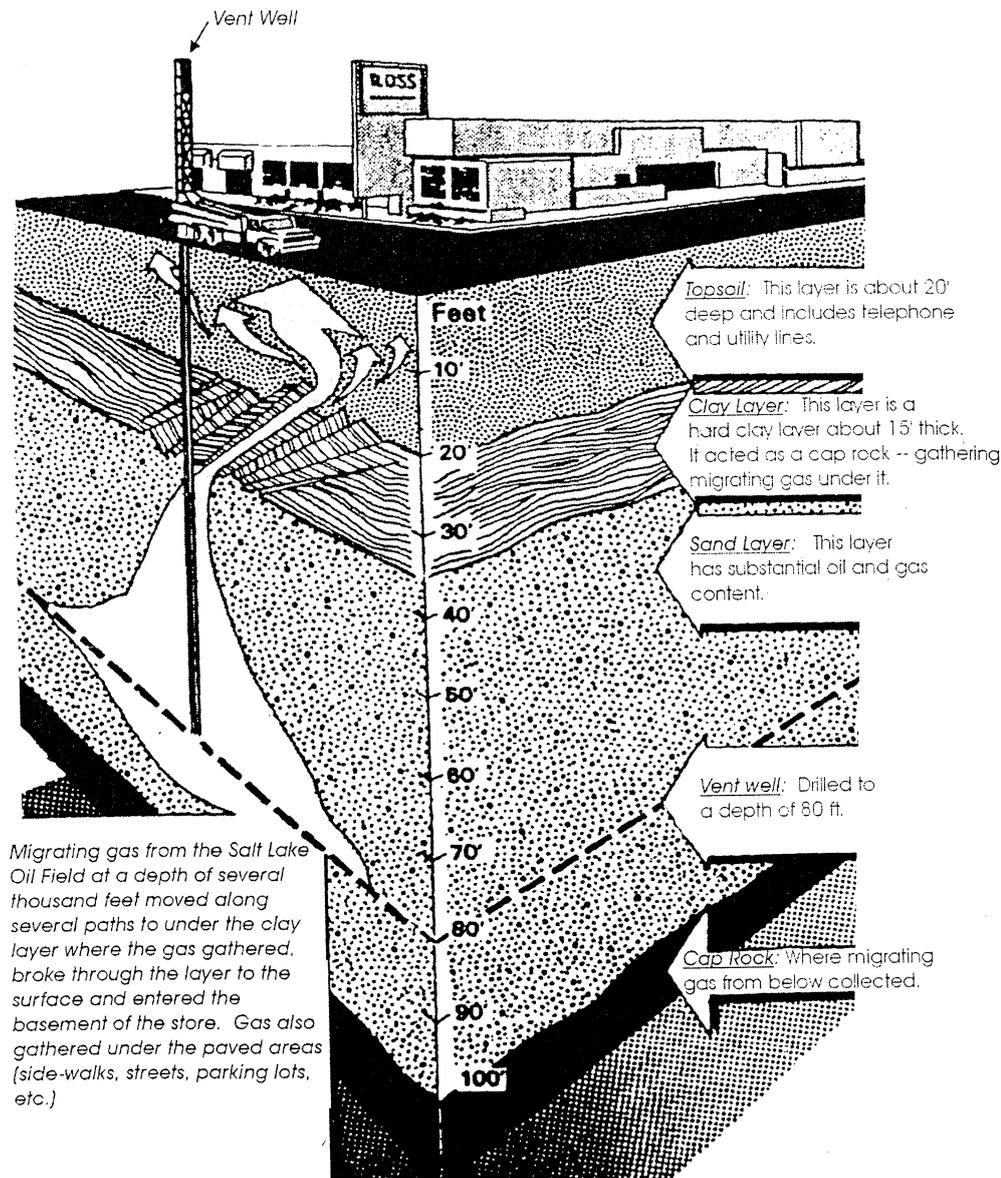


Fig. 1

Schematic showing how gas entered the basement of the department store and the surrounding area (modified after an article by George Ramos and Ted Thackery in the Los Angeles Times 1985; Illustration by Michael Hall)

buildings in the immediate vicinity of the Third Street and Ogden explosion site. Additionally, these commercial establishments were required to share the weekly monitoring expenses associated with the permanent soil gas probes that are depicted in Fig. 2. Unfortunately, the Anthony No. 1 gas well (see Figs. 1, 2), that was installed to vent gas from the underlying formation, became plugged in the 1989 time period. Namely, the weekly monitoring of the soil probes failed to provide advanced warning of a near-disaster on February 7, 1989.

The near disaster of February 7, 1989

On the morning of February 7, 1989, a pedestrian who was walking by the Gilmore Bank building, located on the

north side of Third Street and across the street from the 1985 explosion site, observed gas bubbling through the ground in a planter box. The fire department was called, which led to the discovery of area-wide gas seeps emerging from below the sidewalks and streets, a near repeat of the 1985 incident, but without an explosion.

It was discovered that the Anthony vent well had become plugged at the perforated intervals of the permeable sand zone depicted in Fig. 1. This condition was aggravated by the ground water movement existing at the depth of vent well.

The response team soon recognized similarities to the 1985 explosion and fires, and the area was immediately cordoned off to prevent ignition and explosion of the gas. In the wake of this near disaster, the City of Los Angeles undertook a second task force study. There is overwhelming scientific evidence that the gas accumulations were the direct result of ongoing oil and gas production, and leaking oil wells.

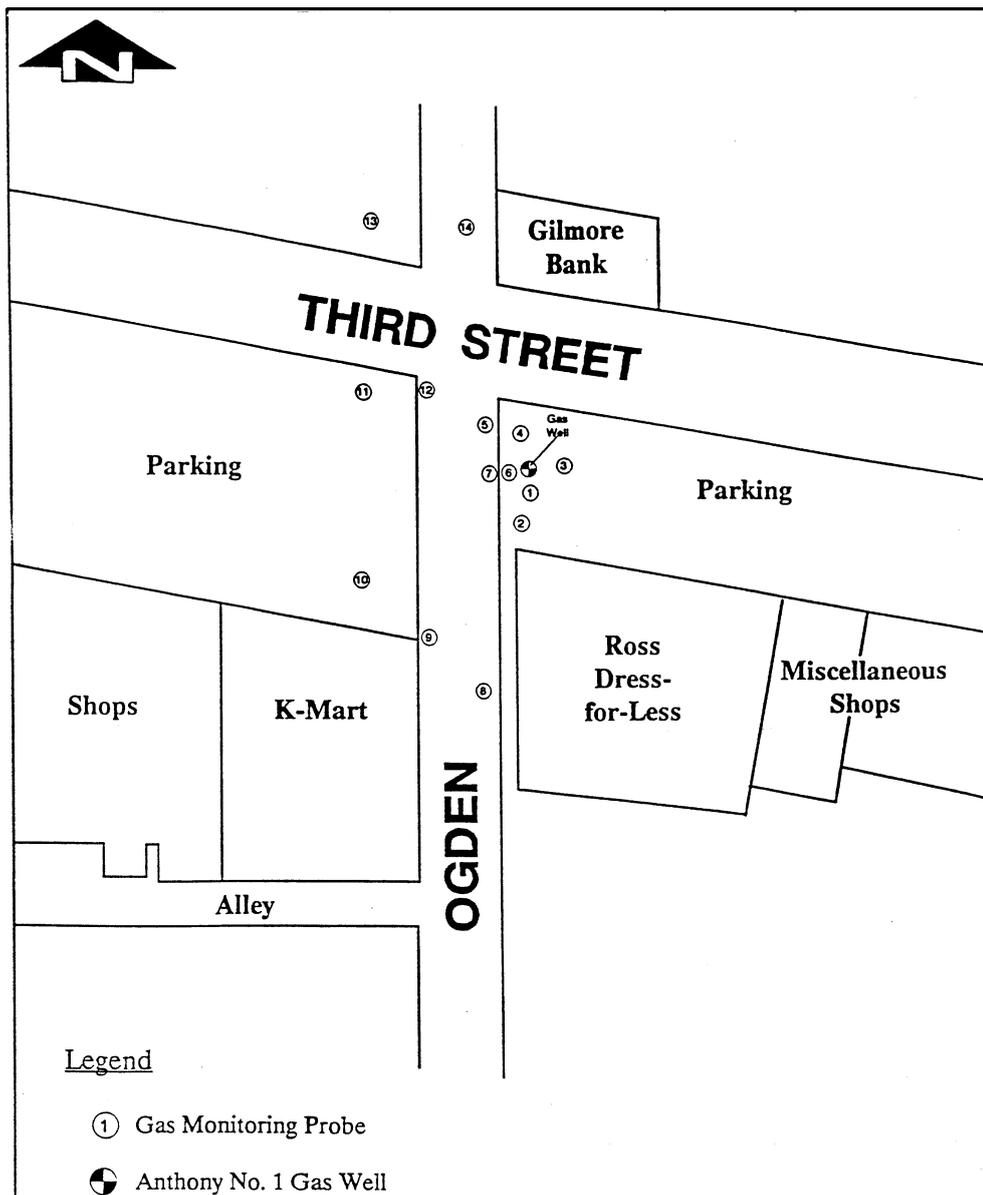


Fig. 2
Probe location map; 3rd St. and Ogden Drive, Los Angeles, California (courtesy of City of Los Angeles Fire Department)

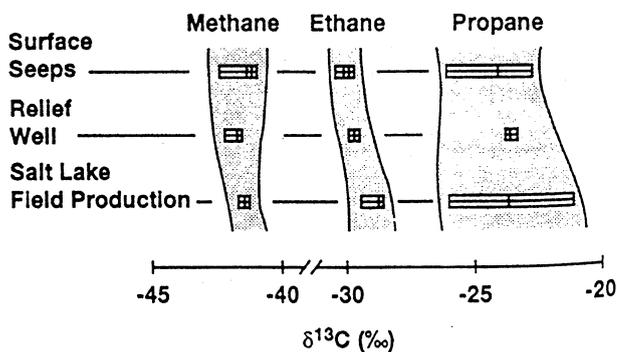


Fig. 3
Carbon isotopic fingerprinting of gas leaking from reservoir to the surface (after Schoell and others 1993, Fig. 8, p. 7)

Well records clearly demonstrate that the Metropolitan No. 5 well had developed serious corrosion leaks in the well casing. These leaks were ongoing, and caused large

quantities of oilfield gases to leak into secondary collector zones below both the explosion site and under the Hancock Park Elementary School.

The gas fingerprinting experts (Schoell and others 1993; Jenden 1985) showed the match between the field production gases and the gas from seeps at the surface (Fig. 3).

There is an increased risk of a similar incident occurring somewhere else within approximately 70 oilfields within the Los Angeles Basin. The most important lesson to be learned from the Fairfax explosion is the need to carefully evaluate the integrity of the many old oil wells in the Los Angeles Basin that can serve as the primary source and/or the pathways for the oilfield gases to migrate to the surface. The authors have confirmed this enormous hazard by evaluating hundreds of documented well leaks, and identifying the causes of the leaks. Virtually all well leaks can be traced to the poor

well completion and/or abandonment procedures (e.g., poor cementing practices).

Environmental hazards of oil well leaks

Wells that were drilled and completed many years ago are subject to ongoing corrosion and deterioration of both the steel casings and the cements.

Gas intrusion into cemented wellbores and the resultant leakage to the surface and porous formations below the wellhead have been persistent problems in the oil and gas industry for many years (Marlow 1989). Pressure and temperature cycling on the cement bonding characteristics, an acute problem in the gas storage industry, can give rise to shoe leaks and loss of bonding in the annular cement. To help quantify the annular leakage problem in gas storage wells, a survey was prepared and sent to the members of the American Gas Associations Pipeline Research and Storage Reservoir Supervisory Committees. The survey attempted to determine the magnitude of the annular leakage problem.

Tests showed that even when the most up-to-date cement types and techniques are used, leakage can and will occur in a significant number of cases (Marlow 1989 pp. 1147, 1148). For example, in a study of 250 casing jobs over a 15-month period with new cements, 15% of the wells leaked (Watters and Sabins 1980). Accordingly, the poor cementing and completion practices, typical of the many old wells located in the Los Angeles Basin, are giving rise to very serious environmental problems associated with gas leakage to the surface in the annular space, as discussed herein.

Numerous fields have accumulations of hydrogen sulfide that will eventually destroy the integrity of both the steel and cement relied upon to provide protection against gas migration, including abandonments performed to the current standards of the DOGGR. The corrosive conditions of hydrogen sulfide are well known, and have defied engineering solutions (Craig 1993).

Ongoing seismic activity in the Los Angeles Basin is also a major factor in contributing to a well integrity problem. For example, the 1971 Sylmar earthquake was responsible for causing well blowouts in the Fairfax (Salt Lake Oilfield) area (Khilyuk and others 2000).

Wilshire and Curson gas seep

A very serious gas seep at the intersection of Wilshire and Curson (directly across the street, and south of the La Brea Tar Pits) was discovered in 1999. This required the City of Los Angeles to install a vent pipe on the south-west corner of this intersection in order to direct the oilfield gases into the air above the adjoining three story commercial building. The odors from the gas emitted from the vent pipe are noticeable throughout the area.

The commercial office building to the immediate east of this seep location was experiencing gas migration through the foundation and into the building. A ventilation system is operating 24 h/day within the subterranean parking structure of that building in order to mitigate against the risk of an explosion.

Historical records of the area, reviewed by the writers, revealed that an old abandoned well had been drilled near the location of the seep. However, the high-density commercial development in the area has prevented finding the well.

South Salt Lake oilfield gas seeps from gas injection

In January 2003, serious gas leakage problems were discovered in the South Salt Lake Oilfield, located in a residential area near the Fairfax area (viz., in the vicinity of Allendale and Olympic Boulevard). The oilfield operator had been injecting natural gas into the South Salt Lake Oilfield for approximately two years, under elevated pressures to enhance recovery. However, gas began leaking to the surface along abandoned and poorly completed wellbores. In fact, the Division of Oil and Gas records reveal that numerous wells were drilled before the official records were maintained. Accordingly, the existence and abandonment status of some of these wells is unknown. High-density urban development, largely of apartment buildings has occurred directly over many of the old wells.

Montebello underground gas storage

The partially depleted Montebello Oilfield was converted into an underground gas storage operation. Natural gas was transported into the field through interstate pipelines and injected under high pressure (exceeding 105.6 kg/cm²) into the 8th Zone at a depth of approximately 2,286 m. This storage gas was discovered leaking to the surface along old wellbores that had been drilled in the 1930s era. In some instances, homes had to be abandoned and torn down to provide access to drilling rigs in an attempt to repair and/or reabandon old wells. Studies revealed that the cement plugs used in well abandonment and the integrity of the well casings and cements were not adequate to seal off the high-pressure storage gas from migrating along the wellbores to the surface. This facility had to be abandoned because of the gas leaks. However, it will take many years to deplete the gas to pre-storage conditions.

These examples indicate the importance of a systematic examination of how wells leak, and the dangers posed by allowing residential construction to occur directly over old wells. If each well leak is evaluated in isolation of the long history of problems in an area, the true dangers may not be recognized.

Playa Del Rey underground gas storage

The Playa del Rey Oilfield, located in the Marina del Rey area of the Los Angeles Basin, was converted to an underground gas storage operation in the 1942 time period, and has been operated in that manner ever since. The Venice Oilfield adjoins the area to the immediate north. The gas storage reservoir has been leaking into the adjoining Venice Oilfield since the early years of operation (Riegle 1953). There are over 200 old and abandoned wells throughout this area, including wells that had to be abandoned in order to accommodate the construction of the Marina del Rey Boat Harbor (Fig. 4). For example, some old wells are located directly below the main channel that connects to the Pacific Ocean. Numerous gas seeps have been observed by the authors of this paper within the boat harbor, and within the Ballona Flood Control Channel that bisects the area and extends eastward along the old Los Angeles Riverbed alignment.

The Los Angeles River was responsible for depositing a massive gravel layer that extends eastward providing a highly permeable zone for leaking oilfield gases to collect and migrate easterly, including under the influence of tidal forces. The gravel zone begins (viz., below surface sediments) at a depth of approximately 15 m (referred to as the "15-meter Gravel") and extends to a depth of several

hundred feet. This gravel zone interconnects many of the old wells in the area, and serves to conceal the identity of wells that are experiencing the worst leakage. Gas fingerprinting has established that the leaking well gases match the gases seeping to the surface along the flood control channel and into the surrounding residential areas.

This gravel zone is saturated with oilfield gases, which becomes additionally pressurized during the heavy rains as a result of the shallow aquifer being recharged. Surface gas seeps become very pronounced because of this pressurization, and can be observed bubbling through standing water during rains. Probes placed into the 15-meter Gravel Zone have measured gas flow rates as high as 20–30 l/min. Also, drilling rigs have experienced blowouts as a result of encountering the high-pressure gas zone when penetrating to 15 m.

These examples, including the Ross Department Store explosion and vent well histories, reveal the importance of understanding the underlying hydrology in the identification of hazardous oilfield gas seeps to the surface (also see Toth 1996). These studies have confirmed that the underlying permeable aquifers can act to conceal the true magnitude of the gas migration hazards. Accordingly, soil gas studies must include determination of the magnitude of dissolved oilfield gases contained in the near-surface aquifers. This may include multiple zones, requiring the use of deep soil probes.

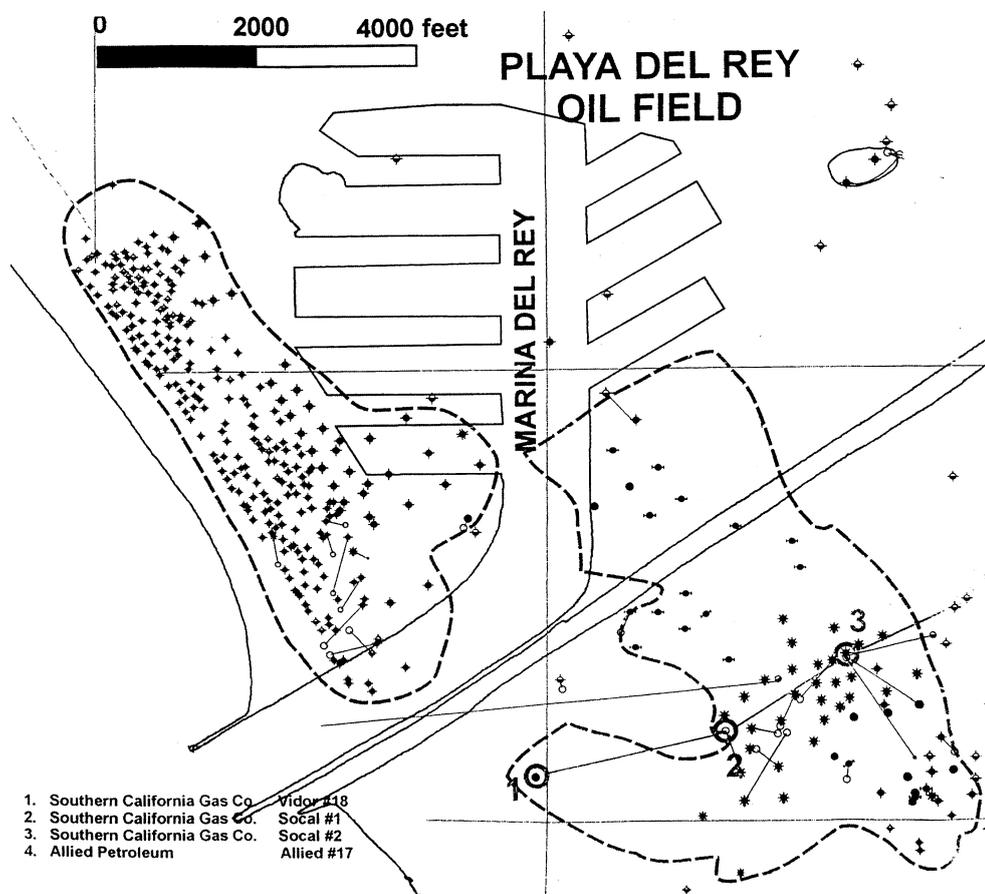


Fig. 4
Playa Del Rey oilfield (courtesy of Jack West, petroleum geologist, Fullerton, California)

A review of well abandonment records for the Playa del Rey and Venice oilfields has revealed very serious leakage problems. Leakage within the annular space between the casing and drillhole, because of poor cementing (see above), is a serious problem. Most of the wells depicted in Fig. 4 were drilled in the 1930s, before prudent cementing practices were used. For example, wells that had been abandoned as recently as 1993—to make way for housing developments—were found to be leaking when excavations were begun for the actual construction. In each case, homes were constructed directly over the old wells after minimal efforts were taken in an attempt to reseal the wells. Because of the small lots and high-density construction, there will be no room for reaccessing the wells using conventional drilling rigs.

Most of the construction in the Playa del Rey and Venice oilfield areas has failed to provide gas detection or other mitigation measures (e.g., as required by the Methane Ordinance) in order to deal with these gas migration hazards. For example, the underground gas storage operations at Playa del Rey involves injection of storage gas under high pressure (approximately 120 kg/cm²). Gas inventory studies (Tek 1987) have shown that leakage is directly proportional to the reservoir pressure maintained for gas storage (see Fig. 5). This raises serious questions about the appropriateness of locating gas storage fields in highly populated urban settings, especially where many homes have been built directly over poorly-abandoned wells. It is paramount that a fundamental understanding of how wells leak and proper procedures for monitoring are developed. Gas storage pressures are typically selected by

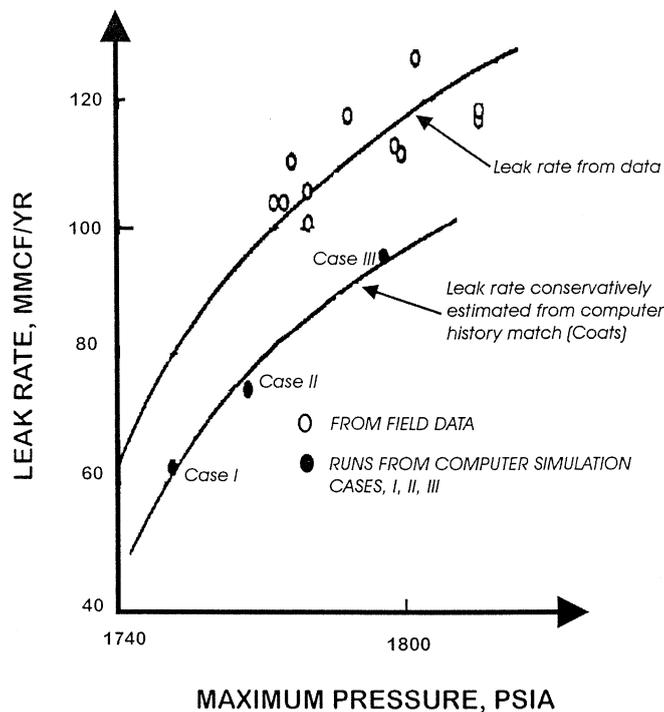


Fig. 5

Gas leak rate for various maximum reservoir pressures for Leroy Gas Storage project, Wyoming (modified after Tek 1987, Fig. 11–16)

Fig. 6

Los Angeles City oilfield (after California Division of Oil and Gas 1991)

the gas storage operator to maximize the storage volume, and to enhance retrievability of the gas when market demands dictate recovery (usually during cold spells when usage skyrockets). Also, cyclic operations associated with gas injection and withdrawal may create fractures.

Hutchinson, Kansas, gas storage leaks, explosions and fires of January 17–18, 2001

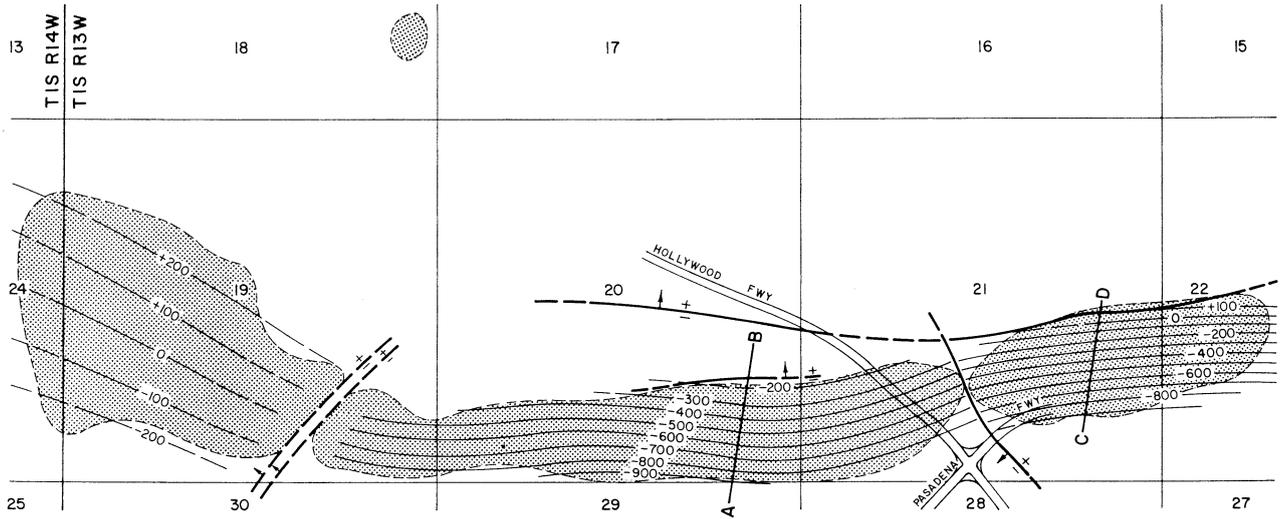
Underground gas storage leaks caused a devastating explosion and fires in the downtown area of Hutchinson, Kansas, on January 17, 2001 (Allison 2001). There was a release of natural gas from the ground water under several stores. Upon ignition, windows were blown out, and within minutes two businesses were ablaze. The fire department was unable to extinguish the flames because of the ongoing migration of gas into the area.

On the following day, leaking gas migrated into a trailer park on the outskirts of the town, causing a second explosion, and killing two people. The gas leakage was traced to a leaking storage gas reservoir about 7 miles from the town. Possibly, gas migrated along the fractures, formed as a result of subsidence, into the aquifer, and the water carried this gas to the sites of explosions.

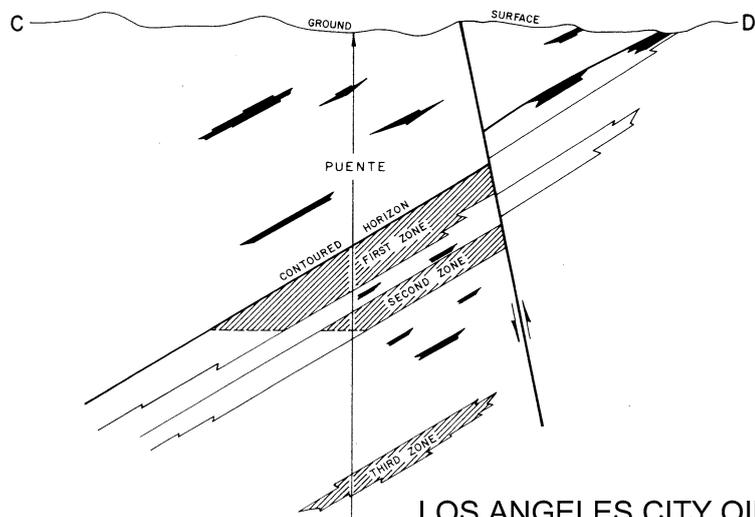
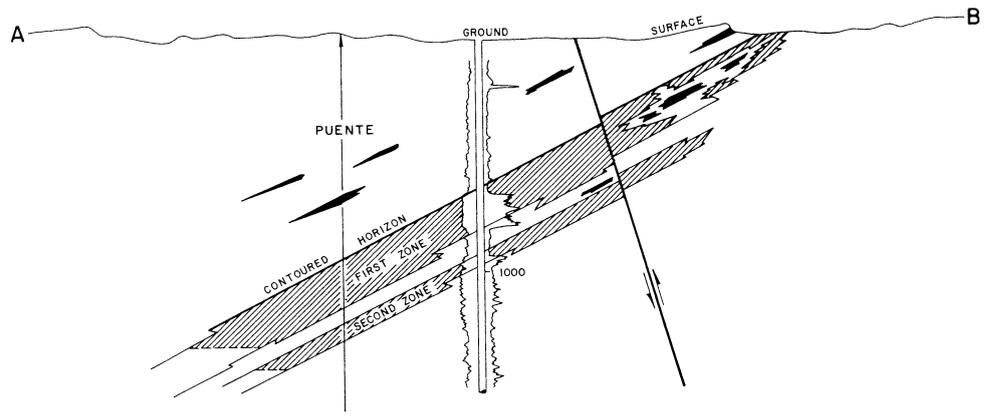
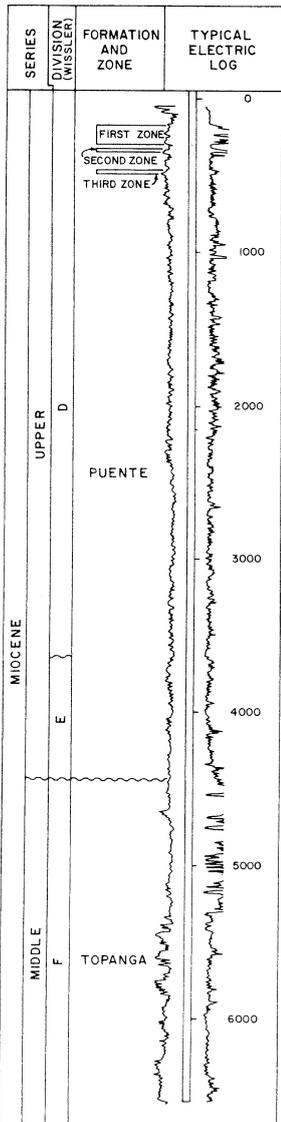
Santa Fe Springs oilfield

A study was undertaken by the authors to determine the integrity of operational oil wells in the Santa Fe Springs oilfield. To facilitate this review, a time period was selected after heavy rains in which the well cellars were partially filled with water. This allowed observation of gas bubbles seeping to the surface along well casings. Results were systematically recorded for more than 50 wells, some of which were used for waterflooding operations at pressures approaching 84.4 kg/cm². Approximately 75% of the wells were found to be leaking.

The waterflooding for enhanced oilfield recovery can be a dangerous practice due to hydraulic fracturing which could create avenues for the migration of gas to the surface creating an explosion hazard. Pressurization of an oilfield by way of water injection or gas injection requires careful attention to the integrity of the wells throughout the oilfield, and should not be undertaken until a soil gas monitoring program has been implemented in the vicinity of each well and fault to detect the potential leakage of gas to the surface. This is also necessary to determine the need for well repairs and/or well reabandonment.



CONTOURS ON TOP OF FIRST ZONE



LOS ANGELES CITY OIL FIELD

Belmont school construction on an oilfield

The Belmont Learning Center, a proposed high school in downtown Los Angeles, was in the process of being constructed over the Los Angeles City Oil Field before being abandoned. The site chosen was on a 0.14 km² parcel of land bounded by 1st Street to the south, Temple Street to the north, and Beaudry St. to the east. This location is over a shallow oilfield that has an outcrop to the surface just north of the building site. Furthermore, major faults criss-cross the area as illustrated in Fig. 6 (California Division of Oil and Gas 1991). The area is also part of the Elysian Park blind thrust fault system that has a generally east-west trend, which helps explain the uplifting and tilting of petroliferous formation depicted in Fig. 6.

Oil wells in the area continue to produce from shallow oil deposits at a depth no greater than 213 m. Most of the wells were drilled in the early 1900s, and continue to produce. All of the oilfield production gases are released to the atmosphere in the residential areas surrounding the wells. This includes four operational wells at the northwest corner of the school property.

Environmental studies, undertaken only after construction was undertaken, have revealed oilfield gas seepage to the surface over most of the 0.14 km² parcel, including the area directly under the school buildings. The project was abruptly halted when gas seepage was detected in the main electrical vault room of the project, just before the power was to be energized.

Soil gas studies revealed that methane (explosive levels) and other gases are migrating to the surface, including hydrogen sulfide. Measurements at the wellhead, and at other seep locations, revealed releases to the air of over 300 parts per million (ppm) of hydrogen sulfide. At depth, hydrogen sulfide was measured at over 3,000 ppm. These alarming results were extensively evaluated by the authors herein, and commented on during the many environmental reviews for the project (Endres 1999, 2002).

Over \$175 million has been spent on the project by the Los Angeles Unified School District. At least \$20 million has been spent on environmental site characterization alone. A double passive membrane has been proposed to be installed over the entire 0.14 km² site. One expert proposed drilling of a slant well to intercept the main avenue of gas migration (fault) and, thus, divert the direction of gas movement.

A recent discovery of surface faulting extending under several of the school buildings has placed a further halt on construction, and may doom the entire project.

This case history clearly identifies the extreme caution needed in evaluating the environmental suitability of sites located over oilfields, especially for school construction. The State of California has passed recent legislation that requires direct participation by the Department of Toxic Substances Control (DTSC) in the future school site selection process in order to avoid a repeat of the Belmont failure.

Subsidence problems caused by oilfield fluids production

One of the most serious environmental problems caused by oilfield operations within the Los Angeles Basin has been subsidence (Chilingarian and others 1995). Subsidence exists in virtually every oilfield within the Los Angeles Basin (Wentworth and others 1969). Subsidence is caused by the reduction of pore pressure within the reservoir resulting from fluids production. The resulting increase in the effective stress causes compaction which is propagated to the surface, typically causing a bowl-shaped subsidence at the surface, centered over the oilfield (see Fig. 7). The subsidence area is approximately twice the size of the oilfield itself (Khilyuk and others 2000). The enormity of the problem is well known for the Wilmington Oilfield that reached approximately 8.5 m before corrective action was taken by implementing a massive water injection program. This required legislative action in order to bring about a unitization of the oilfield to allow the flooding water program to be implemented. It has also become the public policy of the State of California to arrest subsidence, especially in coastal areas, through the use of water injection.

Minimizing the consequences of subsidence requires implementing a subsidence-monitoring program. The standard in use today in oilfields throughout the world (Endres and others 1991) is the Global Positioning Satellite System (GPS). The disasters of the past can be directly traced to the failure to perform adequate monitoring for subsidence. Conventional surveying and now satellite geodesy, permit determination of vertical and horizontal movements of the land surface above oilfields with great accuracy and at relatively minimal cost.

The Baldwin Hills reservoir failure of 1963

On December 14, 1963, at about 11:15 a.m., an unprecedented flow of water was heard in the spillway pipe at Baldwin Hills Dam in the Inglewood Oilfield area of Los Angeles. A short time later water broke violently through the downstream face of the dam, causing massive property damage to homes located below the dam and five deaths. The owner, the Los Angeles Department of Water and Power, had operated the dam continuously from July 1951 until its failure on December 14, 1963. Although an ongoing surveillance for leaks within spillways was carried out, no monitoring for oilfield subsidence was undertaken. The Inglewood Oilfield, discovered in September 1924, lies under the western half of the Baldwin Hills area. It covers about 4.9 km² and in 1963 had more than 600 producing wells (see Fig. 8). The field adjoins the reservoir site on the south and west, the nearest reported production at the time of the reservoir failure being from three wells within 213 m of the south rim.

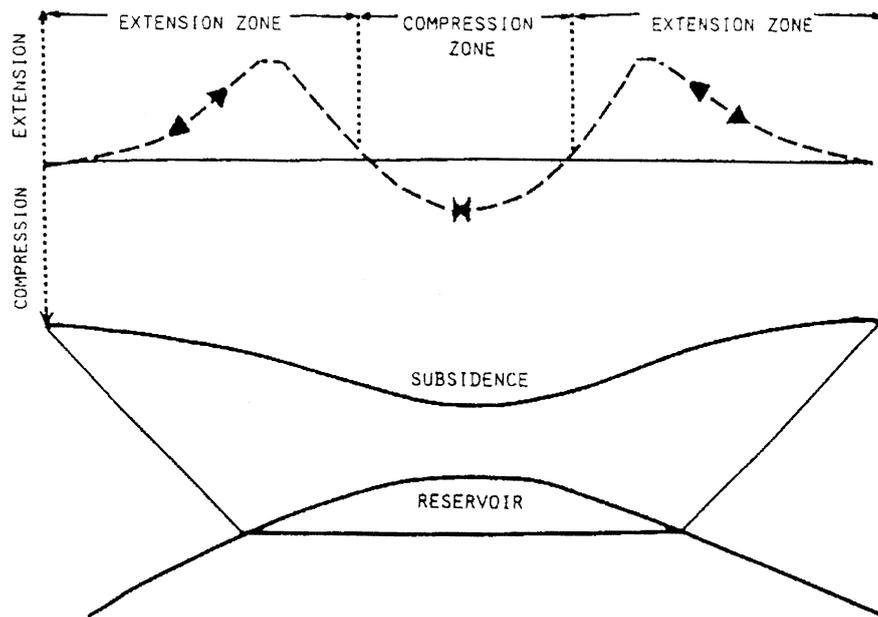


Fig. 7

Schematic diagram of compressive and tensile stress distribution in subsiding formation (modified after Gurevich and Chilingarian 1993, Fig. 1, p. 244)

Analysis of failure revealed ground movement that correlated directly with the Inglewood Oilfield fluids production (see Fig. 9). The total area of subsidence resembled an elliptical bowl with its center about 805 m west of the reservoir and centered over the oilfield. Subsidence at the reservoir site was about 0.9 m, compared to nearly 3.4 m at the subsidence bowl. Noteworthy was the fact that the southwest corner (viz., direction of maximum subsidence) had dropped more than the northeast corner, resulting in differential settlement across the dam of approximately 0.15 m. Furthermore, a review of survey data from 1934 to 1961 and 1963 showed lateral movement in the direction of subsidence depression.

The Inglewood-Newport Beach active strike-slip fault also bisects the area (see Fig. 8), with numerous faults branching off of the main fault in the area. Drilling records clearly reveal these many branching faults, indicating the enormous potential for differential movement along individual fault blocks. Indeed, a post-accident investigation revealed that differential fault block movement had caused rupturing of the asphaltic membrane used as a water seal over the floor of the dam.

Although fluid extraction and resultant subsidence were the prime contributors to the rupture of the reservoir, there is substantial evidence to indicate that water injection to stimulate oil production was also a contributing factor (Hamilton and Meehan 1971). Increased fluid pressures in the reservoir resulting from secondary recovery were sufficient to force brine water to the surface along faults. These forces, along with the lubricating influence of the water exacerbated differential movement along the individual fault blocks.

Recently, a large housing development was proposed for the Baldwin Hills area, virtually over the above described subsidence area. Large retaining walls (exceptionally high) were contemplated to enhance views (and presumably to add value to the individual lots). These retaining walls would have been extremely vulnerable to geologically

active and subsidence-prone area. When the developer became aware of the history of land movement in the area from ongoing oilfield production, the property was sold to the State for use as a public park.

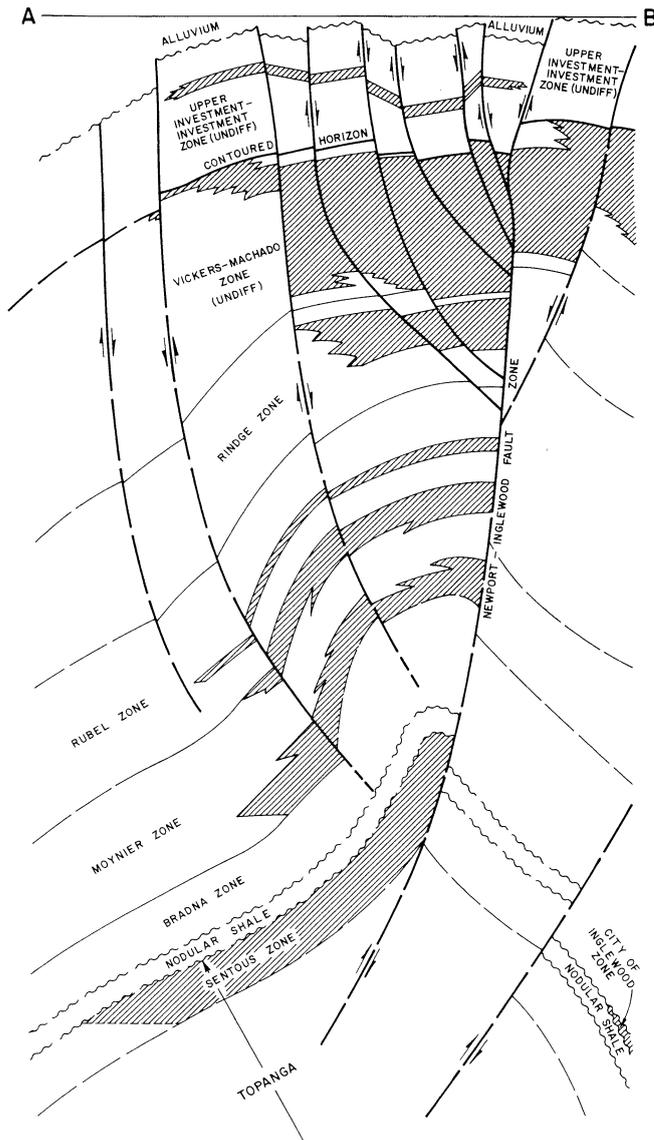
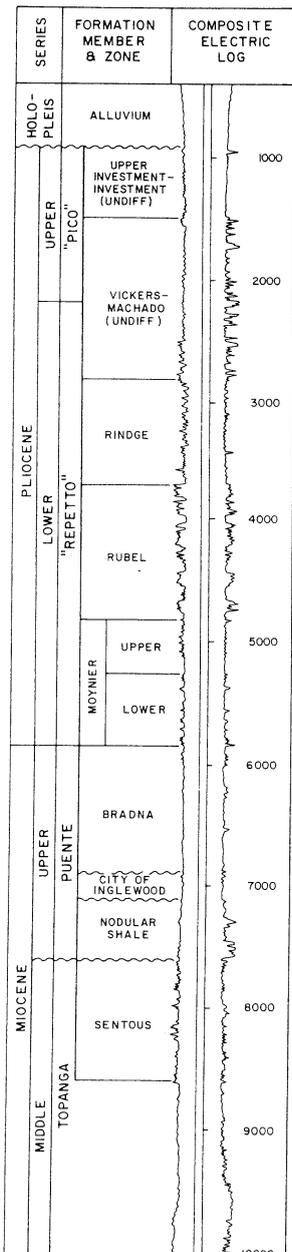
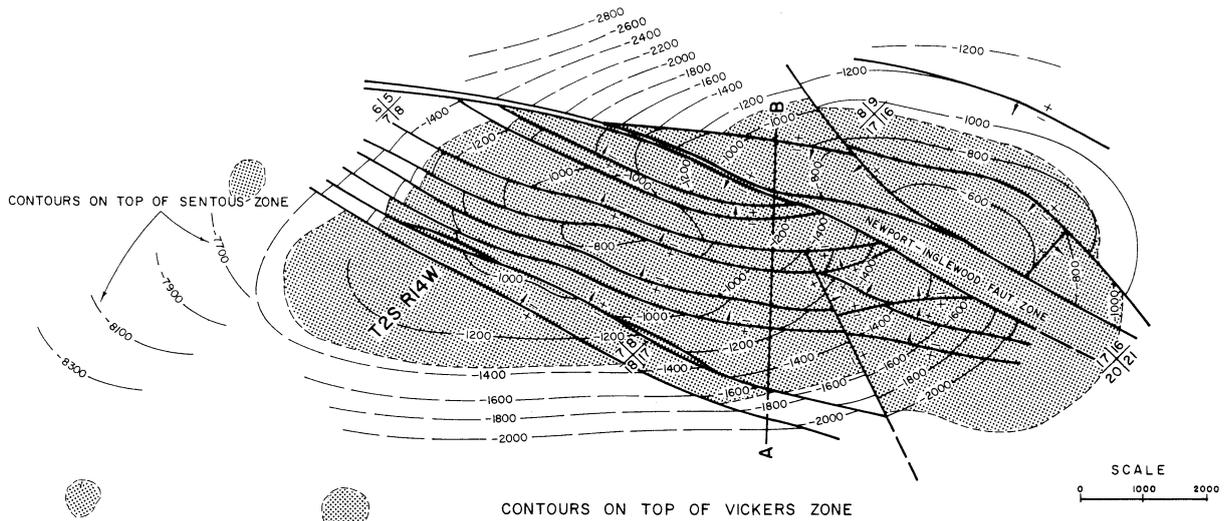
This case history highlights the importance of proper planning and monitoring of the land movement in an area that has been heavily impacted by major faulting, oilfield subsidence, and secondary recovery.

Redondo Beach, King Harbor subsidence

During a winter storm in January 1988, waves overtopped the breakwater constructed by the U.S. Army Corps of Engineers in order to protect the Redondo Beach King Harbor Boat Marina and surrounding commercial structures. Enormous damage resulted, including the destruction of the Portofino Inn. King Harbor is located at the northwest end of the Torrance Oil Field, directly over the Redondo Beach Oilfield (which is considered an extension of the Torrance Oilfield). The City of Redondo Beach had granted permission for offshore drilling from slant wells in that city.

The heights of benchmarks (used by the U.S. Army Corps of Engineers to construct the breakwater) were based on a U.S. Coast and Geodetic Survey of 1945. These benchmarks were assumed fixed, because the Corps of Engineers did not suspect subsidence until 1985, when surveys showed the breakwater crests to be as much as 0.6 to 0.9 m above the original design elevations. Apparently, nothing was done to protect the harbor, or to warn the commercial establishments prior to the storm of January 1988.

Investigation following the disaster revealed that nearly 0.6 m of subsidence had occurred under the breakwater as a result of oil production beginning in 1943, but with



INGLEWOOD OIL FIELD

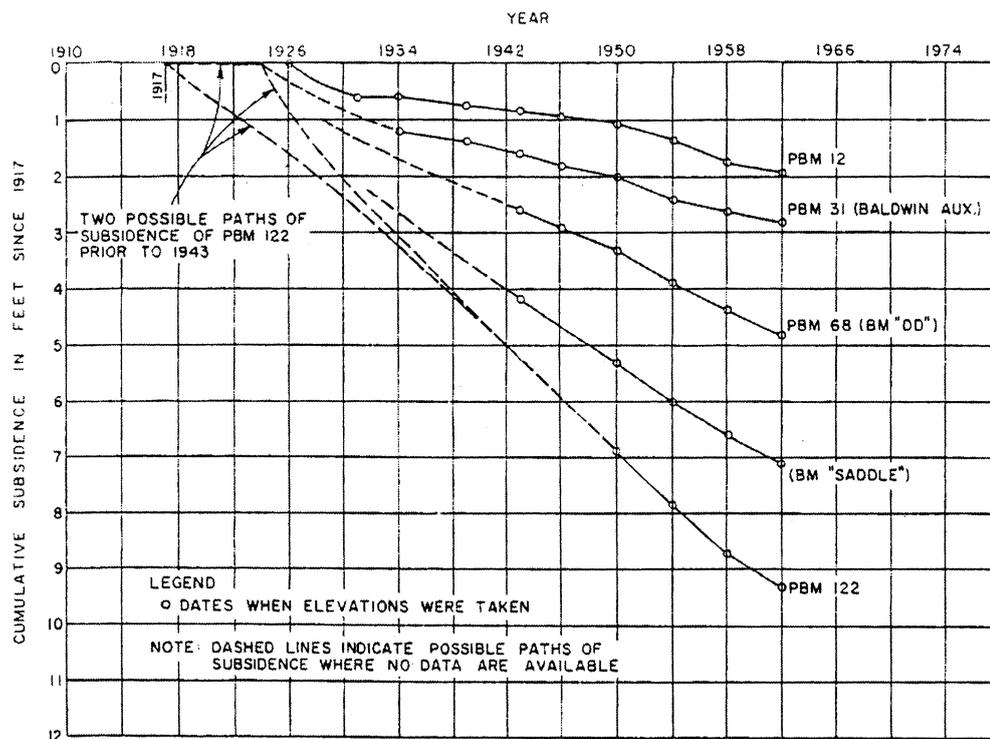


Fig. 9
Subsidence of benchmarks, Baldwin Hills area, Los Angeles, California (after California Department of Water Resources, Baldwin Hills Reservoir, Apr. 1964)

accelerated subsidence occurring after the approval of tideland oil production in 1956.

A jury trial in the Torrance Superior Court resulted in a multi-million dollar judgment against the U.S. Army Corps of Engineers and the City of Redondo Beach. Several oil companies involved in the oil production settled prior to the case going to trial.

The main lesson to be learned is that this disaster could have been averted if proper monitoring for subsidence had been undertaken. It is important to note that the judgment was upheld on appeal, in which the Appellate Court found that undertaking oilfield production in such an urban setting constituted an ultra hazardous activity, requiring the utmost standard of care. Virtually every oilfield in the Los Angeles Basin has experienced subsidence as a result of fluid production. Accordingly, an appropriate standard of care for all oilfield operators should be to undertake monitoring from the onset of production.

Playa Del Rey/Marina Del Rey subsidence

Historical measurement data regarding subsidence in the Playa del Rey/Venice oilfield areas reveal almost 0.6 m of subsidence from the time that oil production began in the 1920s and through 1970. However, no subsidence

Fig. 8

Structural contour map of the Inglewood Oilfield, Los Angeles, California. Contours are on top of the Vickers Zone (after California Division of Oil and Gas 1991)

monitoring has occurred since 1970, despite the fact that fluid production has continued to the present. The Marina del Rey breakwater is vulnerable to subsidence, as is the coastal area.

The most vulnerable are the old wells that were drilled and completed in the 1930s. Any damage to the oil wells (including cements) due to movement along faults present the potential for increased gas migration to the surface. This is especially critical because the oilfields underlying the area are being used to store high-pressure gas transported in from out of the State of California. Figure 10 is presented to illustrate the interrelationship among earthquakes, gas migration, and subsidence resulting from oilfield production (Chilingarian and others 1995; Gurevich and others 1993).

Clearly, these oilfield operations required the utmost degree of vigilance in order to protect the high-density urban development in the area. Monitoring for subsidence and gas migration is essential in order to meet this standard of care.

The release of air toxics from surface operations, wellheads and pipelines

The Federal Environmental Protection Agency (EPA) has determined that the primary hazardous air pollutants (HAP) emitted from oil and natural gas transmission and storage facilities are (see Federal Register, Volume 63, No.25/Feb.6, 1998):

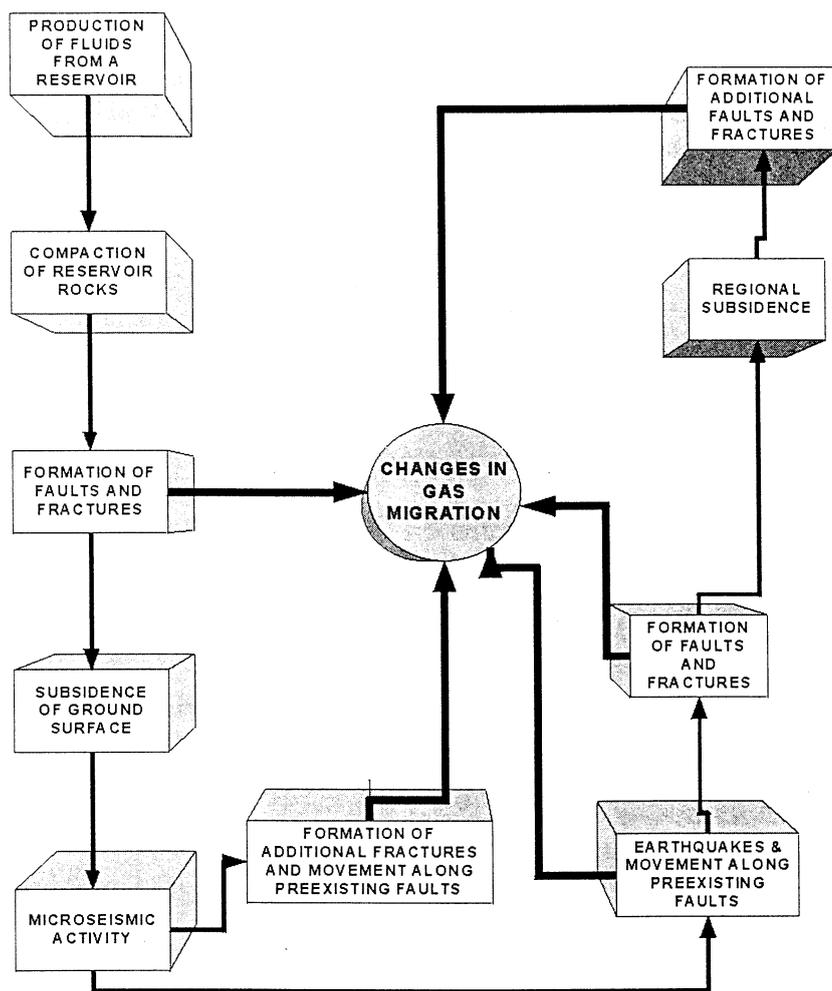


Fig. 10

Schematic diagram of system relationships among the production of fluids, compaction, subsidence, and seismic activity (Modified after Chilingarian and others 1995, Fig. 1, p. 41)

1. Benzene
2. Toluene
3. Ethylbenzene
4. Xylenes

These compounds are collectively referred to as the BTEX chemicals. The BTEX chemicals are the aromatic components of crude oil. For a further discussion of these hazardous components of crude oil see McMillen and others (2001). Although crude oil has variable contents of aromatic hydrocarbons, depending upon the origin, the API rating of the crude oil can be a good predictor of the content of aromatics, especially benzene (see Fig. 11). The higher the API gravity of the crude oil, the higher the percentage of aromatics in the crude oil.

Tissot and Welte (1978) found that 95% of the crude oils produced around the world fell into the distribution pattern shown in Fig. 12. As an example, the composition of a 35^o API-gravity crude oil is as follows (Hunt 1979):

| Molecular type | Weight percent |
|----------------|----------------|
| Paraffins | 25 |
| Naphthenes | 50 |
| Aromatics | 17 |
| Asphaltenes | 8 |
| Total | 100 |

The majority of crude oils have been reported to contain 15 to 40% aromatics. The aromatics are characterized by a double carbon bond, which has been directly linked to the health hazards posed by these chemicals. Benzene, a known human carcinogen, has been linked in the medical literature to leukemia, aplastic anemia, lymphomas and a variety of other cancer related ailments.

Oil and gas production facilities are required to provide warnings to the public regarding certain hazardous oilfield chemicals, including benzene and toluene, under California Health and Safety Code Section 25249.6 (otherwise known as Proposition 65).

Most facilities are not required to identify the amount or the specific types of chemicals being released to the atmosphere from their operations. The Federal EPA has identified dehydration equipment as a major source of benzene and toluene air toxics emissions, and has proposed legislation to curtail such emissions, especially in residential areas.

Venting of oilfield gases to the atmosphere must be viewed as a hazardous activity, because the oilfield gases can contain appreciable levels of benzene. Oilfield gases and condensates have the highest contents of benzene. A typical content of benzene in the oilfield gases can vary between 30 parts per million (ppm) to over 800 ppm. For this reason, the natural gas should be carefully tested for its benzene content before venting of large quantities of

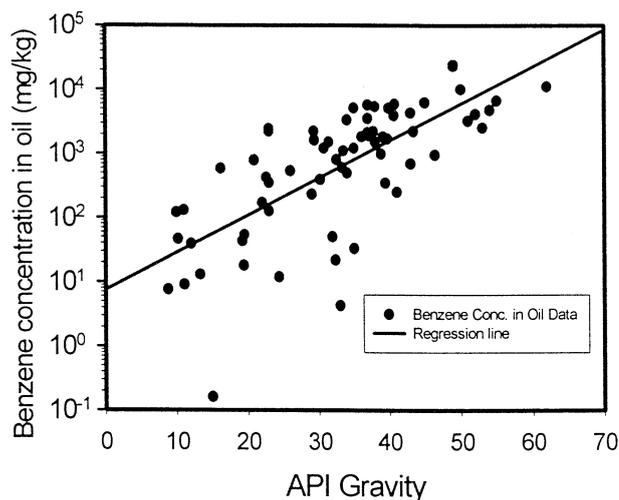


Fig. 11

Benzene concentrations versus API gravity for 61 crude oils and 14 condensates (API gravity data were unavailable for eight crude oils) (after Rixey 2001)

gas is undertaken. Also, vent stack emissions should be carefully monitored. Additional concerns and precautions must be taken in and around sour oilfield operations. Hydrogen sulfide, even in small quantities, can be hazardous to the health. The research conducted at the University of Southern California Medical Facility (Kilburn 1998, 1999) has established central nervous system damage from the neurotoxin effects of hydrogen sulfide even at concentration in air as low as 1 ppm. This is much lower than the workplace standards that have been considered safe in the past. This also highlights the importance of not relying upon workplace standards regarding air toxics emissions in the case of residential areas and school sites. Safety, health, and environmental considerations need to be made a top priority in the land use planning where urban development coexists with the oil- and gas-field operations.

Conclusions

The history of the Los Angeles Basin oilfields has demonstrated the need to exercise a high degree of vigilance regarding the environmental hazards posed by these operations. Land use planning and governmental entity decisions regarding allowing massive real estate development over and adjacent to these operations sometime ignored the health and safety risks posed by these operations. The primary purpose of this paper has been to show the importance of reviewing a long history of environmental problems created by this mixed land usage, and to identify what steps need to be taken to avert future disasters. This includes the necessity of taking the following steps:

Gas migration monitoring: Much closer attention must be given to the need to perform ongoing monitoring for gas migration into the near surface soils in areas heavily impacted by historical oil production, and where there are many old and abandoned wells. It is very important to monitor gas migration near the fault zones.

Subsidence monitoring: Monitoring for subsidence in the oil and gas producing areas is necessary in order to protect against the undermining of foundations and highly sensitive changes in elevation (especially in coastal areas), and to reduce the risk of gas migration hazards. Subsidence gives rise to faults and fractured zones, which are avenues for gas migration.

Air Toxics monitoring: The release of air toxics from surface operations, wellheads and pipelines must be carefully monitored in order to protect the public health, especially from the release of such chemicals as benzene, toluene, ethylbenzene, xylene (viz., the BTEX aromatic hydrocarbons) and hydrogen sulfide. Great caution is required in the operation of vapor recovery equipment and in the monitoring of toxic emissions in order to take corrective action.

Soil and groundwater monitoring: Soil and groundwater must be carefully evaluated for petroleum and drilling

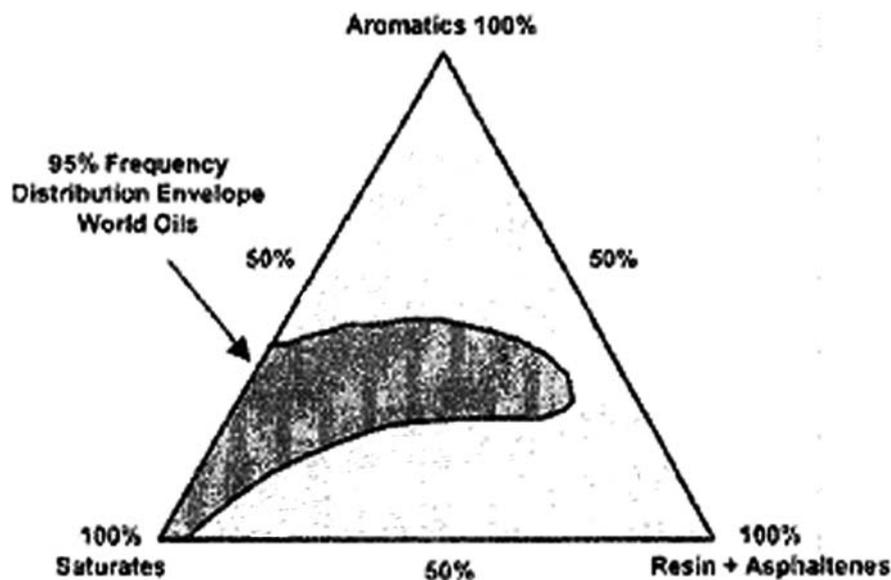


Fig. 12

Ternary diagram showing the class composition of crude oils (after Tissot and Welte 1978)

mud contamination, and appropriate steps must be taken to remediate the soil and water contamination before development is allowed to proceed. This requires an evaluation of the underlying aquifers, which become a ready target for the oil and gas migration hazards.

Soil gas monitoring: Soil gas monitoring is an essential step in the evaluation of soil and aquifer contamination by historic oil and gas field operations. It is also necessary to determine what mitigation measures may be necessary to protect against migration of explosive and toxic oilfield gases into residential and commercial structures. This will be an ongoing problem in many areas that must employ gas detectors, vent pipes, membrane barriers and ventilation systems in order to protect against the gas migration hazards.

Oil and gas well leaks and ongoing monitoring: Oil and gas wells must be carefully evaluated, and old wells must be abandoned to protect against the risk of oilfield gases migrating up the old wellbores and entering the near-surface environment. There has been a long history of this very serious problem, establishing that the prior well abandonment procedures have been often inadequate in dealing with this extremely dangerous problem.

Building over abandoned wells: Land planning and issuance of building permits should require adequate room to provide access for a drilling rig to reenter old wells, when they begin leaking.

As a final conclusion, the authors would like to quote the editorial of Professor George V. Chilingar, Founder of Journal of Petroleum Science and Engineering and Managing Editor (*J Petrol Sci Eng* 9:237): "... Underground gas storage and oil and gas production in urban areas can be conducted safely if proper procedures are followed." "After recognition of the existing problem, proper safe operating procedures can be easily developed."

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REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS

DISCUSSION DRAFT

CALIFORNIA CODE OF REGULATIONS, TITLE 14 CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

[SECTION 1724.9 IS DELETED]

NEW ARTICLE ADDED:

Article 4. Requirements for Underground Gas Storage Projects

1726. Purpose, Scope, and Applicability.

The purpose of this article is to set forth regulations governing underground gas storage projects. Underground gas storage projects and gas storage wells are not subject to the requirements of Sections 1724.6 through 1724.10.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.1. Definitions.

(a) The following definitions are applicable to this article:

(1) "Area of review" means the volumetric vertical and horizontal extent of the reservoir used for underground gas storage and surrounding areas that may be subject to its influence. The area of review is delineated by the geologic extent of the reservoir such as impervious rock, structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces in a three dimensional image.

(2) "Caprock" means the rock layer or layers at the upper boundary of the storage reservoir acting as the primary barrier preventing upward migration of fluids.

(3) "Fluid" means liquid or gas.

(4) "Gas storage well" means a well used to inject or withdraw gas from an underground storage project.

(5) "Reservoir" means the hydrocarbon reservoir that is being used to store natural gas in an underground gas storage project. The entire depth interval of a reservoir from the shallowest to the deepest depth can be subdivided into one or more depth intervals, which are referred to in this article as "zones".

(6) "Underground gas storage project" means a project for the injection and withdrawal of natural gas into an underground reservoir for the purpose of storage. An underground gas storage project includes the reservoir used for storage, the confining caprock, gas storage wells, observation wells, and any other wells approved for use in the project. A gas storage project also includes the wellheads and, to the extent that they are subject to regulation by the Division, attendant facilities, and other appurtenances.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.2. Approval of Underground Gas Storage Projects.

(a) A Project Approval Letter shall be obtained from the Division before any injection occurs as part of an underground gas storage project. The Project Approval Letter shall specify the location and nature of the underground gas storage project, as well as the conditions of the Division's approval. Changes to the operational parameters of an underground gas storage project are subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground gas storage project operations shall not occur or continue unless consistent with the terms and conditions of a current Project Approval Letter.

(b) The Division will review underground gas storage projects to verify adherence to the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter to ensure that they effectively prevent damage to life, health, property, and natural resources. Ongoing approval of an underground gas storage project is at the Division's discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division.

(c) If the Division determines that operation of an underground gas storage project is inconsistent with the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, then upon written notice from the Division specified operations shall cease immediately, or as soon as it is safe to do so.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.3. Risk Management Plans.

(a) For each underground gas storage project, the operator shall submit a Risk Management Plan to the Division for review and approval. The Risk Management Plan shall identify potential threats and hazards to well and reservoir integrity, as well as life, health, property, and natural resources; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate each risk identified as well as overall and integrated risks; and specify a process for periodic review and reassessment of the risk assessment and prevention protocols. Risk assessment and prevention protocols shall be consistent with and additional to any other existing requirement in statute or regulation. The operator shall state what method and guidance it has followed in preparing the risk assessment. The Risk Management Plan shall specify a schedule for submission of risk assessment results to the Division. All Risk Management Plans shall include at least the following risk assessment and prevention protocols:

(1) Well construction and design standards, consistent with the requirements of Section 1726.5. If the operator has gas storage wells that are not in conformance with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan for either bringing the wells into conformance or phasing the wells out of use.

(2) For each gas storage well, employment as appropriate of surface and/or subsurface automatic or remote-actuated safety valves based on the following:

(A) The well's distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people may assemble such as campgrounds, recreational areas, or playgrounds;

(B) Gas composition, total fluid flow, and maximum flow potential;

(C) The distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

(D) The risks created by installation and servicing requirements of safety valves;

(E) The risks to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

(F) Proximity to environmentally or culturally sensitive areas;

(G) Alternative protection measures which could be afforded by barricades or distance or other measures;

(H) Age of well;

(I) The risks of well sabotage;

(J) The current and predicted development of the surrounding area, topography and regional drainage systems and environmental considerations; and

(K) Evaluation of geologic hazards such as seismicity, active faults, landslides, subsidence, and potential for tsunamis.

(3) Ongoing verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage. The mechanical integrity testing protocols for gas storage wells shall, at a minimum, adhere to the requirements of Section 1726.6.

- (4) Corrosion monitoring and evaluation including the following:
 - (A) Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;
 - (B) Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;
 - (C) Corrosion potential of annular and packer fluid;
 - (D) Corrosion potential of current flows associated with cathodic protection systems;
 - (E) Corrosion potential of all formation fluids, including fluids in formations above the storage zone; and
 - (F) Corrosion potential of uncemented casing.
 - (5) Ongoing evaluation of gas storage wells including monitoring of casing pressure changes at the wellhead, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.
 - (6) Material balance monitoring in accordance with the requirements of Section 1726.7(b).
 - (7) Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.
 - (8) Identification of potential threats and hazards associated with operation of the underground gas storage project including the following:
 - (A) Evaluation of likelihood of events and consequences related to the events;
 - (B) Determination of risk ranking to develop preventive and mitigating measures to monitor or reduce risk;
 - (C) Documentation of risk evaluation and description of the basis for selection of preventive and mitigating measures;
 - (D) Provision for data feedback and validation;
 - (E) Regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness; and
 - (F) Analysis and risk assessment of geologic hazards including, and not limited to seismicity, faults, subsidence, inundation by tsunamis, sea level rise, and floods.
 - (G) Analysis and risk assessment of hazards associated with the potential for fire.
 - (9) If observation wells are employed, identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level.
 - (10) Consideration of potential for impacts to groundwater quality resulting from operations of the underground gas storage project.
 - (11) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.
 - (12) An emergency response plan that accounts for the threats and hazards identified in the Risk Management Plan and that complies with the requirements of Section 1726.9.
- (b) The Division will make completed Risk Management Plans and significant updates to the Risk Management Plans available to the California Public Utilities Commission. If any part of a

Risk Management Plan is subject to confidential treatment, then the Division will segregate the confidential records and only provide them if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.4. Underground Gas Storage Project Data Requirements.

(a) For all underground gas storage projects, the operator shall provide the Division with data, analysis, and interpretation that demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources. The operator shall provide the data specified in this section and any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the proposed project. The data provided by the operator shall be to a level of detail and certainty satisfactory to the Division, and the operator shall ensure that required data is complete and current, regardless of the date of approval of the gas storage project. The data submitted to the Division shall include the following:

(1) Oil and gas reserves of all proposed storage zones prior to start of injection, including calculations, to indicate the storage capacity of the reservoir being considered for gas storage.

(2) Description of existing or proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.

(3) Proposed produced water disposal method.

(4) Maximum and minimum reservoir pressure for the underground gas storage project and the data and calculations supporting the bases for the pressure limits. The pressure limits shall account for the following:

(A) The pressure required to inject fluids, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, caprock, wells, well heads, piping or associated facilities.

(B) The minimum reservoir pressure shall take into account the historic minimum operating pressure and reservoir geomechanical competency. The impacts of intended minimum reservoir pressure shall be accounted for as it relates to geomechanical stress and liquid influx.

(5) An engineering and geological study demonstrating that injected gas will not migrate out of the approved zone or zones, such as through another well, geologic structure, faults, fractures or fissures, or holes in casing. The study shall include, but is not limited to:

(A) Statement of primary purpose of the project.

(B) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations.

(C) A comprehensive geologic characterization of the gas storage project including lithology of the storage zone or zones and sealing mechanisms as well as all formations encountered from surface to the deepest well in the project. The geologic characterization shall include any

information that may be required to ensure injected or withdrawn gas does not have an adverse effect on the project or pose a threat to life, health, property or natural resources. The geologic characterization shall include potential pathways for gas migration and areas or formations where potential entrapment of migrated gas could occur. Information to accompany the geologic study shall include but is not limited to:

- (i) Structure contour maps drawn on a geologic marker at or near the top of each gas storage zone in the project area, indicating faults and other lateral containment features.
- (ii) Isopach map of each gas storage reservoir or subzone in the project area.
- (iii) At least two geologic cross sections through at least four gas storage wells in the project area and the areas immediately adjacent.
- (iv) Representative electric log to a depth below the deepest producing zone identifying all geologic units, formations, aquifers with groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, aquifers with groundwater that has 3,000 or less milligrams per liter of total dissolved solids content, oil or gas zones, and gas storage reservoirs.
- (v) Additional information including, but not limited to: isopach, isoGOR, isoBAR, structure-contour, 3-D, water-oil, or gas-oil ratio maps of the project and other information which will delineate all known features such as faults and fractures within the area of influence of the gas storage project.

(D) Reservoir fluid data for each gas storage zone, such as oil gravity and viscosity, water quality, presence and concentrations of non-hydrocarbon components in the associated gas (e.g. hydrogen sulfide, helium, etc.), and specific gravity of gas.

(E) A map of the area of review showing the location and status of all wells within and adjacent to the boundary of the area of review. The wellbore path of directionally drilled wells shall be shown, with indication of the interval penetrating the gas storage zone(s) of the underground gas storage project.

(F) Casing diagrams, including all data specified in Section 1726.4.1, of all wells that are within the area of review and that are in the same or a deeper zone as the gas storage project, including directionally drilled wells that intersect the area of review in the same or deeper zone. The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for gas to migrate outside of the approved zone of gas storage or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources. At a minimum, the casing diagrams must demonstrate that:

- (i) Plugged and abandoned wells have cement across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the intended zone of injection; and
- (ii) Wells that are not plugged and abandoned and that have been inactive for more than two years have cement plugs across all hydrocarbon zones, the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(G) Identification of all wells within the area of review that are not in the same or a deeper zone as the underground gas storage project, including description of the total depth of the well and the estimated top of the gas storage reservoir below the well.

(H) Wells completed in or penetrating through the intended gas storage reservoir shall be identified and evaluated for containment assurance for the design of gas storage operation volumes, pressure, and flow rates. The operator should identify, and the Division confirm, wells which may require integrity testing or well logging in order to meet the integrity demonstration. The Division may select plugged and abandoned wells to be re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of gas storage operations.

(I) The planned or estimated well drilling and plugging and abandonment program to complete the project, showing all gas storage wells, plugged and abandoned wells, other wells related to the project, and unit boundaries.

(J) Maps of the locations of underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production or gas storage operations within the area of review, to the extent it is publicly available.

(6) A gas storage injection and withdrawal plan that includes all of the following:

(A) Maximum anticipated surface injection pressure and maximum anticipated daily rate of injection, by well.

(B) Monitoring system or method acceptable to the Division to be utilized to ensure the gas injected is confined to the intended approved zone(s) of injection.

(C) A wellhead monitoring system acceptable to the Division for the detection of leaks.

(D) A list of proposed cathodic protection measures for plant, lines, and wells, where employed.

(E) A summary of the source and analysis of the gas injected, submitted to the Division on an annual basis.

(7) The name and API number of all gas storage wells and other wells that are part of the underground gas storage project.

(8) Any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the underground gas storage project.

(b) Updated data shall be provided to the Division if conditions change or if more accurate data become available.

(c) All data filed with the Division under this section shall be submitted electronically, in a format acceptable to the Division. All maps, diagrams and exhibits shall be clearly labeled as to scale, north arrow, coordinate system, and purpose, and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) Where it is infeasible to supply the data specified in subdivision (a), the Division may accept alternative data, provided that the alternative data demonstrate to the Division's satisfaction that injected gas will be confined to the approved reservoir or reservoirs of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources.

(e) The operator shall consult with the Division if the operator believes that there is a basis under state or federal law for confidential treatment of any data submitted to the Division. If the Division agrees that there is a basis for confidential treatment of data submitted, then the Division will take appropriate steps to maintain the confidentiality of that data.

(f) The Division will make all data received under this section available to the California Public Utilities Commission upon request. If the requested records are subject to confidential treatment, then the Division will only provide the records if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.4.1. Casing Diagrams.

(a) Casing diagrams submitted under Section 1726.4 shall adhere to the following requirements:

(1) Casing diagrams shall include all of the following data:

(A) Operator, lease name, well number, and API number of the well;

(B) Ground elevation from sea level;

(C) Reference elevation (i.e. rig floor or Kelly Bushing);

(D) Base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content;

(E) Base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content;

(F) Sizes, weights, grades, and connection types of casing and tubing;

(G) Details on associated equipment such as subsurface safety valves, packers, gas lift mandrels;

(H) Depths of shoes, stubs, and liner tops;

(I) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, patches, casing damage, top of junk or fish left in well, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;

(J) Drill bit size diameter and depth of drilled hole;

(K) Cement plugs inside casings, including top and bottom of cement plug, with method of determination;

(L) All cement fill behind casings, including top and bottom of cemented interval, with method of determination;

(M) Type and weight (density) of fluid between cement plugs;

(N) Depths and names of the formation(s), zone(s), and geologic markers penetrated by the well, including the top and bottom of the gas storage zone(s);

(O) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job; and

(P) All of the information listed in this paragraph for all previous drilled or sidetracked well bores.

(2) Measured depth and true vertical depth shall be provided for all measurements required under subdivision (a)(1).

(3) For directionally drilled wells, a directional survey shall be provided with inclination, azimuth measurements, and surface location.

(4) Casing diagrams shall be submitted in an electronic format acceptable to the Division.

(5) For all wells to be used for gas injection and/or withdrawal, the casing diagram shall include the mechanical well barrier elements that comprise the primary and secondary barriers as specified in section 1726.5.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.5. Well Construction Requirements.

(a) Operators shall design, construct, and maintain gas storage wells to effectively ensure mechanical integrity under anticipated operating conditions for the underground gas storage project. The operator shall ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and make certain that integrity concerns with a gas storage well are identified and addressed before they can become a threat to life, health, property, or natural resources.

(b) Operators can demonstrate that a gas storage well adheres to the performance standard in subdivision (a) by demonstrating all of the following:

(1) The well has been completed with both primary and secondary mechanical well barriers to isolate the storage gas within the storage reservoir and transfer storage gas from the surface into and out of the storage reservoir.

(A) At minimum, the primary mechanical barrier shall be comprised of the following elements:

(i) Production casing to surface with the required integrity to contain reservoir pressure;

(ii) Tubing with packer and production tree with the required integrity to contain reservoir pressure; and

(iii) Surface Controlled Subsurface Safety Valve (SCSSV) or Christmas tree valve with the required integrity to contain reservoir pressure that halts flow through the well.

(B) At minimum, the secondary mechanical barrier shall be comprised of the following elements:

(i) Casing cement that overlaps at least 100 feet between two concentric casings, with good quality cement bond;

(ii) Wellhead with annular valves and seals and the required integrity to contain reservoir pressure;

(iii) Casing with hanger and seal assembly;

(iv) Tubing hanger with seals; and

(v) Christmas tree master valve.

(2) Each string of casing is designed to safely contain the expected internal and external pressures and tensile loads.

(3) The surface casing is of sufficient size, weight, grade, competency, and depth to support subsequent drilling operations.

(4) The production casing is of sufficient size, weight, grade, competency, and depth to maintain the well integrity, and is compatible with fluid chemical composition. The production casing is designed to accommodate fluids on injection and withdrawal at the maximum expected pressures and velocities. The production casing is free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work are sealed to establish hydraulic isolation.

(5) Casing connections are appropriate for use in the well design and exceed the expected mechanical loads.

(6) The gas storage well is cemented so as to maintain the integrity of the storage zone(s) by providing isolation of the reservoir from communication with other sources of permeability or porosity through the wellbore. Isolation is accomplished by filling the annular space between the casing and formation with competent cement to create a seal so that communication of fluids from the storage zone or other zones of interest is prevented.

(7) The cementing operations used a cement slurry designed for the anticipated wellbore conditions. All casing was cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. Additionally, cementing operations meet or exceed the following requirements:

(A) Surface casing is cemented with sufficient cement to fill the annular space from the shoe to the surface to protect ground water.

(B) Intermediate and production casings, if not cemented to the surface, are cemented with sufficient cement to fill the annular space to at least 500 feet above the gas storage reservoir, oil and gas zones or anomalous pressure intervals and to at least 100 feet above the base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(8) Cement plugs provide for effective zonal isolation.

(9) Any remedial cement slurry and placement techniques are designed for the specific wellbore conditions, formations, and type of repairs.

(10) Cement bond log or evaluation acceptable to the Division is on file that indicates an adequate cement bond between the casing, cement and geologic formations. A competent cement bond extends across the caprock, and at least 100 feet above the gas storage reservoir.

(11) For wells equipped with tubing and packer, packer is set in cemented casing within caprock or at a location acceptable to the Division.

(c) If the operator does not demonstrate that a gas storage well meets the criteria of subdivision (b), then the operator shall demonstrate to the Division's satisfaction that an alternative method of well design and construction has been employed that effectively adheres to the performance standard of subdivision (a). The Division will determine on a case-by-case

basis whether the operator has effectively demonstrated that a gas storage well that does not conform to the criteria in subdivision (b) meets the performance standard in subdivision (a).

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.6. Mechanical Integrity Testing.

(a) The operator shall, at a minimum, conduct the following mechanical integrity testing on each gas storage well:

(1) A temperature and noise log shall be conducted at least annually to ensure integrity. All anomalies identified shall be immediately reported to the appropriate district office and explained to the Division's satisfaction.

(2) A casing wall thickness inspection, employing such methods as magnetic flux and ultrasonic technologies, shall be performed at least every two years to determine if there are possible issues with casing integrity. The results shall be compared against prior results and any other available data to determine the corrosion rate. If the casing wall thickness inspection indicate that within the next 24 months thinning of the casing will diminish the casing's ability to contain the well's maximum allowable operating pressure utilizing Barlow's equation or another method acceptable to the Division, then the well shall be remediated and shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent casing wall thickness inspection schedule for a well if the operator demonstrates to the Division's satisfaction that the well's corrosion rate is low enough that biennial inspection is not necessary.

(3) A pressure test of the production casing shall be conducted at least every two years. If injection in the gas storage well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well. Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. A lower testing pressure may be approved by the Division if necessary to ensure that testing does not compromise the mechanical integrity of the well. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. If a pressure test does not indicate a final stabilized pressure and less than 10 percent pressure loss over a minimum 30 minute test, then the well shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may require a longer duration of up to 60 minutes pressure testing based on individual circumstances. The Division may approve a less frequent pressure testing schedule for a well if the operator demonstrates to the Division's satisfaction that other measures to ensure the integrity of the well warrant less frequent pressure testing.

(b) A newly constructed gas storage well, or a reworked gas storage well that has had its existing production casing modified from its previous condition during rework activities, shall be tested as per subdivision (a).

(c) The Division may require additional testing as needed to demonstrate the integrity of the well.

(d) The appropriate district office shall be notified at least 48 hours before performing mechanical integrity testing so that Division staff may have an opportunity to witness the testing. All mechanical integrity testing shall be documented and copies of test results shall be submitted to the Division in an electronic format within 30 days.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.7. Monitoring Requirements.

(a) In addition to the mechanical integrity testing requirements under Section 1726.6, the operator shall monitor for the presence of annular gas by measuring and recording annular pressure at least once a day. The operator shall evaluate any anomalous annular gas occurrence and report it to the Division. This requirement may be met by employment of a real-time data gathering system, such as Supervisory Control and Data Acquisition.

(b) The material balance behavior of an underground gas storage project's storage reservoir shall be monitored relative to the original design and expected reservoir behavior. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential, as outlined in the Risk Management Plan. Material balance support data will be submitted to the Division at least once a year, or upon request. Acceptable reservoir integrity monitoring and analysis methods include any of the following, or an equally effective method approved by the Division:

(1) Monitoring average reservoir pressure versus inventory and comparing that to expected conditions in order to allow for the discovery and correction of any anomalies or unexpected conditions. Liquid level shall be taken into account when utilizing observation wells. Semiannual field shut-in tests, usually conducted at the point of seasonally high and low inventories, shall be conducted for inventory verification.

(2) Installation and monitoring of strategically located observation wells in the vicinity of spill points, within an aquifer, and above the caprock in potential collector formations to detect the presence or movement of gas using methods which can include review of fluid level records, well pressures, geophysical logging, gas composition or other tools and methods deemed appropriate.

(3) Monitoring offset hydrocarbon production or disposal operations for unexplained flow or pressure changes. The monitoring shall include operations in zones above and below the storage reservoir as well as laterally offset locations.

(4) Conducting subsurface correlation and gas identification logs such as gamma ray-neutron logs to confirm the location of gas being injected into the intended storage reservoir, as needed.

(c) The operator of an underground gas storage project shall employ a real-time data gathering system, such as Supervisory Control and Data Acquisition, by January 1, 2020.

(d) The operator shall continually track all wells that are within the area of review and that are in the same or a deeper zone as the gas storage project and ensure that all such wells that are not plugged and abandoned and that have been inactive for more than two years have cement plugs across all hydrocarbon zones, the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(e) The operator of an underground gas storage project shall adhere to an inspection and leak detection protocol that has been approved by the Division. The protocol shall include inspection of the wellhead assembly and attached pipelines for each of the gas storage wells used in association with the underground gas storage project, and the surrounding area within a 100-foot radius of the wellhead of each of the wells used in an underground gas storage project. The inspection protocol shall provide for inspection at least once a day, employing effective gas leak detection technology such as infrared imaging. The operator's selection and usage of gas leak detection technology shall take into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. The Division will consult with the California Air Resources Board when reviewing an inspection and leak detection protocol submitted under this subdivision. The requirements of this subdivision shall cease to apply if the California Air Resources Board adopt and implement regulations with the same or stricter requirements.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.8. Inspection, Testing, and Maintenance of Wellheads and Valves.

(a) Where installed, the operator of an underground gas storage project shall test all surface and subsurface safety valve systems to ensure ability to hold anticipated pressure at least every six months. The tests shall be conducted in accordance with American Petroleum Institute Recommended Practice 14B (6th Edition, September 2015), or equivalent, to confirm operational integrity. The appropriate district office shall be notified at least 48 hours before performing testing so that Division staff may witness the operations, and documentation of the testing shall be maintained and available for Division review. A closed storage well safety valve system shall be re-opened with operator staff at the site of the valve to ensure the absence of any unforeseen issues. Within 90 days of finding that a surface or subsurface safety valve is inoperable, the operator shall either repair the safety valve or temporarily plug the well. An appropriate alternative timeframe for testing a valve or addressing an inoperable surface or subsurface safety valve may be approved by the Division.

(b) At least annually, the operator of an underground gas storage project shall test the master valve and wellhead pipeline isolation valve for proper function and verify ability to isolate the well.

(c) The operator shall equip gas storage wells with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

(d) The operator shall equip all ports on the wellhead assembly above the casing bowl of gas storage wells with valves, blind flanges, or similar equipment.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.9. Emergency Response Plan.

(a) The operator of an underground gas storage project shall have an emergency response plan approved by the Division and ready for immediate implementation. The emergency response plan shall specify a schedule for carrying out drills to validate the plan. The drills shall address the readiness of personnel and their interaction with equipment including required third party service providers and their current contact information.

(b) The emergency response shall at a minimum address the following scenarios:

- (1) Collisions involving well heads;
- (2) Well fires and blowouts;
- (3) Hazardous material spills;
- (4) Equipment failures;
- (5) Natural disasters/emergencies;
- (6) Leaks and well failures;
- (7) Medical emergencies; and
- (8) Explosions.

(c) The emergency response plan shall at a minimum include all of the following:

- (1) Written actions plans establishing assigned authority to the appropriate qualified person(s) at a facility for initiating effective emergency response and control;
- (2) Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;
- (3) Protocols for emergency reporting and response to appropriate government agencies
- (4) Specification of personnel roles and responsibilities;
- (5) Internal and external communication protocol;
- (6) Emergency contact information including area codes; and
- (7) Procedures for notification.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106 and 3403.5 Public Resources Code.

REQUIREMENTS FOR UNDERGROUND GAS STORAGE PROJECTS

FINAL TEXT OF EMERGENCY REGULATIONS

Added text is shown in underline.

Deleted text is shown in ~~strikethrough~~.

CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 3. Requirements

1724.9. Underground Gas Storage Projects

~~The data required by the Division prior to approval of a gas storage project include all applicable items listed in Section 1724.7(a) through (e), and the following, where applicable:~~

(a) For all underground gas storage projects, the operator shall provide the data required under Section 1724.7 and the operator shall comply with the requirements of Section 1724.10, unless the requirement is clearly not applicable to a gas storage project or the Division otherwise advises that the requirement is not applicable to a gas storage project. The operator shall ensure that required project data is complete and current, regardless of the date of approval of the gas storage project. If project data for an existing project is incomplete, then the operator shall submit the required data to the Division as soon as is practicable. In addition to the data required under Section 1724.7, the operator of an underground gas storage project shall provide the Division with the following:

(1) ~~(a)~~ Characteristics, petrophysical properties, mechanical properties, and maps of the cap rock, such as including areal extent, average isopach thickness, structure contour, formation fracture gradient, primary and secondary permeability, lithology and lithologic variation, and threshold pressure, and locations and characteristics of faults and fractures.

~~(2) (b)~~ Oil and gas reserves of storage zones prior to start of injection, including calculations.

~~(3) (c)~~ List of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.

~~(4) (d)~~ Proposed waste water disposal method.

(b) The Project Approval Letter for an underground gas storage project shall state the maximum and minimum reservoir pressure and include data and calculations supporting the bases for the pressure limits. The pressure limits shall account for the following:

(1) The pressure required to inject intended gas volumes, particularly at total inventory, and the pressure limit shall not exceed the design pressure limits of the reservoir, wells, wellheads, piping or associated facilities.

(2) The minimum reservoir pressure shall not be designed less than historic minimum operated pressure unless reservoir geo-mechanical competency can be demonstrated to the Division's satisfaction. The impacts of intended minimum reservoir pressure shall be accounted for in the data required under subdivision (a)(1) as it relates to geo-mechanical stress, reservoir liquid influx, surface facility gas cleaning and liquid handling, and liquid disposal, all of which affect the maximum reservoir cycling capacity of the storage field and can impact mechanical integrity of the facilities.

(c) In addition to the mechanical integrity testing requirements under 1724.10(j), the operator shall monitor the tubing-casing annulus, if there is one, of each well that is part of an underground gas storage project. The operator shall monitor for presence of annular gas by measuring and recording annular pressure and annular gas flow. Such monitoring shall be done at least once a day when the well is not being used for withdrawal. The operator shall evaluate any anomalous annular gas occurrence and immediately report it to the Division. The operator shall begin complying with this requirement within one month of the effective date of this section.

(d) Where installed, the operator of an underground gas storage project shall function test all surface and subsurface safety valve systems within three months of the effective date of this section, and every six months after that. The tests shall be conducted in accordance with manufacturer's recommendations to confirm operational integrity and mitigate any integrity isolation findings. The appropriate district office shall be notified at least 48 hours before performing testing so that Division staff may witness the operations, and documentation of the testing shall be maintained and available for Division review. A closed storage well safety valve system shall be manually re-opened at the site of the valve after an inspection and not opened from a remote location.

Within 90 days of finding that a surface or subsurface safety valve is inoperable, the operator shall either repair or remove the safety valve or temporarily plug the well. A longer timeframe for addressing an inoperable surface or subsurface safety valve may be approved by the Division.

(e) Within 21 days of the effective date of this section, the operator of an underground gas storage project shall submit an inspection and leak detection protocol to the Division for review and approval. The protocol shall include inspection of the wellhead assembly and attached pipelines for each of the wells used in an underground gas storage project, and the surrounding area within a 100' radius of the wellhead of each of the wells used in an underground gas storage project, unless the operator can demonstrate that some part of that area is obstructed. The inspection protocol shall provide for inspection at least once a day, employing effective gas leak detection technology such as infrared imaging, and shall provide for immediately reporting detected leaks to the Division. The operator's selection and usage of gas leak detection technology shall take into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. The Division will consult with the California Air Resources Board when reviewing an inspection and leak detection protocol submitted under this subdivision.

(f) Within three months of the effective date of this section, and annually thereafter, the operator of an underground gas storage project shall test the operation of the master valve and wellhead pipeline isolation valve for proper function and verify ability to isolate the well. The operator shall submit documentation of the results of testing done under this subdivision within 10 days of completing the testing, but shall immediately notify the Division if testing indicates a lack of function.

(g) Within six months of the effective date of this section, the operator of an underground gas storage project shall submit a Risk Management Plan to the Division for review and approval. The Risk Management Plan shall identify potential threats and hazards to well and reservoir integrity; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate the risk associated with each threat; and specify a process for periodic review and reassessment of the risk assessment and prevention protocols. Risk assessment and prevention protocols shall be consistent with and additional to any other existing requirement in statute or regulation. The Risk Management Plan shall specify a schedule for submission of risk assessment results to

the Division. All Risk Management Plans shall include at least the following risk assessment and prevention protocols:

(1) Ongoing verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage. The protocols for verifying and demonstrating well integrity shall not be limited to compliance with the mechanical integrity testing requirements under Section 1724.10(j), and shall include consideration of the age, construction, and operation of each well.

(2) Corrosion monitoring and evaluation including consideration of the following:

(A) Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;

(B) Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;

(C) Corrosion potential of annular and packer fluid;

(D) Corrosion potential of current flows associated with cathodic protection systems;

(E) Corrosion potential of all formation fluids, including fluids in formations above the storage zone;

(F) Corrosion potential of uncemented casing annuli; and

(G) Corrosion potential of pipelines and other production facilities attendant to the underground gas storage project.

(3) Protocols for evaluation of wells and attendant production facilities that include monitoring of casing pressure changes at the wellhead, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.

(4) Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.

(5) Identification of potential threats and hazards associated with operation of the underground gas storage project including the following:

(A) Evaluation of likelihood of events and consequences related to the threats and hazards;

___ (B) Determination of risk ranking to develop preventive and mitigating measures to monitor or reduce risk;

___ (C) Documentation of risk evaluation and description of the basis for selection of preventive and mitigating measures;

___ (D) Provision for data feedback and validation; and

___ (E) Regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness.

___ (6) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.

___ (h) The requirements of this section shall not be construed to replace or restrict an operator's compliance with any specific requirements applicable to pipelines and associated facilities pursuant to Parts 190-199 of Title 49 of the United States Code of Federal Regulations.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3106, 3220 and 3403.5, Public Resources Code.

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Air Quality

DOCUMENT NUMBER: 275-2101-003

TITLE: Air Quality Permit Exemptions

EFFECTIVE DATES: July 26, 2003,
August 10, 2013 for Category No. 33 and Category No. 38
Exemptions

AUTHORITY: Act of January 8, 1960, P.L. (1959) 2119, No 787, as amended,
known as The Air Pollution Control Act, (35 P.S. § 4001 et seq.)

POLICY: Plan Approval and Operating Permit Exemptions

PURPOSE: The document provides criteria for sources and physical changes to
sources determined to be eligible for permitting exemptions as
sources of minor significance.

APPLICABILITY: Staff/Regulated Public

DISCLAIMER: The policies and procedures outlined in this guidance document
are intended to supplement existing requirements. Nothing in the
policies or procedures shall affect applicable statutory or
regulatory requirements.

The policies and procedures herein are not an adjudication or a
regulation. There is no intent on the part of the Department to give
these rules that weight or deference. This document establishes the
framework for the exercise of DEP's administration discretion in
the future. DEP reserves the discretion to deviate from this policy
statement if circumstances warrant.

PAGE LENGTH: 21 pages

TABLE OF CONTENTS

3.1 Listing of Plan Approval Exemptions ----- 3

 Further Qualifications Regarding Plan Approval Exempted Sources ----- 12

 Physical Changes Qualifying for Exemption ----- 13
 Under Section 127.14(a)(9)

 Exemption Criteria for Operating Permits ----- 16

 State-Only Operating Permit Facility Exemptions ----- 16

 Exempted Facility and Source Categories for Operating Permits ----- 16

 Deferral of Operating Permit Requirements for Area Sources ----- 17

 Trivial Activities ----- 18

**COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY**

**NOTICE
Plan Approval and Operating Permit Exemptions**

Consistent with the applicable provisions of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. §4001 *et seq.* and 25 Pa. Code § 127.14 (relating to exemptions), the Department of Environmental Protection (Department) may determine sources or classes of sources to be exempt from the plan approval and permitting requirements of 25 Pa. Code Chapter 127 (relating to construction, modification, reactivation and operation of sources). This guidance document identifies the following: exemptions under Section 127.14(a); exemptions under Section 127.14(a)(8) that do not require submission of a Request for Determination (RFD) form; exemption criteria that the Department may use when an owner or operator of a source or a facility is seeking an exemption from plan approval; further qualifications regarding plan approval exempted sources; exemptions under Section 127.14(a)(9) related to physical changes; and exemption criteria for operating permits. This amended guidance document is applicable to sources that will be constructed as new or modified sources after the effective date of this document. It does not apply to sources that were constructed or modified prior to the effective date of this guidance document and operating lawfully without a permit. Sources exempted from plan approvals are not automatically exempted from operating permit requirements.

Words and terms that are not defined in this document have the meaning set forth in 25 Pa. Code §121.1 (relating to definitions) or the APCA (35 P.S. § 4003), 25 Pa. Code, Chapters 121 - 145 and applicable definitions codified in the Code of Federal Regulations including 40 CFR Parts 60 and 63.

Listing of Plan Approval Exemptions

Section 127.14(a) Exemptions

In accordance with § 127.14(a), approval is not required for the construction, modification, reactivation or installation of the following:

1. Air conditioning or ventilation systems not designed to remove pollutants generated by or released from other sources.
2. Combustion units rated at 2.5 million or less Btus per hour of heat input.
3. Combustion units with a rated capacity of less than 10 million Btus per hour of heat input fueled by natural gas supplied by a public utility or by commercial fuel oils which are No. 2 or lighter-viscosity less than or equal to 5.82 C St--and which meet the sulfur content requirements of § 123.22 (relating to combustion units). Combustion units converting to fuel oils which are No. 3 or heavier-viscosity greater than 5.82 C St or contain sulfur in excess of the requirements of § 123.22 require approval. For the purpose of this section, commercial fuel oil shall be virgin oil which contains no reprocessed, recycled, or waste material added.

4. Sources used in residential premises designed to house four or less families.
5. Space heaters which heat by direct heat transfer.
6. Mobile sources.
7. Laboratory equipment used exclusively for chemical or physical analyses.
8. Other sources and classes of sources determined to be of minor significance by the Department.

Section 127.14(a)(8) Exemptions

The following is a list of those sources and classes of sources determined, in accordance with § 127.14(a)(8), to be exempt from the Plan Approval requirements of §§ 127.11 and 127.12. The commencement of construction of sources is exempted from the plan approval requirements provided the exemption criteria are met. Unless labeled otherwise, emission rates are to be considered actual tons per year (tpy). Note that certain exceptions and qualifications regarding this list are contained in the discussion that follows the list.

1. Incinerators with rated capacities less than 75 lb per hour burning a municipal or residual waste as defined by the Bureau of Land Recycling and Waste Management.
2. Shot blast and sandblasting units with appropriately designed fabric collectors, cartridge collectors or scrubbers manufactured as an integral part of the design and which have exhaust volumes equal to or smaller than 5,000 scfm.
3. Combustion turbines rated at less than 1,000 horsepower or 10.7 gigajoules per hour.
4. Internal combustion engines rated at less than 100 brake horsepower. Note Category 38 addresses oil and gas facilities.
5. Portable, temporary internal combustion engines used for 14 days or less at special events (such as county fairs, circuses and concerts).
6. Internal combustion engines regardless of size, with combined NO_x emissions less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season and 6.6 tons per year on a 12-month rolling basis for all exempt engines at the site.
7. Natural gas-fired heat-treating furnaces with less than 10 million Btus per hour heat input (fuel burning emissions only).
8. Steam aspirated vacuum degassing of molten steel.
9. Coal handling facilities processing less than 200 tons per day. (Thermal coal dryers and pneumatic coal cleaners remain subject to the requirements of § 127.11). This exemption includes internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.

10. Wet sand and gravel operations (screening only) and dry sand and gravel operations (including crushers) processing unconsolidated materials with a rated capacity of less than 150 tons per hour.
11. Coal and non-metallic mineral handling activities directly associated with either deep or surface mines that consist only of conveyors and non-vibratory screens (aka. grizzlies). This exemption includes internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.
12. Portable crushers that are controlled with properly located water sprays or with fabric filters, have a rated capacity less than 150 tons per hour, operated during daylight, and located on a site for less than 60 days; provided, however, that the crushers do not process materials containing asbestos. This exemption includes; associated screens and drop points; tub grinders used to mulch grubbing waste; and, internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.
13. Concrete batch plants and associated storage vessels that are equipped with appropriately designed fabric collectors.
14. Bulk material storage bins, except those associated with a production facility with total actual facility particulate emissions greater than 10 tpy.
15. Storage vessels for volatile organic compounds [which do not contain hazardous air pollutants (HAPs)] which have capacities less than 40 m³ (10,000 gallons) based on vessel dimensions, unless subject to § 129.59 (bulk gasoline terminals) or § 129.60(b) and (c) (bulk gasoline plants).
16. Storage vessels containing non-VOC, non-malodorous, or nonhazardous air pollutant materials.
17. Diesel fuel, Nos. 2, 4 and 6 fuel oils, or kerosene and jet fuel storage and dispensing facilities as long as the stored or dispensed product has a vapor pressure less than 1.5 psia.
18. Covered wastewater transfer systems such as covered junction boxes, sumps, and tanks at industrial sites.
19. Plastic bead or pellet milling, screening, and storage operations (does not include handling and storage of resin powders).
20. Plastic parts casting ovens and injection molding processes.
21. Tire buffing.
22. Paper trimmers/binders.
23. Vocational education shops. Chemistry laboratories at schools and colleges.
24. Bench-scale laboratory equipment used for kinetic studies, mass/energy transport studies, chemical synthesis and physical or chemical analysis.
25. Research and development activities with annual emission rates:

- i. less than or equal to 20 tpy of CO;
 - ii. less than or equal to 0.12 tpy of lead;
 - iii. less than or equal to 3 tpy of PM₁₀;
 - iv. less than or equal to 8 tpy of SO₂ or VOC;
 - v. less than or equal to 10 tpy of NO_x;
 - vi. less than or equal to one tpy of a single HAP or 2.5 tpy of a combination of HAPs.
26. Woodworking facilities including sawmills and pallet mills which process green wood; or, small woodworking facilities processing kiln-dried wood or wood products (flakeboard, particleboard, etc.) associated with pattern shops, retail lumber yards, shipping and packing departments, etc. This category also includes woodworking facilities of any size processing kiln-dried wood or wood products equipped with appropriately designed fabric collectors designed to have emission rates that are less than 0.01 gr/dscf.
- This exemption does not apply to woodworking facilities processing wood that has been treated with a wood preservative of any kind. The term "woodworking facilities" refers only to operations in which wood or a wood product is sawed, sanded, planed, or similarly shaped or reshaped. The term does not include such activities as painting, finishing, hardboard manufacturing, plywood manufacturing, and the like.
27. Smokehouses.
28. Slaughterhouses (rendering cookers remain subject to the requirements of § 127.11).
29. Restaurant operations.
30. Degreasing operations using solvents containing no more than 5% VOC by weight, except those emitting more than 2.7 tons of VOCs or those subject to the Federal NESHAP for halogenated solvent cleaners under 40 CFR Part 63.
31. Sources of uncontrolled VOC emissions not addressed elsewhere in this exemption listing modified or newly added, such that emission increases are less than 2.7 tpy. Facilities' claiming this exemption must provide a 15-day prior written notification to the Department and limit VOC emission increases to less than 2.7 tpy.
32. Dry-cleaning facilities that are not subject to § 129.70, NSPS, MACT (area MACT sources are currently deferred from plan approval and operating permit requirements), PSD or NSR requirements.
33. a. Retail gasoline dispensing facilities and similar vehicle-fueling operations at industrial facilities.
- b. Compressed natural gas dispensing facilities meeting the following requirements:

- i. Combined NO_x emissions from the stationary internal combustion engines at a facility less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 of the same year) and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by the Department in plan approvals, general plan approval/general operating permits or emissions from sources at the facility approved under Category No. 33(a).
- ii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph must be met. Compliance with this criterion will be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs. of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emissions criteria do not include emissions from sources which are approved by the Department in plan approvals, general plan approval/general operating permits, or emissions from sources approved under Category No. 33(a) at the facility.
- iii. The owner or operator of the compressed natural gas fueling station will annually perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. The LDAR program will be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. For the storage vessel, any leak detection and repair are to be performed in accordance with 40 CFR Part 60, Subpart OOOO.
 - A. A leak is considered repaired if one of the following can be demonstrated:
 1. No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;

2. A concentration of 2.5% methane or less using a gas leak detector;
3. No visible leak image when using an optical gas imaging camera;
4. No bubbling at leak interface using a soap solution bubble test specified in Method 21. A procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or
5. Any other method approved by the Department.

B. Leaks, repair methods and repair delays are to be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon written request from the owner or operator of the facility documenting the justification for the requested extension.

34. Sources of particulate matter (not subject to NESHAPs, NSPS, PSD, or major source requirements) that are controlled by a baghouse, have an emission rate which meets the limits of Chapter 123, and are exhausted indoors and cannot be bypassed to exhaust to the outdoor atmosphere. These sources should not emit more than 0.12 tpy of lead, one tpy of a single HAP or 2.5 tpy of a combination of HAPs. Multiple sources within this category may be exempt from plan approval requirements.
35. Sources emitting inert gases only, such as argon, helium, krypton, neon, and xenon; pure constituents of air such as nitrogen, oxygen, or carbon dioxide; or, methane or ethane.
36. Source(s) qualifying under § 127.449 as de minimis emission increases.
37. Sources that exhaust to a filter/baghouse and have particulate loading (before control) below limits specified in Chapter 123.
38. Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:
 - a. Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.

- b. Well drilling, completion and work-over activities.
- c. Non-road engines as defined in 40 CFR § 89.2.
- d. Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in subparagraphs i, ii, iii, iv and v are met.
 - i. Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment are to be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.
 - A. A leak is considered repaired if one of the following can be demonstrated:
 - 1. No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;
 - 2. A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;
 - 3. No visible leak image when using an optical gas imaging camera;
 - 4. No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or

5. Any other method approved by the Department.
- B. Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.
- ii. Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department.
 - iii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.
 - iv. Flaring activities as outlined below:
 - A. Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.
 - B. Flaring used for repair, maintenance, emergency or safety purposes.
 - C. Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.
 - D. Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring

operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.

- v. Combined NO_x emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emission criteria do not include emissions from sources which are approved by plan approvals or the general plan approvals/general operating permits at the facility.

The owner or operator will comply with all applicable state and federal requirements including notification, record keeping, and reporting requirements as specified in 40 CFR Part 60 Subpart OOOO. The owner or operator will also demonstrate compliance with the exemption criteria using any generally accepted model or calculation methodology within 180 days after the well completion or installation of a source. The owners and operators of sources not meeting the provisions of subsections a-d of this category may submit an RFD form to the Department. If the RFD is not approved by the Department, an application for authorization to use a general permit or a plan approval application is to be submitted to the Department, as appropriate.

- 39. Combustion units with a rated capacity of less than 10 million Btus per hour of heat input fueled by natural gas supplied by an independent gas producer. Sources firing natural gas supplied by an independent producer shall be given the same consideration given sources that fire natural gas provided by a public utility.
- 40. Any source qualifying for exemption based on criteria contained in a general permit developed in accordance with the procedures described in §§ 127.601 through 127.642.
- 41. Powdered metal sintering furnaces using only organic lubricants equal to or less than 0.75% organic lubricant by weight. The furnace atmosphere must contain hydrogen (H₂) at 3% or greater. The furnace must also maintain an operating flame curtain between the part entry and pre-heat zone. In the absence of an operating flame curtain, the furnace must operate an afterburner.

A sintering furnace using only metal containing lubricants may be exempted if the furnace emits particulate matter not exceeding 0.15 lb./hr. (determined by mass balance or stack tests). Note, for mass balance purposes, the following conversion factors are to be used:

Zinc Stearate to Zinc Oxide particulate matter = 0.129,

Lithium Stearate to Lithium Carbonate particulate matter = 0.15.

The Department may approve alternate conversion factors provided a satisfactory written justification is submitted to the Department.

A sintering furnace using organic lubricants and operating outside the limitations specified above, may be exempted under a case-by-case determination through the execution of a Request for Determination of Requirement for Plan Approval Application form. The owner/operator of a sintering furnace exempt from permitting requirements must notify the Department within 30 days of the furnace installation. For sintering furnaces using metal containing lubricants, records must be maintained to demonstrate compliance with the particulate matter emission limit of 0.15 lb/hour for each product.

Facilities that use both organic and metal-containing lubricants are exempted if the lubricants are less than 0.75% organic lubricant by weight; and, the furnace is designed and operated as described in the preceding paragraph and emits particulate matter at rates less than 0.15 lb./hr (determined by mass balance or stack tests).

The previous exemption does not apply to sintering furnaces used to sinter parts that are treated with oil.

42. Facilities engaged primarily in collision repair and refinishing of automobiles and light duty trucks.
43. Remediation of gasoline or fuel oil contaminated soil, groundwater or surface water by equipment installed, maintained and operated as provided herein. All air exhaust points are controlled by dual, activated carbon beds operating in series or a thermal/catalytic oxidizer. For activated carbon beds, monitoring (e.g. intrinsically safe ionization detector) at an appropriate frequency (e.g., one-fourth the predicted time to breakthrough of the first bed) must be performed at the inlet, between the first and second beds and after the second bed. If breakthrough of the first bed is detected, the first bed is removed, the second bed is shifted to the first position and the new bed is placed in the second position. Monitoring, operating, and maintenance records are maintained and available to the Department upon request. Equipment installed and operated as described above must be designed to achieve a minimum VOC control efficiency of 90%. As long as actual annual emissions after control are less than one TPY VOC or HAPs, the remediation project is determined to be of minor significance in accordance with 127.14 (8), no Air Quality Plan Approval is required and no Request for a Determination (RFD) needs to be filed. Other remediation projects may be considered for exemption via a Request For Determination and may be required to obtain Plan Approval at the discretion of the Department on a case-by-case basis.
44. Any source granted an exemption by the Department through the execution of a Request for Determination of Requirement for Plan Approval/Operating Permit (RFD) form.

Further Qualifications Regarding Plan Approval Exempted Sources:

1. This notice shall not be construed to exempt facilities that include multiple sources of air contaminants, unless specifically stated in the source category.
2. The addition of any source that would subject the facility to major source New Source Review or Prevention of Significant Deterioration, Title V or Reasonably Available Control Technology (RACT) requirements shall comply with plan approval requirements, even if such sources are within a category in the above list.

3. Sources exempt from plan approval may be required to be included in the operating permit if the source is not included in the trivial activity listing.
4. Sources located in Allegheny and Philadelphia Counties may be subject to different permitting requirements. Please contact the Allegheny County Air Quality Program at 412-567-8115 or the Philadelphia Air Management Services at 215-823-7580 for information applicable to sources located in those counties.
5. Any sources claiming an exemption based on emission thresholds must keep adequate records to clearly demonstrate to the Department that the applicable thresholds are not exceeded.

These determinations do not exempt the above-listed sources from compliance with the emission limitations, work practice, and other applicable requirements contained in Chapters 121, 122, 123, 124, 127, 129, and 135. Although a source may be exempt from the plan approval and operating permit requirements of Chapter 127, the source is subject to all other applicable air quality regulations. For example, combustion units exempt from the requirements of Chapter 127 are not exempt from the opacity limitations of § 123.41 or the emission limitations of § 123.22. Storage vessels for organic compounds with capacities between 2,000 gallons to 40,000 gallons, not subject to the requirements of Chapter 127, must install pressure relief valves in accordance with the requirements of § 129.57. (Note: Storage vessels in this size range would also not be subject to the requirements of §§ 129.59 and 129.60.)

If the Department determines that any exempted source is causing air pollution in violation of Section 8 of the Air Pollution Control Act, 35 P. S. § 4008, or 25 Pa. Code 121.7, the Department may order the installation of additional air cleaning devices. In those cases, plan approvals and operating permits may be required.

Requests for exemptions from the plan approval requirements of Chapter 127 for multiple source facilities must be considered on a case-by-case basis.

As noted in Category 44 of the list, additional exemptions, when appropriate, may be obtained through the submission of a completed Request for Determination of Requirement for Plan Approval Application form. These forms are available from any of the Department's Air Quality offices and on the DEP website [www. dep.state.pa.us](http://www.dep.state.pa.us) under the Air Quality page.

Physical Changes Qualifying for Exemption Under Section 127.14(a)(9)

In accordance with § 127.14(a)(9), the Department has determined that the following physical changes qualify for plan approval exemption if the change: a) would not violate the terms of an operating permit, the Air Pollution Control Act, the Clean Air Act or the regulations adopted under the acts; b) would not result in emission increases above the allowable in the operating permit; and, c) would not result in an increased ambient air quality impact for an air contaminant. These changes may be made without notification to the Department.

Caution: Do not make determinations regarding the following list without consideration of the preceding criteria.

1. Changes in the supplier or formulation of similar raw materials, fuels, paints and other coatings which do not affect emissions and which meet all applicable standards and limitations.
2. Changes in product formulations that do not affect air emissions.
3. Changes that result in different speciation of pollutants but fall within permit limitations.
4. Changes in the method of raw material addition.
5. Changes in the method of product packaging.
6. Changes in temperature, pressure, or other operating parameters that do not adversely affect air cleaning device performance or air emissions.
7. Additions of or changes to sampling connections used exclusively to withdraw materials for testing and analysis including air contaminant detection and vent lines.
8. Changes to paint drying oven length designed to alter curing time, so long as capture efficiencies of control equipment are not altered.
9. Routine maintenance, inspection and cleaning of storage tanks and process vessels or the closure or dismantling of a storage tank or process.
10. Changing water sources to air cleaning devices when there is no effect on air cleaning device performance or air emissions.
11. Moving a source from one location to another at the same facility with no change in operation or controls.
12. Installation of an air-cleaning device that is not installed to comply with regulatory requirements and will not be used to generate emission reduction credits.
13. Repairing, replacing, upgrading, maintaining, or installing pollution control device instrumentation or component equipment including pumps, blowers, burners, filters, filter bags, devices for measuring pressure drop across an air cleaning device or a filter breakage detector for a baghouse, provided such changes would not violate an operating permit term or condition.
14. Installing a fume hood or vent system for industrial hygiene purposes or in a laboratory.
15. The temporary (no longer than six months) replacement of a source with a source of equal or less emission potential.
16. Repairing, replacing, upgrading, maintaining, or installing equipment and processes at oil and gas extraction and production facilities and operations. The category includes equipment or processes used either to drill or alter oil and natural gas to the point of lease custody transfer, to plug abandoned wells and restore well sites, or treat and dispose of associated wastes.

In accordance with § 127.14(c), additional physical changes may be determined to be of minor significance and not subject to plan approval requirements through the following procedure:

1. If the changes do not involve the installation of equipment, the changes may be made within 7 calendar days of the Department's receipt of a written request provided the Department does not request additional information or objects to the change within the 7-day period.
2. If the changes involve the installation of equipment, the changes may be made within 15 calendar days of the Department's receipt of a written request provided the Department does not request additional information or objects to the change within the 15-day period.
3. If the change would violate the terms of an operating permit the plan approval exemption may be processed contemporaneously with the minor operating permit modification under the procedures described in § 127.462.

Exemption Criteria for Operating Permits

A Title V operating permit is needed by all facilities that have the potential to emit (PTE) exceeding the levels described in the definition of "Title V facility." A state-only operating permit is needed for facilities that do not have a PTE which exceeds the Title V facility thresholds, but which has actual emissions equal to or exceeding the facility levels summarized below. An existing facility which does not have a PTE exceeding the Title V facility thresholds and which does not have actual emissions exceeding the levels shown below is exempt from the requirement to obtain an operating permit.

State-Only Operating Permit Facility Exemptions*

| Pollutant | PTE< | Actual Emission Rate< |
|------------------|----------------|---------------------------------|
| CO | 100 TPY | 20 TPY |
| NO _x | 100 TPY** | 10 TPY |
| SO _x | 100 TPY | 8 TPY |
| PM ₁₀ | 100 TPY | 3 TPY |
| VOCs | 50 TPY** | 8 TPY |
| Single HAP | 10 TPY | 1 TPY |
| Multiple HAPs | 25 TPY | 2.5 TPY |

- * Sources located in Allegheny and Philadelphia Counties may be subject to different permitting requirements. Please contact the Allegheny County Air Quality Program at 412-567-8115 or the Philadelphia Air Management Services at 215-823-7580 for information applicable to sources located in those counties.
- * 25 TPY for Severe Ozone NA areas including Bucks, Chester, Delaware, and Montgomery counties.

Sources listed in the plan approval exemption list should be included in an operating permit application unless it is also included in the listing of trivial activities. When a RFD is issued for a source not included on the list of trivial activities the source need not be brought onto the operating permit until the renewal of the operating permit. So long as all applicable requirements are met there is no need to revise an operating permit to include a source installed under an RFD or the de minimis provisions of an operating permit. Only in the case where a physical change of minor significance would violate the terms of an operating permit should a plan approval exemption and a minor permit modification under § 127.462 be processed contemporaneously. A facility that currently has or should have a plan approval or an operating permit is not exempted from the operating permit requirements. However, if the facility would now be eligible for exemption, the owner/operator may submit a RFD in accordance with § 127.14(c).

Exempted Facility and Source Categories for Operating Permits

Unless preclude by the Clean Air Act, or the regulations there under, the following facilities and source categories are exempted from the operating permit requirements of § 127.402.

1. Residential wood stoves.
2. Asbestos demolition/renovation sites.
3. Facilities engaged primarily in collision repair and refinishing of automobiles and light duty trucks.
4. Retail gasoline stations.

Deferral of Operating Permit Requirements for Area Sources

Sources subject to MACT standards are not exempted from operating permit requirements. However, the permitting of MACT area sources will be deferred at this time. Area MACT sources emit or have the PTE less than 10 tpy of any hazardous air pollutant or 25 tpy of any combination of hazardous air pollutants. These non-major sources include: perchloroethylene dry cleaning, halogenated solvent cleaning, ethylene oxide commercial sterilization and fumigation operations, hard and decorative chromium electroplating, chromium anodizing tanks and secondary lead smelters. These MACT area sources are still required to meet all applicable emission control requirements established by the respective MACT requirement. The owner or operator of a MACT area source need not submit an operating permit application until December 9, 2004.

Trivial Activities

Trivial activities are those located within a facility, which do not create air pollution in significant amounts. These insignificant activities need not be described in a Title V or state-only operating permit application. Also, these activities do not require a plan approval. Sources listed in the plan approval exemption list should be included in an operating permit application unless it is also listed in the following list. Certain of these listed activities include qualifying statements intended to exclude many similar activities.

1. Combustion emissions from propulsion of mobile air contamination sources. The term "mobile air contamination source" means an air contamination source, including, but not limited to, automobiles, trucks, tractors, buses and other motor vehicles; railroad locomotives; ships, boats and other waterborne craft. The term does not include a source mounted on a vehicle, whether the mounting is permanent or temporary, which source is not used to supply power to the vehicle. Examples might include lawn mowers, tow and lift vehicles, and the like.
2. Air-conditioning units used for human comfort that do not have applicable requirements under Title VI of the Act.
3. Ventilating units used for human comfort that do not exhaust air pollutants into the ambient air from any manufacturing, industrial or commercial process.
4. Electric space heaters. Propane and gas fired space heaters with a plant-wide capacity less than 2.5 million Btus per hour heat input and which have not been subject to RACT requirements.
5. Electrically heated furnaces, ovens and heaters, and other electrically operated equipment from which no emissions of air contaminants occur.
6. Non-commercial food preparation.
7. Use of office equipment and products, not including printers or businesses primarily involved in photographic reproduction.
8. Any equipment, machine or device from which emission of air contaminant does not occur.
9. Janitorial services and consumer use of janitorial products.
10. Internal combustion engines used for landscaping purposes.
11. Garbage compactors and waste barrels.
12. Laundry activities, except for dry-cleaning and steam boilers.
13. Bathroom/toilet vent emissions.
14. Emergency (backup) electrical generators at residential locations.

15. Tobacco smoking rooms and areas.
16. Blacksmith forges.
17. Plant maintenance and upkeep activities (such as, grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots) provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and not otherwise triggering a permit modification.¹
18. Repair or maintenance shop activities not related to the source's primary business activity, not including emissions from surface coating or de-greasing (solvent metal cleaning) activities, and not otherwise triggering a permit modification.
19. Portable electrical generators that can be moved by hand from one location to another.²
20. Hand-held equipment for buffing, polishing, cutting, drilling, sawing, grinding, turning or machining wood, metal or plastic.
21. Brazing, soldering and welding equipment, and cutting torches related to maintenance and construction activities that do not result in emission of HAP metals.³
22. Air compressors and pneumatically operated equipment, including hand tools.
23. Batteries and battery charging stations, except at battery manufacturing plants.
24. Storage tanks, vessels, and containers holding or storing liquid substances that will not emit any VOC or HAP.
25. Propane or natural gas tanks and containers.
26. Storage tanks, reservoirs, and pumping and handling equipment of any size containing soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.
27. Equipment used to mix and package, soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.
28. Drop hammers or hydraulic presses for forging or metalworking.
29. Equipment used exclusively to slaughter animals, but not including other equipment at slaughterhouses, such as rendering cookers, boilers, heating plants, incinerators, and electrical power generating equipment.
30. Vents from continuous emissions monitors and other analyzers.
31. Natural gas pressure regulator vents.
32. Hand-held applicator equipment for hot melt adhesives with no VOC in the adhesive formulation.

33. Equipment used for surface coating, painting, dipping or spraying operations, except those that will emit VOC or HAP.
34. CO₂ lasers used only on metals and other materials that do not emit HAP in the process.
35. Consumer use of paper trimmers/binders.
36. Electric or steam-heated drying ovens and autoclaves, but not the emissions from the articles or substances being processed in the ovens or autoclaves or the boilers delivering the steam.
37. Salt baths using nonvolatile salts that do not result in emissions of any regulated air pollutants.
38. Laser trimmers using dust collection to prevent fugitive emissions.
39. Bench-scale laboratory equipment used for kinetic studies, mass/energy transport studies, chemical synthesis and physical or chemical analysis.
40. Sources emitting inert gases only, such as argon, helium, krypton, neon, and xenon; pure constituents of air such as nitrogen, oxygen, or carbon dioxide; or the organic aliphatic hydrocarbon gases methane and ethane.
41. Routine calibration and maintenance of laboratory equipment or other analytical instruments.
42. Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.
43. Hydraulic and hydrostatic testing equipment.
44. Environmental chambers not using hazardous air pollutant (HAP) gasses.
45. Shock chambers.
46. Humidity chambers.
47. Solar simulators.
48. Fugitive emissions related to movement of passenger vehicles, provided the emissions are not counted for applicability purposes and any required fugitive dust control plan or its equivalent is submitted.
49. Process water filtration systems and demineralizers, but not including air strippers.
50. Demineralized water tanks and demineralizer vents.
51. Boiler water treatment operations, not including cooling towers.
52. Oxygen scavenging (de-aeration) of water.
53. Potable water treatment systems.

54. Ozone generators.
55. Fire suppression systems and activities involved in fire protection training, first aid or emergency medical training.
56. Emergency road flares.
57. Steam vents and safety relief valves.
58. Steam leaks.
59. Steam cleaning operations.
60. Steam sterilizers.
61. Reserved.
62. Typesetting, image setting, and plate making equipment used in the preparatory phase of printing.

If an applicant conducts an activity that is believed trivial but not covered by this listing, the applicant may list the activity in an operating permit application and provide a written justification for listing the activity as trivial. If the Department accepts the applicant's justification, no further information will be required on the activity. If the Department rejects the justification, additional information must be included in an operating permit application submitted to the Department.

¹Cleaning and painting activities qualify if they are not subject to VOC or HAP control requirements. Asphalt batch plant owners/operators must still get a permit.

²"Moved by hand" means that it can be moved without the assistance of any motorized or non-motorized vehicle, conveyance, or device.

³Brazing, soldering and welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals are more appropriate for treatment as insignificant activities based on size or production level thresholds. Brazing, soldering, welding and cutting torches directly related to plant maintenance and upkeep and repair or maintenance shop activities that emit HAP metals are treated as trivial and listed separately in this appendix.

**WPX ENERGY ROCKY MOUNTAIN, LLC'S AND WPX ENERGY PRODUCTION, LLC'S
PRE-HEARING STATEMENT**

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS REGARDING PROPOSED
REVISIONS TO:

REGULATION NUMBER 3, PARTS A, B, AND C;

REGULATION NUMBER 6, PART A;

REGULATION NUMBER 7

WPX ENERGY ROCKY MOUNTAIN, LLC and WPX ENERGY PRODUCTION, LLC (collectively "WPX"), by and through undersigned counsel, respectfully submits to the Colorado Air Quality Control Commission ("Commission") its Prehearing Statement ("PHS") in the above-referenced rulemaking.

I. Executive Summary.

Pursuant to 5 CCR 1001-1 ("Procedural Rules"), Section V.E.6.c.(i), WPX provides the following executive summary in support of its PHS.

In general, WPX supports the Division's proposed regulations, recognizing that the regulations require stringent and broad-based requirements in excess of federal requirements, particularly for certain owners and operators, like WPX, who operate in the Piceance attainment areas. The proposed regulations implement a "one size fits all" approach, even though operations and potential fugitive emissions vary between basins state-wide. WPX operates in the Piceance basin, where, as even the state recognizes, potential fugitives are lower than other areas of the state. As such, WPX is supportive of the proposed regulations except where the requirements impose significant cost expenditures without corresponding increased environmental benefits. WPX thus has proposed minimal targeted revisions to the proposed regulatory language relating to the LDAR requirements to address these issues, without impacting the environmental benefit proposed by the regulations.

In general, WPX requests three changes to the proposed language of Regulation 7: (1) An "off-ramp" to decreasing frequency of instrument-based monitoring under the Leak Detection and Repair ("LDAR") requirements (or "skip monitoring") as a demonstration of reduced leaks is made (with the corresponding requirement of going back to the initial frequency if more than a limited number of leaks are detected in subsequent monitoring events) (5 CCR 1001-9, § XVII.F.5e); (2) clarification of what constitutes "unsafe to monitor" scenarios (5 CCR 1001-9, § XVII.F.5.g.(ii)); and (3) extending the date on which existing and new well production facilities must meet the proposed 500 ppm leak detection rate to January 1, 2016 (5 CCR 1001-9, § XVIII.F.6). In addition, WPX is proposing several clarifications to correct obvious typographical, grammatical, and formatting errors

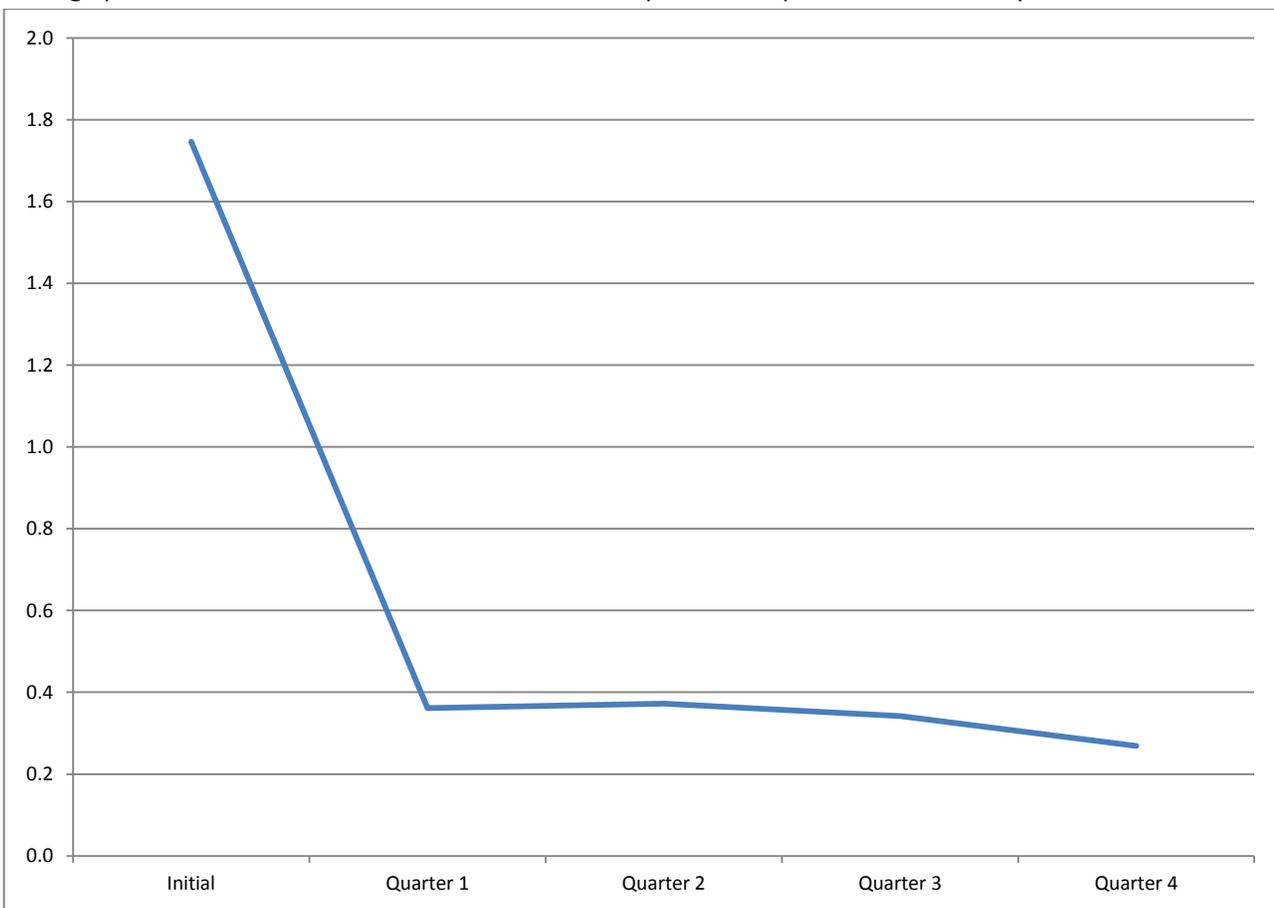
in the Division’s proposed regulations, and to create consistency in how the regulations address the same issues and incorporate clarifications by the Division discussed during the stakeholder process.

Based on case-specific studies of ongoing LDAR programs across a number of states and time periods, WPX includes documentation in its PHS that, following implementation of an LDAR program, the leak rate frequency found upon initial monitoring drops significantly during subsequent regular monitoring, to less than a one percent leak rate of components. Such reduced leak rates have been demonstrated to be sustainable in the long term. This data, summarized in the attached technical report by a recognized long-term LDAR consultant, Trihydro, supports the concept of allowing “skip monitoring” (or the practice of allowing for reduced monitoring frequency based on demonstrated good performance) as a valid concept in LDAR programs. The key points included in Trihydro’s analysis, *see* PHS EX A, demonstrate the following:

- Following implementation of an LDAR program, the leak rate frequency found upon initial monitoring can be expected to drop significantly during subsequent monitoring throughout the first year, to less than a one percent leak rate as observed in the analysis.

See PHS EX A, Figure 4:

Average percent new leaks found over number of components inspected in Case Study 1.



- This lower leak rate frequency is sustainable in the longer-term.
- Caution must be used when comparing leak rate data from other facilities or locations that may have significant differences from the facilities regulated under the proposed regulation.
- The specified fugitive emission factors will result in over estimating uncontrolled actual emissions. This is due to the manner in which the factors were developed, EPA's assumed 10,000 ppm leak rate, and the outdated data used to develop those emission factors (the data is approximately 20 years old).
- By not incorporating the concept of "skip period monitoring" into the proposed regulation, companies that implement high performance LDAR programs will be penalized.
- Facility LDAR monitoring is time consuming.

See attached PHS EX A.

WPX's targeted proposal therefore allows owners and operators who consistently demonstrate low leak rates to be rewarded for consistent low emissions. Comparison of longstanding LDAR programs for gas plant components that are similar to well production facility components demonstrates that, after the initial leak detection monitoring period, ongoing periodic monitoring events do not increase the frequency of leak detection. In fact, after the initial leak detection, discovery of leaks declines dramatically and continues at the low levels during the ongoing quarterly monitoring events.

In addition, some of the Division's proposed regulations require compliance with leak detection concentrations that are far below the current requirements. Manufacturers and suppliers need time to demonstrate and construct equipment and components that meet the more stringent levels; owners and operators need time to, if necessary, replace or retrofit equipment and components that do not meet the more stringent proposed requirements. Again, WPX is not challenging the proposed regulation standards, but simply for practicality and to ensure proper implementation, is requesting a slight modification as to when such stringent leak detection concentrations are applicable. Note that WPX acknowledges the immediate requirement for leak detection to 2000 ppm (much more stringent than the current 10,000 ppm standard), and is only requesting a slight delay in implementing the 500 ppm leak detection concentration for existing well production facilities and for any new facilities.

Finally, as noted above, operations and facility layouts vary throughout the state. Many of WPX's production facility locations are remote, and spread over larger areas with significant distances between locations. Many of the facilities are also subject to seasonal access issues, poor road conditions, and harsher weather at elevations. WPX is concerned about the safety of its operators and therefore proposes clarifying the language on what constitutes unsafe conditions for monitoring to ensure the safety of its employees and contractors.

WPX believes that its expert's testimony would be valuable to the Commission. WPX also believes it important to convey to the Commission the differences within the state, particularly with respect to its Piceance operations. As such, WPX requests forty-five minutes to present its direct

case (expert and factual testimony) and fifteen minutes for rebuttal and any additional time that may be required to cross-examine adverse witnesses.

II. Specific Factual and Legal Issues.

A. Not All Operators Are Similarly Situated.

WPX is in a unique position with all our Colorado exploration and production operations located in the Piceance Basin. We acknowledge that reducing VOCs emissions is important but would also like the Commission to recognize that potential emissions from our operations are different than emissions from other Basins in the state and that the economics for controlling these emissions are also different. All of WPX's operations in the Piceance Basin are located in an attainment area in Garfield and Rio Blanco Counties. A number of factors associated with the Piceance Basin are anticipated to make implementing a rigorous LDAR program even more challenging than at other production facilities within the state.

WPX production facilities are primarily natural gas operations with limited condensate production. The potential fugitive emissions from our production facilities are very low. These fugitive emissions have been estimated to be less than APEN thresholds (two tons per year) and in many cases are less than 0.5 tons per year. Our total VOC/hydrocarbon emissions from our production facilities are also considerably smaller than from other basins due to a number of factors. The natural gas wells in this area produce much lower volumes of condensate and the condensate is not as volatile as condensate produced from other areas. The operating/production pressures are also different compared to the DJ Basin. The division has assigned the Piceance Basin attainment area VOC emission factors of 10 lb/bbl for condensate tanks based on the lower production rates, operational differences, and the nature of the condensate. The State emission factor for condensate tanks in the DJ Basin is 13.7 lb/bbl. WPX's actual site-specific emission factors based on analytical data collected from WPX site condensate are only a fraction (10 to 50 percent) of the state emission factors – or 1 to 5 lbs/bbl – significantly lower than the State factors.

In addition to the factors described above, many of WPX's production facility locations are remote, spread over larger areas with significant distances between locations. Many of the facilities are also subject to seasonal access issues, poor road conditions, and harsher weather at elevations. WPX utilizes SCADA systems, site visits, and other remote tools to actively manage and ensure that operation and production activities are performed in an environmentally responsible manner. All of these factors identified above will contribute significant challenges to implement a rigorous LDAR program; however we recognize the value of a LDAR program that focuses on achieving effective environmental benefit/emission reductions and minimizes administrative burdens and eliminates unnecessary activities that do not contribute to finding and fixing leaks.

B. Proposed Justifications for Targeted Revisions to the Proposed Rules.

For above reasons, as well as the justifications set forth below, WPX identifies the following factual issues and provides justification for its proposed changes as follows.

1. Proposed revisions to Section XVII.F.5.e.

XVII.F.5.e. **The largest estimated uncontrolled actual emissions from a single storage tank battery determines** the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected **either in accordance with Table 3 or Alternative Table 3A.**¹

Descriptors were added to language in paragraph XVII.F.5.e to clarify how inspection frequencies are to be determined based on the largest “uncontrolled actual emissions” from a single storage tank battery. Without these clarifications this paragraph may not be interpreted consistently and it may not be clear which LDAR inspection frequency is applicable to a particular production facility. During the rule making Work Group meetings, this clarification was provided by the Division as its interpretation of how storage tank “uncontrolled actual emissions” would apply in determining which threshold to which a production facility would be subject.

2. Proposed revisions to Section XVII.F.5.e.

XVII.F.5.e.² **The largest estimated uncontrolled actual emissions from a single storage tank battery determines** the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected **either in accordance with Table 3 or Alternative Table 3A.**

| Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks) | Inspection Frequency |
|--|---|
| > 0 and ≤ 6 | One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO |
| > 6 and ≤ 12 | Annually with monthly AVO |
| > 12 and ≤ 50 | Quarterly with monthly AVO |
| > 50 | Monthly |
| Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC | Monthly |

An alternative inspection frequency schedule pursuant to Alternative Table 3A may be implemented once a reduced LDAR demonstration is made. A reduced LDAR

¹ Note that the text set forth here contains WPX’s proposed language, with highlighting to illustrate where WPX proposes changes to the Division’s proposed regulation. For the actual redlined version of the proposed language, *see* ALT EX D at p. 11.

² Note that the text set forth here contains WPX’s proposed language, with highlighting to illustrate where WPX proposes changes to the Division’s proposed regulation. For the actual redlined version of the proposed language, *see* ALT EX D at p. 11-13.

demonstration requires that an owner or operator identify fewer than either (1) the specified number of leaking components listed in “Demonstration of Reduced LDAR – Monitoring History” in Alternative Table 3A or (2) two percent of the total components for that facility during a single monitoring event, for at least two consecutive monitoring events.

Once the reduced LDAR demonstration is made pursuant to this Section, the alternative inspection frequency pursuant to Alternative Table 3A may remain in place until, during any monitoring event under the alternative inspection frequency, more leaks are identified than allowed under Alternative Table 3A’s “Demonstration of Reduced LDAR – Monitoring History.” Using the alternative inspection frequency identified in Alternative Table 3A, during any monitoring event, if more leaks are identified than listed in the “Demonstration of Reduced LDAR – Monitoring History,” then the original monitoring frequency identified in Table 3 shall become applicable until or if the operator can make another reduced LDAR demonstration for that facility.

| Alternative Table 3A | | |
|--|---|---|
| Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks) | Demonstration of Reduced LDAR - Monitoring History | Alternative Inspection Frequency |
| > 0 and ≤ 6 | | One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO |
| > 6 and < 12 | | Annually with monthly AVO |
| > 12 and ≤ 50 | 5 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events. | Annually with monthly AVO |
| > 50 | 10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events. | Quarterly with monthly AVO |
| Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC | 10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events. | Quarterly with monthly AVO |

WPX believes that if a rigorous LDAR program is applied to well production facilities it should be implemented to ensure the environmental benefit/fugitive VOC emission reductions are achieved and that the program minimizes administrative burdens and does not utilize unnecessary resources. The proposed LDAR inspection frequencies are extremely intense and would be the most resource intensive program applied to any production facility in the county. The proposed monthly inspection frequencies are more intense than dictated by federal requirements for new gas plants and refineries (which only require quarterly monitoring). Given that the potential fugitive emissions from

gas plants are significantly higher than production facilities, more frequent inspections may not achieve any added environmental benefit for production facilities.

In WPX's proposal, an alternative inspection frequency may be applied if a company is able to demonstrate a specified low number of leaks in their monitoring history (two consecutive monitoring events). The reduced inspection frequencies are applied only to the Instrument Based Monitoring as the monthly AVO remains in place and constant. WPX used representative component counts within the various production threshold categories as a basis of how many components would represent two percent of the total components at a facility recognizing that it is unlikely and infeasible that site-specific component counts for each production facility could be obtained and maintained for many operators given the number and nature of production facilities and activities. However, WPX has proposed allowing the flexibility to use the representative number or a percentage of the total components at a facility if an owner or operator so chooses. The requested changes are performance based and the inspection frequencies revert back to the original frequencies if the number of leaks identified rise above the identified thresholds; ensuring production facilities maintain a low number of new component leaks.

WPX believes that reduced Instrument Based Monitoring inspection frequencies are justified by the following facts:

- Information provided by Trihydro, provided in PHS EX A, indicates that, by implementing a LDAR program, a facility can expect to find more leaks initially and then the percent of leaks found over time decreases to a very consistent low percent over time. Performing Instrument Based Monitoring on a monthly or quarterly basis in addition to monthly AVO LDAR monitoring does not make economic sense. Crucially, based on the data, there would not be any added environmental benefit for the additional resources expended.
- Implementing a LDAR program will be more resource intense for production facilities than for gas plants as an equal number of components for a gas plant would be spread over a greater distance for production facilities. Implementation of LDAR at production facilities located in the Piceance Basin may be even more difficult due to the remoteness of the facilities, distance between facilities, higher elevations, and road conditions. WPX's production facilities are located over a vast area in remote locations with significant distance between locations. On a fair weather day, the driving time between some facilities can take thirty (30) minutes to three (3) hours and travel time increases due to poor weather and road conditions. *See* PHS EX B and PHS EX C.
- WPX's estimated potential fugitive VOC emissions from all of its production sites are below APEN thresholds (2 tons/year) and the majority of facilities are below 0.5 tons per year. Therefore the potential environmental benefit of continuing frequent monitoring for each of these sites is very small when monitoring has already demonstrated consistent compliance with low leak levels.
- As indicated in information provided by an LDAR expert, reduced frequency LDAR monitoring or "Skip Monitoring" is an accepted practice that encourages implementation of effective LDAR programs with good performance. PHS EX A.

- Based on the information provided by Trihydro, *see* PHS EX A, the estimated fugitive emissions are being overestimated because the emission factors currently being applied to calculate fugitives are inflated. Using a 500 ppm leak definition will further make the estimated fugitive emissions based on these EPA emission factors more inflated. Therefore the environmental benefit or emission reductions are also being over estimated making the cost per ton of fugitive emission reductions much higher than estimated by the Division.

Note that for consistency and to match the revised language in XVII.F.5.e., WPX has also proposed clarifying language referring to both Table 3 (already included) and Alternative Table 3A (new) in Sections XVII.F.5.c and d. *See* ALT EX D at 11.

3. Proposed revisions to Section XVII.F.5.f.

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than ~~20~~12 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to ~~20~~12 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

Corrections were made to the language in Section XVII.F.5.f to make the numbers consistent with Table 3 (12 instead of 20). WPX believes this was a typographical error. If not, then the numbers in Table 3 in Section XVII.F.5.e. need to be revised to replace 12 with 20. *See* ALT EX D at 13.

4. Revisions to Section XVII.F.5.g.(ii)

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).³

Additions were made to language in Section XVII.F.5.g.(ii) to specifically include scenarios that may prevent monitoring due to conditions that endanger personnel or equipment. WPX recognizes that there are a number of conditions, events, or situations that could prevent safe

³ Note that the text set forth here contains WPX's proposed language, with highlighting to illustrate where WPX proposes changes to the Division's proposed regulation. For the actual redlined version of the proposed language, *see* ALT EX D at p. 13-14.

monitoring. It was the intention of these additions to identify some of these scenarios to ensure monitoring is done safely and for enforcement clarification. *See also* PHS EX C.

5. Revisions to Section XVII.F.6.

- XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm after January 1, 2016.
- XVII.F.6.b. For Method 21 monitoring at facilities constructed after ~~May 1, 2014~~ January 1, 2016, a leak is any concentration of hydrocarbon above 500 ppm.⁴

Clarifications were made to the language in Section XVII.F.6.a and b. These changes were made for consistency to better match other implementation dates included in the regulation, including facilities with uncontrolled actual VOC emissions between zero and 12 tons per year.

In addition, implementation of the 500 ppm leak definition after January 1, 2016 allows time for companies and equipment suppliers to ensure that equipment purchased for new production or existing facilities can meet the 500 ppm leak definition requirements. WPX contacted a number of our equipment suppliers to gage potential impacts of incorporating a 500 ppm leak definition. We have received a mixed response from our vendors. While some vendors are prepared to provide equipment that meets these standards, others vendors need time to evaluate their equipment to determine if they can meet these new standards with their existing equipment or need to re-design/re-engineer their equipment. As such, pushing out the time frame to require the 500 ppm leak definition standards allows both vendors and owners and operators time to ensure compliance with the proposed standard at both existing and new facilities.

To ensure consistency with these proposed changes, the language at Section XVII.F.7.d. was similarly revised to include the clarification that the 500 ppm standard for existing well production facilities does not go into effect until January 1, 2016 (although the 2000 ppm standard will go into effect for existing well production facilities immediately), and to ensure that the 500 ppm standard does not go into effect for any new facility until January 1, 2016. *See* ALT EX D at 15. The referenced language is set forth below:

- XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities after January 1, 2016), or 500 ppm for new facilities or existing well production facilities after January 1, 2016, then the emission shall not be considered a leak for purposes of this Section.

⁴ Note that the text set forth here contains WPX's proposed language, with highlighting to illustrate where WPX proposes changes to the Division's proposed regulation. For the actual redlined version of the proposed language, *see* ALT EX D at p. 14.

6. Proposed revisions to Section XVII.C.3.a.

- XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory (“AVO”) inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are difficult, unsafe, or inaccessible to monitor pursuant to Section XVII.F.5.g.⁵

WPX proposes this revision for clarification and consistency with the LDAR definition of what is difficult, unsafe, or inaccessible to monitor. As currently drafted, the proposed STEM regulations only included that AVO monitoring is not required for components and tanks that are “unsafe to monitor.” WPX proposes the clarification with reference to Section XVII.F.5.g, which defines what is difficult, unsafe, or inaccessible to monitor and provides consistency in the proposed regulations.

7. Proposed revisions to Section XVII.F.4.

- XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

WPX proposed the above typographical correction, to change the “of other Division approved method” to the intended “or other Division approved method.”

III. List of Issues for Commission to Resolve.

As addressed above, the issues WPX requests the Commission to resolve are limited in nature, and can be summarized into three main points.

The primary issue is whether it is appropriate to implement skip period monitoring, a recognized practice in LDAR programs, where an owner or operator consistently demonstrates a reduction in leaks below a specified threshold. If continued decreased leaks are not demonstrated, then WPX agrees that the original monitoring frequency should be reestablished until the reduced leak threshold is again demonstrated.

A secondary issue is whether the proposed regulations, in light of their stringent requirements and first-time enforcement of such requirements for the regulated facilities, provide sufficient time to suppliers of component parts to assure owners and operators that the equipment that is in place, or that will be installed in new facilities, is adequate to meet the new requirements. Based on

⁵ Note that the text set forth here contains WPX’s proposed language, with highlighting to illustrate where WPX proposes changes to the Division’s proposed regulation. For the actual redlined version of the proposed language, see ALT EX D at p. 6.

discussions with suppliers, additional time is needed to ensure that companies and suppliers can be assured of the 500 ppm leak detection rate. At issue here is whether a slight delay in implementing the 500 ppm leak detection rate, recognizing that the 2000 ppm leak detection rate will go into effect immediately, is therefore warranted.

A final issue for the Commission's consideration is clarifying what constitutes "unsafe" conditions for monitoring, particularly since owners and operators across the state are not similarly situated with respect to the location and conditions of access to their facilities.

IV. Exhibits.

The following Exhibits are proposed for submission in support of WPX's position on the Division's proposed rulemaking:

1. Trihydro Corporation Report, including its accompanying figures and tables. *See* PHS EX A.
2. Map of WPX's Piceance operating locations. *See* PHS EX B.
3. Photographs illustrating the location of and types of facilities WPX has within the State, including documentation of remoteness and challenges in inclement weather. *See* PHS EX C.
4. Any exhibits identified by any other person or party.

V. List of Witnesses.

1. Brad Moss, District Production Manager, WPX Piceance Operations.

Mr. Moss may testify regarding the operations of WPX in the Piceance, including a description of why its operations differ from other areas in the state.

2. Jay Christopher, Business Unit Manager, Air and Process Services, Trihydro Corporation.

Mr. Christopher may testify regarding the report submitted by Trihydro Corporation, including the basis for, and conclusions of that report.

3. JoDell Mizoue, Environmental Supervisor, Air Compliance, WPX.

Ms. Mizoue may testify regarding the operations of WPX in the Piceance, including information about costs and time associated with monitoring, recordkeeping and documentation associated with the proposed regulations.

4. Any witness identified or called by any other person or party.
5. Impeachment and rebuttal witnesses.

6. Any witness identified in any exhibit submitted by any other person or party.

VI. Written Testimony.

WPX submits the report by Trihydro Corporation as written testimony to be incorporated into the record. WPX reserves the right to call its witnesses to explain and present the data and conclusions reached in the report.

WPX has not submitted written testimony of other potential witnesses as it has not been ordered by the Commission, but if so required, reserves its right to submit such testimony with its rebuttal to the Prehearing Statements, or by other such time frame ordered by the Commission.

VII. Text of Alternative Proposed Rule.

WPX refers the Commission to its ALT EX D, attached to WPX's simultaneously filed Alternative Proposal, which sets forth in redlined and highlighted text WPX's alternative proposed rule. Note that the revisions suggested by WPX are found at p. 6 and pgs. 10 -15 of the ALT EX D. As noted, WPX does not believe that its targeted comments rise to the level of an alternate proposal, but out of an abundance of caution has presented them as such, along with the accompanying required documents set forth in Procedural Rules Section V.C.3.a through k. *See* WPX's Alternate Proposal ("ALT") submitted simultaneously with WPX's Prehearing Statement.

VIII. Narrative Pursuant to Section 25-7-105.1, 110.5(1)(d) and 133(3).

WPX notes that its alternate proposal does not introduce new or different requirements than the regulations proposed by the Division. As noted by the Division, the proposed rules are more stringent than the federal regulations. WPX's alternate proposal is no more stringent than the Division's proposed regulatory language. As such, WPX relies on and incorporates here the statements made by the Division in its Agenda Item Control Sheet Issue Statement (submitted November 18, 2013), as well as the Draft Statement of Basis, Specific Statutory Authority, and Purpose (submitted by the Division on November 18, 2013) as part of this rulemaking, which address the issues required by Procedural Rule Section V.E.6.c.(viii).

IX. Final Economic Impact Analysis.

Pursuant to the Commission's Order dated December 18, 2013 ("Order"), any alternate proposal submitted to the Commission does not need to include a Final Economic Impact Analysis. *See* Order, Subpart B. The Commission has ordered that the Final Economic Impact Analysis be filed on or before January 30, 2014. As such, WPX does not include a final economic impact analysis at this point.

However, as requested by the Division, WPX points out that the initial economic analysis submitted by the Division on November 18, 2013 as it relates to LDAR issues, Section C, pages 14 to 20, underestimates the costs associated with LDAR implementation (the only section addressed in WPX's alternate proposal). WPX believes that the costs set forth by the Division are underestimated for several reasons, including that the Division only estimates one additional FTE will be necessary to conduct the inspections, and that the Division did not calculate any costs associated with the

additional documentation required by the increased monitoring requirements (including the AVO monitoring), nor did the Division calculate any costs associated with the time to repair and document the inspections or any leaks that are found. In addition, the Division's estimate of times necessary to conduct inspections does not take into account the location and time to travel from one facility to another, which in some areas of the state, particularly where WPX operates, can take up to three hours in good weather just to get to a site.

WPX also notes that its alternate proposal will in any event potentially save some costs for owners and operators if they can demonstrate reduced leak detection rates on a regular basis and therefore the costs associated with WPX's alternate proposal, at a minimum, would be less than costs associated with the Division's proposal.

WPX reserves its right to submit a final economic analysis on or before January 30, 2014 as allowed by the Commission's Order.

X. Reservation of Rights.

WPX expressly reserves its right to amend, delete, modify, add to, and/or supplement the materials and issues, including additional legal argument or witnesses and exhibits identified in this Prehearing Statement and provided to the Commission along with this document, and including WPX's Alternate Proposal, based on the Division's presentation in its case-in-chief, as well as in consideration of alternate rule proposals and prehearing statements (including direct testimony or lists of witnesses) that may be submitted by other parties to this matter.

Respectfully submitted this 6th day of January, 2014.

WPX ENERGY ROCKY MOUNTAIN, LLC and WPX
ENERGY PRODUCTION, LLC



By: _____

Lisa A. Decker #19962
Senior Counsel
WPX Energy, Inc.
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CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of January, 2014, the foregoing **WPX ENERGY ROCKY MOUNTAIN, LLC'S AND WPX ENERGY PRODUCTION, LLC'S PRE-HEARING STATEMENT** was filed and delivered via electronic mail to the following:

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/s/ Lisa A. Decker _____

Lisa A. Decker

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION

**REGARDING REVISIONS TO REGULATION NUMBERS 3, 6 AND 7
February 12-21, 2014 Hearing**

**REBUTTAL STATEMENT OF
ENCANA OIL AND GAS (USA) INC.**

Encana Oil & Gas (USA) Inc. (Encana) filed for and was granted party status in the above-captioned matter. Encana duly and timely filed its prehearing statement. Pursuant to the 25 November 2013 Notice of Public Rulemaking in the above-captioned matter, and the Air Quality Control Commission's (Commission) procedural rule V.E.6.d, Encana now respectfully submits this rebuttal statement and accompanying materials.

I. EXECUTIVE SUMMARY

In December 2012, the Air Pollution Control Division (Division) notified the oil and gas industry, other stakeholders, and the public that the Division was “considering revisions related, but not limited, to the full adoption of 40 CFR Part 60, Subpart OOOO (“NSPS OOOO”) and to air pollutant emission notice reporting and construction permit thresholds, as well as additional control measures for oil and gas operations and equipment.”¹ Almost a year later, the Commission formally initiated a rulemaking proceeding to consider revisions to Regulations 3, 6, and 7 to fully incorporate by reference NSPS OOOO and to “establish state-only volatile organic compound (VOC) and other hydrocarbon emission control requirements for oil and natural gas operations.”² In the intervening months, the Division convened numerous large stakeholder meetings, as well as smaller subcommittee meetings to explore a wide range of issues related to the instant proceeding. Numerous stakeholders participated and, in many

¹ <http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheadname1=Content-Disposition&blobheadname2=Content-Type&blobheadvalue1=inline%3B+filename%3D%22Notice+of+2013+Rulemaking+Stakeholder+Meetings.pdf%22&blobheadvalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251844864207&ssbinary=true> (last visited Jan. 24, 2014).

² <http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheadname1=Content-Disposition&blobheadname2=Content-Type&blobheadvalue1=inline%3B+filename%3D%22Notice+Of+Rulemaking+Hearing.pdf%22&blobheadvalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251913358003&ssbinary=true> (last visited Jan. 24, 2014)

instances, submitted written materials outlining the issues they asserted should be addressed in a rulemaking. The agendas and some of the materials exchanged can be found on the Division's web site.³

Encana agrees with the argument expressed by many parties that fair notice and process is integral to the development of regulatory proposals that satisfy Colorado's procedural requirements for rulemaking, as well as fundamental fairness. But while some of the more than thirty parties to this rulemaking assert that the Commission's process fails one or more particulars of Colorado's Administrative Procedure Act (APA), Colo. Rev. Stat. § 24-4-101, *et seq.* (2013), the record of stakeholder consultation prior to the notice of rulemaking and the materials filed in this matter by the Division and other stakeholders, including Encana, suggest the procedural requirements of the Colorado APA have been more than met.

Every interested party has been given abundant opportunity to raise issues and propose alternative approaches for management and control of atmospheric emissions from the oil and gas industry. The materials posted on the Division's web site provide a picture of the robust back-and-forth that was had among diverse parties. Many of the concerns expressed during that process are reflected in the Division's proposal. For example, many industry parties expressed concerns about how visible emissions are monitored and enforced; the Division's proposal includes language to accomplish that goal.

Encana believes that more than adequate process has been provided. Moreover, by the time all parties, including the Division, have had full opportunity to present their arguments and evidence at hearing, it will be clear that the more granular admonitions of the APA also have been satisfied. *See, e.g.*, Colo. Rev. Stat. § 24-4-103(4)(b).

Encana believes the Division has also met the requirements of the Colorado Air Pollution Prevention and Control Act (Colorado Air Act), Colo. Rev. Stat. § 25-7-101, *et seq.* (2013). Colorado has a long and proud tradition as a leading-edge innovator in managing and controlling air pollution, owing in large part to the Act's commitment to proactive action to prevent air pollution problems as well as to manage existing air pollution. The proposal from the Division is in keeping with that tradition.

The proposal from the Division will measurably reduce emissions of volatile organic compounds and hydrocarbons across the state from the oil and gas sector, including in the Denver Metro/North Front Range Ozone Nonattainment Area. The Division's proposal will accomplish that goal, in substantial part, by establishing a requirement for instrument-based monitoring of wellhead facilities and compressor stations to ensure that leaks are timely repaired, and by establishing a Storage Tank Emissions Management program that will reduce emissions and

³ <http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820> (last visited Jan. 24, 2014).

increase capture efficiency from storage tanks in the oil and gas sector. By requiring these control measures on a statewide basis, the Commission would be making a permissible policy decision, within its scope of authority, to proactively address air pollution in some parts of the state that currently are designated as attainment while working to reduce air pollution in the ozone nonattainment area.

As noted already, the Colorado Air Act anticipates that the Commission will act in response to existing problems and in anticipation of potential future air quality problems. Nothing requires the Commission to limit the scope of its regulations to a specific region; indeed, the Act contemplates that in appropriate circumstances, the Commission may establish statewide control measures, as the Division proposes here. While the Act creates an expectation of reasoned decision-making, a goal no doubt shared by all parties, the Act permits the Commission to set priorities and to attack problems seriatim. The Colorado Air Act does not require the Commission to resolve large and complex problems at one rulemaking.

Based on its experience in Wyoming's Jonah Field (see section V, *infra*) Encana believes that the Division's proposal reflects a common-sense approach that appropriately balances environmental benefits and costs. As such, the Division's proposal falls within the scope of the Colorado Air Act.

It is worthy of mention that some parties seek even more stringent requirements for monitoring, repair, and certain control measures than those proposed by the Division. Other parties seek less frequent monitoring, less demanding repair requirements, and less stringent control measures. The Division has plotted a thoughtful, comprehensive, but balanced middle ground in addressing air pollution, relying upon technologically feasible and cost-effective strategies. Encana stated at the outset its support for the Division's proposal, and reiterates that support in this rebuttal statement.

II. NARROWING ISSUES:

PROPOSED LANGUAGE FROM DCP MIDSTREAM PREHEARING STATEMENT

In its prehearing statement, DCP Midstream stated that it supports the Division's proposal as an appropriate policy step but urged the Commission to consider five discrete, targeted clarifications that would ease and clarify compliance with Section XVII by natural gas compressor stations without diminishing the environmental benefits to be gained by adoption of these revisions. Those targeted clarifications consisted of the following changes:

1. A minor revision to the proposed definition of Natural Gas Compressor Station to make clear that these regulations do not extend to natural gas processing stations, which already are subject to significant federal emissions control requirements;

2. A minor revision to the glycol dehydrator control requirements to ensure that operators are not required to replace existing, permitted and effective emissions controls;
3. Revision of the definition of component, along with accompanying additions to ensure that compressor seals and open ended lines and valves are appropriately managed;
4. Minor revisions to the Statement of Basis and Purpose regarding the definition of Well Production Facility to make clear the demarcation between a natural gas producer's well facilities and those facilities operated by a midstream company; and
5. Minor revisions to the Storage Tank inspection and monitoring requirements to clarify the operation of those requirements with respect to midstream facilities as opposed to those at well production facilities.

Encana carefully considered these proposed revisions, and concluded that they clarify the proposed revisions to Section XVII and ease compliance burdens and cost without lessening the proposed revisions' effectiveness. Consequently, Encana endorses these revisions *in toto*.

III. THE COMMISSION HAS THE STATUTORY AUTHORITY TO REGULATE VOCs AND HYDROCARBONS

The Commission's authority to regulate emissions of volatile organic compounds and nitrogen oxides, both of which are ozone precursors, from the oil and gas sector (and other source categories) is clear. However, the Division's proposal in this instance would expand Regulation 7's reach to include hydrocarbon emissions from the oil and gas sector. Several parties have challenged the Commission's authority to do so.

Certainly, "state agencies are creatures of statute and have 'only those powers expressly conferred by the legislature.'" *Pawnee Well Users, Inc. v. Wolfe*, 2013 WL 6172292 (Colo S.Ct. Nov. 25, 2013)(citations omitted). It is equally true that in construing a statutory provision, the courts will look first to the express language of the statute itself, and will resort to alternative tools of statutory construction only if the statutory language is ambiguous. *Jefferson County Bd. of Equalization v. Gerganoff*, 241 P.3d 932, 935 (2010);⁴ *Dept. of Revenue v. Woodmen of the World*, 919 P.2d 806, 809-810 (1996).

The Colorado Air Act specifically provides that the Commission shall promulgate emissions controls, and that such controls may include regulations pertaining to "sulfur oxides, sulfuric

⁴ Even were the statute ambiguous, a reviewing court would give great weight to an agency's interpretation of its own organic statute. *Smith v. Farmers Insurance Exchange*, 9 P.3d 335, 340 (2000).

acids, hydrogen sulfide, nitrogen oxides, carbon oxides, hydrocarbons, fluorides, and any other chemical substance.” Colo. Rev. Stat. § 25-7-109(2)(c)(2013)(emphasis added).

The plain language of this enabling legislation provides the Commission with the authority to adopt the regulation at issue here. Encana offers no opinion on whether the Commission has the authority to regulate any other pollutant. That question is not presented in this instance, and it is not necessary for the Commission to address it in a hypothetical context. It is sufficient to note that the General Assembly has given the Commission the authority to regulate emissions of hydrocarbons.

IV. THIS RULEMAKING COMPORTS WITH THE PROCEDURAL REQUIREMENTS OF THE ADMINISTRATIVE PROCEDURE ACT AND THE COLORADO AIR ACT

A. Administrative Procedure Act

The Administrative Procedure Act (APA), Colo. Rev. Stat. § 24-4-101, *et seq* (2013), creates a roadmap for adoption of rules by administrative agencies. While some parties disagree, Encana believes that a fair reading of the process and the record show that the Division has adhered to the statutory mileposts along the way, assuring compliance with the spirit as well as the legal requirements of the APA.

The Division formally notified stakeholders more than a year ago that the Division was contemplating revisions to Regulations 3, 6 and 7 with respect to the oil and gas sector.⁵ The Division convened a stakeholder process that involved numerous meetings as well as the exchange of ideas, both in writing and orally. The Division and stakeholders engaged in a robust discussion of alternatives. Along the way, some issues were raised but left unresolved. In other instances, the parties moved toward agreement. For example, the notion of a Storage Tank Emission Management (STEM) program emerged as an alternative to the initial idea of adopting a presumptive-BACT control requirement. Along the way, different groups of stakeholders offered their individual recommendations for what a rulemaking proposal should embrace. The proposal that the Division ultimately settled on relied in many respects upon a joint proposal that had been developed in a collaborative effort by Encana, Anadarko Petroleum Corporation, Noble Energy, and Environmental Defense Fund. Even that proposal incorporated numerous elements developed by other stakeholders throughout the process.

⁵ <http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheadername1=Content-Disposition&blobheadername2=Content-Type&blobheadervalue1=inline%3B+filename%3D%22Notice+of+2013+Rulemaking+Stakeholder+Meetings.pdf%22&blobheadervalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251844864207&ssbinary=true> (last visited Jan. 24, 2014).

Consistent with the provisions of the APA, the Division then submitted to the Commission Memoranda of Notice requesting that the Commission consider revisions to Regulations 3, 6, and 7.⁶ The Division's proposal included draft language of the proposal accompanied by draft Statements of Basis and Purpose and plain language explanations of the proposed action. The Division's proposal was accompanied by a draft Economic Impact Analysis.⁷ At its regular meeting on November 21, 2013, the Commission formally noticed its intent to initiate a rulemaking proceeding to consider revisions to Regulations 3, 6, and 7.

The APA permits affected interest to request the preparation of a cost-benefit analysis, a regulatory impact analysis, or both, for inclusion in the rulemaking process. Colo. Rev. Stat. § 24-4-103(2.5)(a). Several parties made just such a request.⁸ The Division has agreed to prepare these documents, and the Hearing Officer directed that the cost-benefit statement be made available by the Division no later than February 7, and that the regulatory impact analysis be made available no later than February 14.⁹

In Encana's view, the Division has adhered to the procedural requirements for rulemaking established by the General Assembly. The Division has compiled substantial information in the record to demonstrate the basis and purpose of the proposed regulation, Colo. Rev. Stat. § 24-4-103(4)(b)(I), and Encana believes that record is sufficient to justify adoption of the proposed rules in this case.

⁶ The memoranda of notice can be found at <http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820>.

⁷ All of these materials can be found at the Commission's web site, *id.*

⁸ A list of the requesters, and copies of their requests can be found at the Commission's web site:

<http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheadername1=Content-Disposition&blobheadername2=Content-Type&blobheadervalue1=inline%3B+filename%3D%22Combined+List+of+Requests+for+Cost+Benefit+and+Regulatory+Analysis+%2846+pages+-+revised+12%2F20%2F13%29%29.pdf%22&blobheadervalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251929901749&ssbinary=true>.

⁹ <http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheadername1=Content-Disposition&blobheadername2=Content-Type&blobheadervalue1=inline%3B+filename%3D%22Order+by+the+Commission.pdf%22&blobheadervalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251929901605&ssbinary=true>. It is important to note that “[f]f the agency has made a good faith effort” to comply with the requirement for preparation of a cost-benefit analysis, the rule :shall not be invalidated in the basis that the contents of the cost-benefit analysis are insufficient or inaccurate.” Colo. Rev. Stat. § 24-4-103(2.5)(d)(2013).

B. Colorado Air Act

Several parties contend that the proposal falls short of the requirements set by the Colorado Air Act. However, an examination of the Act's requirements and their application in this proceeding demonstrates that the core requirements of the Air Act have been met.

In adopting Colorado's Air Act, the General Assembly declared that

... it is the policy of the state to maintain the national ambient air quality standards, and to prevent the significant deterioration of air quality in those portions of the state where air quality is better than the national ambient air quality standards. To that end, it is the purpose of this article to require the use of all available practical methods which are technologically feasible and economically reasonable so as to reduce, prevent, and control air pollution throughout the state of Colorado.

Colo. Rev. Stat. § 25-7-102 (2013). The same section requires that control measures "bear a reasonable relationship to the economic, environmental, and energy impacts and others costs of such measures." In its prehearing statement and Economic Impact Analysis, the Division, along with other parties, provided substantial information on the economic reasonableness and feasibility of the LDAR, STEM and control measures called for in this proposal. Encana will provide additional support for that proposition in their testimony. Encana also believes the proposed rule reasonably balances costs and environmental benefits. Accordingly, Encana believes the record will more than adequately support adoption of the instant proposal.

Section 25-7-102 also requires the Division to develop and maintain an inventory of emissions to facilitate the Division's and the Commission's manifold responsibilities. The Division and the Regional Air Quality Council have been developing such inventories for some years. The Regional Air Quality Council's prehearing statement refers both to emissions inventories and trends, and ongoing modeling efforts with respect to the Denver Metro/North Front Range Ozone Nonattainment Area. The Division has provided substantial information on the relative emissions and emission trends of different source categories. Some parties argue that the inventories overstate emissions and emissions trends from the oil and gas sector and other parties argue those inventories significantly understate emissions and emission trends. While the Division and other entities will continually revise and update inventories as new science becomes available, the record reflects that the Division has submitted extensive information on this issue. Therefore, Encana believes this requirement of the Air Act has been satisfied.

Notably, the Air Act grants the Commission "maximum flexibility in developing an effective air quality control program," permits the Commission to divide the state into "such control regions or areas as may be necessary or desirable for effective administration of this article," and specifically notes that the Commission may adopt regulations that are applicable to the whole

state or to specified areas of the state. Colo. Rev. Stat. § 25-7-106(1)(a)-(c) (2013). This section of the Colorado Air Act acknowledges the inherent complexity involved in understanding the generation, transport, and chemistry of air pollution, and provides the Commission with the necessary flexibility to adapt its regulations as science develops and situations change.

Some parties argue that the Commission erred in making its proposed regulations applicable statewide, even though the Commission's organic statute expressly permits such action. Some also argue, in addition, that by applying these regulations statewide, the Commission proposes to effectively designate the entire state as a nonattainment area under the federal Clean Air Act. Encana does not believe that is the case here. The Division has expressly and emphatically stated that the proposed amendments to Regulation 7 would be state-only and will not be proposed for inclusion in Colorado's state implementation plan; the proposed rules include specific notations to that effect. Such action is explicitly contemplated by Colo. Rev. Stat. § 25-7-105.1. The mere act of applying a targeted, discrete, common sense set of regulations to the oil and gas sector statewide does not convert this to a SIP action, to a re-designation of areas as nonattainment, or to creation of a statewide nonattainment area. Rather, it speaks to the Division's desire to reduce complexity in its regulations, and to address air pollution issues proactively, which Encana supports.

Adopting these rules as state-only requirements fits well with the Division's stated goal of addressing existing and potential air pollution issues within the state's legal authority, without adding the extra burden of making these provisions federally enforceable. This will permit the state and the industry to work together to implement these measures, assess their effectiveness, and to consider technical adjustments as new data are collected. The Division has explained why, in its view, these measures are needed, even if they may exceed current federal requirements. *See* Colo. Rev. Stat. § 110.5(5)(2013).

C. Conclusion.

The Colorado General Assembly has chosen to vest part-time citizen bodies, such as the Air Quality Control Commission, with rulemaking authority, bounded by the APA. *Colorado Ground Water Comm'n v. Eagle Peak Farms, Ltd.*, 919 P.2d 212, 216 (1996). The instant rulemaking is quasi-legislative in nature, and necessarily calls upon the Commission to make policy as well as factual determinations, though policy determinations may predominate. *Id. See also, Citizens for Free Enterprise v. Dept. of Revenue*, 649 P.2d 1054, 1063-1064 (1982). Of course, the Commission's decision must be based on the administrative record, Colo. Rev. Stat. § 24-4-106, and if the agency's decision is reasonable it will be affirmed. *Brighton Pharmacy, Inc. v. Colorado State Pharmacy Bd.*, 160 P. 3d 412 (Colo. App. 2007)

The Division has compiled a record demonstrating the basis and purpose for regulation in this matter, as well as substantial evidence that the control measures being proposed are

economically reasonable and technically feasible. Other parties have provided and will provide additional support for the Division's proposal. The Division calculates that the proposed regulations will yield significant reductions in emissions of volatile organic compounds and hydrocarbons across the state, including in the ozone nonattainment area. The Division also has provided information on the reasonableness of the phase-in schedule for instrument-based monitoring, the effective dates for installation of controls on glycol dehydrators, and replacement of high-bleed pneumatics with low-bleed pneumatics. The Division reasonably concluded that application of these measures statewide would provide additional environmental benefits at a reasonable cost while reducing confusion for the regulated industry and the general public. While some parties argue for more frequent instrument-based monitoring and others argue for less frequent instrument-based monitoring of components at wellhead facilities and compressor stations, the Division's proposal can be tied to evidence in the record showing that its policy choice reflects a careful balancing of the proposal for additional regulation with a due regard for the cost and feasibility of the proposed control measures.

V. THE PROPOSED LEAK DETECTION AND REPAIR REQUIREMENTS ARE ECONOMICALLY REASONABLE AND TECHNICALLY FEASIBLE

A. Auditory, Visual, and Olfactory Inspections.

The proposal will require Auditory, Visual, and Olfactory (AVO) inspections of tanks and other equipment as an adjunct in many cases to instrument-based monitoring. Encana currently has operational practices and procedures in place that can support this requirement with limited cost. In Encana's operations, lease operators visit well production facilities on a regular basis, typically daily or every other day, and complete monitoring tasks supporting the current Regulation 7 requirements such as monitoring pilot lights, checking for the presence or absence of smoke, etc. Additionally, Encana already has data tracking systems in place to track and record these compliance monitoring tasks. As such, adding AVO inspections to the lease operators' duties will result in little additional cost to Encana. However, Encana will need to train the lease operators to conduct and record their AVO inspections as part of their regular duties. Encana estimates that the lease operators will be able to visit 10-30 sites per day in the DJ Basin, and 10-20 sites per day in the Piceance Basin. For facilities with emissions controls, the results of those AVO inspections could then be captured in the company's tracking database, which currently exists. Encana will need to expand this database to capture the results of AVO inspections at sites without emissions controls and estimates these costs will be minimal.

B. Encana's Experience with Leak Detection and Repair Supports the Economically Reasonable Approach Reflected in the Division's Proposal.

Driven by the desire for regulatory certainty and other business considerations, Encana has gained significant experience with LDAR programs at its operations in the Jonah Field in Wyoming. In total, Encana conducts approximately 2,040 instrument-based inspections per year at its Jonah facilities and carefully records the results. Encana uses a comprehensive database to track inspections and corresponding leaks. With these data Encana is able to calculate the annual non-amortized cost of the program. While Encana can speak only to its experiences, Encana has a unique perspective on the utility and cost-reasonableness of LDAR programs.

The Division's proposal requires owners and operators of well production facilities to use instrument-based technologies to inspect their facilities for leaks, and repair leaks that exceed a certain defined threshold. The Division's proposal establishes different inspection frequencies for Leak Detection and Repair (LDAR) for facilities based on uncontrolled actual emissions. Some parties have argued that the inspection frequencies should be made more rigorous, even for the smallest sources, and that the value of the natural gas recovered offsets the program costs. As noted below, it has been Encana's experience that the value of the gas recovered does not offset the program costs of an instrument-based monitoring program for well production facilities. Other parties also have suggested that an instrument-based system loses its efficacy after an initial set of inspections. However, Encana's experience with an instrument-based monitoring program for well production facilities show that leaks continued to be detected well into the established LDAR program.

Notably, under the Division's proposal, the smallest sources, with uncontrolled actual emissions less than 6 tons per year, will require a single instrument-based inspection. Encana calculates that these one-time inspections will yield significant environmental benefits, because the monitoring data from the company's experience in Wyoming shows the greatest number of leaks was discovered within the first monitoring event. Larger facilities will be required to conduct more frequent instrument-based inspections, and the largest facilities will be required to conduct inspections on a monthly basis. Data from Encana's Wyoming program suggest that while emissions decrease after an initial set of inspections, a number of small leaks continue to be discovered as the program progresses. This supports the utility of more frequent inspections at larger facilities because these facilities have greater potential for higher total emissions volumes and numbers of leaks.¹⁰

Viewed somewhat differently, Encana's data also suggest that while the largest reductions in VOC emissions occur in the first year of an LDAR program, regardless of whether the program entails monthly, quarterly, or annual inspections, emissions reductions are still being realized in subsequent years of the LDAR program. Encana also examined its Wyoming data for monthly

¹⁰ In graphing the decline in emissions and numbers of leaks detected, Encana used actual data combining all facilities. Encana expects that the shape of the curve showing the decline in emissions would be less steep if the frequency of inspections also declined. These data suggest that while tiering is essential, building in an option to reduce inspection frequencies may lead to both higher volumes of emissions and higher numbers of leaks.

monitoring over a four-year period, and extrapolated those data to other monitoring frequencies. These data suggest that monthly inspections result in the lowest emissions but significant reductions are still achieved at the other monitoring frequencies. However, as noted above, an LDAR program is likely to produce the greatest reductions in VOC emissions from large facilities and that the potential for diminishing returns is reduced by the use of tiered monitoring frequencies. Encana believes that the tiered monitoring is the best approach for balancing costs with benefits.

Encana's experience shows that at no time, under any monitoring frequency, does the value of the gas recovered equal or exceed the costs of the monitoring program. In fact, the delta between costs and savings, measured solely by the value of natural gas captured, is significant at all inspection frequencies. This is directly contrary to the claims made by a witness for the Conservation Organizations and an exhibit offered by the Local Government Coalition.

At the same time, it has been Encana's experience that building into the regulation a tiered approach, in which larger facilities are subject to progressively more frequent instrument-based monitoring, is significant in examining the costs and benefits of an LDAR program. By applying its Wyoming experience to its Colorado assets, Encana estimates that total costs of the proposed rule (non-amortized) will decline significantly after the initial year (in which capital costs are incurred). As noted elsewhere, this tiered approach is likely to yield the greatest environmental benefit: while small facilities' leaks likely will be captured after an initial inspection, larger facilities likely will have more components and higher pressures and, therefore, higher potential emissions. Accordingly, more frequent inspections are useful at those large facilities.

Finally, Encana emphasizes that while it supports the rule at issue here, as a common sense, achievable set of control measures, Encana's data show that these measures will impose significant costs and that the value of recovered gas will not offset those costs. Implementation of the leak detection requirements, for example, will require at least an initial inspection at more than 1,100 facilities, as well as quarterly or monthly inspections at more than another 300 facilities. A requirement to conduct annual inspections at those 1,100 facilities, each with tank emissions of less than 6 tons/year, would dramatically increase the program's total costs and logistical challenges of an LDAR program, yet likely would yield a very modest incremental environmental benefit, at most. Encana strongly cautions the Commission about the additional costs that would be imposed by an inspection regime more stringent than contemplated by the proposed rule.

VI. CONCLUSION

Encana believes that the legal and procedural requirements for rulemaking in this case have been satisfied and urges adoption of the Division proposal, with appropriate technical and clarifying changes as the hearing may reveal are necessary.

VII. REBUTTAL WITNESSES

Witnesses who may testify at the hearing, on both in support of the proposed regulations and on rebuttal on behalf of Encana include:

1. James Martin
Beatty & Wozniak, P.C.
Attorney for Encana Oil & Gas (USA) Inc.

Mr. Martin may testify to the legal and policy issues raised in Encana's Prehearing Statement, Rebuttal Statement, and accompanying materials.

2. Cindy Allen
Team Lead – Environmental and Regulatory Compliance
Encana Oil & Gas (USA) Inc., acting by and through its authorized agent,
Encana Services Company Ltd.

Ms. Allen may testify to Encana's experience with leak detection and repair.

VII. WRITTEN TESTIMONY

At this time, Encana does not intend to submit written witness statements. However, Encana reserves its right to file written testimony in advance of the hearing if doing so would assist in achieving a more efficient hearing.

VIII. ATTACHMENTS

A. Encana submits the attached legal memorandum to aid the Commission in its evaluation of claims and arguments that Encana believes are outside the scope of the Commission's Notice: **LEGAL MEMORANDUM ASSERTING CERTAIN CLAIMS ARE OUTSIDE THE SCOPE OF THE NOTICE OF RULEMAKING**

B. RESUME OF CINDY ALLEN

IX. REQUEST FOR TIME

Absent intervening events, Encana foresees no need for time in addition to the time allocation as provided by the Hearing Officer's Prehearing Order.

Respectfully submitted this 30th day of January 2014.

By: _____/s/

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ATTORNEY FOR ENCANA OIL & GAS (USA) INC.

Oil and Natural Gas Sector Leaks

Report for Oil and Natural Gas Sector Leaks

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards

(OAQPS)

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Table of Contents

| | |
|--|----|
| PREFACE..... | 1 |
| 1.0 INTRODUCTION..... | 2 |
| 2.0 OIL AND NATURAL GAS SECTOR LEAKS EMISSIONS DATA AND EMISSIONS ESTIMATES | 4 |
| 2.1 Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995) | 6 |
| 2.2 GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks (GRI/U.S. EPA, 1996)..... | 9 |
| 2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013) | 16 |
| 2.4 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014) | 17 |
| 2.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)..... | 22 |
| 2.6 City of Fort Worth Natural Gas Air Quality Study (ERG, 2011) | 24 |
| 2.7 Measurements of Well Pad Emissions in Greeley, CO (Modrak, 2012) | 26 |
| 2.8 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)..... | 28 |
| 2.9 Mobile Measurement Studies in Colorado, Texas, and Wyoming (Thoma, 2012) | 29 |
| 2.10 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)..... | 31 |
| 2.11 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)..... | 32 |
| 2.12 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006) | 34 |

| | | |
|-----|--|----|
| 3.0 | AVAILABLE EMISSIONS MITIGATION TECHNIQUES | 36 |
| 3.1 | Leak Detection | 36 |
| | 3.1.1 Portable Analyzers | 36 |
| | 3.1.2 Optical Gas Imaging (IR Camera) | 39 |
| | 3.1.3 Acoustic Leak Detector | 42 |
| | 3.1.4 Ambient/Mobile Monitoring | 44 |
| 3.2 | Repair | 45 |
| | 3.2.1 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)..... | 46 |
| | 3.2.2 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002) | 47 |
| | 3.2.3 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)..... | 48 |
| | 3.2.4 Natural Gas STAR Directed Inspection and Maintenance (U.S. EPA, 2003a, U.S. EPA, 2003b, and U.S. EPA, 2003c)..... | 49 |
| | 3.2.5 Update of Fugitive Equipment Leak Emission Factors (CAPP, 2014).. | 52 |
| 4.0 | SUMMARY | 54 |
| 5.0 | CHARGE QUESTIONS FOR REVIEWERS | 55 |
| 6.0 | REFERENCES..... | 57 |

PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:

www.epa.gov/airquality/oilandgas/whitepapers.html

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater air emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on air emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

Oil and gas production from unconventional formations such as shale deposits or plays has grown rapidly over the last decade. Oil and natural gas production is projected to steadily increase over the next two decades. Specifically, natural gas development is expected to increase by 44% from 2011 through 2040 (U.S. EIA, 2013b) and crude oil and natural gas liquids are projected to increase by approximately 25% through 2019 (U.S. EIA, 2013b). According to the U.S. Energy Information Administration (EIA), over half of new oil wells drilled co-produce natural gas (U.S. EIA, 2013a). The projected growth is primarily led by the increased development of shale gas, tight gas, and coalbed methane resources utilizing new production technology and techniques such as horizontal drilling and hydraulic fracturing.

Along with the increase in number of wells, the amount of related equipment that has the potential to leak will increase as well. The emissions that occur from leaks are in the form of gasses or evaporated liquids that escape to the atmosphere. Some of the potential leak emissions from these sources include methane and VOCs. The proportion of the different types of air

emissions is affected by the composition of the gas in the formation. For example, there tends to be a higher concentration of VOCs in wet gas plays than in dry gas plays.

The emissions data and the mitigation techniques in this paper are based on the onshore natural gas leak emissions that occur from natural gas production, processing, transmission, and storage. However, some of these emissions estimates and mitigation techniques are also applicable to oil wells that co-produce natural gas.

For the purposes of this paper, leaks are defined as VOC and methane emissions that occur at onshore facilities upstream of the natural gas distribution system (i.e., upstream of the city gate). This includes leak emissions from natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leak emissions from these sites include agitator seals, compressors seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves, and improperly controlled liquids storage.¹ For the purposes of this paper, emissions from equipment intended to vent as part of normal operations, such as gas driven pneumatic controllers, are not considered leaks. The definition of leak emissions in this paper was derived by reviewing the various approaches taken in the available literature. Many studies and data sources define leak emissions differently, therefore, in the discussion of these various sources in Section 2 the definition each study uses is compared to the definition presented here.

Leak emissions occur through many types of connection points (e.g., flanges, seals, threaded fittings) or through moving parts of valves, pumps, compressors, and other types of process equipment. Changes in pressure, temperature and mechanical stresses on equipment may eventually cause them to leak. Leak emissions can also occur when connection points are not fitted properly, which causes leaks from points that are not in good contact. Other leaks can occur due to normal operation of equipment, which over time can cause seals and gaskets to

¹ Emissions from storage vessels are often required to be controlled by state or federal regulations (e.g., reduced by 95%). Emissions beyond the required level of control from control equipment that is not operating properly, such as leaking vapor recovery units or improperly sized combustors, are considered leaks for the purposes of this white paper.

wear. Weather conditions can also affect the performance of seals and gaskets that are intended to prevent leaks. Lastly, leak emissions can occur from equipment that is not operating correctly, such as storage vessel thief hatches that are left open or separator dump valves that are stuck open.

This document provides a summary of the EPA's understanding of VOC and methane leak emissions at onshore oil and natural gas production, processing, and transmission facilities. This includes available emission data, estimates of VOC and methane emissions and available mitigation techniques. Section 2 of this document describes the EPA's understanding of emissions from leaks at onshore oil and natural gas production, processing, and transmission facilities, and Section 3 discusses available mitigation techniques to reduce emissions from leaks at these facilities. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist the EPA with obtaining a more comprehensive picture of VOC and methane emissions from leaks and available mitigation techniques.

2.0 OIL AND NATURAL GAS SECTOR LEAKS EMISSIONS DATA AND EMISSIONS ESTIMATES

There are a number of published studies that have estimated leak emissions from the natural gas production and petroleum, processing and transmission sector. These studies have used different methodologies to estimate these emissions, including the use of equipment counts and emission factors, extrapolation of emissions from equipment, and measurement and analysis of leaks. In some cases the studies focus on different portions of the natural gas production and petroleum, processing and transmission and storage sector (e.g., well sites), while others try to account for all leak emissions across the oil and gas sectors. Some of these studies are listed in Table 2-1, along with an indication of the type of information contained in the study (i.e., activity level).

Table 2-1. Summary of Major Sources of Leaks Emissions Information

| Name | Affiliation | Year of Report | Activity Factor |
|--|--|-----------------------|------------------------------|
| Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995) | U.S. Environmental Protection Agency | 1995 | None |
| Methane Emissions from the Natural Gas Industry: Equipment Leaks (GRI/U.S. EPA, 1996) | Gas Research Institute (GRI)/ U.S. Environmental Protection Agency | 1996 | Nationwide |
| Greenhouse Gas Reporting Program (U.S. EPA, 2013) | U.S. Environmental Protection Agency | 2013 | Facility |
| Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014) | U.S. Environmental Protection Agency | 2014 | Regional |
| Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013) | Multiple Affiliations, Academic and Private | 2013 | Nationwide |
| City of Fort Worth Natural Gas Air Quality Study, Final Report (ERG, 2011) | City of Fort Worth | 2011 | Fort Worth, TX |
| Measurements of Well Pad Emissions in Greeley, CO (Modrak, 2012) | ARCADIS/Sage Environmental Consulting/U.S. Environmental Protection Agency | 2012 | Colorado |
| Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013) | Carbon Limits | 2013 | Canada and the U.S. |
| Mobile Measurement Studies in Colorado, Texas, and Wyoming (Thoma, 2012) | U.S. Environmental Protection Agency | 2012 and 2014 | Colorado, Texas, and Wyoming |
| Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014) | ICF International | 2014 | Nationwide |

| Name | Affiliation | Year of Report | Activity Factor |
|---|------------------------------|----------------|--|
| Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002) | Clearstone Engineering, Ltd. | 2002 | 4 gas processing plants |
| Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006) | Clearstone Engineering, Ltd. | 2006 | 5 gas processing plants, 12 well sites, 7 gathering stations |

Although methane emissions from oil and natural gas production operations have been measured, analyzed and reported in studies spanning the past few decades, VOC emissions from these operations are not as well represented.

2.1 Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995)

The EPA protocol provides standard procedures for estimating the total organic compound mass emissions from leaks at oil and natural gas production facilities. The protocol provides four different approaches for estimating leak mass emissions at oil and natural gas production sites. The correlation equations and emission factors were developed from leak data collected from refineries, marketing terminals, oil and gas production operations and synthetic organic chemical manufacturing industry (SOCMI) facilities.

Emission factors and correlations have been developed for the following equipment types: valves, pumps, compressors, pressure relief valves, connectors, flanges, and open-ended lines. An "others" category has also been developed for the petroleum industry. Development of emission factor and correlation equations for the oil and natural gas production facilities were derived from data from six gas plants that were screened by the EPA and the American Petroleum Institute² and from leak emission measurement data from 24 oil and natural gas

² DuBose, D.A., J.I. Steinmetz, and G.E. Harris (Radian Corporation). Frequency of Leak Occurrence and Emission

production facilities collected by the American Petroleum Institute.^{3,4} The emissions calculated from these emission factors and correlation equations are leak emissions that occur at onshore oil and natural gas production and natural gas processing facilities.

Protocol Leak Estimation Approaches

The protocol document provides four approaches that can be used to estimate mass emissions from leaks.

Average Emission Factor Approach

The first approach involves counting the components by type (e.g., valves, pump seals, connectors, flanges, and open-ended lines) and service (e.g., gas, heavy oil, light oil, and water/oil) at the facility and applying the appropriate average oil and gas production operations emission factors to these counts (see Table 2-4 in U.S. EPA, 1995) to calculate the total organic compound emissions from leaking equipment. There is also an “other” equipment type emission factor that was derived for compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents.

Although the average emission factors are in units of kilogram per hour per individual source, it is important to note that these factors are most valid for estimating emissions from a population of equipment (U.S. EPA, 1995). The average factors are not intended to be used for estimating emissions from an individual piece of equipment over a short time period (e.g., 1 hour).

Factors for Natural Gas Liquid Plants. Final Report. Prepared for U.S. Environmental Protection Agency. Research Triangle Park, NC. EMB Report No. 80-FOL-1. July 1982.

³ Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, Prepared for American Petroleum Institute, 1993.

⁴ Emission Factors for Oil and Gas Production Operations, API 4615, Star Environmental, Prepared for American Petroleum Institute, 1995.

Screening Ranges Approach

The second approach to estimating leak emissions is the screening range approach. This approach is intended primarily to aid in the analysis of old datasets that were collected for older regulations that used 10,000 parts per million by volume (ppmv) as the leak definition. This approach uses the results from EPA Method 21 measurement of leak concentration of components to determine the number of components with a leak greater than or equal to 10,000 parts per million (ppm) and the number of components with a leak less than 10,000 ppm. The estimated emissions are then calculated using the count of components by type, service, and screening value ($\geq 10,000$ ppm or $< 10,000$ ppm) at the facility and applying the appropriate average oil and gas production operations emission factors to these counts (see Table 2-8 in U.S. EPA, 1995).

This screening range approach is a better indication of the actual leak rate from individual equipment than the average emission factor approach (U.S. EPA, 1995). However, available data indicate that measured mass emission rates can vary considerably from the rates predicted by use of these screening range emission factors.

EPA Correlation Approach

The third approach is a correlation approach that uses the measured Method 21 screening value (in ppm) for each component and inputs that screening value into correlation equations that calculate the emission rate (see Table 2-10 in U.S. EPA, 1995). This approach offers an additional refinement to estimating emissions from leaks by providing an equation to predict mass emission rate as a function of concentration determined by EPA Method 21 screening for a particular equipment type. Correlations for the petroleum industry apply to refineries, marketing terminals and oil and gas production operations. The petroleum industry correlation equations estimate total organic compound (TOC) emission rates.

The EPA Correlation Approach is preferred when actual screening values (in ppm) are available. Correlations can be used to estimate emissions for the entire range of non-zero screening values, from the highest potential screening value to the screening value that represents the minimum detection limit of the monitoring device. This approach involves entering the non-

zero, non-pegged screening value into the correlation equation, which predicts the TOC mass emission rate based on the screening value. Default zero emission rates are used for screening values of zero ppmv and pegged emission rates are used for pegged screening values, where the screening value is beyond the upper limit measured by the portable screening device.

The "default-zero" leak rate is the mass emission rate associated with a screening value of zero. (Note that any screening value that is less than or equal to ambient background concentration is considered a screening value of zero.) The correlations mathematically predict zero emissions for zero screening values. However, data collected by the EPA show this prediction to be incorrect (U.S. EPA, 1995), because mass emissions have been measured from equipment having a screening value of zero. A specific goal when revising the petroleum industry correlations was to collect mass emissions data from equipment that had a screening value of zero. These data were used to determine a default-zero leak rate associated with equipment with zero screening values.

Unit Specific Correlation Approach

The fourth approach calls for developing unit-specific correlations and corresponding mass emission rates. This is done by measuring the screening value in ppm and measuring the mass emission rate by “bagging” the component. A component is bagged by enclosing the component to collect leaking vapors. Measured emission rates from bagged equipment coupled with screening values can be used to develop unit-specific screening value/mass emission rate correlation equations. Unit-specific correlations can provide precise estimates of mass emissions from leaks at the process unit. However, it is recommended that unit-specific correlations are only developed in cases where the existing EPA correlations do not give reasonable mass emission estimates for the process unit (U.S. EPA, 1995).

2.2 GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks (GRI/U.S. EPA, 1996)

This report provides an estimate of annual methane emissions from leaks from the natural gas production sector using the component method. The component method uses average emission factors for components and the average number of components per facility to estimate

the average facility emissions. The average facility emissions were then extrapolated to a national estimate using the number of natural gas production facilities.

The study used two approaches to estimate component emissions for the onshore natural gas production, offshore natural gas production, natural gas processing, natural gas transmission and natural gas storage sectors. The first approach involved screening components using a portable hydrocarbon analyzer and using EPA correlation equations (U.S. EPA, 1995) to estimate the leaking emissions. The EPA correlation equations provide an average leak rate per source using the equipment type (e.g., connectors, flanges, open-ended lines, pumps, valves, other), type of material (e.g., gas, heavy oil, light oil, water/light oil), the leak definition used, and the leak fraction determined by the screening. This approach was used to determine component emission factors for some onshore production sources, natural gas processing and the offshore production sector.

The screening of components involved using a portable instrument to detect leaks around, flanges, valves, and other components by traversing the instrument probe over the entire surface of the component. The components were divided into the following categories:

- Valves (gas/vapor, light liquid, heavy liquid)
- Pump Seals (light liquid, heavy liquid)
- Compressor Seals (gas/vapor)
- Pressure Relief Valves (gas/vapor)
- Connectors, which include flanges and threaded unions (all services)
- Open-Ended Lines (all services)
- Sampling Connections (all services)

All components associated with an equipment source or facility were screened using the procedures specified in EPA Method 21. The maximum measured concentration was recorded using a portable instrument that met the specifications and performance criteria in EPA Method 21. In general, an organic vapor analyzer (OVA) that used a flame ionization detector (FID) was

used for conducting the screening measurements. A dilution probe was used to extend the upper range of the instrument from 10,000 to 100,000 ppmv.

The second approach used the GRI Hi-FlowTM (trademark of the Gas Research Institute) sampler or a direct flow measurement to replace data measured using the enclosure method. This method was used to determine emission factors for some of the offshore production sources. The sampler has a high flow rate and generates a flow field around the component that captures the entire leak. As the sample stream passes through the instrument, both the flow rate and the total hydrocarbon (THC) concentration are measured. The mass emission rate can then be determined using these measurements. Offshore leak emissions are not covered in this paper; therefore, the estimates derived from this method will not be discussed further.

For onshore natural gas production, the facilities were broken up into two categories; eastern natural gas production and western gas production to account for regional differences in the methane content of the natural gas. The sources of these leak emissions include gas wells, separators, heaters, dehydrators, metering runs and gathering compressors.

A summary of the average equipment emissions, activity factor, and annual methane emissions for the onshore production sector is presented in Table 2-2. These factors have been used in other reports and studies of methane emissions from the oil and gas sector, including the Inventory of U.S. Greenhouse Gas Emissions and Sinks, which will be discussed in more detail in Section 2.1.4.

As shown in the tables, the study estimated that 15,512 million standard cubic feet per year (MMscf/yr) of methane are emitted as leaks from 271,928 onshore natural gas production wells in the U.S. for the 1992 base year. This converts to approximately 292,930 metric tons (MT) of methane emitted to the atmosphere in the base year.

Table 2-2. GRI/EPA National Annual Emission Estimate for Onshore Natural Gas Production in the United States (1992 Base Year)^a

| Equipment | Average Equipment Methane Emissions (scf/yr) | Activity Factor, Equipment Count | Annual Methane Emissions (MMscf) | Annual Methane Emissions (MT)^b | 90% Confidence Interval |
|---------------------------------------|---|---|---|--|--------------------------------|
| <i>Eastern U.S.</i> | | | | | |
| Gas Well | 2,595 | 129,157 | 335 | 6,326 | 27% |
| Separator | 328 | 91,670 | 30.1 | 568 | 36% |
| Heater | 5,188 | 260 | 1.35 | 25.5 | 218% |
| Dehydrator | 7,938 | 1,047 | 8.31 | 157 | 41% |
| Meters/Piping | 3,289 | 76,262 | 251 | 4,740 | 109% |
| Gathering Compressors | 4,417 | 129 | 0.570 | 10.8 | 44% |
| Eastern U.S. Total | | | 626 | 11,827 | 46% |
| <i>Western U.S.</i> | | | | | |
| Gas Well | 13,302 | 142,771 | 1,899 | 35,859 | 25% |
| Separator | 44,536 | 74,674 | 3,326 | 62,805 | 69% |
| Heater | 21,066 | 50,740 | 1,069 | 20,186 | 110% |
| Dehydrator | 33,262 | 36,777 | 1,223 | 23,094 | 32% |
| Meters/Piping | 19,310 | 301,180 | 5,816 | 109,823 | 109% |
| Sm Gathering Compressors ^c | 87,334 | 16,915 | 1,477 | 27,895 | 93% |
| Lg Gathering Compressors ^d | 552,000 | 96 | 53.0 | 1,001 | 136% |
| Gathering Stations ^e | 1,940,487 | 12 | 23.3 | 440 | 176% |
| Western U.S. Total | | | 14,886 | 281,103 | 45% |
| Total | | | 15,512 | 292,930 | - |

a - Derived from Tables 5-2 and 5-3 (GRI/U.S. EPA, 1996).

b - Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.

c - Sm. gathering compressor emission factor does not include compressor seal emissions.

d - Lg. gathering compressor emission factor does not include compressor seal or compressor blowdown emissions.

e - Gathering station emission factor does not include site blowdown line emissions.

The national annual methane emissions from natural gas processing were calculated using published statistics from the Oil and Gas Journal. The 1992 data from the journal listed the total number of natural gas processing plants to be 726. The national methane emissions were calculated using this activity factor and the average facility methane emissions for a natural gas processing plant. The plant methane emissions were calculated using average component counts for gas processing equipment (e.g., valves, connectors, open-ended lines, pressure relief valves, blowdown open-ended lines, compressor seals and miscellaneous). For natural gas processing plants, the average emissions from equipment was estimated to be 2.89 MMscf/yr (18.9 MT). The annual methane emissions from the equipment associated with reciprocating compressors and the equipment associated with centrifugal compressors located at natural gas processing plants were estimated to be 0.538 MMscf/yr (10.2 MT) and 0.031 MMscf/yr (0.585 MT), respectively, in 1992. These methane emissions from the gas processing plant and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not leaks for the purposes of this paper. The ratio of reciprocating and centrifugal compressors located at these plants was based on site visit data from 11 natural gas processing plants. The ratio determined from this data was calculated to be 85% reciprocating and 15% centrifugal. Table 2-3 summarizes the national annual methane emissions from natural gas processing plants, which was estimated to be 3,968 MMscf or 74,921 MT.

Table 2-3. GRI/EPA National Annual Emission Estimate for Natural Gas Processing Plants in the United States (1992 Base Year)^a

| Equipment | Average Facility Methane Emissions (MMscf/yr) | Activity Factor, Number of Plants/Compressors | Annual Methane Emissions (MMscf) | Annual Methane Emissions (MT)^b | 90% Confidence Interval |
|--|--|--|---|--|--------------------------------|
| Gas Processing Plant ^c | 2.40 | 726 | 1,744 | 32,925 | 27% |
| Reciprocating Compressors ^d | 0.538 | 4,092 | 2,201 | 41,571 | 36% |
| Centrifugal Compressors ^e | 0.031 | 726 | 22.5 | 425 | 218% |
| Total | | | 3,968 | 74,921 | 46% |

a - Derived from Table 5-5 (GRI/U.S. EPA, 1996).

b - Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.

c - Gas processing plant emission factor does not include site blowdown emissions.

d - Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.

e - Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

The annual methane emission from transmission compressor stations was calculated using activity data based on statistics by the Federal Energy Regulatory Commission (FERC). The data reported to FERC account for 70% of the total transmission pipeline mileage. The split between reciprocating and turbine compressors was estimated using data from the GRI TRANSDAT database. The average methane emissions from compressor station equipment were estimated to be 3.01 MMscf/yr (56.8 MT) in 1992. The annual methane emissions from the equipment associated with reciprocating compressors and the equipment associated with centrifugal compressors located at transmission stations were estimated to 0.552 MMscf/yr (10.4 MT) and 0.018 MMscf/yr (0.34 MT), respectively. Table 2-4 summarizes the national annual methane leak emissions from natural gas transmission stations, which was estimated to be 50,733 MMscf or 957,999 MT. These methane emissions from the compressor station and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not equipment leaks for the purposes of this paper.

Table 2-4. GRI/EPA National Annual Emission Estimate for Natural Gas Transmission Compressor Stations in the United States (1992 Base Year)^a

| Equipment | Average Facility Methane Emissions (MMscf/yr) | Activity Factor, Number of Stations/Compressors | Annual Methane Emissions (MMscf) | Annual Methane Emissions (MT)^b | 90% Confidence Interval |
|--|--|--|---|--|--------------------------------|
| Compressor Stations ^c | 1.94 | 1,700 | 3,298 | 62,276 | 103% |
| Reciprocating Compressors ^d | 0.552 | 6,799 | 3,753 | 70,869 | 68% |
| Centrifugal Compressors ^e | 0.018 | 681 | 12.3 | 231 | 44% |
| Total | | | 50,733 | 957,999 | 52% |

a - Derived from Table 5-6 (GRI/U.S. EPA, 1996).

b - Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.

c - Compressor station emission factor does not include site blowdown emissions.

d - Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.

e - Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

For natural gas storage facilities, the annual methane emissions were calculated using activity data based on published data in Gas Facts. The number of compressors and injection/withdrawal wells located at natural gas storage facilities were estimated using data collected from site visits to eight facilities. The average methane emissions from natural gas storage facilities were estimated to be 6.80 MMscf/yr (128 MT). The annual average methane emissions from an injection/withdrawal well were estimated to be 0.042 MMscf/yr (0.79 MT). The annual methane emissions from equipment for reciprocating and centrifugal compressors were estimated to be 0.47 MMscf/yr (8.9 MT) and 0.017 MMscf/yr (0.32 MT), respectively, in 1992. The national methane emissions from storage facilities were estimated to be 4,644 MMscf or 87,713 MT and are provided in Table 2-5. These methane emissions from the storage facility and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not leaks for the purposes of this paper.

Table 2-5. GRI/EPA National Annual Emission Estimate for Natural Gas Storage Facilities in the United States (1992 Base Year)^a

| Equipment | Average Facility Emissions (MMscf/yr) | Activity Factor, Number of Facilities/ Compressors | Annual Methane Emissions (MMscf) | Annual Methane Emissions (MT) ^b | 90% Confidence Interval |
|--|---------------------------------------|--|----------------------------------|--|-------------------------|
| Storage Facilities ^c | 6.80 | 475 | 3,230 | 61,004 | 100 |
| Injection/Withdrawal Wells | 0.042 | 17,999 | 756 | 14,275 | 76 |
| Reciprocating Compressors ^d | 0.47 | 1,396 | 656 | 12,390 | 80 |
| Centrifugal Compressors ^e | 0.017 | 136 | 2.3 | 43.7 | 130 |
| Total | | | 4,644 | 87,713 | 57 |

a - Derived from Table 5-7 (GRI/U.S. EPA, 1996).

b - Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.

c - Storage facility emission factor does not include site blowdown emissions.

d - Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.

e - Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released the 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems⁵ collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

The GHGRP covers a subset of national emissions, as facilities are required to submit annual reports only if total GHG emissions are 25,000 metric tons carbon dioxide equivalent (CO₂e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors. In some cases, facilities have a choice of using one of the multiple available calculation methods for an emission source provided.

⁵ The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98, subpart W.

Methods for calculating emissions from leaks depend on the industry segment. Facilities in the onshore petroleum and natural gas production segment use population counts and population emission factors for calculating emissions from leaks. Population counts are determined based on either (1) a count of all major equipment (wellheads, separators, meters/piping, compressors, in-line heaters, dehydrators, heater-treaters, and headers) multiplied by average component counts specified in the subpart W regulations, or (2) a count of each component individually for the facility. Emissions are then calculated by multiplying population count by the appropriate population emission factor specified in the subpart W regulations.

Facilities in the onshore gas processing and gas transmission segments use counts of leaking components and leak emission factors for calculating emissions from leaks. The counts of leaking components are identified during an annual leak survey using an optical gas imaging (OGI) instrument, EPA Method 21, infrared (IR) laser beam illuminated instrument, or an acoustic leak detection device. Once the leaking components have been identified and counted, the emissions are calculated by multiplying the count of a specific type of leaking component by the appropriate leak emission factor specified in the subpart W regulations.

For the 2012 reporting year, reported methane emissions from leaks from onshore petroleum and natural gas production were 364,453 MT, onshore natural gas processing were 13,527 MT, and onshore natural gas transmission compression were 15,868 MT.

2.4 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. GHG emissions and removals by source and by economic sector over a time series, beginning with 1990. The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining).

The natural gas production system covers all equipment that process or transport natural gas from oil and gas production sites. (All equipment that process or transport hydrocarbon

liquids are covered in the oil systems section of the GHG Inventory.) The natural gas production segment is broken into six regions (North East, Midcontinent, Rocky Mountain, South West, West Coast, and Gulf Coast) and includes estimates for gas wells, separation equipment, gathering compressors, gathering pipelines, drilling and well completions, normal operations, condensate tank vents, well workovers, liquids unloading, vessel blowdowns, and process upsets.

For the natural gas production segment, only methane emissions from gas wells, field separation equipment, and gathering compressor systems will be discussed from the GHG Inventory. Leaks from gas wells include emissions from various components, such as connectors and valves, on a wellhead. Field separation equipment includes heaters, separators, dehydrators, meters and piping. Gathering compressor systems include reciprocating compressors, equipment such as scrubbers and coolers associated with the compressors, and the piping. Leaks from field separation equipment and gathering compressor systems include emissions from components in these equipment and systems. The only exception is the gathering compressors source that includes both leak emissions and vented emissions from compressor seals in the GHG Inventory. (Note: Vented emissions from compressors are not defined as leaks in this paper, but are discussed in the white paper on compressors.) The 2014 GHG Inventory (published in 2014; containing emissions data for 1990-2012) calculates potential⁶ methane leak emissions from gas wells and field separation equipment using emission factors from the GRI/EPA study (GRI/U.S. EPA, 1996). The emission factors from the GRI/EPA study are split regionally into Eastern and Western factors. These emission factors are adapted in the 2014 GHG Inventory for each of the NEMS regions by adjusting the GRI/EPA emission factors for the NEMS region-specific methane content in produced natural gas. All of the emission factors from the GRI/EPA study assume methane content of 78.8% in the produced natural gas. However, the 2014 GHG

⁶ The calculation of emissions for each source of in the GHG Inventory generally involves first the calculation of potential emissions (methane that would be emitted in the absence of controls), then the compilation of emissions reductions data, and finally the calculation of net emissions by deducting the reductions data from the calculated potential emissions. This approach was developed to ensure an accurate time series that reflects real emission trends. Key data on emissions from many sources are from GRI/U.S. EPA 1996, and since the time of this study practices and technologies have changed. While the study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. As updated emission factors reflecting changing practices are not available for most sources, the GRI/U.S. EPA 1996 emission factors continue to be used for many sources for all years of the GHG Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time.

Inventory uses regional methane contents obtained from a 2001 study by the Gas Technology Institute (GTI) on unconventional gas and gas composition⁷ to adjust the GRI/EPA emission factors to account for the regional methane content differences. The GHG Inventory emissions are then calculated by applying the modified GRI/EPA emission factors to component counts for each year of the GHG Inventory. Because component counts are not available for each year of the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data.⁸ The 2014 GHG Inventory, emission factors, and methane emissions are presented by region in Table 2-6. The 2014 GHG Inventory estimated 332,662 MT of potential methane leak emissions from gas wells and field separation equipment from natural gas production activities in 2012.

Table 2-6. 2011 Data and Calculated Methane Potential Leak Emissions for the Natural Gas Production Segment by Region^a

| Region | Activity | Activity Data | Emission Factor | Calculated Potential Emissions (MT) |
|------------|-------------------------------------|---------------|-----------------------|-------------------------------------|
| North East | Associated Gas Wells | 38,770 | NA | NA |
| | Non-associated Gas Wells | 112,607 | 7.67 scfd/well | 6,071 |
| | Gas Wells with Hydraulic Fracturing | 46,367 | 7.54 scfd/well | 2,457 |
| | Heaters | 318 | 15.38 scfd/heater | 34 |
| | Separators | 112,872 | 0.97 scfd/separator | 771 |
| | Dehydrators | 22,164 | 23.53 scfd dehydrator | 3,665 |
| | Meters/Piping | 7,910 | 9.75 scfd/meter | 542 |

⁷ GRI-01/0136 GTI's Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. August, 2001.

⁸ For example, recent data on various types of field separation equipment in the production stage (i.e., heaters, separators, and dehydrators) are unavailable. Each of these types of field separation equipment was determined to relate to the number of gas wells. Using the number of each type of field separation equipment estimated by GRI/EPA in 1992, and the number of gas wells in 1992, a factor was developed that is used to estimate the number of each type of field separation equipment throughout the time series. The annual well count data used for these sources were obtained from a production database maintained by DrillingInfo, Inc. (DrillingInfo, 2012).

| Region | Activity | Activity Data | Emission Factor | Calculated Potential Emissions (MT) |
|----------------|-------------------------------------|----------------------|------------------------|--|
| Midcontinent | Associated Gas Wells | 27,470 | NA | NA |
| | Non-associated Gas Wells | 77,896 | 7.45 scfd/well | 4,080 |
| | Gas Wells with Hydraulic Fracturing | 30,156 | 8.35 scfd/well | 1,771 |
| | Heaters | 43,869 | 14.9 scfd/heater | 4,596 |
| | Separators | 47,003 | 0.94 scfd/separator | 311 |
| | Dehydrators | 15,064 | 95.54 scfd dehydrator | 10,118 |
| | Meters/Piping | 143,186 | 9.45 scfd/meter | 9,509 |
| Rocky Mountain | Associated Gas Wells | 32,598 | NA | NA |
| | Non-associated Gas Wells | 9,665 | 35.05 scfd/well | 2,381 |
| | Gas Wells with Hydraulic Fracturing | 73,755 | 40.72 scfd/well | 21,115 |
| | Heaters | 38,040 | 56.73 scfd/heater | 15,172 |
| | Separators | 41,627 | 120 scfd/separator | 35,099 |
| | Dehydrators | 11,630 | 89.58 scfd dehydrator | 7,324 |
| | Meters/Piping | 97,399 | 52.01 scfd/meter | 35,609 |
| South West | Associated Gas Wells | 155,119 | NA | NA |
| | Non-associated Gas Wells | 13,860 | 37.24 scfd/well | 3,628 |
| | Gas Wells with Hydraulic Fracturing | 27,627 | 37.24 scfd/well | 7,232 |
| | Heaters | 11,243 | 58.97 scfd/heater | 4,661 |
| | Separators | 23,316 | 125 scfd/separator | 20,435 |
| | Dehydrators | 5,784 | 93.11 scfd dehydrator | 3,786 |
| | Meters/Piping | 55,885 | 54.06 scfd/meter | 21,237 |

| Region | Activity | Activity Data | Emission Factor | Calculated Potential Emissions (MT) |
|---------------|-------------------------------------|----------------------|------------------------|--|
| West Coast | Associated Gas Wells | 29,726 | NA | NA |
| | Non-associated Gas Wells | 1,999 | 42.49 scfd/well | 597 |
| | Gas Wells with Hydraulic Fracturing | 95 | 42.49 scfd/well | 28 |
| | Heaters | 2,094 | 67.29 scfd/heater | 991 |
| | Separators | 1,529 | 142 scfd/separator | 1,529 |
| | Dehydrators | 292 | 106 scfd dehydrator | 218 |
| | Meters/Piping | 3,994 | 61.68 scfd/meter | 1,732 |
| Gulf Coast | Associated Gas Wells | 39,709 | NA | NA |
| | Non-associated Gas Wells | 27,024 | 7.96 scfd/well | 1,512 |
| | Gas Wells with Hydraulic Fracturing | 49,862 | 7.96 scfd/well | 2,789 |
| | Heaters | 17,222 | 64.60 scfd/heater | 7,821 |
| | Separators | 50,591 | 136.57 scfd/separator | 48,571 |
| | Dehydrators | 10,719 | 102.00 scfd dehydrator | 7,686 |
| | Meters/Piping | 90,288 | 59.21 scfd/meter | 37,584 |

^a Derived from ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories (U.S. EPA, 2014).

The gas processing and gas transmission segments are not broken into regions like the gas production segment in the 2014 GHG Inventory. Instead, these segments provide national level emission estimates for their individual emission sources. For both segments, leak emissions include emissions from all components in the gas plants and on compression systems. The transmission segment leaks include leaks from transmission pipelines. The 2014 GHG Inventory calculates potential methane emissions from these sources using emission factors from the GRI/EPA study (GRI/U.S. EPA, 1996) and a 2010 ICF International (ICF) memo to the EPA on centrifugal compressors (ICF, 2010). The GHG Inventory emissions are calculated by applying

the emission factors to activity counts (in this case, gas plants, compressor station counts, compressor counts, and pipeline miles) for each year of the inventory. Because some component counts are not available for each year of the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data.⁹ The 2014 GHG Inventory gas processing and gas transmission sources, emission factors, and methane emissions are presented in Table 2-7. For 2012, the 2014 GHG Inventory estimated 33,681 MT of potential methane emissions from gas processing leak emissions and 114,348 MT of potential methane emissions from gas transmission leak emissions.

Table 2-7. 2011 Data and Calculated Methane Potential Leak Emissions for the Natural Gas Processing and Natural Gas Transmissions Segments^a

| Segment | Activity | Activity Data | Emission Factor | Calculated Potential Emissions (MT) |
|------------------|----------------|---------------|--------------------|-------------------------------------|
| Gas Processing | Plants | 606 | 7,906 scfd/plant | 33,681 |
| Gas Transmission | Pipeline Leaks | 303,126 | 1.55 scfd/mile | 3,311 |
| | Station | 1,799 | 8,778 scfd/station | 111,037 |

^a Derived from ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories, pg. A-177 (U.S. EPA, 2014).

For 2012, the 2014 GHG Inventory data estimates that potential emissions from leaks in production, processing and transmission are approximately 480,691 million MT of methane or about 8% of overall potential methane emissions from oil and gas.

2.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. This study used direct

⁹ For example, individual compressor counts and compressor station counts are not available. Instead, these are obtained using a ratio of compressors to gas plants (for processing) and ratios of stations to pipeline miles and compressors to pipeline miles (for transmission) in the base year 1992. The 1992 ratios are then multiplied by the activity drivers, i.e., gas plant count or miles of pipeline, in the current year to estimate activity in current year.

measurements of methane emissions at 190 onshore natural gas sites in the U.S. (150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 workovers). The study covered the natural gas production segment.

For leak emissions, the study collected emissions data from 150 sites, 146 sites with wells and 4 sites with separators and other equipment on site. Leak emissions data from piping, valves, separators, wellheads, and connectors are provided in Table 2-8. The first step used to identify leaks from natural gas production sites was to scan the site using an OGI camera. The threshold for detection of a leak with the camera was 30 g/hr (Allen et al., 2013). After leaks were identified by the camera, the flow rate and the concentration of the leaks were measured using a Hi-Flow Sampler™ and the mass emission rate calculated. The instrument was calibrated using samples consisting of pure methane in ambient air. To account for the effect of ethane, propane, butane and higher alkanes on the leak measurements, gas composition data were collected for each natural gas production site that was visited. Based on the gas composition, the percentage of carbon accounted for by methane in the sample stream was determined. This percentage, multiplied by the total gas flow rate reported by the instrument, was the methane flow.

Table 2-8. Summary of Emissions from Leaks

| | Emissions Per Well ^a | | | | |
|--|---------------------------------|---------------|---------------|----------------|----------------|
| | Appalachian | Gulf Coast | Midcontinent | Rocky Mountain | All Facilities |
| Number of Sites with Wells Visited (number of wells with leaks detected) | 47 (30) | 54 (31) | 26 (19) | 19 (17) | 146 (97) |
| Methane Emission Rate (scf/min/well) | 0.098 ± 0.059 | 0.052 ± 0.030 | 0.046 ± 0.024 | 0.035 ± 0.026 | 0.064 ± 0.023 |
| Whole Gas Emissions Rate (based on site specific gas composition) (scf/min/well) | 0.100 ± 0.060 | 0.058 ± 0.033 | 0.055 ± 0.034 | 0.047 ± 0.034 | 0.070 ± 0.024 |

^a All leaks detected with the OGI camera, and does not include emissions from pneumatic pumps and controllers.

The study authors concluded the average values of leak emissions per well reported in Table 2-8 are comparable to the average values of potential emissions per well for gas wells, separators, heaters, piping and dehydrator leaks (0.072 scf methane/min/well) from the 2013 GHG Inventory, calculated by dividing the potential emissions in these categories in the 2013 GHG Inventory by the number of wells (Allen et al., 2013).

2.6 City of Fort Worth Natural Gas Air Quality Study (ERG, 2011)

The city of Fort Worth solicited a study that reviewed air quality issues associated with natural gas exploration and production. The goals of the study were to answer the following four questions:

- How much air pollution is being released by natural gas exploration in Fort Worth?
- Do sites comply with environmental regulations?
- How do releases from these sites affect off-site air pollution levels?
- Are the city's required setbacks for these sites adequate to protect public health?

To answer these questions, the study collected ambient air monitoring and direct leak and vented emissions measurements and performed air dispersion modeling. The study collected data from 375 well pads, 8 compressor stations, a gas processing plant, a saltwater treatment facility, a drilling operation, a hydraulic fracturing operation, and a completion operation. The point source test data was collected using an OGI camera, a toxic vapor analyzer (TVA), a Hi-Flow Sampler™ and stainless steel canisters. Each site was surveyed with an OGI camera and, if a leak was observed by the camera, the concentration of the leak was measured using the TVA. In addition, 10% of the total valves and connectors and the other components were surveyed using the TVA to determine leaks at or above 500 ppmv. The emission rates of the leaks identified by the OGI camera and the TVA survey were determined using a Hi-Flow Sampler™ to measure the volumetric flow rate of the leak. Gas samples from selected leaks were collected in stainless steel canisters for VOC and HAP analysis by a gas chromatograph/mass spectrometer (GC/MS).

Based on the results of the point source leak survey, the study estimated the total organic emissions to be 20,818 tons per year or 18,819 megagrams per year (Mg/yr), with well pads

accounting for more than 75% of the total emissions. Hydrocarbons with low toxicities (methane, ethane, propane, and butane) accounted for approximately 98% of the emissions from this study. A summary of the average and maximum emissions from each of the site types is provided in Table 2-9. Table 2-10 provides a summary of the measured emissions by equipment type (e.g., connector, valve, other). Valves include manual valves, automatic actuation valves, and pressure relief valves. Connectors include flanges, threaded unions, tees, plugs, caps and open-ended lines where the plug or cap was missing. The category “Other” consists of all remaining components such as tank thief hatches, pneumatic valve controllers, instrumentation, regulators, gauges, and vents.

Table 2-9. Average and Maximum Point Source Emission Rates by Site Type^a

| Site Type | TOC (tons/yr) | | VOC (Tons/yr) | |
|-----------------------------|---------------|---------|---------------|---------|
| | Average | Maximum | Average | Maximum |
| Well Pad | 16 | 445 | 0.07 | 8.6 |
| Well Pad with Compressor(s) | 68 | 4,433 | 2 | 22 |
| Compressor Station | 99 | 276 | 17 | 43 |
| Processing Facility | 1,293 | 1,293 | 80 | 80 |

a - Derived from Table 3.5-1 (ERG, 2011).

Table 2-10. Average and Maximum Point Source Emission Rates by Equipment Type^a

| Equipment Type | Methane (lb/yr) | | VOC (lb/yr) | |
|----------------|-----------------|---------|-------------|---------|
| | Average | Maximum | Average | Maximum |
| Connectors | 8,918 | 169,626 | 27.6 | 171 |
| Other | 20,914 | 497,430 | 142 | 4,161 |
| Valves | 27,585 | 570,083 | 29.7 | 123 |

a - Derived from Emissions Calculation Workbook spreadsheet.

Some general observations of the well pad data provided in the Fort Worth report are:

- At least one leak was detected at 283 out of the 375 well pads monitored with an OGI technology with an average of 3.2 leaks detected per well pad;
- The TVA detected at least one leak greater than 500 ppm at 270 of the 375 well pads that were monitored with an average of 2.0 leaks detected per well pad;
- The number of wells located on well pads ranged from 0 to 13 with the average number of wells being 2.98 with a 99% confidence level of 0.31;
- The average number of components at each well site was 212 valves, 1596 connectors, 3 storage tanks, and 0.4 compressors;
- 124 out of the 375 well pads had at least one compressor onsite;
- There were 17 different owners of the 375 well sites in the Fort Worth area with the average number of well sites per owner being 22;
- Of the 1,330 leaks that were detected using either OGI technology or the TVA, 200 (15%) were classified as connector type leaks, 90 (7%) were classified as valve type leaks, and 1,040 (78%) were classified as other type leaks.
- Of these 1,330 leaks that were detected using OGI technology or the TVA, 1,018 (77%) were classified as non-tank leaks and the remaining 312 (23%) were classified as tank leaks.

2.7 Measurements of Well Pad Emissions in Greeley, CO (Modrak, 2012)

An onsite direct measurement study of emissions from 23 well pads in areas near

Greeley, CO (Weld County) was performed over a one-week period in July 2011. This study used the same source testing contractor and non-invasive leak detection and measurement procedures (OGI and Hi-Flow Sampler™) as in the City of Fort Worth Natural Gas Air Quality Study (ERG, 2011). Other than the number of production pads investigated (375 vs. 23), there were three major differences in the studies.

- The City of Fort Worth Air Quality Study was conducted in a predominately dry gas area of the Barnett shale whereas the Greeley study was conducted in an area with much higher relative condensate/oil production rates (wet gas). A typical leak or vented emission in a dry gas area is likely to have a higher methane to VOC ratio compared to an emission in a wet gas area.
- The State of Colorado requires emissions from condensate/oil tanks to be collected and controlled (e.g. routed to an enclosed combustors). In the City of Fort Worth Air Quality Study, most storage tanks contained produced water and were not controlled.
- The City of Fort Worth Air Quality Study used the EPA Compendium Method TO-15 and ASTM 1945 (for methane) for source canister analysis, whereas the Greeley study used the Ozone Precursor method (EPA/600-R-98/161) coupled with ASTM 1946/D1945 analysis of methane, ethane and propane. The canister analysis set used in the Greeley study had significantly more overlap for oil and gas product-related compounds (i.e. ethane, propane, other alkanes), whereas the TO-15 method provided more coverage for HAP compounds.

The objectives of the limited scope Greeley well pad study were to improve understanding of methane and speciated VOC emissions and investigate the use of commercially available non-invasive measurement approaches for application to wet gas production operations (including tank emissions).

The average production pad in the Greeley study consisted of 5 wells, 258 valves, 2,583 connectors, 3 condensate tanks, 1 produced water tank, 4 thief hatches, 5 pressure relief devices, 3 separators and 1 enclosed combustor control device. A total of 93 emission points were found with OGI technology at the 23 production sites and the emission rates were measured using a high volume sampler with a subset of 33 additionally sampled using evacuated canisters. A

disproportionate number of detected emissions were found to be associated with storage tanks (72%). For the purposes of this white paper, a tank-related air emission is considered a leak if it exceeds the state or local emission limits. The study authors concluded condensate tank-related emissions observed in the Greeley study were not effectively collected and controlled. However, due to single point and instantaneous nature of the measurements, it is not known if these uncollected emissions exceed the state allowance.

Considering only emissions measurements with canister analysis, the average methane emissions from all storage tanks, excluding samples of known flash emissions, were much lower in the Greeley study compared to the City of Fort Worth Air Quality Study, 0.77 tons/year (n=21) and 21.9 tons/year (n=54), respectively. In contrast, the average VOC tank related emissions were much higher in the Greeley study compared to the City of Fort Worth Air Quality Study, 5.38 tons/year and 0.48 tons/year, respectively. Non-tank emissions followed similar trends: emissions of methane were higher in the City of Fort Worth Air Quality Study (7.73 tons/year (n=92) and 1.01 tons/year in the Greeley study (n=5)), while VOC emissions were higher in the Greeley study (0.46 tons/year in the Greeley study and 0.02 tons/year in the City of Fort Worth Air Quality Study). The authors noted that these emission estimates are based on instantaneous measurements. Because tank-related emissions vary diurnally and by season and may contain a residual flash emissions component, the extrapolation to yearly values (i.e., tons/year) is for informational purposes only and should not be used for comparison to permit or control limits. A journal article with additional analysis of these studies is in preparation (Modrak, 2012; Brantley et al., 2014a).

2.8 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)

The study presented a summary of 4,293 surveys from two private sector firms that provide gas emission detection and measurement services to oil and gas facilities in the U.S. and Canada. These surveys only covered certain regions of the U.S. and Canada. The surveys included three categories of facilities: gas processing plants (614 surveys), compressor stations (1,915 surveys; includes both gas transmission and gas gathering systems), and well sites (1,764 surveys; includes single well heads and sites with up to 15 well heads). The surveys were

conducted using OGI technology to locate leaking components and the leak rates were measured using a high-volume sampler. In some cases, where the facility owners did not need a precise volume measurement or where the leaking component was difficult to access for measurement, an estimate (evaluated visually using OGI technology based on the extensive experience of the operators) was used to make the decision to repair.

The study found that of the 58,421 components that were identified in the surveys, 39,505 (68%) were either leaking or venting gas. A summary of the leak rates for each of the categories is provided in Table 2-11. As the table shows, the study found that gas processing plants had the highest leak rate, followed by compressor stations and then well sites. The study noted that vents are the most common source of gas emissions from the identified emission sources, and about 40% of the vent emissions come from instrument controllers and compressor rod packing. Other vent sources come from production/storage tanks, lube oil vents, compressors, pumps, and engines. (Note: vented emissions are not considered leaks for the purposes of this paper).

Table 2-11. Distribution of Facilities Within Each Category by Leak Rate (in Mcf of gas per facility per year)^a

| Category | No leaks | ≤ 99 | 100-499 | 500-1499 | ≥ 1500 |
|-----------------------------|-----------------|-------------|----------------|-----------------|---------------|
| Gas processing plants | 3% | 17% | 32% | 25% | 23% |
| Compressor stations | 11% | 30% | 36% | 15% | 9% |
| Well sites & well batteries | 36% | 38% | 18% | 5% | 2% |

a - Derived from Table 3 (CL, 2013).

The study results show that, for the facilities in the study, gas processing plants are the most likely to have leaks and the most likely to have large leaks, followed by compressor stations, and, lastly, well sites.

2.9 Mobile Measurement Studies in Colorado, Texas, and Wyoming (Thoma, 2012)

As will be described in detail in Section 3.4, emerging mobile measurement technologies are providing new capability for detection and measurement of emissions from upstream oil

and gas production and other sectors. The EPA developed and applied one such mobile inspection technique as part of its Geospatial Measurement of Air Pollution (GMAP) program. (Thoma, 2012; Brantley et al., 2014b). Designed to be a rapidly-deployed inspection approach that can cover large areas, OTM 33A can locate unknown emissions (e.g., pipeline leaks or malfunctions) and can provide an emission rate assessment for upstream oil and gas sources, such as well pads located in relatively open areas. With measurements executed from stand-off observation distances of 20 m to 200 m, the mobile approach is not as accurate as onsite direct measurements but can provide source strength assessments with an accuracy of +/- 30% under favorable conditions with repeat measurements. OTM 33A relies on statistically representative downwind plume sampling, relatively obstruction-free line of sight observation, and a knowledge of the distance to the source (Thoma, 2012; Brantley et al., 2014b).

The EPA used OTM 33A to conduct several survey field campaigns in Weld County, CO in July 2010 and July 2011; areas near Fort Worth, TX (Wise, Parker, Tarrant, and Denton Counties) in September 2010 and 2011; in Sublette County, WY in June 2011, July 2012 and June 2013; and in the Eagle Ford, TX area (Maverick, Dimmit, La Salle, Webb, and Duval Counties) in September 2011. A total of 84 methane emission assessments were conducted in the Fort Worth area, 216 in WY, 93 in CO, and 22 in the Eagle Ford with offsite canister acquisition. Additionally, VOC emission estimates were executed at approximately 46% of these measurements. A subset of these field studies are described in (Thoma, 2012) with an expanded discussion, and slight revision of results to be published in (Brantley et al., 2014b). These data are primarily from well pads and represent an integration of all emissions (leak and vented) on the site. (Note: Vented emissions are not defined as “leaks” in this paper, therefore, the emission rates presented below include emissions that are not considered leaks in this paper). The study authors note, as with all instantaneous measurement approaches, the OTM 33A assessment may capture emissions that are short-term in nature (i.e., flash emissions) so extrapolation to annual emissions is difficult.

The preliminary results from the study (Thoma, 2012) show median methane emission rates of 0.21 grams per second (g/s), 0.43 g/s and 0.79 g/s and VOC emission rates of 0.16 g/s, 0.04 g/s and 0.30 g/s for the CO, TX, and WY studies, respectively (excluding Eagle Ford).

The study authors note that using improved analysis procedures, the above median rates will likely be revised slightly lower in a future publication. Offsite OGI was used in many cases to positively identify the origin of emissions. The study authors concluded that many of the high emission values were attributed to maintenance-related issues such as open thief hatches, failed pressure relief valves, or stuck dump valves. The difference in VOC emissions between the TX studies and the CO and WY studies is a result of the natural gas from the TX well sites being a dry natural gas. Additional analysis of the emission measurements including comparisons to natural gas, condensate/oil, and produced water production will be contained in a forthcoming article (Brantley et al., 2014b).

2.10 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)

The Environmental Defense Fund (EDF) commissioned ICF to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Well site leaks (includes heaters, separators, dehydrators and meters/piping) and pipeline leaks are two of the 22 emission sources that are included in the study.

The study relied on the 2013 GHG Inventory for methane emissions data for the oil and natural gas sector. The emissions data were revised to include updated information from the GHGRP (U.S. EPA, 2013) and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. One of the major differences in the revised 2011 baseline methane emissions estimate developed by ICF is the inclusion of a separate category for gathering and boosting operations. The 2013 GHG Inventory includes gathering and boosting operations in the onshore production segment and is based on the GRI/EPA measurement study (GRI/U.S. EPA, 1996).

The 2011 baseline methane inventory developed by ICF used the wellhead emission factor developed from the University of Texas study (Allen et al., 2013) to estimate leak emissions from well sites, which was reported as 97.6 scf/day. This emissions factor was applied to the natural gas well counts obtained from World Oil magazine to estimate the total methane leak emissions from well sites. These changes resulted in an estimated 14 billion cubic feet (264,000 MT) of methane emissions from wellheads in comparison.

Leak emissions from heater, separators, dehydrators, and meters/piping in the natural gas production sector were calculated using the GRI/EPA emissions factors for each of these emission sources. The study estimated methane emissions were 15 billion cubic feet (283,000 MT) from these sources.

Natural gas processing plant leak emissions were determined by ICF using data from the GHGRP (U.S. EPA, 2013) and a list of processing plants maintained by the EIA. The study by ICF determined that there are 909 gas processing and treatment facilities in the U.S. The study estimated methane emissions from processing facilities to be 3 billion cubic feet (56,600 MT).

The study did not provide specific equipment leak information for the natural gas transmission and storage sectors. However, the report did provide information on pipeline leaks from transmission of natural gas. The report estimated methane emissions of 0.2 billion cubic feet (3,800 MT).

The estimate of total national emissions from leaks in the natural gas production, processing, transmission and storage segments for 2011 was 604,000 MT of methane.

2.11 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)

This study, referred to as “Clearstone I,”¹⁰ presented the results of the implementation of a comprehensive directed inspection and maintenance (DI&M) program at four gas processing

¹⁰ “Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants.” Prepared for GTI and the U.S. EPA under grant 827754-01-0, by Clearstone Engineering. June 20, 2002. Also, note that a follow-up study, referred to as Clearstone II, was released in 2006, which studied five processing plants, one being a repeat from the plants studied in Clearstone I.

plants in the western U.S. in 2000. The work done during this study involved a survey of all gas service equipment components, as well as the measurement or engineering calculation of gas flows into the vent and flare systems. This study did not focus on hydrocarbon liquid services. In total, 101,193 individual gas service components were screened, along with 5 process vents, 28 engines, 7 process heaters, and 6 flare/vent systems.

The leak survey was conducted using bubble tests with soap solution, portable hydrocarbon gas detectors, and ultrasonic leak detectors. A screening value of 10,000 ppm or greater was used as the leak definition. The majority of components were screened using soap solution, but if a component was determined to be emitting gas, a hydrocarbon gas analyzer was used to determine if the component would be classified as a leaker per the above definition. Most leak rates were measured using a Hi-Flow™ Sampler, unless the leak was above the upper limit of the unit’s design (14 m³/hour). If the Hi-Flow™ Sampler could not be used, bagging or other direct measurement techniques were used, as appropriate.

From the survey, approximately 2,630 of the 101,193 screened components (2.6%) were determined to be leaking. The study states that “components in vibrational, high-use or heat-cycle gas service were the most leak prone.” The majority of the leaks were attributed to a relatively small number of leaking components. Table 2-12 presents the breakdown of leak emissions by component type.

Table 2-12. Distribution of Natural Gas Emissions from Leaking Component Types

| Component Type | Percent of Leak Emissions |
|--|----------------------------------|
| Valves | 30.0% |
| Connectors | 24.4% |
| Compressor Seals ^a | 23.4% |
| Open-Ended Lines | 11.1% |
| Crankcase Vents (on Compressors) | 4.2% |
| Pressure Relief Valves | 3.5% |
| Other (Pump Seals, Meters, Regulators) | 3.4% |

^a For the purposes of this paper, compressor seal emissions are not considered leaks.

The study also provided an analysis of the payback periods for fixing the identified leaks. That analysis is discussed in Section 3.2 of this paper.

2.12 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)

This study, referred to as “Clearstone II,”¹¹ presented the results of a comprehensive emissions measurement program at 5 gas processing plants, 12 well sites, and 7 gathering stations in the U.S. in 2004 and 2005. This work was done as follow up on a study done in 2000, referred to as Clearstone I, in which four gas processing plants were surveyed. (Note: one of the gas processing plants surveyed in the Clearstone I study was also surveyed in the Clearstone II study.) The work done involved a survey of all gas service equipment components at these 24 sites. The goal was to identify cost-effective opportunities for reducing natural gas losses and process inefficiencies. In total, 74,438 individual components were screened.

The leak survey was conducted using bubble tests with soap solution, portable hydrocarbon gas detectors, and ultrasonic leak detectors. A screening value of 10,000 ppm or greater was used as the leak definition. The majority of components were screened using soap solution, but if a component was determined to be emitting gas, a hydrocarbon gas analyzer was used to determine if the component would be classified as a leaker per the above definition. Most leak rates were measured using a Hi-Flow™ Sampler, unless the leak was above the upper limit of the unit’s design (14 m³/hour). For consistency, both the Clearstone I and Clearstone II surveys used the same Hi-Flow™ Sampler. If the Hi-Flow™ Sampler could not be used, bagging or other direct measurement techniques were used, as appropriate.

¹¹ “Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.” Prepared for the U.S. EPA under grant XA-83046001-1, by National Gas Machinery Laboratory, Clearstone Engineering, and Innovative Environmental Solutions, Inc. March 2006. Note: This study, referred to as “Clearstone II”, was a follow up to a study released in 2002, referred to as “Clearstone I,” which surveyed four processing plants, one of which was resurveyed in Clearstone II.

Secondarily to the above leak detection methodology, for all five surveys of gas processing plants in the study, OGI cameras were also used in order to compare the performance of the OGI cameras with conventional leak detection methods. Although no quantitative comparison was done, the study concluded that the cameras are able to screen components about three times as quickly as the other methods, find leaks that are inaccessible to the other methods, and allow for rapid leak source identification.

From the survey, approximately 1,629 of the 74,438 screened components (2.2%) were determined to be leaking. The study states, similarly to Clearstone I, that “components in vibrational, high-use, and heat-cycle gas service were the most leak prone.” Further, the majority of the leak emissions could be attributed to a relatively small number of the leaking components. Table 2-13 presents the breakdown of natural gas leak emissions by component type.

Table 2-13. Distribution of Natural Gas Emissions from Leaking Component Types

| Component Type | Percent of Leak Emissions |
|--|---------------------------|
| Open-Ended Lines | 32% |
| Connectors | 30% |
| Compressor Seals | 20% |
| Block Valves | 15% |
| Other (PRVs, Meters, Regulators, etc.) | 3% |

The study also provides a comparison for the one gas plant that was surveyed in both studies. This plant was resurveyed in order to investigate changes in its leak characteristics. It was noted that about 30% of the equipment components in the plant had been decommissioned between the surveys due to the replacement of old process units with newer ones. Generally, the replacement process units and equipment components had substantially reduced emission rates compared to the decommissioned units. The overall reduction for the new units was an 80% decrease in total hydrocarbon (THC) emissions compared to the old units. However, the THC emissions for the plant as a whole increased about 50% between the two surveys. The study

gives several possible reasons for this, including the fact that the five-year timeframe between surveys exceeded the mean repair life for most of the components. The study also states that there may have been inadequate follow-up to maintenance recommendations provided during the first survey, as the documentation of repairs indicated it was “unclear what maintenance activities were undertaken in response to the Phase I survey.”

3.0 AVAILABLE EMISSIONS MITIGATION TECHNIQUES

There are a number of technologies available that can be used to identify leaks and a number of approaches to repairing those leaks. The technologies for identifying leaks and the approaches to repairing leaks are discussed in separate sections below.

3.1 Leak Detection

A variety of approaches are used for leak detection. For many regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using an analyzer, such as a TVA or an OVA. In addition, other monitoring tools such as OGI cameras, soap solution, acoustic leak detection, ambient monitors and electronic screening devices can be used to monitor process components. A summary of these technologies is presented below.

3.1.1 Portable Analyzers

Description

A portable monitoring instrument is used to detect hydrocarbon leaks from individual pieces of equipment. These instruments are intended to locate and classify leaks based on the leak definition of the equipment as specified in a specific regulation, and are not used as a direct measure of mass emission rate from individual sources. The instruments provide a reading of the concentration of the leak in either ppm, parts per billion (ppb), or percent concentration. For portable analyzers, EPA Reference Method 21 requires the analyzer to respond to the compounds being processed, be capable of measuring the leak definition concentration specified in the

regulation, be readable to $\pm 2.5\%$ of the specified leak definition concentration and be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate.

The portable analyzers can be used to estimate the mass emissions leak rate by converting the screening concentration in ppm to a mass emissions rate by using the EPA correlation equations from the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995). The correlation equations in the Protocol can be used to estimate emissions rates for the entire range of screening concentrations, from the detection limit of the instrument to the “pegged” screening concentration, which represents the upper limit of the portable analyzers (U.S. EPA, 2003a).

The portable analyzers must be calibrated using a reference gas containing a known compound at a known concentration. Methane in air is a frequently used reference compound. The calibration process also determines a response factor for the instrument, which is used to correct the observed screening concentration to match the actual concentration of the leaking compound. For example, a response factor of “one” means that the screening concentration read by the portable analyzer equals the actual concentration at the leak (U.S. EPA, 2003a). Screening concentrations detected for individual components are corrected using the response factor (if necessary) and are entered into the EPA correlation equations to extrapolate a leak rate measurement for the component (U.S. EPA, 2003a).

Applications

The portable monitoring instruments operate on a variety of detection principles, with the three most common being ionization, IR absorption and combustion (U.S. EPA, 1995). The ionization detectors operate by ionizing the sample and then measuring the charge (i.e., number of ions) produced. Two methods of ionization currently used are flame ionization and photoionization. A standard flame ionization detector (FID) measures the total carbon content of the organic vapor sampled. Certain portable FID instruments are equipped with gas chromatograph (GC) options making them capable of measuring total gaseous non-methane organics or individual organic components (U.S. EPA, 1995). The photoionization detector (PID) uses ultraviolet light (instead of a flame) to ionize organic vapors. As with FIDs, the detector response varies with the functional group in the organic compounds. Photoionization

detectors have been used to detect leaks in process units in the Synthetic Organic Chemical Manufacturing Industry (SOCMI), especially for certain compounds, such as formaldehyde, aldehydes, and other oxygenated compounds, which may not give a satisfactory response on a FID or combustion-type detector (U.S. EPA, 1995).

Nondispersive infrared (NDIR) instruments operate on the principle of light absorption characteristics of certain gases. These instruments are usually subject to interference because other gases, such as water vapor and CO₂, may also absorb light at the same wavelength as the compound of interest (U.S. EPA, 1995). These detectors are generally used only for the detection and measurement of single components. For this type of detection, the wavelength at which a certain compound absorbs IR radiation is predetermined and the device is preset for that specific wavelength through the use of optical filters (U.S. EPA, 1995).

Combustion analyzers are designed either to measure the thermal conductivity of a gas or to measure the heat produced by combustion of the gas. The most common method in which portable VOC detection devices are used involves the measurement of the heat of combustion. These detection devices are referred to as hot wire detectors or catalytic oxidizers. Combustion analyzers, like most other detectors, are nonspecific for gas mixtures (U.S. EPA, 1995). In addition, combustion analyzers exhibit reduced response (and, in some cases, no response) to gases that are not readily combusted, such as formaldehyde and carbon tetrachloride (U.S. EPA, 1995).

The typical types of portable analyzers used for detecting leaks from components are OVAs and TVAs. An OVA is an FID, which measures the concentration of organic vapors over a range of 9 to 10,000 ppm (U.S. EPA, 2003a). A TVA combines both a FID and a PID and can measure organic vapors at concentrations exceeding 10,000 ppm. Toxic vapor analyzers and OVAs measure the concentration of methane in the area around a leak (U.S. EPA, 2003a).

Screening is accomplished by placing a probe inlet at an opening where leakage can occur. Concentration measurements are observed as the probe is slowly moved along the interface or opening, until a maximum concentration reading is obtained. The maximum concentration is recorded as the leak screening value. Screening with TVAs and OVAs can be a

slow process, requiring approximately one hour for every 40 components, and the instruments require frequent calibration.

Costs

The costs of the portable analyzers vary based on the type of analyzer used to measure leak concentrations. The documentation for the EPA National Uniform Emission Standards for Equipment Leaks (40 CFR part 65, subpart J) provides a cost of \$10,800 for a portable monitoring analyzer (RTI, 2011). Additional costs would also include labor costs associated with performing the screening and would depend on the number of components screened.

3.1.2 Optical Gas Imaging (IR Camera)

Description

Optical gas imaging (OGI) is a technology that operates much like a consumer video-camcorder and provides a real-time visual image of gas emissions or leaks to the atmosphere. The OGI camera works by using spectral wavelength filtering and an array of IR detectors to visualize the IR absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of equipment and components at a facility, and is an effective means of detecting leaks when the technology is used appropriately. The EPA has worked extensively with OGI technology and is in the process of further evaluating its capabilities. Information presented below, unless otherwise cited, is based on that evaluation work.

Applications

The detection capability of the OGI camera is based on a variety of factors such as detector capability, gas characteristics of the leak, optical depth of the plume and temperature differential between the gas and background. The EPA is currently studying OGI technology in order to determine its capabilities and limitations.

The OGI system provides a technology that can potentially reduce the time, labor and

costs of monitoring components. The capital cost of purchasing an OGI system is estimated to be \$85,000 (Meister, 2009). The ICF economic analysis estimated the capital cost of the OGI system to be \$124,000 (ICF International, 2014). The EPA estimated that the OGI can monitor 1,875 pieces of equipment per hour at a petroleum refinery (RTI, 2012). This study assumes for every hour of video footage, the operator would spend an additional 1.4 hours conducting activities for calibration, OGI adjustments, tagging leaks and other activities. Another estimate, (ICF Consulting, 2003) stated that OGI can monitor 35 components per minute (2,100 components per hour). In comparison, the average screening rate using a handheld TVA or OVA is roughly 700 components per day (ICF Consulting, 2003). However, the EPA's recent work with OGI systems suggests these studies underestimate the amount of time necessary to thoroughly monitor components for leaks using OGI technology. Additionally, the number of pieces of equipment that could be monitored per hour at an upstream oil and gas facility would likely be less than at a refinery given that equipment tends to be farther apart at these facilities than at a refinery.

By increasing the number of pieces of equipment that can be viewed per hour, the OGI system could potentially reduce the cost of identifying leaks in upstream oil and gas facilities when compared to using a handheld TVA or OVA. A recent study (CL, 2013) analyzed 4,293 leak detection surveys completed for the oil and gas industry using OGI systems. These surveys were completed by external contractors hired by the owner or operator of the oil and gas facility. This study estimated the average abatement cost to be approximately \$0 per ton of VOC and approximately -\$375 per ton of VOC for well sites and compressor stations, respectively. These estimates assume all leaks that are found are repaired and the recovered methane can be sold for \$4/Mcf. The average costs of performing the OGI surveys in the study are \$2,300 for a compressor station, \$1,200 for multi-well batteries, \$600 for single well batteries and \$400 for well sites (CL, 2013). (Note: Only a prepublication draft was available of this report when the EPA was completing this white paper.)

Another advantage of OGI for detecting leaks is finding leaks not directly related to components while in the process of surveying the overall site. Leaks such as degradation in the exterior of tanks or leaks in lines buried underground would be seen with OGI but very hard to locate with a handheld TVA or OVA.

For the application of this technology to this sector, the gas characteristics are well suited for the typical OGI camera technology because the leaks tend to be almost all methane, alkane or aromatics. Methane, alkanes and aromatics are all detectable due to having carbon-hydrogen bonds.

OGI Operational Considerations

While the operator or inspector using OGI technology can see leaking emissions from equipment, quantifying the emissions is difficult. To quantify emissions with an OGI camera, extensive metadata, such as apparent background temperature, gas leak temperature, leak size and wind speed must also be taken. These parameters would then be used with a developed and evaluated algorithm to quantify emissions. The EPA is not aware of the existence or evaluation of such an algorithm at this time. However, in addition to algorithms, operators can use quantification equipment such as a Hi-Flow™ Sampler.

The OGI system is also sensitive to the ambient conditions around the equipment that is being inspected. The larger the temperature differential between the leaking gas and the contrasting background (e.g., sky, ground or equipment), the easier the leaking gas is to see. The apparent temperature of the sky, a commonly used background, is also highly dependent on weather conditions such as cloud cover, ambient temperature and relative humidity. Additionally, high or variable wind conditions can reduce the optical depth and make it difficult for gas leaks to be identified, because the gas plume is quickly carried away from the source of the leak. Both these characteristics could result in operators being unable to identify leaks if the ambient conditions are not optimal.

Lastly, the effectiveness of an OGI instrument is dependent on the training and expertise of the operator. Well-trained and experienced operators are able to detect leaks with the OGI system that lesser experienced operators do not detect.

Current OGI Usage in the Oil and Gas Industry

The EPA is not aware of any studies that estimate the extent of the usage of OGI systems in the oil and natural gas production sector. However, certain proposed and existing regulations allow OGI systems as an option for fulfilling leak detection requirements, and some companies

are using the technology voluntarily such as through the Natural Gas STAR program. Additionally, the GHGRP subpart W allows for the use of OGI technology in some circumstances and the Alternative Work Practice regulation (40 CFR Part 60, subpart A) allow the use of OGI technology along with an annual Method 21 survey as an alternative to a traditional leak detection and repair (LDAR) program using Method 21.

The State of Colorado recently proposed regulations that would require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. These proposed regulations allow OGI inspections, Method 21 or other “[d]ivision approved instrument based monitoring device or method” to detect leaks (CO Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Proposed November 18, 2013).

The State of Wyoming, as part of its permitting guidance, requires facilities with emissions greater than 4 tpy of VOCs in the Upper Green River Basin, the Jonah-Pinedale Anticline Development Area and Normally Pressured Lance to conduct quarterly leak emissions inspections, and OGI inspections are allowed in addition to Method 21 inspections or audio-visual-olfactory inspections (Wyoming Department of Environmental Quality, Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance, September 2013).

The Alberta Energy Regulator requires that a “licensee of a facility must develop and implement a program to detect and repair leaks.” These programs must “meet or exceed” the Canadian Association of Petroleum Producer’s (CAPP) best management practice (BMP) for leak emissions management (CAPP, 2011). The CAPP BMP allows OGI technology for performing these leak inspections (CAPP, 2007).

Lastly, the EPA has found that owners and operators are voluntarily using OGI systems to detect leaks. However, the EPA does not know the extent of these voluntary efforts within the industry on a national level.

3.1.3 Acoustic Leak Detector

Description

Acoustic leak detectors are used to detect the acoustic signal that results when pressurized gas leaks from a component. This acoustic signal occurs due to turbulent flow when pressurized gas moves from a high-pressure to a low-pressure environment across a leak opening (U.S. EPA, 2003a). The acoustic signal is detected by the analyzer, which provides an intensity reading on the meter. Acoustic detectors do not measure leak rates, but do provide a relative indication of leak size measured by the intensity of the signal (or how loud the sound is) (U.S. EPA, 2003a).

Applications

Generally, two types of acoustic leak detection methods are used; high frequency acoustic leak detection and ultrasound leak detection. High frequency acoustic detection is best applied in noisy environments where the leaking components are accessible to a handheld sensor (U.S. EPA, 2003a). Ultrasound leak detection is an acoustic screening method that detects airborne ultrasonic signals in the frequency range of 20 kHz to 100 kHz and can be aimed at a potential leak source from a distance of up to 100 feet (U.S. EPA, 2003a). Ultrasound detectors can be sensitive to background noise, although most detectors typically provide frequency tuning capabilities so that the probe can be tuned to a specific leak in a noisy environment (U.S. EPA, 2003a).

A URS Corporation/University of Texas at Austin (URS/UT) study described a “through-valve acoustic leak detection device” or VPAC that was used to measure leaks at six sites (four gathering/boosting stations and two natural gas processing plants) (URS/UT, 2011). Leak measurements were made using the VPAC device and high volume sample to compare the readings from the two devices. The study authors found that there was no statistically significant correlation between the VPAC and the direct flow measurements, and the study authors determined that the VPAC method was not considered to be an accurate alternative to direct measurement for the sources tested (URS/UT, 2011).

Costs

No cost data for acoustic leak detectors were available in the studies or research

documents.

3.1.4 Ambient/Mobile Monitoring

Description

A growing number of research and industry groups are using mobile measurement approaches to investigate a variety of source emissions and air quality topics. For oil and natural gas applications, a vehicle can be equipped with at minimum a methane measurement instrument and GPS to facilitate discovery of previously unknown sources and in more advanced forms, provide information on source emission rates.

Applications

Mobile leak detection techniques sample emission plumes from stand-off (sometimes offsite) observing locations and are, therefore, generally less accurate than direct (onsite) source measurements. Mobile leak detection techniques can cover large survey areas and can be particularly useful in identifying anomalous operating conditions (e.g., pipeline leaks and well pad malfunctions) in support of onsite OGI and safety programs. All mobile techniques require downwind vehicle access and favorable wind conditions for plume transport to the observing location. The presence of trees or other obstructions can limit the efficacy of mobile leak detection techniques and in some cases prevent the application of remote source emission rate assessment.

Mobile leak detection instrument packages require some expertise for operation, especially in source emission rate measurement applications. Additionally, while mobile leak detection techniques can detect emissions around a site, such as a well site or gathering station, it cannot necessarily pinpoint the equipment that is the source of those emissions. Mobile leak detection techniques might be best used in conjunction with OGI technology; an OGI inspection would be triggered by the detection of above normal emissions by the mobile leak detection technique. In conversations with operators of upstream oil and natural gas facilities, the EPA has discovered that some companies are voluntarily using this two-phase approach to detect and then pinpoint VOC and methane leaks. It is believed that future forms of mobile leak detection

techniques for the oil and gas sector may include lower cost, work truck-mounted systems that provide fully autonomous detection capability for anomalous emissions in support of such an onsite OGI inspection (Thoma, 2012).

An example of a mobile leak detection technique applicable to the upstream oil and gas sector is being developed under the EPA's Geospatial Measurement of Air Pollution (GMAP) program (Thoma, 2012). The near-field OTM 33A produces a 20-minute "snapshot" measure of emissions from near ground level point sources at observation distances of approximately 20 to 200 m. With strict application and favorable conditions, this type of point sensor-based remote measurement has source emission rate measurement accuracies in the $\pm 30\%$ range with ensemble averages achieving accuracies within $\pm 15\%$ by reducing random error effects. Although future, fixed deployment, low cost sensor systems may provide long-term emission level monitoring capability for oil and gas production sites,¹² current mobile assessment approaches can only provide a "snapshot" of emissions. Because some oil and gas upstream sources possess significant temporal and seasonal variability, the short-term nature of observation must be considered to avoid error in exportation of instantaneous emissions (e.g., to tons per year estimates). Results of well pad measurements from multiple oil and gas fields using mobile measurement are presented in Section 2.

Costs

Current mobile measurement instrument packages can range in cost from approximately \$20,000 - \$100,000 depending on the capability of the package.

3.2 Repair

After a leak is detected, the owner or operator of the facility must decide whether or not to fix the leak, unless they are required to fix the leak due to regulatory or permitting obligations.

¹² A collaborative request for proposal (RFP) was released in the spring of 2014 by Apache Corporation, BG Group, EDF, Hess Corporation, Noble Energy, and Southwestern Energy called the "Methane Detectors Challenge: Continuous Methane Leak Detection for the Oil and Gas Industry." The "Challenge" is "designed to spur the development of cutting-edge, new technologies that provide continuous detection of methane emissions." Available at: <http://www.edf.org/energy/natural-gas-policy/methane-detectors-challenge>

This decision can be based on several factors, including, the cost of fixing the leak and the size of the leak. A number of studies discuss costs and effectiveness of various leak repair options.

3.2.1 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)

This study, discussed previously in Section 2, provided an analysis of the net present values (NPVs) of repairing all of the identified leaks in the surveys using the estimated repair cost and the value of the recovered gas. The study found that over 90% of gas emissions from leaks can be repaired with a payback period of less than one year, assuming a value of \$3 per thousand cubic feet (\$/Mcf) for the recovered gas. However, when compared with the cost of the monitoring (estimated to be \$600 to \$1,800 per facility), the economic benefits of repairing the leaks at most facilities are less than the total cost of the survey. For well sites and well batteries, the study estimated that 1,424 of the sites (81%) had a negative NPV, which averaged -\$1,160 per facility. However, when the all of the individual well sites and well batteries are aggregated into a group, the aggregated NPV is positive, which suggests that a minority of sites have high leak rates and, thus, a positive NPV for monitoring and fixing leaks. These sites skew the mean NPV to a positive value.

The study also analyzed two alternative repair strategies: only repair leaks that are economic to repair (e.g., NPV > 0 for the repair) or repair of leaks that exceeded a certain threshold (e.g., 20 thousand cubic feet per year (Mcf/yr)). A summary of the findings for each of the scenarios is provided in Table 3-1.

Table 3-1. Comparison of Three Hypothetical Repair Strategies for Multi-Well Batteries^a

| Category | Repair all leaks | Repair leaks with a NPV>0 | Repair leaks > 20 Mcf |
|---|------------------|---------------------------|-----------------------|
| Potential leak reductions after survey | 94.5% | 92.6% | 88.1% |
| Methane abatement cost (\$/ton CO ₂ e) | 1 | 0.8 | 1.7 |
| VOC abatement cost (\$/ton VOC) | 46 | 41 | 79 |
| Average number of leaks to repair | 3.8 | 3.5 | 2.9 |

a - Derived from Table 3 (CL, 2013).

The study concludes that the potential leak reductions after survey, methane abatement cost, VOC abatement cost, and average number of leaks to repair are similar under each of the three strategies. The study authors conclude that the results are similar because once a leak is found it is almost always economic to repair it.

The study also provided costs of repair and leak detection based on the survey data. The average cost of hiring an external service provider to perform a survey using OGI technology was determined to be \$1,200 for multi-well batteries, \$600 for single well batteries, and \$400 for a well site. The range of costs of repair for well sites is shown in Table 3-2.

Table 3-2. Total Average Leak Rate and Repair Costs by Components at Well Sites

| Component | Leak rate (cfm) | Repair Costs | | | |
|-----------------------|-----------------|------------------|------------------|------------------|------------------|
| | | Minimum | Average | Median | Maximum |
| Connector/Connection | 0.11 | \$15 | \$56 | \$50 | \$5,000 |
| Instrument Controller | 0.03 | \$20 | \$129 | \$50 | \$2,000 |
| Valve | 0.04 | \$20 | \$90 | \$50 | \$5,500 |
| Open-Ended Line | 0.02 | --- ^b | --- ^b | --- ^b | --- ^b |
| Regulator | 0.02 | \$20 | \$189 | \$125 | \$1,000 |

a - Derived from Tables 6 and 7 (CL, 2013).

b – Repair costs for open-ended lines were not provided in the document.

3.2.2 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)

The Clearstone I study, discussed in Section 2, provided analysis of the payback periods for fixing the identified leaks, and what level of emission reductions could be achieved. Overall, the study estimated that up to 95% of total natural gas losses can be reduced cost-effectively (assumed gas price of \$4.50 per Mcf), which corresponds to methane reductions of nearly 80%. The study also presents scenarios where only those reduction opportunities having a certain payback period (e.g., 6 months or 1 year) are implemented. For those cases, the estimated

percent of total natural gas loss reduction and corresponding reductions in methane are presented in Table 3-3. One caveat from the study is that the payback periods do not take into account the cost of the leak detection survey, only factoring in cost of repair and benefit of the gas captured.

Table 3-3. Achievable Emission Reduction Percentages for Given Positive Payback Periods

| Emission Type Reduction | Payback Period | | | |
|-------------------------|----------------|----------|-----------|-----------|
| | < 6 months | < 1 year | < 2 years | < 4 years |
| Natural Gas | 78.8% | 92.3% | 93.1% | 94.9% |
| Methane | 71.9% | 78.1% | 79.2% | 79.5% |

The study estimated that implementing all of the cost-effective repair opportunities identified would result in gross annual cost savings of approximately \$1.1 million across the plants in the study (based on a gas value of \$4.50 per Mcf). This amounts to over 50% of total cost-effective loss reduction opportunities identified for all emission sources (leaks, flaring, combustion equipment, and storage tanks) at the plants, and results in an average annual net savings of approximately \$280,000 per site (the site-specific values range between \$180,000 and \$330,000).

3.2.3 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)

The Clearstone II study, discussed in Section 2, analyzed the cost-effectiveness of repairing the leaks identified in the surveys that were performed. The study estimated that up to 96.6% of total natural gas losses could be reduced cost-effectively (assuming a gas price of \$7.15 per Mcf), which corresponds to methane reductions of 61%. The study also estimated that the average annual lost gas values from the sites surveyed were \$536,270 per gas plant, \$49,018 per gathering station, and \$3,183 per well site.

This study also provided the base repair cost and mean repair life for 16 types of components. The values for several of the more common components reported in the study are summarized in Table 3-4.

Table 3-4. Basic Repair Costs and Mean Repair Life for Several Common Leaking Components

| Component Type | Basic Repair Costs | | Mean Repair Life (years) |
|-------------------------------|--------------------|---------|--------------------------|
| | Low | High | |
| Compressor Seals ^a | \$2,000 | \$2,000 | 1 |
| Flanges | \$25 | \$400 | 2 |
| Open-End Lines | \$60 | \$1,670 | 2 |
| Pressure Relief Valves | \$79 | \$725 | 2 |
| Threaded Connections | \$10 | \$300 | 2 |
| Tubing Connections | \$15 | \$25 | 4 |
| Valves | \$60 | \$2,229 | 2 - 4 |
| Vents | \$2,000 | \$5,000 | 1 |

^a For the purposes of this paper, compressor seal emissions are not considered leaks.

3.2.4 Natural Gas STAR Directed Inspection and Maintenance (U.S. EPA, 2003a, U.S. EPA, 2003b, and U.S. EPA, 2003c)

For detecting and repairing leaks, the Natural Gas STAR program recommends implementation of a DI&M program to economically reduce methane emissions from leaking components (U.S. EPA, 2003a, U.S. EPA, 2003b, and U.S. EPA, 2003c). A DI&M program, which can be implemented at any facility in the upstream or downstream sector of the industry, starts with a comprehensive baseline emissions survey. This survey involves screening all of the components at the facility to identify the leaking components, as well as measuring the identified leaks to determine emission rates. Determining an emissions rate is an important step that allows the economic evaluation of mitigation techniques. Natural Gas STAR partners have reported using OGI technology to effectively scan large numbers of components in a short span of time. The choice of leak detection equipment typically depends on the number of components to be scanned. Optical gas imaging technology is popular at facilities that have thousands of

components, such as at processing plants. From previous field studies conducted by the EPA and Natural Gas STAR partners, the EPA has observed that typically 20% of the top leaking components account for approximately 80% of the emissions from a facility. This provides a strong basis to conduct DI&M at facilities because fixing a small number of leaks can significantly reduce the total leak emissions from a facility.

Once the leaking sources have been identified, the next step recommended is the economic analysis of mitigation techniques. The estimated repair costs for the identified leaks can be compared to the potential savings from fixing the leaks based on the value of natural gas, and the leaks that are determined to be economical to fix by the owner can be repaired.

Not all leaks identified can be fixed immediately. For example, leaks on a flange on a transmission pipeline cannot be fixed without shutting down the system and purging the pipeline of all the natural gas. The identification of leaks before a shutdown through a DI&M program helps facilities focus on specific areas during a shutdown cycle. Shutdown cycles are usually short, lasting from a day up to a week.

The Natural Gas STAR program also lists average emission rates, repair cost ranges, and payback periods for fixing leaks at several different facilities. Tables 3-5 and 3-6 show the emission rates and repair costs for several common leaking components at gas processing plants, transmission compressor stations, and gate stations.

Table 3-5. Total Average Leak Rate and Repair Costs by Component at Processing Plants

| Component | Average Component Leak Rate by Location (Mcf/yr) | | | Average Repair Cost |
|------------------------------|---|--------------------------|------------------------|---------------------|
| | Non-Compressor | Reciprocating Compressor | Centrifugal Compressor | |
| Connections | 6.7 | - | - | \$25 |
| Flanges | 88.2 | 89.7 | 115 | \$150 |
| Pressure Relief Valves | 3.9 | 308 | - | \$150 |
| Other Valves | 25 | 127 | 63.4 | \$130 |
| Compressor Seal ^a | - | 1,440 | 485 | \$2,000 |
| Open-Ended Line (OEL) | 43 | - | - | \$65 |
| Compressor Blowdown OEL | - | 1,417 | 2,887 | \$5,000 |

Note: Adapted from exhibit 5 in “Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations” Lessons Learned document. Available online: http://epa.gov/gasstar/documents/ll_dimgasproc.pdf

^a For the purposes of this paper, compressor seal emissions are not considered leaks.

Table 3-6. Total Average Leak Rate and Repair Costs by Component at Compressor Stations

| Component | Average Component Leak Rate by Location (Mcf/yr) | | Average Repair Costs | |
|-----------------------|--|----------------|----------------------|---------|
| | On Compressor | Off Compressor | Low | High |
| Ball/Plug Valves | 0.64 | 5.33 | \$40 | \$120 |
| Blowdown Valve | - | 207.5 | \$200 | \$600 |
| Compressor Valve | 4.1 | - | \$60 | \$60 |
| Unit Valve | - | 3,566 | \$70 | \$2,960 |
| Flange | 0.81 | 0.32 | \$300 | \$1,250 |
| Open-Ended Line | - | 81.8 | \$45 | \$45 |
| Pressure Relief Valve | - | 57.5 | \$1,000 | \$1,000 |
| Connection | 0.74 | 0.6 | \$10 | \$30 |

Note: Adapted from exhibits 4 and 5 in “Directed Inspection and Maintenance at Compressor Stations” Lessons Learned document. Available online: http://epa.gov/gasstar/documents/ll_dimcompstat.pdf.

3.2.5 Update of Fugitive Equipment Leak Emission Factors (CAPP, 2014)

In February of 2014, CAPP issued a report on emission factors for leaks at upstream oil and gas facilities in Alberta and British Columbia. This report served as an update to similar factors that were developed in 2005, prior to the implementation of DI&M BMPs in both these provinces. The report compares the 2005 leak emission factors to the 2014 leak emission factor in order to draw conclusions regarding the effectiveness of the DI&M BMPs in Alberta and British Columbia.

Leak survey results provided by eight industry participants in Alberta and British Columbia were the basis of the emission factors. The results came from 120 facilities and included approximately 276,947 components. All surveys were conducted after 2007. The study authors used this data to develop average emission factors for each type of component and then

compared those factors to the factors developed in 2005. Table 3-7 provides a comparison of the emission factors for each type of component from the 2005 study and the 2014 study.

Table 3-7. Comparison of Total Hydrocarbon Leak Emission Factors for Upstream Oil and Gas Facilities that have Implemented DI&M BMPs

| Sector | Component | Service^a | 2014 Emission Factor (kg/hour) | 2005 Emission Factor (kg/hour) | Ratio of 2014 to 2005 Emission Factors |
|---------------|------------------------------|----------------------------|---------------------------------------|---------------------------------------|---|
| Gas | Compressor Seal ^b | GV | 0.04669 | 0.71300 | 0.065 |
| Gas | Connector | GV | 0.00082 | 0.00082 | 1.000 |
| Gas | Connector | LL | 0.00016 | 0.00055 | 0.298 |
| Gas | Control Valve | GV | 0.03992 | 0.01620 | 2.464 |
| Gas | Open-Ended Line | All | 0.04663 | 0.46700 | 0.100 |
| Gas | Pressure Relief Valve | All | 0.00019 | 0.01700 | 0.011 |
| Gas | Pump Seal | All | 0.00291 | 0.02320 | 0.125 |
| Gas | Regulator | All | 0.03844 | 0.00811 | 4.740 |
| Gas | Valve | GV | 0.00057 | 0.00281 | 0.205 |
| Gas | Valve | LL | 0.00086 | 0.00352 | 0.245 |
| Oil | Compressor Seal | GV | 0.01474 | 0.80500 | 0.018 |
| Oil | Connector | GV | 0.00057 | 0.00246 | 0.232 |
| Oil | Connector | LL | 0.00013 | 0.00019 | 0.684 |
| Oil | Control Valve | GV | 0.09063 | 0.01460 | 6.207 |
| Oil | Open-Ended Line | All | 0.15692 | 0.30800 | 0.509 |
| Oil | Pressure Relief Valve | All | 0.00019 | 0.01630 | 0.012 |
| Oil | Pump Seal | All | 0.00230 | 0.02320 | 0.099 |
| Oil | Regulator | All | 0.52829 | 0.00668 | 79.085 |
| Oil | Valve | GV | 0.00122 | 0.00151 | 0.809 |
| Oil | Valve | LL | 0.00058 | 0.00121 | 0.479 |

Note: Adapted from Table 10 in “Update of Fugitive Equipment Leak Emission Factors” document (CAPP, 2014).

Available online: <http://www.capp.ca/getdoc.aspx?DocId=238773&DT=NTV>

^a GV = Gas/Vapor, LL = Light Liquid

^b For the purposes of this paper, compressor seal emissions are not considered leaks.

The study authors conclude that emissions from leaks have decreased 75% among the survey participants since the implementation of the DI&M programs in Alberta and British Columbia. The leak factors for almost all categories of equipment decreased. The authors did not use this data to develop national or regional estimates of total leak emissions.

4.0 SUMMARY

The EPA has used the information presented in this paper to inform its understanding of leak emissions and potential techniques that can be used to identify and mitigate leaks in the oil and natural gas production, processing, transmission and storage sectors. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- The 2014 GHG Inventory estimates there are approximately 332,662 MT of potential methane leak emissions from gas production, 33,681 MT of potential methane leak emissions from gas processing, and 114,348 MT of potential methane leak emissions gas transmission.
- Several studies suggest that the majority of methane and VOC emissions from leaks come from a minority of components (CL, 2013; Clearstone, 2002; and Clearstone, 2006). Furthermore, one study concludes that the majority of methane and VOC emissions from leaks come from a minority of sites (CL, 2013). One study found that the majority of leak emissions from these sites may be attributed to maintenance-related issues such as open thief hatches, failed pressure relief valves, or stuck dump valves (Thoma, 2012).
- The methane and VOC leak emissions from well sites depend on a number of different factors including: the number of wells located at the site, the number of compressors located at the well site and the number and type of processing equipment (separators, heaters, etc.) used at the site.
- Currently, portable analyzers provide an effective approach for both locating and measuring the concentration of leaks from oil and natural gas production sites.
- There are several other technologies being used to detect leaks for the oil and natural gas sectors. These technologies include OGI and ambient/mobile monitoring.

- OGI is being increasingly used to locate leaks in the oil and gas industry. The technology can potentially provide a more time and cost efficient method for locating leaks than traditional technologies, such as portable analyzers. However, there may be limitations to this technology.
 - The technology must be used methodically in order to address certain limitations, such as sensitivities to ambient conditions.
 - OGI technology does not quantify emissions. It may be possible to develop algorithms to quantify emissions with data from OGI, but, to the EPA's knowledge, such algorithms are not currently available.
- Ambient/mobile monitoring and OGI technology might be most effective when used in tandem. In such cases, an OGI inspection could be triggered by the detection of above normal emissions by the ambient/mobile monitoring equipment. This approach potentially could reduce or eliminate OGI inspections at facilities with minimal leak emissions.
- Available information suggests that once a leak is found it is almost always economical to repair the leak. According to the studies reviewed, the cost of detecting the leak is generally far larger than the cost of fixing the leak.
- The CAPP 2014 study and experience through the Natural Gas STAR program suggest DI&M programs can effectively decrease leak emissions.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify VOC and methane emissions from leaks in the oil and natural gas sector?
2. Please comment on the approaches for quantifying emissions and on the emission factors used in the data sources discussed. Please comment on the national estimates of emissions and emission factors for equipment leaks presented in this paper. Please comment on the activity data used to calculate these emissions, both on the total national and regional equipment counts.
3. Are the emission estimating procedures and leak detection methods presented here equally applicable to both oil and gas production, processing, and transmission and storage sectors?

4. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from leaks and available techniques for detecting those leaks? Please list the additional studies you are aware of.
5. Are there types of wells sites, gathering and boosting stations, processing plants, and transmission and storage stations that are more prone to leaks than others? Some factors that could affect the potential for leaks are the number and types of equipment, the maintenance of that equipment, and the age of the equipment, as well as factors that relate to the local geology. Please discuss these factors and others that you believe to be important.
6. Did this paper capture the full range of technologies available to identify leaks at oil and natural gas facilities?
7. Please comment on the pros and cons of the different leak detection technologies. Please discuss efficacy, cost and feasibility for various applications.
8. Please comment on the prevalence of the use of the different leak detection technologies at oil and gas facilities. Which technologies are the most commonly used? Does the type of facility (e.g., well site versus gathering and boosting station) affect which leak detection technology is used?
9. Please provide information on current frequencies of revisit of existing voluntary leak detection programs in industry and how the costs and emission reductions achieved vary with different frequencies of revisit.
10. Please comment on the potential for using ambient/mobile monitoring technologies in conjunction with OGI technology. This would be a two-phase approach where the ambient/mobile monitoring technology is used to detect the presence of a leak and the OGI technology is used to identify the leaking component. Please discuss efficacy, cost and feasibility.
11. Please comment on the cost of detecting a leak when compared to the cost to repair a leak. Multiple studies described in this paper suggest that detecting leaks is far more costly than repairing leaks and, due to generally low costs of repair and the subsequent product recovery, it is almost always economical to repair leaks once they are found. Please comment on this overall conclusion.

12. If the conclusion is correct that it is almost always economical to repair leaks once they are found, then how important is the quantification of emissions from leaks when implementing a program to detect and repair leaks?
13. Please comment on the state of innovation in leak detection technologies. Are there new technologies under development that are not discussed in this paper? Are there significant advancements being made in the technologies that are not described in this paper?

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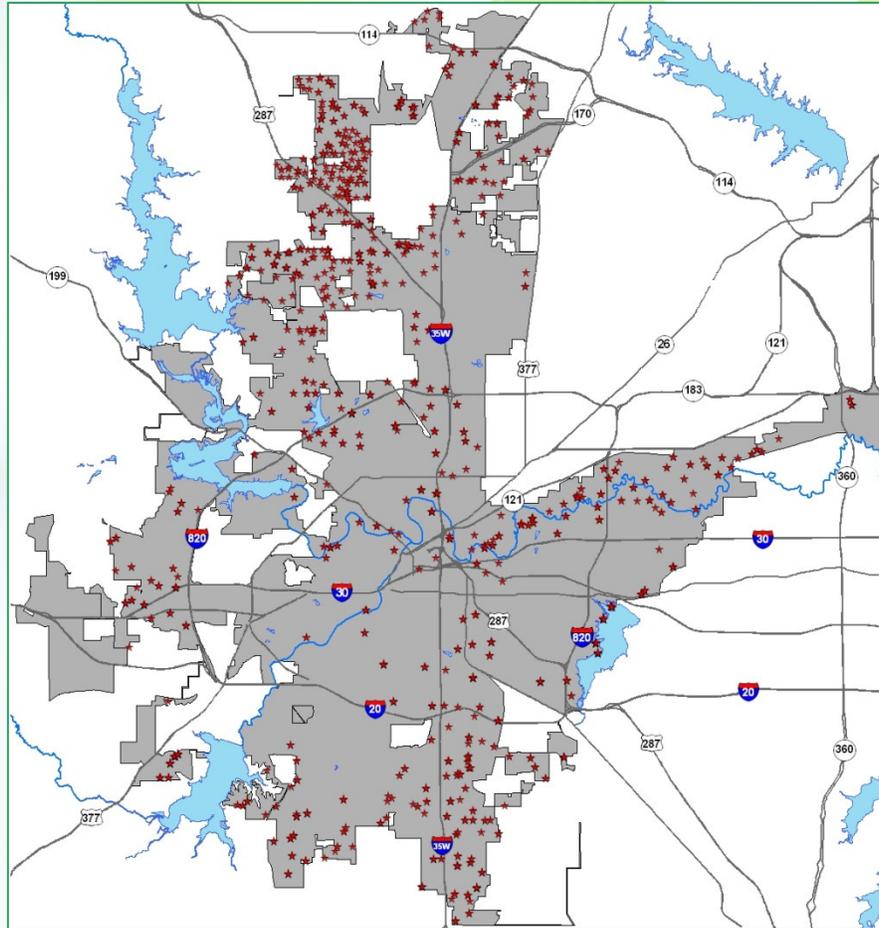
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City of Fort Worth Natural Gas Air Quality Study

Final Report



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Table of Contents

| | <u>Page</u> |
|---|-------------|
| Executive Summary | xii |
| 1.0 Introduction | 1-1 |
| 2.0 Ambient Air Monitoring..... | 2-1 |
| 2.1 Site Selection | 2-2 |
| 2.1.1 Site S-1 (Background Site)..... | 2-4 |
| 2.1.2 Site S-2 (Mobile Sources Site)..... | 2-6 |
| 2.1.3 Site S-3 (Pre-Production Site)..... | 2-6 |
| 2.1.4 Site S-4 (High-Level Activity Site, Collocated)..... | 2-8 |
| 2.1.5 Site S-5 (High-Level Activity Site, Collocated)..... | 2-9 |
| 2.1.6 Site S-6 (Moderate-Level Activity/Fence line Site) | 2-10 |
| 2.1.7 Site S-7 (Moderate-Level Activity/Fence line Site) | 2-11 |
| 2.2 Sampling Protocol..... | 2-12 |
| 2.3 Sample Analysis | 2-15 |
| 2.4 Quality Assurance/Quality Control..... | 2-18 |
| 2.4.1 Completeness | 2-19 |
| 2.4.2 Measurement Precision | 2-20 |
| 2.4.3 Measurement Accuracy | 2-22 |
| 2.5 Ambient Air Monitoring Results | 2-22 |
| 2.5.1 Summary Statistics..... | 2-22 |
| 2.5.2 Study Period Averaging | 2-28 |
| 2.5.3 Key Pollutants..... | 2-50 |
| 2.5.4 Integration with Meteorology | 2-51 |
| 2.6 Ambient Air Monitoring Conclusions | 2-73 |
| 3.0 Point Source Testing | 3-1 |
| 3.1 Introduction | 3-1 |
| 3.2 Point Source Emissions Survey Sampling Equipment | 3-3 |
| 3.2.1 The FLIR™ Infrared Camera | 3-6 |
| 3.2.2 The Toxic Vapor Analyzer (TVA)..... | 3-7 |
| 3.2.3 The Hi Flow Sampler | 3-8 |
| 3.2.4 Summa Canisters..... | 3-9 |
| 3.2.5 Miscellaneous Equipment | 3-10 |
| 3.3 Point Source Survey and Sampling Procedures..... | 3-10 |
| 3.3.1 Pre-Test Equipment Preparation | 3-11 |
| 3.3.2 Final Preparations | 3-12 |
| 3.3.3 Site Arrival | 3-12 |
| 3.3.4 IR Camera Survey | 3-14 |
| 3.3.5 Method 21 Site Survey with the Toxic Vapor Analyzer | 3-15 |
| 3.3.6 Hi Flow Sampler Emissions Testing..... | 3-17 |
| 3.3.7 Canister Sampling | 3-17 |
| 3.3.8 Completion of the Site Survey..... | 3-20 |
| 3.4 Emissions Calculation Procedures..... | 3-23 |

| | | |
|------------|---|------------|
| 3.4.1 | Well Pad, Compressor Station, Gas Plant, and Salt Water Disposal Facility Emissions | 3-23 |
| 3.4.2 | Direct Emission Calculations | 3-24 |
| 3.4.3 | Indirect Emission Calculations -- Correlation Equation Development..... | 3-26 |
| 3.4.4 | Applying Canister Results to Non-Canister Emission Points | 3-27 |
| 3.4.5 | Surrogate Canister Profiles | 3-29 |
| 3.4.6 | Calculation of Non-Sampled Low Level Emission Points..... | 3-30 |
| 3.4.7 | Compressor Engine Emissions | 3-32 |
| 3.4.8 | Well Drilling and Fracking Engine Emissions | 3-32 |
| 3.4.9 | Calculation of Method 21 TOC Screening Emission Factors | 3-32 |
| 3.5 | Point Source Emissions Results..... | 3-33 |
| 3.5.1 | Well Activity Emissions..... | 3-62 |
| 3.5.2 | Method 21 TOC Screening Emission Factors | 3-64 |
| 3.6 | Quality Control Results..... | 3-64 |
| 3.6.1 | IR Camera Daily Demo Results..... | 3-65 |
| 3.6.2 | Hi Flow Sampler Calibration Verification | 3-65 |
| 3.6.3 | TVA Calibration Procedures | 3-79 |
| 3.6.4 | Field Data Review..... | 3-89 |
| 3.6.5 | Canister Sample Collection QC..... | 3-89 |
| 3.6.6 | Analytical QC Results | 3-97 |
| 3.7 | Point Source Testing Conclusions | 3-98 |
| 4.0 | Air Dispersion Modeling..... | 4-1 |
| 4.1 | Modeling Scenarios and Source Parameters | 4-1 |
| 4.1.1 | Scenario 1 (Typical Well Pad)..... | 4-4 |
| 4.1.2 | Scenario 2 (Worst-Case Well Pad) | 4-7 |
| 4.1.3 | Scenario 3 (Worst-Case Compressor Station) | 4-11 |
| 4.1.4 | Scenario 4 (Co-located Worst-Case Well Pad and Worst-Case Compressor Station)..... | 4-14 |
| 4.2 | Model Setup and Options | 4-15 |
| 4.2.1 | Receptor Grids | 4-15 |
| 4.2.2 | Meteorological Data and Surface Parameters..... | 4-16 |
| 4.3 | Model Output..... | 4-16 |
| 4.4 | Electronic Modeling Files | 4-28 |
| 4.5 | Air Dispersion Modeling Conclusions..... | 4-31 |
| 5.0 | Public Health Evaluation..... | 5-1 |
| 5.1 | Methodology..... | 5-1 |
| 5.2 | Interpretation of Ambient Air Monitoring Data | 5-3 |
| 5.2.1 | Sensitivity of Monitoring Methods | 5-3 |
| 5.2.2 | Health Evaluation for Measured 24-Hour Average Concentrations..... | 5-9 |
| 5.2.3 | Health Evaluation for Program-Average Concentrations | 5-17 |
| 5.2.4 | Measured Concentrations: Main Findings, Limitations, and Uncertainties | 5-23 |
| 5.3 | Interpretation of Dispersion Modeling Data..... | 5-23 |
| 5.3.1 | Comparison of Modeled and Measured Air Pollution Levels | 5-24 |

| | | |
|------------|---|------------|
| 5.3.2 | Health Evaluation for Modeled 1-Hour Average Concentrations | 5-25 |
| 5.3.3 | Health Evaluation for Modeled Annual Average Concentrations | 5-32 |
| 5.3.4 | Adequacy of Setback Limits..... | 5-36 |
| 5.3.5 | Modeled Concentrations: Main Findings, Limitations, and Uncertainties | 5-41 |
| 5.4 | Additional Context for Selected Pollutants | 5-41 |
| 5.5 | Public Health Evaluation Conclusions..... | 5-51 |
| 6.0 | Regulatory Assessment | 6-1 |
| 6.1 | Federal Air Quality Rules..... | 6-1 |
| 6.1.1 | Operating Permits | 6-1 |
| 6.1.2 | Construction Permits | 6-2 |
| 6.1.3 | New Source Performance Standards | 6-2 |
| 6.1.4 | National Emission Standards for Hazardous Air Pollutants..... | 6-4 |
| 6.1.5 | Greenhouse Gas Reporting Program..... | 6-6 |
| 6.2 | Texas Commission on Environmental Quality Air Quality Rules | 6-6 |
| 6.2.1 | Permit-by-Rules | 6-7 |
| 6.2.2 | Standard Permit..... | 6-8 |
| 6.2.3 | New Source Review Permits | 6-9 |
| 6.2.4 | Control of Air Pollution from Visible Emissions and Particulate Matter | 6-9 |
| 6.2.5 | Control of Air Pollution from Sulfur Compounds..... | 6-9 |
| 6.2.6 | Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants | 6-10 |
| 6.2.7 | Control of Air Pollution from Volatile Organic Compounds..... | 6-10 |
| 6.2.8 | Control of Air Pollution from Nitrogen Compounds..... | 6-10 |
| 6.2.9 | Federal Operating Permits | 6-11 |
| 6.3 | City of Fort Worth Air Quality Rules | 6-11 |
| 6.4 | Regulatory Assessment Conclusions | 6-11 |
| 7.0 | Full Build-Out Estimates | 7-1 |
| 7.1 | Factors Affecting Natural Gas Production | 7-2 |
| 7.2 | Methodology for Forecasting Natural Gas Production | 7-5 |
| 7.3 | 2010 Base Year Emissions Inventory | 7-6 |
| 7.4 | 2010 through 2018 Projected Emissions Inventories..... | 7-16 |
| 7.5 | Full Build-Out Estimates Conclusions..... | 7-21 |
| 8.0 | Conclusions and Recommendations..... | 8-1 |
| 8.1 | Task Level Conclusions | 8-1 |
| 8.2 | Study Question Answers | 8-3 |
| 8.3 | Recommendations..... | 8-6 |
| 9.0 | References | 9-1 |

Appendix 2-A—COC Forms for Sites S-1 and S-5

Appendix 2-B—Analytical Results for SNMOC at Sites S-1 through S-5

Appendix 2-C—Analytical Results for EPA Compendium Method TO-15 at Sites S-1 through S-5

Appendix 2-D—Analytical Results for EPA Compendium Method TO-11A at Sites S-4 and S-5

Appendix 2-E—COC Forms and Analytical Results for Sites S-6 and S-7

Appendix 2-F—Final Concentration Data

Appendix 2-G—NATA Lowest Comparison Levels

Appendix 2-H—Final Meteorological Data

Appendix 3-A—Site Emissions Summary

Appendix 3-B—Emissions Workbook and Field Data

Appendix 3-C—Canister Data (Electronic)

Appendix 4-A—Electronic Modeling Files

Appendix 5-A—Additional Information on Health-Based Screening Values

List of Tables

| | <u>Page</u> |
|---|-------------|
| Table 2.1-1. Final Ambient Air Network Monitoring Sites | 2-2 |
| Table 2.2-1. Schedule of Collection Events | 2-13 |
| Table 2.3-1. EPA Compendium Method TO-15 Target Compounds and Method Detection Limits | 2-15 |
| Table 2.3-2. SNMOC Target Compounds and Method Detection Limits | 2-17 |
| Table 2.3-3. Carbonyl Target Compounds and Method Detection Limits..... | 2-18 |
| Table 2.3-4. Methane Method Detection Limit | 2-18 |
| Table 2.4-1. Data Quality Objectives..... | 2-19 |
| Table 2.4-2. DQO: Overall Completeness | 2-20 |
| Table 2.4-3. DQO: RSD Precision Calculation for Collocated VOC, Carbonyl, and SNMOC Instruments | 2-21 |
| Table 2.4-4. DQO: RSD Precision Calculation for Collocated and Replicate VOC and SNMOC Analyses | 2-21 |
| Table 2.4-5. VOC and Carbonyl HAP Audit Results | 2-22 |
| Table 2.5-1. Summary of VOC Measurements Across the Entire Monitoring Network..... | 2-24 |
| Table 2.5-2. Summary of Carbonyl Measurements Across the Entire Monitoring Network ... | 2-27 |
| Table 2.5-3. Summary of Methane and Speciated Non-Methane Organic Compounds Across the Entire Monitoring Network | 2-29 |
| Table 2.5-4. Site S-1 Pollutant Study Averages | 2-33 |
| Table 2.5-5. Site S-2 Pollutant Study Averages | 2-36 |
| Table 2.5-6. Site S-3A Pollutant Study Averages | 2-38 |
| Table 2.5-7. Site S-3B Pollutant Study Averages..... | 2-40 |
| Table 2.5-8. Site S-4 Pollutant Study Averages | 2-42 |
| Table 2.5-9. Site 5 Pollutant Study Averages..... | 2-45 |
| Table 2.5-10. Site S-6 Pollutant Study Averages | 2-48 |
| Table 2.5-11. Site S-7 Pollutant Study Averages | 2-49 |
| Table 2.5-12. Site S-1 Key Pollutant Averages..... | 2-52 |
| Table 2.5-13. Site S-2 Key Pollutant Averages..... | 2-53 |
| Table 2.5-14. Site S-3A Key Pollutant Averages | 2-53 |
| Table 2.5-15. Site S-3B Key Pollutant Averages | 2-54 |
| Table 2.5-16. Site S-4 Key Pollutant Averages..... | 2-54 |
| Table 2.5-17. Site S-5 Key Pollutant Averages..... | 2-55 |
| Table 2.5-18. Site S-6 Key Pollutant Averages..... | 2-55 |
| Table 2.5-19. Site S-7 Key Pollutant Averages..... | 2-56 |
| Table 2.5-20. Meteorological Stations Used in This Study | 2-61 |
| Table 3.1-1. Point Source Sites by Owner and Type | 3-4 |
| Table 3.4-1. Comparison of Emissions Between Tank and Non-Tank Emission Sources | 3-27 |
| Table 3.4-2. Non-Canister Methane Emissions Calculation Example..... | 3-29 |
| Table 3.4-3. Surrogate Tank and Non-Tank Emission Profiles..... | 3-29 |
| Table 3.5-1. Average and Maximum Point Source Emission Rates by Site Type ^a | 3-33 |
| Table 3.5-2. Average Point Source Emission Volumes by Site Type | 3-34 |
| Table 3.5-3. Point Source Emissions Summary by Site ^a | 3-35 |
| Table 3.5-4. Summary of Repeat Surveys ^a | 3-62 |

| | |
|--|------|
| Table 3.5-5. TOC Screening Emission Factors | 3-64 |
| Table 3.6-1. IR Camera ID: GasFindIR Daily Demo September – October, 2010..... | 3-66 |
| Table 3.6-2. IR Camera ID: GF-320 Daily Demo September – October, 2010..... | 3-68 |
| Table 3.6-3. IR Camera ID: Dexter Daily Demo September – October, 2010 | 3-70 |
| Table 3.6-4. IR Camera ID: GasFindIR Daily Demo January – February, 2011 | 3-71 |
| Table 3.6-5. IR Camera ID: GF-320 Daily Demo January – February, 2011 | 3-73 |
| Table 3.6-6. Hi Flow ID: QS1002 Verification September – October 2010..... | 3-75 |
| Table 3.6-7. Hi Flow ID: QS1005 Verification September – October 2010..... | 3-76 |
| Table 3.6-8. Hi Flow ID: QS1002 Verification January – February, 2011..... | 3-77 |
| Table 3.6-9. Hi Flow ID: QX1007 Verification January – February, 2011 | 3-78 |
| Table 3.6-10. TVA S/N: 5362 Calibration and Drift Check Results September – October 2010..... | 3-79 |
| Table 3.6-11. TVA S/N: K10419 Calibration and Drift Check Results September – October 2010..... | 3-81 |
| Table 3.6-12. TVA S/N: 5362 Calibration and Drift Check Results January – February 2011 | 3-83 |
| Table 3.6-13. TVA S/N: 0528413543 Calibration and Drift Check Results January – February 2011 | 3-85 |
| Table 3.6-14. TVA S/N: R6488 Calibration and Drift Check Results January – February 2011 | 3-86 |
| Table 3.6-15. TVA S/N: R1376 Calibration and Drift Check Results January – February 2011 | 3-88 |
| Table 3.6-16. Duplicate Canister Results..... | 3-90 |
| Table 4.1-1. Source Types Modeled | 4-4 |
| Table 4.1-2. Scenario 1 (Typical Well Pad) Model Input Emission Rates | 4-5 |
| Table 4.1-3. Scenario 2 (Worst-Case Well Pad) Model Input Emission Rates..... | 4-8 |
| Table 4.1-4. Scenario 3 (Worst-Case Compressor Station) Model Input Emission Rates | 4-11 |
| Table 4.3-1. Modeled Impacts—Scenario 1 (Typical Well Pad) | 4-16 |
| Table 4.3-2. Modeled Impacts—Scenario 2 (Worst-Case Scenario Well Pad)..... | 4-18 |
| Table 4.3-3. Modeled Impacts—Scenario 3 (Worst-Case Compressor Station)..... | 4-21 |
| Table 4.3-4. Modeled Impacts—Scenario 4 (Co-located Well Pad and Compressor Station) . | 4-24 |
| Table 4.4-1. BEEST Pollutant Abbreviation Crosswalk..... | 4-29 |
| Table 5.2-1. Ranges of Detection Limits, by Laboratory..... | 5-4 |
| Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels..... | 5-10 |
| Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels | 5-18 |
| Table 5.3-1. Monitor-to-Model Comparisons for Selected Pollutants..... | 5-24 |
| Table 5.3-2. Modeled 1-Hour Average Concentrations and TCEQ Short-Term Screening Levels..... | 5-26 |
| Table 5.3-3. Modeled Annual Average Concentrations and TCEQ Long-Term Screening Levels..... | 5-33 |
| Table 5.5-1. Key Findings for Health Evaluation..... | 5-53 |
| Table 6.2-1. New PBR Emission Rates..... | 6-7 |
| Table 6.4-1. Sources Above Regulatory Thresholds | 6-12 |
| Table 7.3-1. 2010 Base Year Well Pad Emissions Inventory | 7-7 |
| Table 7.3-2. 2010 Base Year Compressor Station Emissions Inventory | 7-10 |
| Table 7.3-3. 2010 Base Year Cumulative Emissions Inventory..... | 7-13 |

Table 7.4-1. Growth Factors for Years 2010–2018 7-16

Table 7.4-2. Projected Emissions for Years 2010–2018..... 7-17

Table 8.2-1. Average Emissions by Site Type 8-3

Table 8.2-2. Total City-Wide Emissions from Natural Gas Production Activity, by Pollutant
Category..... 8-3

Table 8.2-3. Sources Above Regulatory Thresholds 8-4

Table 8.2-4. Off-Site Air Pollution Levels for Selected Pollutants as Determined Through
the Ambient Air Monitoring Network..... 8-5

Table 8.2-5. Off-Site Air Pollution Levels for Selected Pollutants as Determined Through
Air Dispersion Modeling 8-5

List of Figures

| | <u>Page</u> |
|--|-------------|
| Figure 2.1-1. Ambient Air Monitoring Sites | 2-3 |
| Figure 2.1-2. Aerial Map of Site S-1—Fire Station 33..... | 2-4 |
| Figure 2.1-3. Overview of Barnett Shale Well Pads Near Site S-1 | 2-5 |
| Figure 2.1-4. Aerial Map of Site S-2—Environmental Collection Center..... | 2-6 |
| Figure 2.1-5. Aerial Map of Site S-3A—Eastside Landfill..... | 2-7 |
| Figure 2.1-6. Aerial Map of Site S-3B—Devon Energy Lease..... | 2-8 |
| Figure 2.1-7. Aerial Map of Site S-4—Brennan Service Center..... | 2-9 |
| Figure 2.1-8. Aerial Map of Site S-5—Fire Station 34..... | 2-10 |
| Figure 2.1-9. Aerial Map of Site S-6—Spinks Airport (South) | 2-11 |
| Figure 2.1-10. Aerial Map of Site S-7—Spinks Airport (North) | 2-12 |
| Figure 2.5-1. Acetaldehyde Average Concentrations by Site | 2-57 |
| Figure 2.5-2. Benzene Average Concentrations by Site | 2-57 |
| Figure 2.5-3. 1,3-Butadiene Average Concentrations by Site..... | 2-58 |
| Figure 2.5-4. Carbon Tetrachloride Average Concentrations by Site..... | 2-58 |
| Figure 2.5-5. <i>p</i> -Dichlorobenzene Average Concentrations by Site | 2-59 |
| Figure 2.5-6. Formaldehyde Average Concentrations by Site | 2-59 |
| Figure 2.5-7. Tetrachloroethylene Average Concentrations by Site..... | 2-60 |
| Figure 2.5-8. Meteorological Stations and Monitoring Site Locations..... | 2-64 |
| Figure 2.5-9. Site S-1 Windrose Comparisons | 2-65 |
| Figure 2.5-10. Site S-2 Windrose Comparisons | 2-66 |
| Figure 2.5-11. Site S-3A Windrose Comparisons | 2-67 |
| Figure 2.5-12. Site S-3B Windrose Comparisons..... | 2-68 |
| Figure 2.5-13. Site S-4 Windrose Comparisons | 2-69 |
| Figure 2.5-14. Site S-5 Windrose Comparisons | 2-70 |
| Figure 2.5-15. Site S-6 Windrose Comparisons | 2-71 |
| Figure 2.5-16. Site S-7 Windrose Comparisons | 2-72 |
| Figure 3.1-1. Point Source Survey Sites (August 2010 – February 2011)..... | 3-5 |
| Figure 3.1-2. Wet Gas and Dry Gas Well Pads | 3-6 |
| Figure 3.2-1. IR Camera Imaging at a Well Site | 3-7 |
| Figure 3.2-2. Method 21 Screening with the TVA at a Well Site | 3-8 |
| Figure 3.2-3. Sampling a Tank Vent with the Hi Flow Sampler | 3-9 |
| Figure 3.2-4. Collecting a Canister Sample from the Exhaust Port of the Hi Flow Sampler .. | 3-10 |
| Figure 3.3-1. Front Gate Signage..... | 3-13 |
| Figure 3.3-2. Point Source Site Characterization Form | 3-14 |
| Figure 3.3-3. Canister Sample Locations | 3-19 |
| Figure 3.3-4. Canister Sampling Manifold..... | 3-20 |
| Figure 3.3-5. Site Documentation – Wells | 3-21 |
| Figure 3.3-6. Site Documentation – Tanks and Separators..... | 3-21 |
| Figure 3.3-7. Site Documentation – Lift Compressor..... | 3-22 |
| Figure 3.3-8. Example Site Sketch | 3-22 |
| Figure 3.4-1. Emissions Calculation Flowchart | 3-25 |
| Figure 3.4-2. Default-Zero Values..... | 3-31 |

Figure 3.5-1. The Effect of Compressors on Site Emissions 3-34

Figure 3.5-2. Average TOC Emissions by Component Category 3-59

Figure 3.5-3. Average TOC Emissions in Category “Other” 3-59

Figure 3.5-4. Average Annual Emissions from Well Pad Compressor Engines 3-60

Figure 3.5-5. Non-Tank vs. Tank: Average VOC and HAP Emissions 3-60

Figure 3.5-6. Average Wet Gas vs. Dry Gas TOC Emissions..... 3-61

Figure 3.5-7. Average Wet Gas vs. Dry Gas VOC and HAP Emissions 3-61

Figure 3.5-8. Well Activity Emissions (lbs/hr) 3-63

Figure 3.7-1. Thief Hatch Left Open 3-99

Figure 3.7-2. Pneumatic Valve Controller on Separator..... 3-100

Figure 3.7-3. Storage Tank Vent 3-101

Figure 3.7-4. Natural Gas Pressure Regulator 3-101

Figure 3.7-5. Hole in Tank Roof - Miscellaneous Emission Source 3-102

Figure 4.1-1. Storage Tanks 4-2

Figure 4.1-2. Fugitive Emission Points..... 4-3

Figure 4.1-3. Natural Gas Compression Engine 4-4

Figure 4.1-4. Scenario 1 Layout (Typical Well Pad)..... 4-7

Figure 4.1-5. Scenario 2 Layout (Worst-Case Well Pad)..... 4-10

Figure 4.1-6. Scenario 3 Layout (Worst-Case Compressor Station) 4-14

Figure 4.1-7. Scenario 4 Layout (Co-located Well Pad and Compressor Station)..... 4-15

Figure 4.3-1. Formaldehyde Modeling Results for Scenarios 1 - 4..... 4-27

Figure 5.2-1. All Measurements of Hexachloro-1,3-Butadiene during the Ambient Air
Monitoring Program 5-16

Figure 5.3-1. Locations of Estimated Annual Average Benzene Concentrations Greater Than
TCEQ’s Long-Term ESL, by Modeling Scenario..... 5-38

Figure 5.3-3. Locations of Estimated Annual Average Formaldehyde Concentrations Greater
Than TCEQ’s Long-Term ESL, by Modeling Scenario..... 5-40

Figure 5.4-1. Comparison of Program-Average Benzene Concentrations in Fort Worth to 2010
Annual Average Benzene Concentrations Statewide (see Section 5.4) 5-43

Figure 5.4-2. Toxicity of Acrolein: Short-Term Exposures 5-45

Figure 5.4-3. Toxicity of Acrolein: Long-Term Exposures 5-46

Figure 5.4-4. Comparison of Program-Average Formaldehyde Concentrations in Fort Worth to
2010 Annual Average Formaldehyde Concentrations Statewide (see Section 5.4)... 5-48

Figure 5.4-5. Toxicity of Formaldehyde: Short-Term Exposures 5-49

Figure 5.4-6. Toxicity of Formaldehyde: Long-Term Exposures 5-50

Figure 7.1-1. Natural Gas Production in the Barnett Shale and Tarrant County (1993–2010)... 7-3

Figure 7.1-2. Texas Natural Gas Wellhead Price (2000–2010) 7-3

Figure 7.1-3. Permits, Rig Counts, and Wellhead Gas Prices in Tarrant County (2000–2010).. 7-4

Figure 7.2-1. Projected Production in Eight Shale Plays (BCF) (1998–2018)..... 7-5

Figure 7.2-2. Barnett Shale and Tarrant County Actual and Projected Natural Gas Production
(2000–2018) 7-6

Abbreviations

| | |
|-------------------|--|
| % CH ₄ | Leak expressed as percent methane |
| µg/m ³ | Micrograms per cubic meter |
| AQS | Air Quality Subsystem |
| ATSDR | Agency for Toxic Substances and Disease Registry |
| BACT | Best available control technology |
| BP | Barometric Pressure |
| Btu | British thermal unit |
| CCV | Continuing Calibration Verification |
| CFM | Cubic feet per minute |
| CH ₄ | Methane |
| CO | Carbon monoxide |
| CO ₂ | Carbon dioxide |
| COC | Chain of custody |
| CV | Coefficient of variation |
| DNPB | 2,4-dinitrophenylhydrazine |
| DQO | Data Quality Objective |
| EPA | U.S. Environmental Protection Agency |
| ERG | Eastern Research Group, Inc. |
| FID | Flame ionization detector |
| GC | Gas chromatograph |
| GC/MS | Gas chromatograph/Mass spectrometer |
| GIS | Geographic information system |
| GPS | Global Positioning System |
| H ₂ S | Hydrogen sulfide |
| HAP | Hazardous Air Pollutants |
| Hg | Mercury |
| HI | Hi |
| hp | Horsepower |
| ID | Identification |
| IR | Infrared |
| IRIS | Integrated Risk Information System |
| kPa | Kilopascals |
| lb | Pound |
| lbs/yr | Pounds per year |
| LCL | Lowest Comparison Level |
| LCS | Laboratory Control Standard |
| MDL | Method Detection Limit |
| mm | Millimeter |
| NA | Not available/not applicable |
| NATA | National-Scale Air Toxics Assessment |
| NESHAP | National Emissions Standard for Hazardous Air Pollutants |
| NM | Not monitored |
| NO _x | Oxides of nitrogen |
| NSPS | New Source Performance Standards |

| | |
|-------------------|---|
| NSR | New Source Review |
| NWS | National Weather Service |
| °F | Degrees Fahrenheit |
| PBR | Permit-by-Rule |
| PM | Particulate matter |
| PM _{2.5} | Particulate matter with a diameter of 2.5 micrometers or less |
| PM ₁₀ | Particulate matter with a diameter of 10 micrometers or less |
| ppbC | Parts per billion by carbon |
| ppbv | Parts per billion by volume |
| ppmv | Parts per million by volume |
| PRV | Pressure Relief Valve |
| QA/QC | Quality Assurance/Quality Control |
| QAPP | Quality Assurance Project Plan |
| RH | Relative Humidity |
| RRC | Railroad Commission |
| RSD | Relative standard deviation |
| S/N | Serial Number |
| SATMP | Schools Air Toxic Monitoring Program |
| SCFM | Standard Cubic Feet per Minute |
| SIM | Selected ion monitoring |
| SNMOC | Speciated Non-Methane Organic Compounds |
| SO ₂ | Sulfur dioxide |
| SOCMI | Synthetic Organic Chemical Manufacturing Industry |
| TCD | Thermal Conductivity Detector |
| TCEQ | Texas Commission on Environmental Quality |
| TEMP | Temperature |
| TOC | Total Organic Compounds |
| tpy | Tons per year |
| TVA | Toxic Vapor Analyzer |
| VOC | Volatile Organic Compounds |
| WBAN | Weather Bureau/Air Force Number |
| WD | Wind Direction |
| WS | Wind Speed |

Executive Summary

The city of Fort Worth is home to extensive natural gas production and exploration as it lies on top of the Barnett Shale, a highly productive natural gas shale formation in north-central Texas. The Barnett Shale underlies 23 counties, including four (Tarrant, Denton, Wise, and Parker) that lie partly within the Fort Worth city boundaries. Over the last several years, natural gas production in the Barnett Shale has increased dramatically. This increase in activity has been brought about by advancements in drilling technologies, most notably hydraulic fracturing (fracking) and horizontal drilling.

As the Barnett Shale formation is located beneath a highly populated urban environment, extraction of natural gas from it has involved exploration and production operations in residential areas, near public roads and schools, and close to where the citizens of Fort Worth live and work. Due to the highly visible nature of natural gas drilling, fracturing, compression, and collection activities, many individual citizens and community groups in the Fort Worth area have become concerned that these activities could have an adverse effect on their quality of life.

In response to these concerns, on March 9, 2010, the Fort Worth City Council adopted Resolution 3866-03-2010 appointing a committee to review air quality issues associated with natural gas exploration and production. This committee was composed of private citizens, members of local community groups, members of environmental advocacy groups, and representatives from industry. The committee was charged to make recommendations to the City Council on a scope of work for a comprehensive air quality assessment to evaluate the impacts of natural gas exploration and production, to evaluate proposals submitted in response to a solicitation for conducting this study, and to ultimately choose a qualified organization to conduct the study.

Following an open bidding process, Eastern Research Group, Inc. (ERG) was selected to perform the Fort Worth Natural Gas Air Quality Study (FWNGAQS). ERG was asked to design a study that answered four key questions, originally established by the air quality committee. Since that time, ERG has completed extensive sampling activity throughout Fort Worth, and the sampling results support the following main conclusions:

- *How much air pollution is being released by natural gas exploration in Fort Worth?* ERG estimated emissions for 375 well pads, 8 compressor stations, one gas processing plant, a saltwater treatment facility, a drilling operation, a fracking operation, and a completion operation. Summed across all these sites, the total estimated emissions of organic compounds was 20,818 tons per year, with well pads accounting for more than three-fourths of those total emissions. The emissions contained dozens of pollutants with varying toxicities. Pollutants with relatively low toxicities (e.g., methane, ethane, propane, and butane) accounted for the overwhelming majority—approximately 98%—of the city-wide emissions. However, several pollutants with relatively high toxicities (e.g., benzene) were also emitted from these sites, though in considerably lower quantities. At a small subset of sites, the point source testing team noted signs of malfunctioning equipment that likely caused increased emissions. For example, some hatches atop tanks were ajar and not closed, and corrosion had apparently caused a hole to form on the roof of at least

one tank. Enhanced inspection and maintenance of equipment at the sites can help ensure that these preventable emissions are greatly reduced or eliminated. ERG also projected future emission rates based on an analysis of market forces, natural gas reserves, and other factors. This analysis found that city-wide emissions from the production of natural gas are projected to peak in 2012 and 2013 at 9% above 2010 levels. More detailed and technical information on emissions from natural gas sites is found in Sections 3 and 7 of this report.

- *Do sites comply with environmental regulation?* Numerous state and federal regulations could apply to natural gas production sites, but applicability of all regulations depends on site-specific nuances. The primary environmental regulation that would apply to natural gas extraction sites is TCEQ's oil and gas "permit-by-rule". This regulation is in the Texas Administrative Code and sets criteria for air permitting, based on the amount and type of emissions from a given facility. Based on the emission rates that ERG calculated for this project, five sites—a processing facility, three compressor stations, and one well pad—had overall emission rates that exceed regulatory thresholds that are supposed to trigger certain permitting requirements. Section 6 of this report identifies these five sites and presents their estimated emission rates.
- *How do releases from these sites affect off-site air pollution levels?* Scientists typically use two different methods when trying to understand how a given air pollution source affects local air quality. One approach is to conduct ambient air monitoring, which is directly measuring air pollution levels that people breathe. Another approach is to use dispersion modeling, which is estimating air pollution levels using models that predict how pollutants move through the air from the point where they are released. ERG used both approaches in the FWNGAQS. The ambient air monitoring program identified actual air pollution levels of nearly 140 pollutants at eight locations throughout the city, and the dispersion modeling study estimated air pollution levels at times when, and locations where, ambient monitoring did not take place.

A health-screening analysis of the measured and estimated air pollution levels identified three pollutants—acrolein, benzene, and formaldehyde—as the most important from a risk perspective. While Fort Worth residents are exposed to these and other pollutants released from natural gas sites, the measured and estimated air pollution levels did not reach levels that have been observed to cause adverse health effects. Further, the measured benzene and formaldehyde levels in Fort Worth were not unusually elevated when compared to levels currently measured by TCEQ elsewhere in Texas. There was insufficient data available to do a similar comparison for acrolein. ERG recommended focused additional study to ensure that these pollutants do not reach unhealthy levels in the future. Sections 2, 4, and 5 describe the monitoring, modeling, and health-screening analysis in greater technical detail.

- *Are the city's required setbacks for these sites adequate to protect public health?* For the overwhelming majority of sites considered in this study, the modeling analysis indicates that Fort Worth's 600-foot setback distance is adequate. For the relatively few sites with multiple, large line compressor engines, the modeling analysis found some areas beyond

the setbacks to have estimated acrolein and formaldehyde concentrations greater than protective health-based screening levels published by TCEQ. However, the estimated air pollution levels did not reach levels that have actually been found to cause symptoms or illness among exposed populations. Because the findings for these two pollutants are based entirely on estimated emission rates and modeled air quality impacts (as opposed to measured values), ERG recommends further evaluations of acrolein and formaldehyde at sites with multiple, large line engines to provide greater confidence in the adequacy and protectiveness of the city's setbacks. Some recent, short-term studies of limited scope have monitored for these pollutants, but a longer-term monitoring program is better suited for confirming this study's findings for acrolein and formaldehyde. Section 5 describes how ERG reached its conclusions regarding the adequacy of the city's setback distances.

Although this study did not reveal any significant health threats beyond setback distances, it is important to remember that the sources of concern for this project—natural gas exploration and production activity—are located in residential settings throughout a metropolitan area. Though the most toxic pollutants these sources emit are released in relatively low quantities, ERG fully supports implementing all reasonable precautions to reduce emissions from the well pads and compressor stations. Our recommendations in Section 8 of this report identify several specific opportunities for reducing emissions from natural gas production sites in Fort Worth.

1.0 Introduction

The city of Fort Worth is home to extensive natural gas production and exploration as it lies on top of the Barnett Shale, a highly productive natural gas shale formation in north-central Texas. The Barnett Shale underlies 23 counties, including four (Tarrant, Denton, Wise, and Parker) that lie partly within the Fort Worth city boundaries. Over the last several years, natural gas production in the Barnett Shale has increased dramatically. This increase in activity has been brought about by advancements in drilling technologies, most notably hydraulic fracturing and horizontal drilling.

As the Barnett Shale formation is located beneath a highly populated urban environment, extraction of natural gas from it has involved exploration and production operations in residential areas, near public roads and schools, and close to where the citizens of Fort Worth live and work. Due to the highly visible nature of natural gas drilling, fracturing, compression, and collection activities, many individual citizens and community groups in the Fort Worth area have become concerned that these activities could have an adverse effect on their quality of life.

In response to these concerns, on March 9, 2010, the Fort Worth City Council adopted Resolution 3866-03-2010 appointing a committee to review air quality issues associated with natural gas exploration and production. This committee was composed of private citizens, members of local community groups, members of environmental advocacy groups, and representatives from industry. The committee was charged to make recommendations to the City Council on a scope of work for a comprehensive air quality assessment to evaluate the impacts of natural gas exploration and production, to evaluate proposals submitted in response to a solicitation for conducting this study, and to ultimately choose a qualified organization to conduct the study.

The goals of the air quality study, as established by the air quality committee, are to help city officials answer the following four questions:

- How much air pollution is being released by natural gas exploration in Fort Worth?
- Do sites comply with environmental regulation?
- How do releases from these sites affect off-site air pollution levels?
- Are the city's required setbacks for these sites adequate to protect public health?

In order to answer these questions, the air quality committee identified several key tasks that should be included in this study: ambient air monitoring, point source testing, and air dispersion modeling.

Ambient air monitoring was conducted to measure outdoor pollution levels. Ambient air monitoring was included in the Fort Worth Natural Gas Air Quality Study to measure air pollution levels near selected natural gas facilities.

Point source testing was conducted to determine how much air pollution is being released by natural gas production in Fort Worth, and if natural gas extraction and processing sites

comply with environmental regulations. Under this task, various types of air testing equipment were used to detect, identify, and quantify the type and amount of air pollutants being emitted.

Air dispersion modeling was used to estimate the incremental air quality impacts caused by emissions from natural gas facilities. The modeling results provide perspective on air pollution levels at locations where, and at times when, ambient air samples were not collected. The results were used to assess whether the city's required setbacks (as published in City Ordinance No. 18449-02-2009) are adequately protective of public health.

Finally, a health evaluation compared the results of the ambient air monitoring program and air dispersion modeling to protective health-based screening levels. For selected pollutants, additional context was provided on toxicity and pollution levels typically observed at other locations in Texas.

This report presents the results of each of these tasks and activities, and is organized into eight sections as follows:

- Section 1 – Introduction. This section provides background information on the study.
- Section 2 – Ambient Air Monitoring. This section describes how the ambient air monitoring network was designed and implemented, and presents the ambient air monitoring results.
- Section 3 – Point Source Testing. This section describes how the point source testing task was conducted, what equipment was used, and how the data obtained was used to estimate emissions. The section also summarizes point source testing results.
- Section 4 – Air Dispersion Modeling. This section describes the air dispersion modeling task. It documents the major inputs, assumptions, site configurations, and results.
- Section 5 – Public Health Evaluation. This section interprets the ambient air monitoring data and the air dispersion modeling data from a public health perspective. It also comments on whether the setbacks are adequately protective of public health.
- Section 6 – Regulatory Assessment. This section provides details on the types of air quality regulations that may apply to natural gas exploration and production activities, and draws conclusions (where appropriate) on whether the sites visited under the point source task comply with applicable regulatory thresholds.
- Section 7 – Full Build-Out Estimates. This section discusses the factors expected to affect the growth of natural gas exploration and production in Fort Worth in the coming years and estimates future peak air emissions in Fort Worth.
- Section 8 – Conclusions and Recommendations. This section draws upon the results of each of the project activities to answer the four questions that defined the overall scope of this study. Several recommendations are also provided.

2.0 Ambient Air Monitoring

This section presents the findings of the ambient air monitoring component of this study, and contains six sub-sections.

- 2.1 Site Selection – Describes how the monitoring sites were identified.
- 2.2 Sampling Protocol – Describes how the ambient air monitoring samples were obtained.
- 2.3 Sample Analysis – Describes how the ambient air monitoring samples were analyzed at the laboratory.
- 2.4 Quality Assurance/Quality Control – This section describes the quality assurance and quality control (QA/QC) procedures employed during collection and analysis of the ambient air samples.
- 2.5 Ambient Air Monitoring Results – The results of the ambient air monitoring program are discussed in this section, including site-by-site study results.
- 2.6 Ambient Air Monitoring Conclusions – This section presents the conclusions of the ambient air monitoring program.

Ambient air is the air that people might expect to be exposed to at a road, school, or park near an air pollution emission source, such as a natural gas well pad or compressor station. Ambient air monitors are instruments that measure outdoor pollution levels in the ambient air. In this study, ambient air monitoring was conducted to assess the short-term prevalence and magnitude of concentrations of selected air toxics present in the air outside the property boundaries of air emissions sources such as a natural gas well pad or compressor station.

In this study, air pollution levels of nearly 140 pollutants (including over 40 Hazardous Air Pollutants (HAPs)) were measured over a two-month period with ambient air monitoring stations at eight different locations in Fort Worth. Sampling commenced on September 4, 2010, and concluded on October 31. Data obtained from this ambient air monitoring network can be used to:

- Assist in a better understanding of conclusions drawn from the point source sampling and analysis efforts.
- Characterize exposure to selected air toxics in ambient air at various locations in the city, as related to the proximity to certain natural gas activities (well pads, compressor stations, fracturing operations, etc.).
- Establish a representative determination of the concentration of air toxics, such as benzene, present in the ambient air in the area.
- Allow for a public health evaluation (See Section 5 for the full public health evaluation).

The ambient air monitoring network deployed in the field under this project was implemented in accordance with the *Ambient Air Monitoring Plan*, drafted in August 2010 and finalized on September 15, 2010. The *Ambient Air Monitoring Plan* identifies the goals and objectives of the ambient air monitoring network, provides technical background information (such as historical meteorological data) needed to identify candidate monitoring site locations, specifies the technical approach used to focus the list of candidate monitoring sites, and provides the final list of sites used in the study. Also, prior to implementation of the monitoring study, ERG prepared an approved Level 1 *Ambient Air Monitoring Quality Assurance Project Plan (QAPP)* which provided specific information on the sampling protocols, sampling analyses, and data reporting.

2.1 Site Selection

The final selection of eight monitoring sites occurred in two phases.

In Phase 1, geographic information system (GIS) data was obtained from the city of Fort Worth showing the locations of active and permitted natural gas activities, compressor stations, city property, nearby roadways, meteorological stations, and other features. These data and maps were overlaid to show natural gas activities in relation to residences, schools, businesses, existing (non-natural-gas) emission sources, and city-owned property. Monitoring on city-owned property was desirable for several reasons, including ensuring that the project team had site access seven days a week, maintaining the security of project staff and sampling equipment, and maintaining the integrity of the air sample by limiting the chance of vandalism or other tampering. During Phase 1, 20 potential monitoring site locations were identified.

In Phase 2, project staff visited each potential site to evaluate its suitability as a possible monitoring site location. During these visits, project staff interviewed site personnel and inspected the property, taking particular notice of potential obstructions (trees, buildings, etc.) or limitations (not enough land, no power, etc.) that would disqualify sites. At the end of Phase 2, and after consultation with city staff, eight locations were identified as suitable for inclusion in the ambient air monitoring network. These sites are listed below in Table 2.1-1.

Table 2.1-1. Final Ambient Air Network Monitoring Sites

| Site ID | Site Type | Coordinates |
|---------|---------------------|------------------------------|
| S-1 | Background | 32° 49.114'N 97° 02.953'W |
| S-2 | Mobile sources | 32° 33.379'N 97° 13.164'W |
| S-3A | Pre-production | 32° 45.897'N 97° 15.763'W |
| S-3B | Pre-production | 32° 46.569'N 97° 29.638'W |
| S-4 | High-level activity | 32° 47.249'N 97° 19.715'W |

Table 2.1-1. Final Ambient Air Network Monitoring Sites (Continued)

| Site ID | Site Type | Coordinates |
|---------|-------------------------------------|------------------------------|
| S-4C | High-level activity, collocated | 32° 47.249'N 97° 19.715'W |
| S-5 | High-level activity | 32° 59.044'N 97° 23.131'W |
| S-5C | High-level activity, collocated | 32° 59.044'N 97° 23.131'W |
| S-6 | Moderate-level activity, fence line | 32° 33.37'N 97° 18.820'W |
| S-7 | Moderate-level activity, fence line | 32° 34.223'N 97° 18.815'W |

The technical approach used to finalize the site selection process is described in detail in the *Ambient Air Monitoring Plan*. Figure 2.1-1 shows the ambient air monitoring site locations; each site is described below, along with a figure showing its location in more detail.

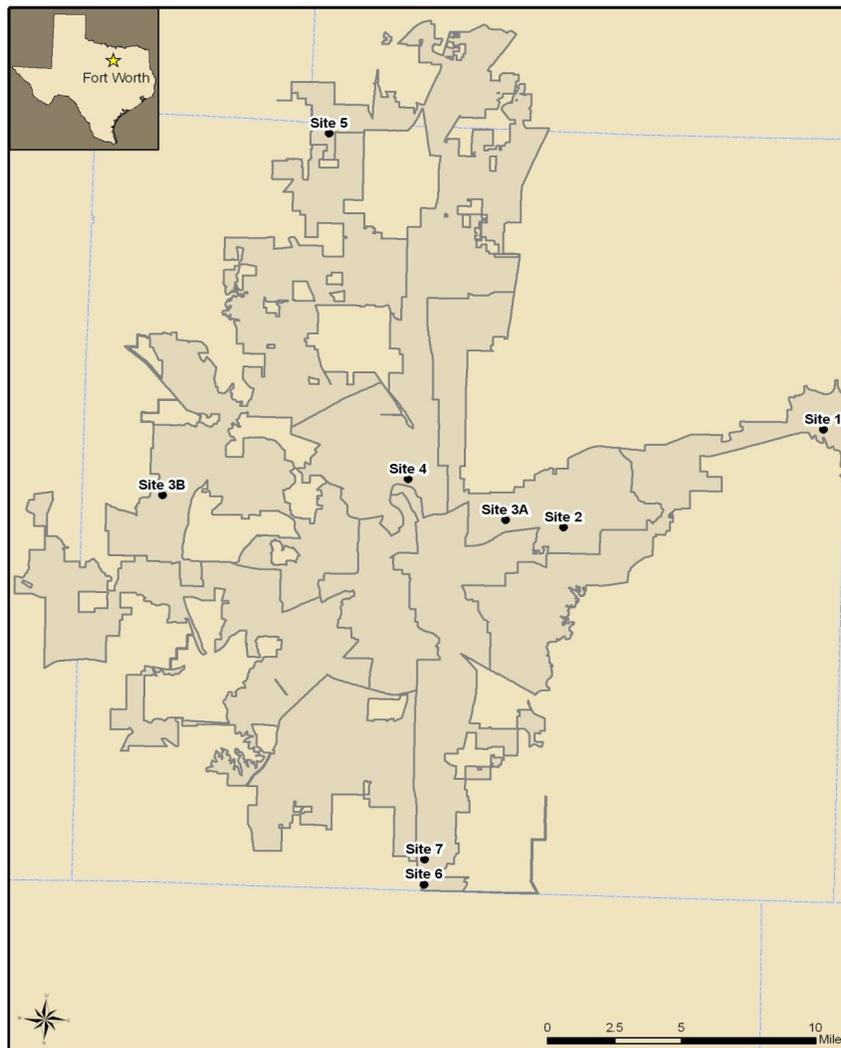


Figure 2.1-1. Ambient Air Monitoring Sites

2.1.1 Site S-1 (Background Site)

Site S-1 is located at Fort Worth Fire Station #33 (Figure 2.1-2), in the easternmost part of the city. Wind at this location predominantly blows from the south and southeast, meaning that there is expected to be minimal influence from natural gas exploration and production activities relative to areas further west (Figure 2.1-3). Therefore, this monitoring site is considered a “background” site, chosen to obtain background information on the air quality within the city of Fort Worth absent any impact from nearby natural gas sources. Speciated organic compounds were characterized at this site using the U.S. Environmental Protection Agency (EPA) Compendium Method TO-15 (see Section 2.3 for a description of EPA Compendium Method TO-15). Twenty samples were obtained from this location using a battery-operated system.



Figure 2.1-2. Aerial Map of Site S-1—Fire Station 33

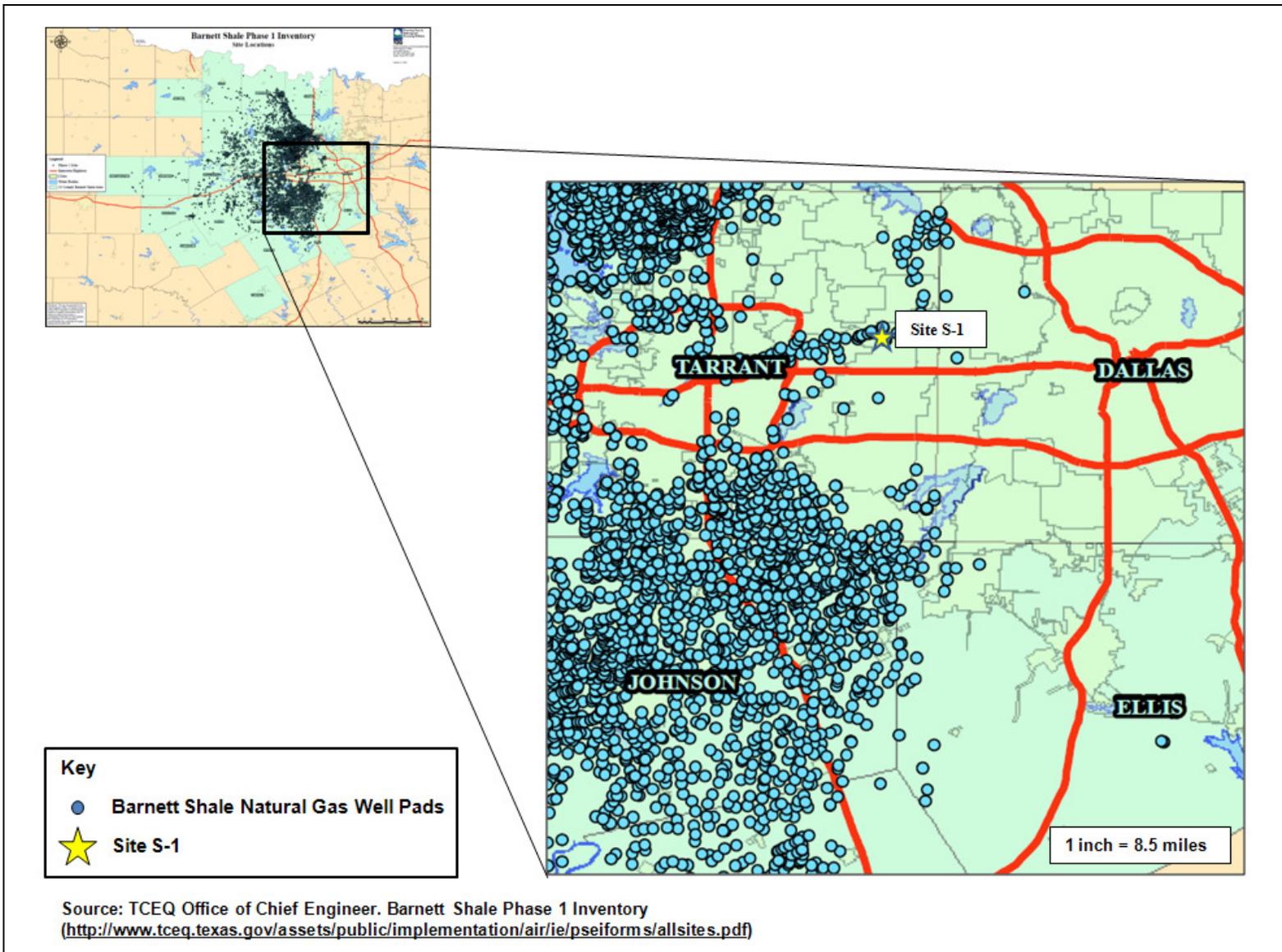


Figure 2.1-3. Overview of Barnett Shale Well Pads Near Site S-1

2.1.2 Site S-2 (Mobile Sources Site)

Site S-2 is located at the city's Environmental Collection Center (Figure 2.1-4), within a half-mile of the intersection of Interstate 820 and Interstate 30. The closest natural gas activity to this site is upwind, approximately 2 miles south of this intersection. Thus, this site was chosen to characterize pollutant concentrations from mobile sources along the two interstates, and to help determine how mobile sources (vehicles) affect ambient air within Fort Worth. Speciated organic compounds were characterized at this site using EPA Compendium Method TO-15. Eighteen samples were obtained from this location using a battery-operated system.



Figure 2.1-4. Aerial Map of Site S-2—Environmental Collection Center

2.1.3 Site S-3 (Pre-Production Site)

Site S-3 was chosen to characterize ambient air quality impacts of “pre-production” activities such as fracturing and flowback operations. The site was moved from one location to another, as described below; speciated organic compounds were characterized at these two locations using EPA Compendium Method TO-15.

Initially, this monitor was located at the Eastside Landfill (Figure 2.1-5), a capped landfill located just off of Interstate 30 to the east of downtown Fort Worth. Depending upon wind direction, this site enabled acquisition of air samples affected by either a fracturing operation (less than a quarter-mile to the south) or the Brentwood Saltwater Disposal Site (0.35 miles to the north). Eight samples were obtained from this location using a battery-operated system. Upon completion of the fracturing job, this site was re-located as described below.

On October 9, 2010, this monitoring site was moved to a Devon Energy lease site west of Fort Worth, approximately 1 mile west of Interstate 820, where fracturing and flowback operations were in process. This was the only site that was not located on city property, but there were no issues of site access from the field technician. Eight samples were obtained from this location using a battery-operated system. The location of this monitor is shown in Figure 2.1-6.



Figure 2.1-5. Aerial Map of Site S-3A—Eastside Landfill



Figure 2.1-6. Aerial Map of Site S-3B—Devon Energy Lease

2.1.4 Site S-4 (High-Level Activity Site, Collocated)

Site S-4, the Brennan Service Center (Figure 2.1-7), was located at a city-owned site north of downtown, less than one-half mile west of Interstate 35. This facility formerly served as a Fire Department Fleet Service Center and currently serves as a residential garbage drop-off station. This site is located within 0.4 miles northwest of one combined well pad and compressor station site, 0.8 miles north of another combined well pad and compressor station site, and 0.2 miles southwest of a well pad site. Concentrations from these natural gas operations, as well as from other sources, were characterized at this site. Speciated organic compounds were characterized at this site using EPA Compendium Method TO-15, and carbonyl compounds (including formaldehyde) were characterized using EPA Compendium Method TO-11A. Twenty volatile organic compound (VOC) and 20 carbonyl samples were obtained from this location using a powered system. This site was also designated as a collocated site, meaning that duplicate VOC and carbonyl samples would be taken at this site periodically. Indicators of sample system data quality are determined using the collocated data.



Figure 2.1-7. Aerial Map of Site S-4—Brennan Service Center

2.1.5 Site S-5 (High-Level Activity Site, Collocated)

Site S-5 was located at Fort Worth Fire Station #34 (Figure 2.1-8), in a residential area in the northern part of Fort Worth. This site's location has a high level of natural gas activity and is within a mile of dozens of natural gas wells upwind of this station. Speciated organic compounds were characterized at this site using EPA Compendium Method TO-15, and carbonyl compounds (including formaldehyde) were characterized using EPA Compendium Method TO-11A. Nineteen VOC and 20 carbonyl samples were obtained from this location using a powered system. This site was also designated as a collocated site.



Figure 2.1-8. Aerial Map of Site S-5—Fire Station 34

2.1.6 Site S-6 (Moderate-Level Activity/Fence line Site)

Site S-6 was located at the Spinks Airport (Figure 2.1-9), in the southern reaches of the city. This site was chosen because the monitor could be placed within 350 feet of an active well pad, making it a useful way to help evaluate the city's setback provisions. Speciated organic compounds were characterized at this site using EPA Compendium Method TO-15, and methane emissions were characterized at this site using EPA Compendium Method TO-14 (see Section 2.3 for a description of EPA Compendium Method TO-14). Nineteen samples were obtained from this location using a battery-operated system.



Figure 2.1-9. Aerial Map of Site S-6—Spinks Airport (South)

2.1.7 Site S-7 (Moderate-Level Activity/Fence line Site)

Site S-7 was also located at the Spinks Airport (Figure 2.1-10) in the southern reaches of the city. This site was also chosen to help evaluate the city's setback provisions, as this monitor was situated within 200 feet of an active well pad. Speciated organic compounds were characterized at this site using EPA Compendium Method TO-15, and methane emissions were characterized at this site using EPA Compendium Method TO-14. Eighteen samples were obtained from this location using a battery-operated system.



Figure 2.1-10. Aerial Map of Site S-7—Spinks Airport (North)

2.2 Sampling Protocol

At each of the eight sites, ambient air samples were collected once every three days. This schedule ensured that samples were collected on both weekdays and weekend days. The schedule provided some insights on how air quality varies by day of the week—an important consideration given that traffic patterns and other emission sources can vary from one day to the next.

The collection and analysis of ambient air monitoring samples for this study was performed in accordance with EPA Compendium Methods TO-15,¹ TO-11A,² and TO-14.³ As described in Section 2.1, each of the eight monitoring sites was chosen for a specific reason. Therefore, the sample collection procedure and analytical method used at each site varied. Table 2.2-1 identifies the original sample collection schedule and type of samples obtained at each site. Additional details on these can be found in the *Ambient Air Monitoring Plan*.

Table 2.2-1. Schedule of Collection Events

| Date | Concurrent VOC/SNMOC Collection ^a | Carbonyl Collection ^b | VOC/SNMOC Duplicate Samples ^a | Carbonyl Duplicate Samples ^b | Concurrent VOC/Methane Collection ^c |
|----------|--|----------------------------------|--|---|--|
| 9/4/10 | Sites S-1 through S-5 | Sites S-4 and S-5 | — | — | Sites S-6 and S-7 |
| 9/7/10 | | | — | — | |
| 9/10/10 | | | — | — | |
| 9/13/10 | | | From two sites | From two sites | |
| 9/16/10 | | | — | — | |
| 9/19/10 | | | — | — | |
| 9/22/10 | | | — | — | |
| 9/25/10 | | | From two sites | From two sites | |
| 9/28/10 | | | — | — | |
| 10/1/10 | | | — | — | |
| 10/4/10 | | | — | — | |
| 10/7/10 | | | From two sites | From two sites | |
| 10/10/10 | | | — | — | |
| 10/13/10 | | | — | — | |
| 10/16/10 | | | — | — | |
| 10/19/10 | | | From two sites | From two sites | |
| 10/22/10 | | | — | — | |
| 10/25/10 | | | — | — | |
| 10/28/10 | | | — | — | |
| 10/31/10 | From two sites | From two sites | | | |

^a Volatile organic compound/speciated non-methane organic compound (VOC/SNMOC) samples analyzed using EPA Compendium Method TO-15.

^b Carbonyl samples analyzed using EPA Compendium Method TO-11A.

^c VOC/methane samples analyzed using EPA Compendium Method TO-15 (VOCs) and EPA Compendium Method TO-14 (methane).

Sampling at Sites S-1 through S-3, S-6, and S-7 was conducted using vacuum-regulated systems. These systems were battery-operated/passive and used pre-cleaned SUMMA[®] canisters to collect VOC and methane samples. Sampling at Sites S-4 and S-5 was conducted using two automated, mass-flow control systems. These systems are electrically powered and used pre-cleaned, evacuated SUMMA[®] canisters to collect VOC samples and 2,4-dinitrophenylhydrazine (DNPH) cartridges to collect carbonyl samples. All seven systems incorporated digital timers to ensure that 24-hour integrated samples were obtained (i.e., 00:01 to 23:50).

In order to obtain an integrated air sample for VOC analysis, air was drawn into a cleaned and pre-evacuated passivated SUMMA[®] canister through a calibrated flow limiting orifice

assembly that regulated the rate and duration of sampling. After the air sample was collected, the canister valve was closed automatically. The day following the sample collection, project staff visited each site; inspected the sample media for any errors, inconsistencies, or signs of tampering; and completed a chain-of-custody (COC) form for each of the samples. For each sample that was deemed viable for analysis, the sample and the COC form were shipped together to the laboratory for analysis. The information on the COC form included the following:

- Sample ID number
- Sampling equipment identification
- Sampling date
- Sampling start time
- Sampling end time
- Elapsed time
- Initial flowrate
- End flowrate
- Average flowrate
- Sample volume (total liters)
- Comments (field observations and/or anomalies during sampling)
- Name and signature of field operator releasing samples for shipment
- Condition of custody seal upon receipt by laboratory
- Condition of samples upon receipt by laboratory
- Signature of laboratory representative receiving shipment
- Date of sample receipt at laboratory

The samples obtained at Sites S-1 through S-5 were analyzed at Eastern Research Group's (ERG's) laboratory in Morrisville, North Carolina, while the samples obtained at Sites S-6 and S-7 were analyzed at TestAmerica's™ laboratory in Austin, Texas. Appendix 2-A contains the COC forms for Sites S-1 through S-5, Appendix 2-B contains the analytical results for SNMOCs at Sites S-1 through S-5, Appendix 2-C contains the analytical results for EPA Compendium Method TO-15 at Sites S-1 through S-5, Appendix 2-D contains the analytical results for EPA Compendium Method TO-11A at Sites S-4 and S-5, and Appendix 2-E contains the COC forms and analytical results for Sites S-6 and S-7.

Upon receipt, the canister information was recorded and the sample stored until analysis. Storage times of up to 45 days without compound concentration losses have been demonstrated for many of the VOCs (e.g., benzene, toluene, ethylbenzene, and xylenes) found in urban atmospheres. Although the required turnaround time under the method guidelines is 45 days, an actual turnaround time of approximately 30 days from sample receipt to sample analysis was typical.

2.3 Sample Analysis

Air toxics and SNMOC concentration data for each sample was obtained in accordance with the guidelines presented in EPA Compendium Method TO-15.¹ Method TO-15 provides guidance on sampling and analytical procedures for the measurement of a subset of the 97 VOCs that are included in the 1989 HAPs listed in Title III of the Clean Air Act Amendments of 1990.⁴ These VOCs are defined as organic compounds having a vapor pressure greater than 10^{-1} Torr at 25°C and 760 millimeter (mm) mercury (Hg), meaning that they are likely to exist in a gaseous phase under standard atmospheric conditions. Method TO-15 is used to analyze air samples for toxic compounds expected to be released from many air pollution sources, including natural gas production related activities.

Target air toxics species, and their corresponding method detection limits (MDLs) are presented in Table 2.3-1. Target SNMOC species and their corresponding MDLs are presented in Table 2.3-2.

Table 2.3-1. EPA Compendium Method TO-15 Target Compounds and Method Detection Limits

| Target Compounds | ppbv ^a | Target Compounds | ppbv |
|---------------------------|-------------------|------------------------------------|-------|
| 1,1,1-Trichloroethane | 0.020 | Dibromochloromethane | 0.011 |
| 1,1,2,2-Tetrachloroethane | 0.011 | Dichlorodifluoromethane | 0.012 |
| 1,1,2-Trichloroethane | 0.018 | Dichlorotetrafluoroethane | 0.012 |
| 1,1-Dichloroethane | 0.017 | Ethyl Acrylate | 0.011 |
| 1,1-Dichloroethene | 0.013 | Ethyl <i>tert</i> -Butyl Ether | 0.009 |
| 1,2,4-Trichlorobenzene | 0.018 | Ethylbenzene | 0.012 |
| 1,2,4-Trimethylbenzene | 0.011 | Hexachloro-1,3-butadiene | 0.012 |
| 1,2-Dibromoethane | 0.012 | <i>m,p</i> -Xylene | 0.014 |
| 1,2-Dichloroethane | 0.015 | <i>m</i> -Dichlorobenzene | 0.010 |
| 1,2-Dichloropropane | 0.025 | Methanol | 0.255 |
| 1,3,5-Trimethylbenzene | 0.010 | Methyl Ethyl Ketone | 0.026 |
| 1,3-Butadiene | 0.010 | Methyl Isobutyl Ketone | 0.010 |
| 1,4-Dioxane | 0.140 | Methyl Methacrylate | 0.021 |
| Acetylene | 0.025 | Methyl <i>tert</i> -Butyl Ether | 0.009 |
| Acrylonitrile | 0.027 | Methylene Chloride | 0.023 |
| Allyl Chloride | 0.110 | <i>n</i> -Butanol | 0.144 |
| Benzene | 0.019 | <i>n</i> -Octane | 0.011 |
| Bromochloromethane | 0.018 | <i>o</i> -Dichlorobenzene | 0.012 |
| Bromodichloromethane | 0.021 | <i>o</i> -Xylene | 0.010 |
| Bromoform | 0.011 | <i>p</i> -Dichlorobenzene | 0.010 |
| Bromomethane | 0.013 | Propylene | 0.028 |
| Carbon Disulfide | 0.011 | Styrene | 0.010 |
| Carbon Tetrachloride | 0.024 | <i>tert</i> -Amyl Methyl Ether | 0.013 |
| Chlorobenzene | 0.014 | Tetrachloroethylene | 0.011 |
| Chloroethane | 0.012 | Toluene | 0.013 |
| Chloroform | 0.017 | <i>trans</i> -1,2-Dichloroethylene | 0.014 |
| Chloromethane | 0.016 | <i>trans</i> -1,3-Dichloropropene | 0.016 |
| Chloromethylbenzene | 0.017 | Trichloroethylene | 0.017 |

Table 2.3-1. EPA Compendium Method TO-15 Target Compounds and Method Detection Limits (Continued)

| Target Compounds | ppbv | Target Compounds | ppbv |
|----------------------------------|-------------|--------------------------|-------------|
| Chloroprene | 0.014 | Trichlorofluoromethane | 0.012 |
| <i>cis</i> -1,2-Dichloroethylene | 0.036 | Trichlorotrifluoroethane | 0.014 |
| 1,2-Dichloropropane | 0.025 | Vinyl Acetate | 0.208 |
| <i>cis</i> -1,3-Dichloropropene | 0.015 | Vinyl Chloride | 0.013 |

^a ppbv = parts per billion by volume

Table 2.3-2. SNMOC Target Compounds and Method Detection Limits

| Target Compound | ppbC | ppbv | Target Compound | ppbC | ppbv |
|-------------------------|------|------|--------------------------|------|------|
| Ethylene | 0.38 | 0.19 | Cyclohexane | 0.19 | 0.03 |
| Ethane | 0.12 | 0.06 | 2-Methylhexane | 0.11 | 0.02 |
| Propane | 0.20 | 0.07 | 2,3-Dimethylpentane | 0.37 | 0.05 |
| Propyne | 0.20 | 0.07 | 3-Methylhexane | 0.15 | 0.02 |
| Isobutane | 0.13 | 0.03 | 1-Heptene | 0.37 | 0.05 |
| Isobutene/1-Butene | 0.15 | 0.04 | 2,2,4-Trimethylpentane | 0.17 | 0.02 |
| <i>n</i> -Butane | 0.17 | 0.04 | <i>n</i> -Heptane | 0.18 | 0.03 |
| <i>trans</i> -2-Butene | 0.14 | 0.04 | Methylcyclohexane | 0.19 | 0.03 |
| <i>cis</i> -2-Butene | 0.18 | 0.04 | 2,2,3-Trimethylpentane | 0.28 | 0.04 |
| 3-Methyl-1-Butene | 0.24 | 0.05 | 2,3,4-Trimethylpentane | 0.14 | 0.02 |
| Isopentane | 0.19 | 0.04 | 2-Methylheptane | 0.17 | 0.02 |
| 1-Pentene | 0.12 | 0.02 | 3-Methylheptane | 0.11 | 0.01 |
| 2-Methyl-1-Butene | 0.24 | 0.05 | 1-Octene | 0.28 | 0.04 |
| <i>n</i> -Pentane | 0.09 | 0.02 | 1-Nonene | 0.24 | 0.03 |
| Isoprene | 0.24 | 0.05 | <i>n</i> -Nonane | 0.18 | 0.02 |
| <i>trans</i> -2-Pentene | 0.14 | 0.03 | Isopropylbenzene | 0.21 | 0.02 |
| <i>cis</i> -2-Pentene | 0.19 | 0.04 | <i>alpha</i> -Pinene | 0.24 | 0.02 |
| 2-Methyl-2-Butene | 0.24 | 0.05 | <i>n</i> -Propylbenzene | 0.20 | 0.02 |
| 2,2-Dimethylbutane | 0.20 | 0.03 | <i>m</i> -Ethyltoluene | 0.15 | 0.02 |
| Cyclopentene | 0.24 | 0.05 | <i>p</i> -Ethyltoluene | 0.24 | 0.03 |
| 4-Methyl-1-Pentene | 0.36 | 0.06 | <i>o</i> -Ethyltoluene | 0.18 | 0.02 |
| Cyclopentane | 0.12 | 0.02 | <i>beta</i> -Pinene | 0.24 | 0.02 |
| 2,3-Dimethylbutane | 0.20 | 0.03 | 1-Decene | 0.24 | 0.02 |
| 2-Methylpentane | 0.14 | 0.02 | <i>n</i> -Decane | 0.23 | 0.02 |
| 3-Methylpentane | 0.20 | 0.03 | 1,2,3-Trimethylbenzene | 0.17 | 0.02 |
| 2-Methyl-1-Pentene | 0.36 | 0.06 | <i>m</i> -Diethylbenzene | 0.24 | 0.02 |
| 1-Hexene | 0.36 | 0.06 | <i>p</i> -Diethylbenzene | 0.14 | 0.01 |
| 2-Ethyl-1-butene | 0.36 | 0.06 | 1-Undecene | 0.22 | 0.02 |
| <i>n</i> -Hexane | 0.24 | 0.04 | <i>n</i> -Undecane | 0.22 | 0.02 |
| <i>trans</i> -2-Hexene | 0.36 | 0.06 | 1-Dodecene | 0.29 | 0.02 |
| <i>cis</i> -2-Hexene | 0.36 | 0.06 | <i>n</i> -Dodecane | 0.29 | 0.02 |
| Methylcyclopentane | 0.14 | 0.02 | 1-Tridecene | 0.29 | 0.02 |
| 2,4-Dimethylpentane | 0.23 | 0.03 | <i>n</i> -Tridecane | 0.29 | 0.02 |

The procedure used to analyze the sample under EPA Compendium Method TO-15 involves extracting a known volume of sample gas from the canister through a mass flow controller to a solid multi-sorbent concentrator. After the concentration step is completed, the VOCs are thermally desorbed, entrained in a carrier gas stream, and then focused in a small volume by trapping on a reduced temperature trap or small volume multi-sorbent trap. The sample is then released by thermal desorption and carried onto two gas chromatographic columns housed in a gas chromatograph (GC). This step separates the individual air toxics and SNMOC species. Air toxics are then measured using a mass spectrometer operated in the selected ion monitoring (SIM) mode. SNMOCs are measured concurrently using a flame ionization detector (FID).

Target carbonyl species from Method TO-11A² and their corresponding MDLs are presented in Table 2.3-3. Methane concentration data was obtained for Sites S-6 and S-7 using Method TO-14.³ The MDL for methane from Method TO-14 is presented in Table 2.3-4.

Table 2.3-3. Carbonyl Target Compounds and Method Detection Limits

| Compound | ppbv |
|--------------------------|-------|
| Formaldehyde | 0.004 |
| Acetaldehyde | 0.005 |
| Acetone | 0.006 |
| Propionaldehyde | 0.002 |
| Crotonaldehyde | 0.002 |
| Butyr/Isobutyraldehyde | 0.002 |
| Benzaldehyde | 0.002 |
| Isovaleraldehyde | 0.002 |
| Valeraldehyde | 0.002 |
| Tolualdehydes | 0.003 |
| Hexaldehyde | 0.001 |
| 2,5-dimethylbenzaldehyde | 0.001 |

Table 2.3-4. Methane Method Detection Limit

| Compound | ppmv |
|----------|-------|
| Methane | 0.154 |

A detailed, technical description of the analytical procedures and sample handling procedures used for each sample can be found in the *Ambient Air Monitoring Plan* and in the *Ambient Air Monitoring Quality Assurance Project Plan*, which was originally submitted in August 2010 and revised in October 2010.

2.4 Quality Assurance/Quality Control

Throughout the process of ambient air network design, field implementation, sample collection, and sample analysis, QA/QC procedures were employed to ensure that the resultant data was of the highest quality and that the program would meet the Data Quality Objectives (DQOs) that were established at its onset. These procedures and steps are fully documented in the *Ambient Air Monitoring Plan* and the *Ambient Air Monitoring Quality Assurance Project Plan*. A summary of the QA/QC plan and results are provided below, including a discussion of DQOs, data completeness, measurement precision, and measurement accuracy.

The project DQOs answer the critical question of how good data must be in order to achieve the project goals. DQOs are used to develop the criteria that a data collection effort should satisfy, including where to conduct monitoring, how many sites to use, when to conduct

monitoring, what the measurement frequency should be, and acceptable measurement precision and accuracy. DQOs for this air quality study are presented in Table 2.4-1.

Table 2.4-1. Data Quality Objectives

| Element | Objective |
|--|--|
| Where to conduct monitoring | All sites must be located in close proximity to the potentially impacted populations, with the exception of the remote site (Site S-1). |
| Number of sites required | Eight fixed-location (including two collocated) sampling sites will be used to represent the entire city. Sites will be at city-owned and/or public use areas. They will be recommended by ERG as representative of the potentially impacted area. Final site selection will be accomplished through concurrence of ERG and Fort Worth Transportation and Public Works Department staff. |
| When to conduct monitoring | Sample collection will be conducted for a two-month duration. Samples will be collected from 00:01 to 23:50 hours (24 hours +/- 1 hour). |
| Frequency of monitoring | Sample collection episodes will be conducted once every three days. This schedule ensures that sampling is conducted multiple times on all days of the week, across the two-month duration of the program. |
| Overall completeness | Overall completeness must be 75% data capture at each monitoring site or greater. |
| Acceptable measurement precision for carbonyls | +/- 30% relative standard deviation (RSD) |
| Acceptable measurement accuracy for carbonyls | +/- 20% bias |
| Acceptable measurement precision for VOCs/SNMOCs | +/- 30% RSD |
| Acceptable measurement accuracy for VOCs | +/- 30% bias |

Prior to field deployment, all the measurement systems were certified to ensure that each system provided unbiased results.

2.4.1 Completeness

“Completeness” refers to the number of valid measurements collected compared to the number of scheduled sampling events. Data completeness requirements are included in the reference methods (see QAPP References, Section 21). Monitoring programs that consistently generate valid results have higher completeness than programs that consistently generate invalid samples. The completeness of an air monitoring program, therefore, is a qualitative measure of how effectively the program was managed.

During the two-month study period, the completeness of the monitoring network met or exceeded the DQO of 75% data capture at each site. Overall completeness was 96%. Table 2.4-2

summarizes the data completeness at each monitoring site by measurement system. As shown previously in Table 2.1-2, a total of 20 VOC/SNMOC samples were scheduled for each monitoring site and 20 carbonyl samples were scheduled for Sites S-4 and S-5.

Although the target number of valid samples was not obtained for Sites S-2, S-3, S-5, S-6, or S-7, the actual number of valid samples met or exceeded the DQO, thus providing sufficient data to calculate robust time-period averages. Invalid samples were due to a combination of equipment failure and human error, summarized below:

- On the first sample collection day (September 4), the sample collection program was incorrectly set, resulting in no sample collection at Sites S-2, S-5 (this affected the TO-15 sample only; the TO-11A carbonyl sample was collected successfully), and S-7.
- The sample collection systems at Sites S-6 and S-7 experienced gauge failure on September 7, so no samples were collected at those sites on that day.
- On September 10, the field operator did not fully open the canister valve at Site S-2, and no sample was collected.
- The October 31 sample collected at Site S-3 was never received at the laboratory, so no sample was analyzed for that site for that date.

A suitable location for Site S-3 (which targeted pre-production operations) was not identified until September 14. Therefore, this site only had 16 sample days. Additionally, due to the study duration (two months) and sampling frequency (1-in-3 days), it was not feasible to schedule make-up samples. Table 2.4-2 shows the final number of samples and completion percentage for each site.

Table 2.4-2. DQO: Overall Completeness

| Monitoring Site | Measurement System | Number of Samples Collected | Number of Samples Scheduled | Completion Percentage |
|-----------------|--------------------|-----------------------------|-----------------------------|-----------------------|
| S-1 | VOC/SNMOC | 20 | 20 | 100% |
| S-2 | VOC/SNMOC | 18 | 20 | 90% |
| S-3 | VOC/SNMOC | 15 | 16 | 94% |
| S-4 | VOC/SNMOC | 20 | 20 ^a | 100% |
| S-4 | Carbonyl | 20 | 20 ^a | 100% |
| S-5 | VOC/SNMOC | 19 | 20 ^a | 95% |
| S-5 | Carbonyl | 20 | 20 ^a | 100% |
| S-6 | VOC/SNMOC | 19 | 20 | 95% |
| S-7 | VOC/SNMOC | 18 | 20 | 90% |
| Total | | 169 | 176 | 96% |

^a Sites S-4 and S-5 had a total target of 40 samples each: 20 VOC samples and 20 carbonyl samples.

2.4.2 Measurement Precision

Measurement precision for this project is defined as the ability to acquire the same concentration from different instruments or samples while they are sampling the same gas stream,

with an acceptable level of uncertainty. It is a measure of mutual agreement among individual measurements of the same property, usually under prescribed similar conditions. For this monitoring program, measurement precision for the pollutants was assessed in two ways: system precision (across instrument samplers for collocated samples) and analytical precision (within instrument samplers for collocated and replicated samples).

Measurement precision is expressed as percent relative standard deviation (% RSD), which is calculated as follows:

$$\%RSD = \frac{\sigma}{\bar{X}} \times 100$$

Where:

σ is the standard deviation of the instrument-specific concentration determinations
 \bar{X} is the average of all instrument-specific concentration determinations

As summarized in Table 2.4-3, the *system precision* overall RSDs for VOCs, carbonyls, and SNMOCs easily met the DQO of 30% RSD.

Table 2.4-3. DQO: RSD Precision Calculation for Collocated VOC, Carbonyl, and SNMOC Instruments

| Method | Number of Collocated Data Sets | RSD Pollutant Ranges (%) | Overall RSD (%) |
|-----------|--------------------------------|--------------------------|-----------------|
| VOCs | 20 | 2.20–35.85 | 7.46 |
| Carbonyls | 20 | 6.15–44.43 | 23.99 |
| SNMOCs | 20 | 0.01–11.31 | 1.40 |

Analytical precision of the VOC and SNMOC methods was determined by collecting two sets of duplicate samples at Sites S-4 and S-5 and analyzing them in replicate. As summarized in Table 2.4-4, the analytical precision overall RSDs for VOCs, carbonyls, and SNMOCs easily met the DQO of 30% RSD.

Table 2.4-4. DQO: RSD Precision Calculation for Collocated and Replicate VOC and SNMOC Analyses

| Method | Number of Replicate Data Sets | RSD Pollutant Ranges (%) | Overall RSD (%) |
|-----------|-------------------------------|--------------------------|-----------------|
| VOCs | 20 | 0.01–21.32 | 4.57 |
| Carbonyls | 20 | 0.36–3.41 | 1.89 |
| SNMOCs | 20 | 1.07–34.11 | 9.21 |

2.4.3 Measurement Accuracy

Measurement accuracy for this project is defined as the ability to acquire the correct concentration data from an instrument or sample analysis with an acceptable level of uncertainty while measuring a reference gas stream of a known concentration. Bias is defined as the systematic or persistent distortion of a measurement process that causes error in one direction. Bias is determined by estimating the positive and negative deviation from the true value as a percentage of the true value.

Accuracy for the VOC and carbonyl analyses was established through audits that EPA prepared and submitted to ERG as a regular function of the EPA National Air Toxics Monitoring Program, which ERG manages and operates for EPA. The most recent audit for VOC HAPs was conducted in March 2010; the most recent audit for carbonyl HAPs was in May 2010. Table 2.4-5 summarizes the audit results for VOC and carbonyl HAPs. As the table shows, the overall percent differences are within 30% for VOC HAPs and 20% for carbonyl HAPs. This meets the DQOs presented in Table 2.4-1.

Table 2.4-5. VOC and Carbonyl HAP Audit Results

| Pollutant Group | Method | Proficiency Test Date | Overall % Difference |
|-----------------|--------|-----------------------|----------------------|
| VOC HAPs | TO-15 | March 2010 | -1.0 |
| Carbonyl HAPs | TO-11A | May 2010 | -11.4 |

2.5 Ambient Air Monitoring Results

This section presents ambient air concentrations, meteorological data, and spatial/temporal trends for the monitoring sites in this study. It first presents information for all the pollutants measured across the monitoring network, then by monitoring site. Finally, a more detailed analysis of a subset of key pollutants is presented by monitoring site. Nearly 140 different chemicals (including over 40 HAPs) were sampled for and analyzed in this study using EPA-approved sampling and analytical methodologies, as described in Section 2.3 of this report. It is important to note that, due to the configuration and purpose of each monitoring site, not all the same pollutants were sampled at each site. This is described in detail in Section 2.2.

2.5.1 Summary Statistics

This section reviews the monitoring data for the entire network. For each method type, it presents study-wide central tendency and variability statistics of the entire set of ambient air monitoring data collected. In total, over 15,000 data points were generated for this study. Individual measurements are presented in Appendix 2-F.

VOCs

A total of 59 VOCs were sampled, analyzed, and reported for in this study (Table 2.5-1). Eight VOCs had detection rates greater than 90%: benzene (94%), carbon tetrachloride (98%), chloromethane (100%), dichlorodifluoromethane (100%), methyl ethyl ketone (99%), propylene (98%), toluene (99%), and trichlorofluoromethane (100%). Acetone (2.807 ppbv), toluene (0.876 ppbv), and methyl ethyl ketone (0.827 ppbv) were the three VOCs with the highest average detected concentrations.

Table 2.5-1 also presents data distribution statistics, such as the minimum value, the maximum value, and the 25th, 50th, and 75th percentile values for the VOCs. As an indicator of variability of the VOC concentrations across the entire monitoring network, the coefficient of variation (CV) ratio is calculated. The CV ratio is the standard deviation divided by the mean, and is used to compare the relative dispersion in one set of data with the relative dispersion of another set of data. The lower the CV ratio, the less variability in the data measurements. The five VOCs with the lowest CV ratios and a minimum of 70% detects are trichlorofluoromethane (0.09), dichlorodifluoromethane (0.10), trichlorotrifluoroethane (0.10), dichlorotetrafluoroethane (0.13), and carbon tetrachloride (0.14). Conversely, the five VOCs with the highest CV ratios and a minimum of 70% detects are toluene (1.84), carbon disulfide (1.61), dichloromethane (1.39), *m,p*-xylene (1.24), and 1,2,4-trimethylbenzene (1.22).

Carbonyls

A total of 11 carbonyl pollutants were sampled, analyzed, and reported for in this study (Table 2.5-2). As described in Section 2.2, carbonyls were only sampled at Sites S-4 and S-5. Eight carbonyls had detection rates greater than 90%: acetaldehyde (100%), benzaldehyde (95%), butyraldehyde (100%), crotonaldehyde (100%), formaldehyde (100%), hexaldehyde (100%), propionaldehyde (100%), and valeraldehyde (93%). Acetaldehyde (2.81 ppbv), formaldehyde (0.931 ppbv), and butyraldehyde (0.110 ppbv) were the three carbonyls with the highest average detected concentrations.

Table 2.5-2 also presents data distribution statistics and CV ratios for the carbonyls. The four carbonyls with the lowest CV ratios and a minimum of 70% detects are crotonaldehyde (0.59), formaldehyde (0.71), acetaldehyde (0.73), and propionaldehyde (0.96). Conversely, the four carbonyls with the highest CV ratios and a minimum of 70% detects are hexaldehyde (1.98), butyraldehyde (1.29), valeraldehyde (1.20), and benzaldehyde (1.11).

Two carbonyls were not detected at either Site S-4 or Site S-5: 2,5-dimethylbenzaldehyde and isovaleraldehyde.

Table 2.5-1. Summary of VOC Measurements Across the Entire Monitoring Network

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|----------------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Acetone | 77 | 2.807 | 0.262 | 8.2 | 1.23 | 2.4 | 4.0 | 0.64 |
| Acetylene | 92 | 0.716 | 0.252 | 3.57 | 0.445 | 0.547 | 0.725 | 0.74 |
| Acrylonitrile | 0 | NA ^a | | | | | | |
| Allyl Chloride | 0 | NA ^a | | | | | | |
| Amyl Methyl Ether, <i>tert</i> - | 1 | NA ^a | | | | | | |
| Benzene | 121 | 0.291 | 0.0635 | 1.83 | 0.154 | 0.208 | 0.314 | 0.96 |
| Bromochloromethane | 0 | NA ^a | | | | | | |
| Bromodichloromethane | 3 | 0.050 | 0.029 | 0.075 | NA ^a | | | |
| Bromoform | 0 | NA ^a | | | | | | |
| Bromomethane | 54 | 0.014 | 0.01 | 0.03 | 0.012 | 0.014 | 0.016 | 0.26 |
| Butadiene, 1,3- | 86 | 0.057 | 0.01 | 0.304 | 0.025 | 0.039 | 0.066 | 0.92 |
| Butanol, <i>n</i> - | 0 | NA ^a | | | | | | |
| Carbon Disulfide | 92 | 0.243 | 0.008 | 1.64 | 0.021 | 0.055 | 0.179 | 1.61 |
| Carbon Tetrachloride | 126 | 0.112 | 0.053 | 0.142 | 0.106 | 0.113 | 0.121 | 0.14 |
| Chlorobenzene | 1 | NA ^a | | | | | | |
| Chloroethane | 9 | 0.091 | 0.015 | 0.237 | 0.017 | 0.086 | 0.097 | 0.89 |
| Chloroform | 91 | 0.031 | 0.014 | 0.105 | 0.021 | 0.026 | 0.033 | 0.51 |
| Chloromethane | 129 | 0.618 | 0.288 | 0.952 | 0.586 | 0.641 | 0.673 | 0.20 |
| Chloromethylbenzene | 1 | NA ^a | | | | | | |
| Chloroprene | 0 | NA ^a | | | | | | |
| Dibromochloromethane | 6 | 0.010 | 0.004 | 0.017 | 0.006 | 0.007 | 0.014 | 0.59 |
| Dibromoethane, 1,2- | 3 | 0.099 | 0.008 | 0.275 | NA ^a | | | |
| Dichlorobenzene, <i>m</i> - | 3 | 0.210 | 0.015 | 0.55 | NA ^a | | | |
| Dichlorobenzene, <i>o</i> - | 3 | 0.187 | 0.016 | 0.482 | NA ^a | | | |
| Dichlorobenzene, <i>p</i> - | 71 | 0.058 | 0.011 | 0.706 | 0.0195 | 0.031 | 0.0585 | 1.66 |

Table 2.5-1. Summary of VOC Measurements Across the Entire Monitoring Network (Continued)

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|--------------------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Dichlorodifluoromethane | 129 | 0.555 | 0.276 | 0.667 | 0.52 | 0.562 | 0.596 | 0.10 |
| Dichloroethane, 1,1- | 1 | NA ^a | | | | | | |
| Dichloroethane, 1,2- | 0 | NA ^a | | | | | | |
| Dichloroethene, 1,1- | 2 | 0.006 | 0.005 | 0.007 | NA ^a | | | |
| Dichloroethylene, <i>cis</i> -1,2- | 0 | NA ^a | | | | | | |
| Dichloroethylene, <i>trans</i> -1,2- | 0 | NA ^a | | | | | | |
| Dichloromethane (Methylene Chloride) | 101 | 0.168 | 0.037 | 2.21 | 0.086 | 0.105 | 0.165 | 1.39 |
| Dichloropropane, 1,2- | 0 | NA ^a | | | | | | |
| Dichloropropene, <i>cis</i> -1,3- | 1 | NA ^a | | | | | | |
| Dichloropropene, <i>trans</i> -1,3- | 1 | NA ^a | | | | | | |
| Dichlorotetrafluoroethane | 92 | 0.019 | 0.008 | 0.026 | 0.017 | 0.018 | 0.02 | 0.13 |
| Dioxane, 1,4- | 0 | NA ^a | | | | | | |
| Ethyl Acrylate | 0 | NA ^a | | | | | | |
| Ethyl <i>tert</i> -Butyl Ether | 1 | NA ^a | | | | | | |
| Ethylbenzene | 94 | 0.142 | 0.023 | 0.935 | 0.051 | 0.089 | 0.173 | 1.06 |
| Hexachloro-1,3-butadiene | 4 | 0.124 | 0.008 | 0.369 | NA ^a | | | |
| Methanol | 37 | 6.64 | 3.30 | 19.40 | 4.84 | 5.75 | 7.69 | 0.475 |
| Methyl Ethyl Ketone | 128 | 0.827 | 0.155 | 8.85 | 0.405 | 0.593 | 0.979 | 1.15 |
| Methyl Isobutyl Ketone | 79 | 0.079 | 0.015 | 0.596 | 0.034 | 0.054 | 0.086 | 1.12 |
| Methyl Methacrylate | 4 | 0.188 | 0.031 | 0.451 | NA ^a | | | |
| Methyl <i>tert</i> -Butyl Ether | 0 | NA ^a | | | | | | |
| Octane, <i>n</i> - | 94 | 0.105 | 0.023 | 0.844 | 0.047 | 0.07105 | 0.109 | 1.09 |
| Propylene | 127 | 0.450 | 0.055 | 2.38 | 0.226 | 0.376 | 0.547 | 0.78 |
| Styrene | 85 | 0.074 | 0.011 | 0.758 | 0.025 | 0.043 | 0.07 | 1.52 |

Table 2.5-1. Summary of VOC Measurements Across the Entire Monitoring Network (Continued)

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|-----------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Tetrachloroethane, 1,1,2,2- | 0 | NA ^a | | | | | | |
| Tetrachloroethylene | 81 | 0.043 | 0.01 | 0.218 | 0.018 | 0.03 | 0.054 | 0.85 |
| Toluene | 128 | 0.876 | 0.079 | 12.6 | 0.251 | 0.393 | 0.828 | 1.84 |
| Trichlorobenzene, 1,2,4- | 8 | 0.176 | 0.014 | 0.842 | 0.029 | 0.0335 | 0.215 | 1.61 |
| Trichloroethane, 1,1,1- | 43 | 0.030 | 0.009 | 0.46 | 0.012 | 0.015 | 0.0215 | 2.32 |
| Trichloroethane, 1,1,2- | 1 | NA ^a | | | | | | |
| Trichloroethylene | 13 | 0.029 | 0.008 | 0.093 | 0.013 | 0.014 | 0.026 | 0.96 |
| Trichlorofluoromethane | 129 | 0.269 | 0.128 | 0.334 | 0.259 | 0.273 | 0.284 | 0.09 |
| Trichlorotrifluoroethane | 103 | 0.089 | 0.042 | 0.107 | 0.087 | 0.090 | 0.093 | 0.10 |
| Trimethylbenzene, 1,2,4- | 94 | 0.084 | 0.010 | 0.732 | 0.033 | 0.047 | 0.097 | 1.22 |
| Trimethylbenzene, 1,3,5- | 90 | 0.054 | 0.009 | 0.584 | 0.0202 | 0.027 | 0.054 | 1.41 |
| Vinyl Acetate | 17 | 0.248 | 0.119 | 0.359 | 0.206 | 0.260 | 0.280 | 0.272 |
| Vinyl chloride | 3 | 0.031 | 0.008 | 0.052 | NA ^a | | | |
| Xylene, <i>m,p</i> - | 96 | 0.406 | 0.051 | 3.12 | 0.121 | 0.229 | 0.514 | 1.24 |
| Xylene, <i>o</i> - | 94 | 0.141 | 0.021 | 0.94 | 0.049 | 0.084 | 0.179 | 1.11 |

NA = not available

^a Summary statistics were only calculated for pollutants detected in at least six samples.

Table 2.5-2. Summary of Carbonyl Measurements Across the Entire Monitoring Network

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|----------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Acetaldehyde | 40 | 2.813 | 0.83 | 9.06 | 1.518 | 2.050 | 3.085 | 0.73 |
| Benzaldehyde | 38 | 0.018 | 0.01 | 0.11 | 0.009 | 0.011 | 0.017 | 1.11 |
| Butyraldehyde | 40 | 0.110 | 0.02 | 0.66 | 0.032 | 0.049 | 0.119 | 1.29 |
| Crotonaldehyde | 40 | 0.061 | 0.02 | 0.19 | 0.037 | 0.052 | 0.072 | 0.59 |
| Dimethylbenzaldehyde, 2,5- | 0 | NA ^a | | | | | | |
| Formaldehyde | 40 | 0.931 | 0.41 | 4.45 | 0.598 | 0.847 | 0.981 | 0.71 |
| Hexaldehyde | 40 | 0.067 | 0.01 | 0.55 | 0.015 | 0.019 | 0.024 | 1.98 |
| Isovaleraldehyde | 0 | NA ^a | | | | | | |
| Propionaldehyde | 40 | 0.088 | 0.02 | 0.38 | 0.023 | 0.0675 | 0.119 | 0.96 |
| Tolualdehydes | 10 | 0.016 | 0.01 | 0.05 | 0.009 | 0.012 | 0.017 | 0.82 |
| Valeraldehyde | 37 | 0.025 | 0.01 | 0.14 | 0.009 | 0.012 | 0.019 | 1.20 |

NA = not available

^a Summary statistics were only calculated for pollutants detected in at least six samples.

Methane and Speciated Non-Methane Organics

Methane was detected in each sample taken (100%)—37 samples at Sites S-6 and S-7 (Table 2.5-3). Methane had the highest concentrations of the study analytes (average of detects = 5,686 ppbv). Methane is not a HAP, and the overall CV ratio was 0.24.

A total of 67 SNMOCs were sampled, analyzed, and reported for in this study (Table 2.5-3). Seven speciated organics had detection rates greater than 90%: *n*-butane (93%), ethane (100%), ethylene (99%), isobutane (97%), isobutene/1-butene (97%), *n*-pentane (98%), and propane (100%). Ethane (16.028 ppbv), propane (5.325 ppbv), and isopentane (4.028 ppbv) were the three SNMOCs with the highest average detected concentrations.

Data distribution statistics and CV ratios for methane and the SNMOCs are also presented in Table 2.5-3. The five SNMOCs with the lowest CV ratios and a minimum of 70% detects are 1-hexene (0.48), isoprene (0.63), ethylene (0.69), 3-methylehexane (0.77), and 2-methylheptane (0.85). Conversely, the five VOCs with the highest CV ratios and a minimum of 70% detects are *n*-decane (1.92), *n*-nonane (1.90), isopentane (1.84), *trans*-2-butene (1.83), and *n*-Pentane (1.80).

All SNMOCs were detected at least once during the study period.

2.5.2 Study Period Averaging

This section presents information on the average pollutant concentrations, at each monitoring site, for the study period. Non-detect observations were replaced with zeroes when calculating these averages. This section focuses only on pollutants that were detected in at least 70% of the samples, because average concentrations for these pollutants have the least influence from non-detect observations. Thus, study period averages for pollutants that had more than 30% of their samples as non-detects were not calculated. This averaging technique is consistent with the study period averaging EPA uses in its Schools Air Toxics Monitoring Program (SATMP)⁵ and National-Scale Air Toxics Assessment (NATA) model-to-monitor comparison.⁶ In addition to the study period average, this section presents the confidence intervals for the study period average concentrations. The confidence interval is calculated using Student's *T*-test at the 95th percentile confidence level.

Table 2.5-3. Summary of Methane and Speciated Non-Methane Organic Compounds Across the Entire Monitoring Network

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|--|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Methane | 37 | 5686.486 | 4180 | 9890 | 4670 | 5570 | 5720 | 0.24 |
| <i>Speciated Non-Methane Organic Compounds</i> | | | | | | | | |
| Butane, <i>n</i> - | 120 | 3.549 | 0.149 | 35.750 | 0.602 | 1.566 | 3.369 | 1.72 |
| Butene, <i>cis</i> -2- | 89 | 0.157 | 0.020 | 3.425 | 0.040 | 0.052 | 0.088 | 2.52 |
| Butene, <i>trans</i> -2- | 93 | 0.132 | 0.018 | 1.243 | 0.032 | 0.042 | 0.079 | 1.83 |
| Cyclohexane | 97 | 0.128 | 0.031 | 0.708 | 0.050 | 0.077 | 0.141 | 1.03 |
| Cyclopentane | 92 | 0.171 | 0.041 | 1.200 | 0.054 | 0.071 | 0.140 | 1.46 |
| Cyclopentene | 2 | 0.040 | 0.030 | 0.049 | NA ^a | | | |
| Decane, <i>n</i> - | 93 | 0.102 | 0.012 | 1.440 | 0.025 | 0.037 | 0.071 | 1.92 |
| Decene, 1- | 3 | 0.024 | 0.020 | 0.031 | NA ^a | | | |
| Diethylbenzene, <i>m</i> - | 17 | 0.020 | 0.009 | 0.082 | 0.011 | 0.017 | 0.020 | 0.85 |
| Diethylbenzene, <i>p</i> - | 40 | 0.028 | 0.009 | 0.102 | 0.015 | 0.022 | 0.032 | 0.76 |
| Dimethylbutane, 2,2- | 92 | 0.132 | 0.031 | 0.805 | 0.058 | 0.079 | 0.140 | 1.09 |
| Dimethylbutane, 2,3- | 92 | 0.306 | 0.040 | 2.517 | 0.070 | 0.098 | 0.230 | 1.65 |
| Dimethylpentane, 2,3- | 92 | 0.169 | 0.041 | 0.729 | 0.087 | 0.122 | 0.190 | 0.80 |
| Dimethylpentane, 2,4- | 92 | 0.114 | 0.020 | 0.821 | 0.033 | 0.045 | 0.114 | 1.42 |
| Dodecane, <i>n</i> - | 90 | 0.038 | 0.006 | 0.327 | 0.018 | 0.029 | 0.038 | 1.22 |
| Dodecene, 1- | 57 | 0.023 | 0.006 | 0.225 | 0.011 | 0.016 | 0.024 | 1.31 |
| Ethane | 129 | 16.028 | 2.08 | 93.2 | 5.2 | 9.45 | 20.7 | 1.00 |
| Ethyl-1-butene, 2- | 9 | 0.284 | 0.049 | 0.870 | 0.074 | 0.250 | 0.395 | 0.95 |
| Ethylene | 128 | 1.118 | 0.275 | 5.400 | 0.671 | 0.985 | 1.270 | 0.69 |
| Ethyltoluene, <i>m</i> - | 91 | 0.054 | 0.010 | 0.301 | 0.026 | 0.036 | 0.068 | 0.92 |
| Ethyltoluene, <i>o</i> - | 76 | 0.044 | 0.012 | 0.386 | 0.019 | 0.027 | 0.045 | 1.18 |
| Ethyltoluene, <i>p</i> - | 90 | 0.042 | 0.010 | 0.340 | 0.020 | 0.026 | 0.043 | 1.10 |

Table 2.5-3. Summary of Methane and Speciated Non-Methane Organic Compounds Across the Entire Monitoring Network (Continued)

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|--------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Heptane, <i>n</i> - | 101 | 0.149 | 0.038 | 0.864 | 0.061 | 0.092 | 0.174 | 0.97 |
| Heptene, 1- | 20 | 0.075 | 0.016 | 0.769 | 0.026 | 0.028 | 0.032 | 2.23 |
| Hexane, <i>n</i> - | 105 | 0.445 | 0.070 | 3.483 | 0.131 | 0.220 | 0.393 | 1.46 |
| Hexene, 1- | 92 | 0.049 | 0.010 | 0.147 | 0.033 | 0.045 | 0.056 | 0.48 |
| Hexene, <i>cis</i> -2- | 26 | 0.042 | 0.014 | 0.262 | 0.022 | 0.029 | 0.035 | 1.18 |
| Hexene, <i>trans</i> -2- | 29 | 0.097 | 0.013 | 0.353 | 0.024 | 0.042 | 0.119 | 1.06 |
| Isobutane | 125 | 1.216 | 0.150 | 9.475 | 0.355 | 0.648 | 1.210 | 1.37 |
| Isobutene/1-butene | 125 | 0.291 | 0.057 | 2.285 | 0.131 | 0.191 | 0.281 | 1.11 |
| Isopentane | 92 | 4.028 | 0.314 | 36.400 | 0.672 | 1.048 | 2.925 | 1.84 |
| Isoprene | 92 | 0.167 | 0.032 | 0.498 | 0.083 | 0.144 | 0.228 | 0.63 |
| Isopropylbenzene | 66 | 0.016 | 0.008 | 0.050 | 0.012 | 0.015 | 0.018 | 0.42 |
| Methyl-1-butene, 2- | 72 | 0.186 | 0.018 | 1.656 | 0.029 | 0.049 | 0.117 | 1.81 |
| Methyl-1-butene, 3- | 1 | NA ^a | | | | | | |
| Methyl-1-pentene, 2- | 25 | 0.077 | 0.015 | 0.258 | 0.022 | 0.046 | 0.109 | 0.95 |
| Methyl-1-pentene, 4- | 31 | 0.051 | 0.020 | 0.131 | 0.035 | 0.042 | 0.055 | 0.49 |
| Methyl-2-butene, 2- | 64 | 0.371 | 0.015 | 2.820 | 0.030 | 0.077 | 0.285 | 1.81 |
| Methylcyclohexane | 92 | 0.170 | 0.035 | 0.817 | 0.073 | 0.109 | 0.193 | 0.89 |
| Methylcyclopentane | 92 | 0.217 | 0.025 | 1.389 | 0.080 | 0.111 | 0.212 | 1.28 |
| Methylheptane, 2- | 92 | 0.065 | 0.016 | 0.295 | 0.032 | 0.043 | 0.070 | 0.85 |
| Methylheptane, 3- | 92 | 0.050 | 0.012 | 0.243 | 0.025 | 0.033 | 0.053 | 0.86 |
| Methylhexane, 2- | 92 | 0.204 | 0.034 | 1.786 | 0.076 | 0.104 | 0.183 | 1.31 |
| Methylhexane, 3- | 92 | 0.288 | 0.046 | 1.236 | 0.156 | 0.201 | 0.350 | 0.77 |
| Methylpentane, 2- | 87 | 0.979 | 0.091 | 6.450 | 0.298 | 0.460 | 0.962 | 1.35 |
| Methylpentane, 3- | 92 | 0.488 | 0.069 | 3.767 | 0.126 | 0.192 | 0.388 | 1.53 |

Table 2.5-3. Summary of Methane and Speciated Non-Methane Organic Compounds Across the Entire Monitoring Network (Continued)

| Pollutant Name | Number of Detects | Average of Detects (ppbv) | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) | 25 th Percentile Concentration (ppbv) | 50 th Percentile Concentration (ppbv) | 75 th Percentile Concentration (ppbv) | Coefficient of Variation |
|---------------------------|-------------------|---------------------------|-------------------------------|-------------------------------|--|--|--|--------------------------|
| Nonane, <i>n</i> - | 93 | 0.083 | 0.015 | 1.278 | 0.026 | 0.034 | 0.061 | 1.90 |
| Nonene, 1- | 41 | 0.037 | 0.009 | 0.247 | 0.017 | 0.021 | 0.049 | 1.10 |
| Octene, 1- | 52 | 0.024 | 0.011 | 0.055 | 0.017 | 0.022 | 0.027 | 0.41 |
| Pentane, <i>n</i> - | 127 | 1.532 | 0.131 | 15.680 | 0.368 | 0.620 | 1.220 | 1.80 |
| Pentene, 1- | 92 | 0.118 | 0.024 | 0.884 | 0.043 | 0.054 | 0.086 | 1.45 |
| Pentene, <i>cis</i> -2- | 87 | 0.123 | 0.019 | 1.070 | 0.028 | 0.038 | 0.073 | 1.76 |
| Pentene, <i>trans</i> -2- | 89 | 0.231 | 0.018 | 2.100 | 0.033 | 0.056 | 0.136 | 1.88 |
| Pinene, <i>alpha</i> - | 80 | 0.052 | 0.008 | 0.423 | 0.021 | 0.033 | 0.064 | 1.08 |
| Pinene, <i>beta</i> - | 34 | 0.040 | 0.011 | 0.211 | 0.015 | 0.027 | 0.046 | 0.99 |
| Propane | 129 | 5.325 | 0.423 | 34.667 | 1.857 | 2.833 | 6.333 | 1.13 |
| Propylbenzene, <i>n</i> - | 86 | 0.030 | 0.009 | 0.216 | 0.015 | 0.020 | 0.034 | 0.96 |
| Propyne | 1 | NA ^a | | | | | | |
| Tridecane, <i>n</i> - | 7 | 0.017 | 0.005 | 0.056 | 0.008 | 0.012 | 0.014 | 1.06 |
| Tridecene, 1- | 5 | 0.022 | 0.007 | 0.068 | NA ^a | | | |
| Trimethylbenzene, 1,2,3- | 71 | 0.037 | 0.008 | 0.280 | 0.013 | 0.019 | 0.034 | 1.33 |
| Trimethylpentane, 2,2,3- | 85 | 0.078 | 0.012 | 0.563 | 0.025 | 0.036 | 0.085 | 1.24 |
| Trimethylpentane, 2,2,4- | 114 | 0.374 | 0.029 | 3.100 | 0.098 | 0.168 | 0.420 | 1.43 |
| Trimethylpentane, 2,3,4- | 92 | 0.109 | 0.011 | 0.785 | 0.036 | 0.059 | 0.121 | 1.24 |
| Undecane, <i>n</i> - | 92 | 0.068 | 0.009 | 0.689 | 0.027 | 0.038 | 0.061 | 1.53 |
| Undecene, 1- | 9 | 0.046 | 0.007 | 0.245 | 0.010 | 0.017 | 0.045 | 1.65 |

NA = not available

^a Summary statistics were only calculated for pollutants detected in at least six samples.

The following observations were made:

- *Site S-1 (background site)*: A total of 71 out of 124 pollutants had at least 70% detects to compute study period averages (Table 2.5-4). The five pollutants with the highest average concentrations were ethane (6.474 ± 3.041 ppbv), propane (3.498 ± 1.207 ppbv), *n*-butane (2.262 ± 1.500 ppbv), isopentane (1.929 ± 1.172 ppbv), and isobutane (1.324 ± 0.727 ppbv). Site S-1 was located in an area with no natural gas wells typically upwind.
- *Site S-2 (mobile sources site)*: A total of 73 out of 124 pollutants had at least 70% detects to compute study period averages (Table 2.5-5). The five pollutants with the highest average concentrations were ethane (10.437 ± 4.571 ppbv), propane (4.812 ± 3.222 ppbv), *n*-butane (2.729 ± 1.574 ppbv), toluene (2.311 ± 1.803 ppbv), and isopentane (1.680 ± 0.615 ppbv). Site S-2 was located in an area next to major roadways.
- *Site S-3A (pre-production activity site)*: Note that this site conducted only nine samples over a three-week time frame. Thus, the average concentrations presented for this site may not be representative of the study period. Nevertheless, a total of 69 out of 124 pollutants had at least 70% detects to compute three-week averages (Table 2.5-6). The five pollutants with the highest average concentrations were ethane (16.133 ± 10.964 ppbv), propane (4.456 ± 3.073 ppbv), *n*-butane (1.408 ± 1.245 ppbv), ethylene (1.364 ± 0.528 ppbv), and isopentane (1.217 ± 0.627 ppbv). Site S-3A was located in an area downwind of fracturing fluid flowback operations.
- *Site S-3B (pre-production activity site)*: When pre-production operations were completed at Site S-3A, this monitoring site was moved to an area where additional pre-production activities were occurring. Thus, this site conducted only six samples over a two-week time frame, and the average concentrations presented for this site may not be representative of the study period. Nevertheless, a total of 63 out of 124 pollutants had at least 70% detects to compute two-week averages (Table 2.5-7). The five pollutants with the highest average concentrations were ethane (22.592 ± 11.170 ppbv), propane (8.844 ± 4.215 ppbv), *n*-butane (3.195 ± 1.526 ppbv), isobutane (1.588 ± 0.769 ppbv), and isopentane (1.087 ± 0.444 ppbv). Site S-3B was located in an area downwind of hydraulic fracturing activities.
- *Site S-4 (high-level activity site)*: A total of 82 out of 136 pollutants had at least 70% detects to compute study period averages (Table 2.5-8). The five pollutants with the highest average concentrations were ethane (18.229 ± 8.241 ppbv), isopentane (12.985 ± 5.511 ppbv), *n*-butane (10.993 ± 5.385 ppbv), propane (10.683 ± 4.918 ppbv), and *n*-pentane (5.491 ± 2.336 ppbv). Site S-4 was located in an area with high levels of well pad and compressor station activity.
- *Site S-5 (high-level activity site)*: A total of 75 out of 136 pollutants had at least 70% detects to compute study period averages (Table 2.5-9). The five pollutants with the highest average concentrations were ethane (14.077 ± 4.074 ppbv), propane (5.049 ± 1.773 ppbv), *n*-butane (2.072 ± 1.109 ppbv), acetaldehyde (1.824 ± 0.408 ppbv), and

Key Point: Pollutant Concentrations
Concentrations measured at Site S-4 were generally higher than at other sites. Concentrations measured at Sites S-6 and S-7 were generally lower relative to other sites.

isopentane (1.297 ± 1.262 ppbv). Site S-5 was located in an area with high levels of well pad activity.

- *Site S-6 (medium-level activity site):* A total of 15 out of 137 pollutants had at least 70% detects to compute study period averages (Table 2.5-10). The five pollutants with the highest average concentrations were methane ($5,758 \pm 796$ ppbv), ethane (21.412 ± 9.997 ppbv), propane (2.982 ± 1.154 ppbv), *n*-butane (1.015 ± 0.432 ppbv), and ethylene (0.632 ± 0.155 ppbv). Site S-6 was located in an area with moderate levels of well pad activity, including within 350 feet downwind of a well pad.
- *Site S-7 (medium-level activity site):* A total of 15 out of 137 pollutants had at least 70% detects to compute study period averages (Table 2.5-11). The five pollutants with the highest average concentrations were methane ($5,672 \pm 650$ ppbv), ethane (23.979 ± 11.236 ppbv), propane (3.967 ± 1.854 ppbv), *n*-butane (1.230 ± 0.604 ppbv), and ethylene (0.690 ± 0.173 ppbv). Site S-7 was located in an area with moderate levels of well pad activity, including within 200 feet downwind of a well pad.

Table 2.5-4. Site S-1 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-----------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetylene | 20 | 0 | 0.665 | 0.177 |
| Benzene | 20 | 0 | 0.245 | 0.059 |
| Butadiene, 1,3- | 18 | 2 | 0.041 | 0.019 |
| Butane, <i>n</i> - | 18 | 2 | 2.262 | 1.500 |
| Butene, <i>cis</i> -2- | 20 | 0 | 0.080 | 0.041 |
| Butene, <i>trans</i> -2- | 20 | 0 | 0.077 | 0.045 |
| Carbon Disulfide | 20 | 0 | 0.043 | 0.026 |
| Carbon Tetrachloride | 20 | 0 | 0.118 | 0.006 |
| Chloroform | 20 | 0 | 0.041 | 0.011 |
| Chloromethane | 20 | 0 | 0.661 | 0.023 |
| Cyclohexane | 20 | 0 | 0.073 | 0.024 |
| Cyclopentane | 20 | 0 | 0.090 | 0.036 |
| Decane, <i>n</i> - | 20 | 0 | 0.044 | 0.011 |
| Dichlorobenzene, <i>p</i> - | 17 | 3 | 0.039 | 0.014 |
| Dichlorodifluoromethane | 20 | 0 | 0.577 | 0.020 |
| Dichloromethane | 20 | 0 | 0.161 | 0.048 |
| Dichlorotetrafluoroethane | 20 | 0 | 0.018 | 0.001 |
| Dimethylbutane, 2,2- | 20 | 0 | 0.085 | 0.023 |
| Dimethylbutane, 2,3- | 20 | 0 | 0.137 | 0.060 |
| Dimethylpentane, 2,3- | 20 | 0 | 0.112 | 0.020 |
| Dimethylpentane, 2,4- | 20 | 0 | 0.055 | 0.020 |
| Dodecane, <i>n</i> - | 20 | 0 | 0.035 | 0.014 |
| Dodecene, 1- | 15 | 5 | 0.014 | 0.007 |

Table 2.5-4. Site S-1 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Ethane | 20 | 0 | 6.475 | 3.041 |
| Ethylbenzene | 20 | 0 | 0.082 | 0.023 |
| Ethylene | 20 | 0 | 1.181 | 0.271 |
| Ethyltoluene, <i>m</i> - | 20 | 0 | 0.035 | 0.009 |
| Ethyltoluene, <i>o</i> - | 16 | 4 | 0.024 | 0.009 |
| Ethyltoluene, <i>p</i> - | 20 | 0 | 0.025 | 0.005 |
| Heptane, <i>n</i> - | 20 | 0 | 0.086 | 0.028 |
| Hexane, <i>n</i> - | 20 | 0 | 0.204 | 0.084 |
| Hexene, 1- | 20 | 0 | 0.041 | 0.006 |
| Isobutane | 20 | 0 | 1.324 | 0.727 |
| Isobutene/1-Butene | 20 | 0 | 0.294 | 0.119 |
| Isopentane | 20 | 0 | 1.929 | 1.172 |
| Isoprene | 20 | 0 | 0.266 | 0.062 |
| Methyl Ethyl Ketone | 20 | 0 | 0.817 | 0.157 |
| Methyl Isobutyl Ketone | 18 | 2 | 0.046 | 0.013 |
| Methyl-1-butene, 2- | 16 | 4 | 0.064 | 0.047 |
| Methylcyclohexane | 20 | 0 | 0.106 | 0.031 |
| Methylcyclopentane | 20 | 0 | 0.121 | 0.042 |
| Methylheptane, 2- | 20 | 0 | 0.037 | 0.009 |
| Methylheptane, 3- | 20 | 0 | 0.028 | 0.007 |
| Methylhexane, 2- | 20 | 0 | 0.099 | 0.030 |
| Methylhexane, 3- | 20 | 0 | 0.202 | 0.050 |
| Methylpentane, 2- | 18 | 2 | 0.462 | 0.204 |
| Methylpentane, 3- | 20 | 0 | 0.220 | 0.091 |
| Nonane, <i>n</i> - | 20 | 0 | 0.032 | 0.008 |
| Pentane, <i>n</i> - | 20 | 0 | 0.939 | 0.454 |
| Pentene, 1- | 20 | 0 | 0.075 | 0.030 |
| Pentene, <i>cis</i> -2- | 19 | 1 | 0.050 | 0.027 |
| Pentene, <i>trans</i> -2- | 18 | 2 | 0.086 | 0.057 |
| Pinene, <i>alpha</i> - | 17 | 3 | 0.050 | 0.019 |
| Propane | 20 | 0 | 3.498 | 1.207 |
| Propylbenzene, <i>n</i> - | 19 | 1 | 0.018 | 0.004 |
| Propylene | 20 | 0 | 0.478 | 0.120 |
| Styrene | 19 | 1 | 0.170 | 0.095 |
| Tetrachloroethylene | 17 | 3 | 0.038 | 0.014 |
| Toluene | 20 | 0 | 0.544 | 0.202 |

Table 2.5-4. Site S-1 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|--------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Trichlorofluoromethane | 20 | 0 | 0.283 | 0.011 |
| Trichlorotrifluoroethane | 20 | 0 | 0.091 | 0.002 |
| Trimethylbenzene, 1,2,3- | 14 | 6 | 0.016 | 0.008 |
| Trimethylbenzene, 1,2,4- | 20 | 0 | 0.077 | 0.024 |
| Trimethylbenzene, 1,3,5- | 20 | 0 | 0.029 | 0.008 |
| Trimethylpentane, 2,2,3- | 17 | 3 | 0.035 | 0.016 |
| Trimethylpentane, 2,2,4- | 20 | 0 | 0.198 | 0.086 |
| Trimethylpentane, 2,3,4- | 20 | 0 | 0.062 | 0.023 |
| Undecane, <i>n</i> - | 20 | 0 | 0.045 | 0.018 |
| Xylene, <i>m,p</i> - | 20 | 0 | 0.185 | 0.063 |
| Xylene, <i>o</i> - | 20 | 0 | 0.073 | 0.024 |

Table 2.5-5. Site S-2 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-----------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetylene | 18 | 0 | 0.707 | 0.156 |
| Benzene | 18 | 0 | 0.300 | 0.043 |
| Butadiene, 1,3- | 18 | 0 | 0.057 | 0.017 |
| Butane, <i>n</i> - | 17 | 1 | 2.729 | 1.574 |
| Butene, <i>cis</i> -2- | 17 | 1 | 0.056 | 0.011 |
| Butene, <i>trans</i> -2- | 18 | 0 | 0.050 | 0.009 |
| Carbon Disulfide | 18 | 0 | 0.034 | 0.018 |
| Carbon Tetrachloride | 18 | 0 | 0.117 | 0.005 |
| Chloroform | 18 | 0 | 0.025 | 0.004 |
| Chloromethane | 18 | 0 | 0.666 | 0.025 |
| Cyclohexane | 18 | 0 | 0.095 | 0.030 |
| Cyclopentane | 18 | 0 | 0.096 | 0.027 |
| Decane, <i>n</i> - | 18 | 0 | 0.257 | 0.174 |
| Dichlorobenzene, <i>p</i> - | 15 | 3 | 0.051 | 0.047 |
| Dichlorodifluoromethane | 18 | 0 | 0.584 | 0.026 |
| Dichloromethane | 18 | 0 | 0.370 | 0.244 |
| Dichlorotetrafluoroethane | 18 | 0 | 0.018 | 0.001 |
| Dimethylbutane, 2,2- | 18 | 0 | 0.098 | 0.021 |
| Dimethylbutane, 2,3- | 18 | 0 | 0.185 | 0.069 |
| Dimethylpentane, 2,3- | 18 | 0 | 0.156 | 0.037 |
| Dimethylpentane, 2,4- | 18 | 0 | 0.079 | 0.026 |
| Dodecane, <i>n</i> - | 18 | 0 | 0.037 | 0.012 |
| Ethane | 18 | 0 | 10.437 | 4.571 |
| Ethylbenzene | 18 | 0 | 0.239 | 0.127 |
| Ethylene | 18 | 0 | 1.379 | 0.259 |
| Ethyltoluene, <i>m</i> - | 18 | 0 | 0.079 | 0.034 |
| Ethyltoluene, <i>o</i> - | 18 | 0 | 0.083 | 0.045 |
| Ethyltoluene, <i>p</i> - | 18 | 0 | 0.069 | 0.038 |
| Heptane, <i>n</i> - | 18 | 0 | 0.152 | 0.060 |
| Hexane, <i>n</i> - | 18 | 0 | 0.333 | 0.140 |
| Hexene, 1- | 18 | 0 | 0.043 | 0.009 |
| Isobutane | 18 | 0 | 0.827 | 0.320 |
| Isobutene/1-Butene | 18 | 0 | 0.271 | 0.049 |
| Isopentane | 18 | 0 | 1.680 | 0.615 |
| Isoprene | 18 | 0 | 0.183 | 0.044 |
| Methyl Ethyl Ketone | 18 | 0 | 0.986 | 0.298 |
| Methyl Isobutyl Ketone | 17 | 1 | 0.123 | 0.073 |

Table 2.5-5. Site S-2 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Methyl-1-butene, 2- | 18 | 0 | 0.070 | 0.024 |
| Methyl-2-butene, 2- | 18 | 0 | 0.095 | 0.051 |
| Methylcyclohexane | 18 | 0 | 0.191 | 0.080 |
| Methylcyclopentane | 18 | 0 | 0.152 | 0.048 |
| Methylheptane, 2- | 18 | 0 | 0.077 | 0.031 |
| Methylheptane, 3- | 18 | 0 | 0.062 | 0.024 |
| Methylhexane, 2- | 18 | 0 | 0.173 | 0.059 |
| Methylhexane, 3- | 18 | 0 | 0.269 | 0.070 |
| Methylpentane, 2- | 18 | 0 | 0.666 | 0.198 |
| Methylpentane, 3- | 18 | 0 | 0.321 | 0.119 |
| Nonane, <i>n</i> - | 18 | 0 | 0.212 | 0.153 |
| Nonene, 1- | 13 | 5 | 0.041 | 0.029 |
| Octane, <i>n</i> - | 18 | 0 | 0.187 | 0.105 |
| Pentane, <i>n</i> - | 18 | 0 | 0.923 | 0.297 |
| Pentene, 1- | 18 | 0 | 0.068 | 0.012 |
| Pentene, <i>cis</i> -2- | 18 | 0 | 0.055 | 0.018 |
| Pentene, <i>trans</i> -2- | 18 | 0 | 0.104 | 0.039 |
| Pinene, <i>alpha</i> - | 16 | 2 | 0.027 | 0.011 |
| Propane | 18 | 0 | 4.812 | 3.222 |
| Propylbenzene, <i>n</i> - | 18 | 0 | 0.047 | 0.025 |
| Propylene | 18 | 0 | 0.552 | 0.116 |
| Styrene | 16 | 2 | 0.044 | 0.017 |
| Tetrachloroethylene | 18 | 0 | 0.061 | 0.029 |
| Toluene | 18 | 0 | 2.311 | 1.803 |
| Trichloroethane, 1,1,1- | 13 | 5 | 0.050 | 0.053 |
| Trichlorofluoromethane | 18 | 0 | 0.281 | 0.011 |
| Trichlorotrifluoroethane | 18 | 0 | 0.091 | 0.003 |
| Trimethylbenzene, 1,2,3- | 15 | 3 | 0.044 | 0.033 |
| Trimethylbenzene, 1,2,4- | 18 | 0 | 0.210 | 0.116 |
| Trimethylbenzene, 1,3,5- | 18 | 0 | 0.077 | 0.042 |
| Trimethylpentane, 2,2,3- | 18 | 0 | 0.070 | 0.024 |
| Trimethylpentane, 2,2,4- | 18 | 0 | 0.345 | 0.120 |
| Trimethylpentane, 2,3,4- | 18 | 0 | 0.098 | 0.026 |
| Undecane, <i>n</i> - | 18 | 0 | 0.125 | 0.074 |
| Xylene, <i>m,p</i> - | 18 | 0 | 0.728 | 0.432 |
| Xylene, <i>o</i> - | 18 | 0 | 0.233 | 0.124 |

Table 2.5-6. Site S-3A Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-----------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetylene | 9 | 0 | 0.735 | 0.399 |
| Benzene | 9 | 0 | 0.301 | 0.128 |
| Butadiene, 1,3- | 8 | 1 | 0.049 | 0.033 |
| Butane, <i>n</i> - | 7 | 2 | 1.408 | 1.245 |
| Butene, <i>cis</i> -2- | 8 | 1 | 0.046 | 0.021 |
| Butene, <i>trans</i> -2- | 9 | 0 | 0.139 | 0.221 |
| Carbon Disulfide | 9 | 0 | 0.050 | 0.053 |
| Carbon Tetrachloride | 9 | 0 | 0.118 | 0.007 |
| Chloroform | 9 | 0 | 0.029 | 0.006 |
| Chloromethane | 9 | 0 | 0.628 | 0.040 |
| Cyclohexane | 9 | 0 | 0.081 | 0.039 |
| Cyclopentane | 9 | 0 | 0.069 | 0.024 |
| Decane, <i>n</i> - | 9 | 0 | 0.034 | 0.013 |
| Dichlorobenzene, <i>p</i> - | 9 | 0 | 0.030 | 0.013 |
| Dichlorodifluoromethane | 9 | 0 | 0.570 | 0.017 |
| Dichloromethane | 9 | 0 | 0.169 | 0.034 |
| Dichlorotetrafluoroethane | 9 | 0 | 0.017 | 0.000 |
| Dimethylbutane, 2,2- | 9 | 0 | 0.070 | 0.025 |
| Dimethylbutane, 2,3- | 9 | 0 | 0.121 | 0.056 |
| Dimethylpentane, 2,3- | 9 | 0 | 0.122 | 0.028 |
| Dimethylpentane, 2,4- | 9 | 0 | 0.055 | 0.023 |
| Dodecane, <i>n</i> - | 9 | 0 | 0.031 | 0.008 |
| Ethane | 9 | 0 | 16.133 | 10.964 |
| Ethylbenzene | 9 | 0 | 0.090 | 0.035 |
| Ethylene | 9 | 0 | 1.364 | 0.528 |
| Ethyltoluene, <i>m</i> - | 9 | 0 | 0.044 | 0.017 |
| Ethyltoluene, <i>o</i> - | 8 | 1 | 0.029 | 0.012 |
| Ethyltoluene, <i>p</i> - | 9 | 0 | 0.025 | 0.009 |
| Heptane, <i>n</i> - | 9 | 0 | 0.098 | 0.053 |
| Hexane, <i>n</i> - | 9 | 0 | 0.241 | 0.139 |
| Hexene, 1- | 9 | 0 | 0.046 | 0.011 |
| Isobutane | 9 | 0 | 0.820 | 0.553 |
| Isobutene/1-Butene | 9 | 0 | 0.236 | 0.088 |
| Isopentane | 9 | 0 | 1.217 | 0.628 |
| Isoprene | 9 | 0 | 0.149 | 0.048 |
| Methyl Ethyl Ketone | 9 | 0 | 0.637 | 0.182 |

Table 2.5-6. Site S-3A Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Methyl Isobutyl Ketone | 9 | 0 | 0.043 | 0.011 |
| Methyl-1-butene, 2- | 8 | 1 | 0.041 | 0.024 |
| Methylcyclohexane | 9 | 0 | 0.113 | 0.051 |
| Methylcyclopentane | 9 | 0 | 0.116 | 0.042 |
| Methylheptane, 2- | 9 | 0 | 0.044 | 0.019 |
| Methylheptane, 3- | 9 | 0 | 0.035 | 0.014 |
| Methylhexane, 2- | 9 | 0 | 0.119 | 0.054 |
| Methylhexane, 3- | 9 | 0 | 0.208 | 0.062 |
| Methylpentane, 2- | 8 | 1 | 0.497 | 0.281 |
| Methylpentane, 3- | 9 | 0 | 0.214 | 0.107 |
| Nonane, <i>n</i> - | 9 | 0 | 0.030 | 0.011 |
| Octane, <i>n</i> - | 9 | 0 | 0.065 | 0.025 |
| Pentane, <i>n</i> - | 9 | 0 | 0.749 | 0.412 |
| Pentene, 1- | 9 | 0 | 0.057 | 0.017 |
| Pentene, <i>cis</i> -2- | 9 | 0 | 0.037 | 0.014 |
| Pentene, <i>trans</i> -2- | 9 | 0 | 0.067 | 0.028 |
| Pinene, <i>alpha</i> - | 9 | 0 | 0.114 | 0.098 |
| Propane | 9 | 0 | 4.456 | 3.074 |
| Propylbenzene, <i>n</i> - | 9 | 0 | 0.018 | 0.006 |
| Propylene | 9 | 0 | 0.525 | 0.221 |
| Styrene | 9 | 0 | 0.042 | 0.019 |
| Tetrachloroethylene | 7 | 2 | 0.025 | 0.014 |
| Toluene | 9 | 0 | 0.573 | 0.304 |
| Trichlorofluoromethane | 9 | 0 | 0.273 | 0.009 |
| Trichlorotrifluoroethane | 9 | 0 | 0.089 | 0.002 |
| Trimethylbenzene, 1,2,4- | 9 | 0 | 0.080 | 0.039 |
| Trimethylbenzene, 1,3,5- | 9 | 0 | 0.030 | 0.013 |
| Trimethylpentane, 2,2,3- | 9 | 0 | 0.044 | 0.022 |
| Trimethylpentane, 2,2,4- | 9 | 0 | 0.221 | 0.120 |
| Trimethylpentane, 2,3,4- | 9 | 0 | 0.071 | 0.036 |
| Undecane, <i>n</i> - | 9 | 0 | 0.035 | 0.010 |
| Xylene, <i>m,p</i> - | 9 | 0 | 0.213 | 0.103 |
| Xylene, <i>o</i> - | 9 | 0 | 0.081 | 0.038 |

Table 2.5-7. Site S-3B Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetylene | 6 | 0 | 0.335 | 0.058 |
| Benzene | 6 | 0 | 0.165 | 0.028 |
| Butane, <i>n</i> - | 6 | 0 | 3.195 | 1.526 |
| Butene, <i>cis</i> -2- | 5 | 1 | 0.594 | 1.386 |
| Butene, <i>trans</i> -2- | 5 | 1 | 0.021 | 0.012 |
| Carbon Disulfide | 6 | 0 | 0.013 | 0.004 |
| Carbon Tetrachloride | 6 | 0 | 0.115 | 0.008 |
| Chloroform | 6 | 0 | 0.017 | 0.002 |
| Chloromethane | 6 | 0 | 0.641 | 0.039 |
| Cyclohexane | 6 | 0 | 0.106 | 0.034 |
| Cyclopentane | 6 | 0 | 0.063 | 0.015 |
| Decane, <i>n</i> - | 6 | 0 | 0.037 | 0.013 |
| Dichlorodifluoromethane | 6 | 0 | 0.598 | 0.031 |
| Dichloromethane | 6 | 0 | 0.086 | 0.020 |
| Dichlorotetrafluoroethane | 6 | 0 | 0.019 | 0.001 |
| Dimethylbutane, 2,2- | 6 | 0 | 0.073 | 0.017 |
| Dimethylbutane, 2,3- | 6 | 0 | 0.071 | 0.018 |
| Dimethylpentane, 2,3- | 6 | 0 | 0.081 | 0.013 |
| Dimethylpentane, 2,4- | 6 | 0 | 0.033 | 0.008 |
| Dodecane, <i>n</i> - | 5 | 1 | 0.017 | 0.014 |
| Ethane | 6 | 0 | 22.592 | 11.170 |
| Ethylbenzene | 6 | 0 | 0.039 | 0.008 |
| Ethylene | 6 | 0 | 0.723 | 0.329 |
| Ethyltoluene, <i>m</i> - | 6 | 0 | 0.019 | 0.007 |
| Ethyltoluene, <i>o</i> - | 5 | 1 | 0.021 | 0.012 |
| Ethyltoluene, <i>p</i> - | 6 | 0 | 0.020 | 0.006 |
| Heptane, <i>n</i> - | 6 | 0 | 0.143 | 0.054 |
| Heptene, 1- | 5 | 1 | 0.031 | 0.024 |
| Hexane, <i>n</i> - | 6 | 0 | 0.324 | 0.134 |
| Hexene, 1- | 6 | 0 | 0.033 | 0.006 |
| Isobutane | 6 | 0 | 1.588 | 0.769 |
| Isobutene/1-Butene | 6 | 0 | 0.138 | 0.047 |
| Isopentane | 6 | 0 | 1.087 | 0.444 |
| Isoprene | 6 | 0 | 0.138 | 0.112 |
| Methyl Ethyl Ketone | 6 | 0 | 0.484 | 0.239 |
| Methylcyclohexane | 6 | 0 | 0.140 | 0.047 |
| Methylcyclopentane | 6 | 0 | 0.079 | 0.018 |

Table 2.5-7. Site S-3B Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Methylheptane, 2- | 6 | 0 | 0.070 | 0.042 |
| Methylheptane, 3- | 6 | 0 | 0.042 | 0.013 |
| Methylhexane, 2- | 6 | 0 | 0.130 | 0.050 |
| Methylhexane, 3- | 6 | 0 | 0.173 | 0.039 |
| Methylpentane, 2- | 6 | 0 | 0.417 | 0.206 |
| Methylpentane, 3- | 6 | 0 | 0.201 | 0.075 |
| Nonane, <i>n</i> - | 6 | 0 | 0.039 | 0.010 |
| Octane, <i>n</i> - | 6 | 0 | 0.084 | 0.029 |
| Pentane, <i>n</i> - | 6 | 0 | 1.010 | 0.406 |
| Pentene, 1- | 6 | 0 | 0.038 | 0.007 |
| Pentene, <i>trans</i> -2- | 6 | 0 | 0.025 | 0.007 |
| Pinene, <i>alpha</i> - | 5 | 1 | 0.018 | 0.015 |
| Propane | 6 | 0 | 8.844 | 4.215 |
| Propylene | 6 | 0 | 0.257 | 0.089 |
| Tetrachloroethylene | 5 | 1 | 0.013 | 0.008 |
| Toluene | 6 | 0 | 0.230 | 0.055 |
| Trichlorofluoromethane | 6 | 0 | 0.277 | 0.015 |
| Trichlorotrifluoroethane | 6 | 0 | 0.093 | 0.004 |
| Trimethylbenzene, 1,2,4- | 6 | 0 | 0.037 | 0.014 |
| Trimethylbenzene, 1,3,5- | 6 | 0 | 0.019 | 0.005 |
| Trimethylpentane, 2,2,3- | 6 | 0 | 0.023 | 0.003 |
| Trimethylpentane, 2,2,4- | 6 | 0 | 0.049 | 0.013 |
| Trimethylpentane, 2,3,4- | 6 | 0 | 0.017 | 0.004 |
| Undecane, <i>n</i> - | 6 | 0 | 0.026 | 0.012 |
| Xylene, <i>m,p</i> - | 6 | 0 | 0.101 | 0.026 |
| Xylene, <i>o</i> - | 6 | 0 | 0.035 | 0.008 |

Table 2.5-8. Site S-4 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-----------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetaldehyde | 20 | 0 | 3.802 | 1.125 |
| Acetone | 20 | 0 | 1.823 | 0.589 |
| Acetylene | 20 | 0 | 1.023 | 0.392 |
| Benzaldehyde | 20 | 0 | 0.025 | 0.012 |
| Benzene | 20 | 0 | 0.686 | 0.221 |
| Butadiene, 1,3- | 20 | 0 | 0.092 | 0.040 |
| Butane, <i>n</i> - | 20 | 0 | 10.993 | 5.385 |
| Butene, <i>cis</i> -2- | 20 | 0 | 0.318 | 0.136 |
| Butene, <i>trans</i> -2- | 20 | 0 | 0.369 | 0.175 |
| Butyraldehyde | 20 | 0 | 0.172 | 0.076 |
| Carbon Disulfide | 20 | 0 | 0.119 | 0.022 |
| Carbon Tetrachloride | 20 | 0 | 0.113 | 0.006 |
| Chloroform | 20 | 0 | 0.026 | 0.004 |
| Chloromethane | 20 | 0 | 0.688 | 0.050 |
| Crotonaldehyde | 20 | 0 | 0.072 | 0.018 |
| Cyclohexane | 20 | 0 | 0.296 | 0.094 |
| Cyclopentane | 20 | 0 | 0.446 | 0.172 |
| Decane, <i>n</i> - | 20 | 0 | 0.137 | 0.092 |
| Dichlorobenzene, <i>p</i> - | 19 | 1 | 0.060 | 0.022 |
| Dichlorodifluoromethane | 20 | 0 | 0.581 | 0.020 |
| Dichloromethane | 20 | 0 | 0.122 | 0.032 |
| Dichlorotetrafluoroethane | 20 | 0 | 0.020 | 0.001 |
| Dimethylbutane, 2,2- | 20 | 0 | 0.304 | 0.106 |
| Dimethylbutane, 2,3- | 20 | 0 | 0.948 | 0.366 |
| Dimethylpentane, 2,3- | 20 | 0 | 0.330 | 0.094 |
| Dimethylpentane, 2,4- | 20 | 0 | 0.326 | 0.114 |
| Dodecane, <i>n</i> - | 20 | 0 | 0.046 | 0.028 |
| Ethane | 20 | 0 | 18.229 | 8.241 |
| Ethylbenzene | 20 | 0 | 0.238 | 0.056 |
| Ethylene | 20 | 0 | 1.778 | 0.632 |
| Ethyltoluene, <i>m</i> - | 20 | 0 | 0.084 | 0.028 |
| Ethyltoluene, <i>p</i> - | 20 | 0 | 0.059 | 0.021 |
| Formaldehyde | 20 | 0 | 1.140 | 0.408 |
| Heptane, <i>n</i> - | 20 | 0 | 0.299 | 0.106 |
| Hexaldehyde | 20 | 0 | 0.114 | 0.083 |
| Hexane, <i>n</i> - | 20 | 0 | 1.301 | 0.507 |

Table 2.5-8. Site S-4 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Hexene, 1- | 20 | 0 | 0.074 | 0.015 |
| Hexene, <i>trans</i> -2- | 18 | 2 | 0.124 | 0.054 |
| Isobutane | 20 | 0 | 2.860 | 1.397 |
| Isobutene/1-Butene | 20 | 0 | 0.666 | 0.275 |
| Isopentane | 20 | 0 | 12.985 | 5.511 |
| Isoprene | 20 | 0 | 0.143 | 0.030 |
| Isopropylbenzene | 19 | 1 | 0.018 | 0.005 |
| Methyl Ethyl Ketone | 20 | 0 | 1.554 | 0.948 |
| Methyl Isobutyl Ketone | 20 | 0 | 0.100 | 0.040 |
| Methyl-1-butene, 2- | 20 | 0 | 0.499 | 0.234 |
| Methyl-2-butene, 2- | 20 | 0 | 0.992 | 0.430 |
| Methylcyclohexane | 20 | 0 | 0.309 | 0.098 |
| Methylcyclopentane | 20 | 0 | 0.566 | 0.195 |
| Methylheptane, 2- | 20 | 0 | 0.111 | 0.036 |
| Methylheptane, 3- | 20 | 0 | 0.087 | 0.027 |
| Methylhexane, 2- | 20 | 0 | 0.499 | 0.207 |
| Methylhexane, 3- | 20 | 0 | 0.538 | 0.143 |
| Methylpentane, 2- | 20 | 0 | 2.543 | 0.930 |
| Methylpentane, 3- | 20 | 0 | 1.423 | 0.541 |
| Nonane, <i>n</i> - | 20 | 0 | 0.102 | 0.048 |
| Octane, <i>n</i> - | 20 | 0 | 0.146 | 0.045 |
| Octene, 1- | 14 | 6 | 0.016 | 0.006 |
| Pentane, <i>n</i> - | 20 | 0 | 5.491 | 2.336 |
| Pentene, 1- | 20 | 0 | 0.328 | 0.127 |
| Pentene, <i>cis</i> -2- | 20 | 0 | 0.382 | 0.155 |
| Pentene, <i>trans</i> -2- | 20 | 0 | 0.763 | 0.310 |
| Pinene, <i>alpha</i> - | 17 | 3 | 0.038 | 0.015 |
| Propane | 20 | 0 | 10.683 | 4.918 |
| Propionaldehyde | 20 | 0 | 0.129 | 0.035 |
| Propylbenzene, <i>n</i> - | 20 | 0 | 0.040 | 0.011 |
| Propylene | 20 | 0 | 0.811 | 0.264 |
| Styrene | 19 | 1 | 0.044 | 0.011 |
| Tetrachloroethylene | 20 | 0 | 0.048 | 0.013 |
| Toluene | 20 | 0 | 1.663 | 0.540 |

Table 2.5-8. Site S-4 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|--------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Trichlorofluoromethane | 20 | 0 | 0.276 | 0.008 |
| Trichlorotrifluoroethane | 20 | 0 | 0.090 | 0.002 |
| Trimethylbenzene, 1,2,3- | 20 | 0 | 0.051 | 0.026 |
| Trimethylbenzene, 1,2,4- | 20 | 0 | 0.218 | 0.084 |
| Trimethylbenzene, 1,3,5- | 20 | 0 | 0.073 | 0.026 |
| Trimethylpentane, 2,2,3- | 20 | 0 | 0.183 | 0.067 |
| Trimethylpentane, 2,2,4- | 20 | 0 | 1.137 | 0.403 |
| Trimethylpentane, 2,3,4- | 20 | 0 | 0.279 | 0.094 |
| Undecane, <i>n</i> - | 20 | 0 | 0.068 | 0.026 |
| Valeraldehyde | 20 | 0 | 0.039 | 0.017 |
| Xylene, <i>m,p</i> - | 20 | 0 | 0.758 | 0.189 |
| Xylene, <i>o</i> - | 20 | 0 | 0.255 | 0.066 |

Table 2.5-9. Site 5 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Acetaldehyde | 20 | 0 | 1.824 | 0.408 |
| Acetone | 20 | 0 | 1.263 | 0.332 |
| Acetylene | 19 | 0 | 0.567 | 0.165 |
| Benzaldehyde | 18 | 2 | 0.009 | 0.002 |
| Benzene | 19 | 0 | 0.197 | 0.035 |
| Butadiene, 1,3- | 15 | 4 | 0.018 | 0.007 |
| Butane, <i>n</i> - | 15 | 4 | 2.072 | 1.109 |
| Butene, <i>cis</i> -2- | 19 | 0 | 0.048 | 0.007 |
| Butene, <i>trans</i> -2- | 18 | 1 | 0.033 | 0.008 |
| Butyraldehyde | 20 | 0 | 0.048 | 0.035 |
| Carbon Disulfide | 19 | 0 | 0.944 | 0.153 |
| Carbon Tetrachloride | 19 | 0 | 0.108 | 0.011 |
| Chloroform | 18 | 1 | 0.033 | 0.008 |
| Chloromethane | 19 | 0 | 0.642 | 0.063 |
| Crotonaldehyde | 20 | 0 | 0.050 | 0.014 |
| Cyclohexane | 19 | 0 | 0.096 | 0.033 |
| Cyclopentane | 19 | 0 | 0.119 | 0.108 |
| Decane, <i>n</i> - | 19 | 0 | 0.031 | 0.013 |
| Dichlorodifluoromethane | 19 | 0 | 0.534 | 0.040 |
| Dichloromethane | 19 | 0 | 0.102 | 0.035 |
| Dichlorotetrafluoroethane | 19 | 0 | 0.019 | 0.002 |
| Dimethylbutane, 2,2- | 19 | 0 | 0.080 | 0.027 |
| Dimethylbutane, 2,3- | 19 | 0 | 0.081 | 0.019 |
| Dimethylpentane, 2,3- | 19 | 0 | 0.117 | 0.025 |
| Dimethylpentane, 2,4- | 19 | 0 | 0.039 | 0.007 |
| Dodecane, <i>n</i> - | 18 | 1 | 0.038 | 0.034 |
| Ethane | 19 | 0 | 14.077 | 4.074 |
| Ethylbenzene | 19 | 0 | 0.076 | 0.024 |
| Ethylene | 19 | 0 | 0.985 | 0.202 |
| Ethyltoluene, <i>m</i> - | 18 | 1 | 0.033 | 0.008 |
| Ethyltoluene, <i>o</i> - | 15 | 4 | 0.019 | 0.012 |
| Ethyltoluene, <i>p</i> - | 17 | 2 | 0.025 | 0.013 |
| Formaldehyde | 20 | 0 | 0.723 | 0.096 |
| Heptane, <i>n</i> - | 19 | 0 | 0.090 | 0.021 |
| Hexaldehyde | 20 | 0 | 0.020 | 0.002 |
| Hexane, <i>n</i> - | 19 | 0 | 0.200 | 0.056 |

Table 2.5-9. Site S-5 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|---------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Hexene, 1- | 19 | 0 | 0.046 | 0.008 |
| Isobutane | 19 | 0 | 1.063 | 0.598 |
| Isobutene/1-Butene | 19 | 0 | 0.171 | 0.036 |
| Isopentane | 19 | 0 | 1.297 | 1.262 |
| Isoprene | 19 | 0 | 0.092 | 0.023 |
| Isopropylbenzene | 18 | 1 | 0.016 | 0.003 |
| Methyl Ethyl Ketone | 19 | 0 | 0.775 | 0.307 |
| Methylcyclohexane | 19 | 0 | 0.105 | 0.024 |
| Methylcyclopentane | 19 | 0 | 0.106 | 0.034 |
| Methylheptane, 2- | 19 | 0 | 0.045 | 0.006 |
| Methylheptane, 3- | 19 | 0 | 0.030 | 0.004 |
| Methylhexane, 2- | 19 | 0 | 0.094 | 0.020 |
| Methylhexane, 3- | 19 | 0 | 0.207 | 0.066 |
| Methylpentane, 2- | 16 | 3 | 0.316 | 0.107 |
| Methylpentane, 3- | 19 | 0 | 0.160 | 0.040 |
| Nonane, <i>n</i> - | 19 | 0 | 0.031 | 0.004 |
| Octane, <i>n</i> - | 19 | 0 | 0.063 | 0.011 |
| Pentane, <i>n</i> - | 19 | 0 | 1.087 | 0.929 |
| Pentene, 1- | 19 | 0 | 0.046 | 0.009 |
| Pentene, <i>cis</i> -2- | 18 | 1 | 0.032 | 0.005 |
| Pentene, <i>trans</i> -2- | 18 | 1 | 0.041 | 0.012 |
| Pinene, <i>alpha</i> - | 15 | 4 | 0.039 | 0.021 |
| Propane | 19 | 0 | 5.049 | 1.773 |
| Propionaldehyde | 20 | 0 | 0.048 | 0.035 |
| Propylbenzene, <i>n</i> - | 16 | 3 | 0.019 | 0.007 |
| Propylene | 19 | 0 | 0.368 | 0.084 |
| Styrene | 18 | 1 | 0.042 | 0.015 |
| Toluene | 18 | 1 | 0.446 | 0.166 |
| Trichlorofluoromethane | 19 | 0 | 0.255 | 0.020 |
| Trichlorotrifluoroethane | 19 | 0 | 0.087 | 0.007 |
| Trimethylbenzene, 1,2,4- | 19 | 0 | 0.057 | 0.017 |
| Trimethylbenzene, 1,3,5- | 18 | 1 | 0.026 | 0.007 |
| Trimethylpentane, 2,2,3- | 15 | 4 | 0.021 | 0.008 |
| Trimethylpentane, 2,2,4- | 19 | 0 | 0.103 | 0.031 |
| Trimethylpentane, 2,3,4- | 19 | 0 | 0.039 | 0.010 |
| Undecane, <i>n</i> - | 19 | 0 | 0.064 | 0.073 |
| Valeraldehyde | 17 | 3 | 0.008 | 0.002 |

Table 2.5-9. Site S-5 Pollutant Study Averages (Continued)

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|----------------------|-------------------|-----------------------|----------------------|----------------------------|
| Xylene, <i>m,p</i> - | 19 | 0 | 0.198 | 0.060 |
| Xylene, <i>o</i> - | 19 | 0 | 0.071 | 0.020 |

Table 2.5-10. Site S-6 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Benzene | 15 | 4 | 0.097 | 0.036 |
| Butane, <i>n</i> - | 19 | 0 | 1.015 | 0.432 |
| Carbon Tetrachloride | 18 | 1 | 0.097 | 0.013 |
| Chloromethane | 19 | 0 | 0.510 | 0.061 |
| Dichlorodifluoromethane | 19 | 0 | 0.511 | 0.017 |
| Ethane | 19 | 0 | 21.412 | 9.997 |
| Ethylene | 18 | 1 | 0.632 | 0.155 |
| Isobutane | 17 | 2 | 0.418 | 0.180 |
| Methane | 17 | 0 | 5758.824 | 795.537 |
| Methanol | 10 | 0 | 6.545 | 1.681 |
| Methyl Ethyl Ketone | 18 | 1 | 0.427 | 0.121 |
| Pentane, <i>n</i> - | 18 | 1 | 0.399 | 0.146 |
| Propane | 19 | 0 | 2.982 | 1.154 |
| Propylene | 18 | 1 | 0.210 | 0.074 |
| Toluene | 19 | 0 | 0.305 | 0.083 |
| Trichlorofluoromethane | 19 | 0 | 0.257 | 0.008 |

Table 2.5-11. Site S-7 Pollutant Study Averages

| Pollutant Name | Number of Detects | Number of Non-detects | Study Average (ppbv) | Confidence Interval (ppbv) |
|-------------------------|-------------------|-----------------------|----------------------|----------------------------|
| Benzene | 14 | 4 | 0.109 | 0.043 |
| Butane, <i>n</i> - | 18 | 0 | 1.230 | 0.604 |
| Carbon Tetrachloride | 16 | 2 | 0.098 | 0.019 |
| Chloromethane | 18 | 0 | 0.523 | 0.071 |
| Dichlorodifluoromethane | 18 | 0 | 0.520 | 0.017 |
| Ethane | 18 | 0 | 23.979 | 11.236 |
| Ethylene | 18 | 0 | 0.690 | 0.173 |
| Isobutane | 16 | 2 | 0.481 | 0.246 |
| Methane | 17 | 0 | 5672.353 | 650.290 |
| Methanol | 18 | 0 | 6.740 | 1.403 |
| Methyl Ethyl Ketone | 18 | 0 | 0.512 | 0.183 |
| Pentane, <i>n</i> - | 17 | 1 | 0.468 | 0.217 |
| Propane | 18 | 0 | 3.967 | 1.854 |
| Propylene | 17 | 1 | 0.234 | 0.107 |
| Toluene | 18 | 0 | 0.314 | 0.128 |
| Trichlorofluoromethane | 18 | 0 | 0.259 | 0.007 |

2.5.3 Key Pollutants

At the conclusion of the ambient air monitoring data collection, ERG conducted an initial public health screening to determine whether selected pollutants were found at levels indicating an urgent health hazard. This screening was conducted using the same health screening values that EPA uses in its NATA (see Appendix 2-G), which are available for 40 pollutants in this study. In Section 5 of this report, ERG presents a broader health evaluation that considers health screening values for all 138 pollutants considered in the monitoring program, as well as the results of the air dispersion modeling effort discussed in Section 4.

Key Point: Key Pollutants

The key pollutants, based on the ambient monitoring data, were:

- Acetaldehyde
- Benzene
- 1,3-Butadiene
- Carbon tetrachloride
- *p*-Dichlorobenzene
- Formaldehyde
- Tetrachloroethylene

In reviewing this initial screening of key pollutants, note that:

- With one exception, ERG found no pollutant concentrations that exceeded any published short-term health benchmark published by the Texas Commission on Environmental Quality (TCEQ), EPA, or the Agency for Toxic Substances and Disease Registry (ATSDR). A single sample was found to have a hexachloro-1,3-butadiene concentration of 0.369 ppb, which is higher than TCEQ's short-term effects screening level (0.2 ppb). However, this particular sample was not analyzed within the method's required holding time, and the testing laboratory cautioned that the measurement is of limited reliability. Further discussion of this pollutant is found in Section 5.2.
- It is only appropriate to compare annual average concentrations, not individual measurements, to long-term health benchmark values such as the EPA NATA values.
- The study period was only for two months at eight sites; the study period averages at these eight sites are assumed to be an estimate of typical annual conditions. This approach is similar to EPA's SATMP study.
- The initial screening presented in this report only addresses 40 pollutants. The health evaluation in Section 5 presents interpretations for all pollutants considered in this monitoring program.

Tables 2.5-12 through 2.5-19 present average concentration summaries of the key pollutants of interest for each site. Key pollutants are ones whose average concentrations were greater than the Lowest Comparison Levels (LCLs) used in this study. Thus, these tables present a "factor of LCL" for each pollutant, and pollutants with a "factor of LCL" greater than 1 are identified as key. Additionally, Figures 2.5-1 through 2.5-7 present each key pollutant's study average confidence interval, which is useful in identifying statistically significant differences.

The following observations were made:

- Benzene and carbon tetrachloride were key HAPs at each site.
- The average acetaldehyde concentration at Site S-4 was considerably higher than the average acetaldehyde concentration at Site S-5 (Figure 2.5-1).
- The average benzene concentration at Site S-4 was considerably higher than all other average benzene concentrations at the other sites. The average benzene concentrations at Sites S-6 and S-7 were also considerably lower than those for Sites S-1, S-2, S-3A, and S-5 (Figure 2.5-2).
- The average 1,3-butadiene concentrations at Sites S-2 and S-4 were considerably higher than the average 1,3-butadiene concentration at Site S-5 (Figure 2.5-3).
- The average carbon tetrachloride concentration at Site S-1 was only considerably higher than the average carbon tetrachloride concentration at Site S-6 (Figure 2.5-4).
- There were no statistically significant differences in average *p*-dichlorobenzene concentrations across Sites S-1, S-2, S-3A, and S-4 (Figure 2.5-5).
- There were no statistically significant differences in average formaldehyde concentrations across Sites S-4 and S-5 (Figure 2.5-6).
- There were no statistically significant differences in average tetrachloroethylene concentrations across Sites S-1, S-2, S-3A, and S-4 (Figure 2.5-7).

2.5.4 Integration with Meteorology

Meteorological observations, such as wind speed and wind direction, can be useful in helping characterize the behavior of the ambient air monitoring data. For this study, no meteorological towers were placed at the monitoring locations, largely because more than 40 National Weather Service (NWS) and TCEQ meteorological stations in and around the city of Fort Worth operated during this monitoring program. Additionally, another dozen meteorological stations from the Weatherbug Network were available to be used.

Closest Meteorological Station

For each monitoring site, ERG identified the closest meteorological station that was operating during the monitoring timeframe. Table 2.5-20 identifies those stations. If observations were missing, or if a significant portion of a day's observations were identified as "calm" (less than 5 miles per hour), surrogate data was used to supplement the meteorological observations. Surrogate data sources include the NWS 1-minute data, TCEQ meteorological stations, and the Weatherbug Network. Table 2.5-20 also presents the surrogate data locations relative to the monitoring sites. All meteorological observations of wind speed, wind direction, temperature, and precipitation are presented in Appendix 2-H.

Table 2.5-12. Site S-1 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|---------------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.245 ^b | 0.187–0.304 | 6.11 |
| 1,3-Butadiene | ppbv | 0.041 ^c | 0.022–0.059 | 2.69 |
| Carbon Tetrachloride | ppbv | 0.118 ^d | 0.112–0.123 | 4.38 |
| <i>p</i> -Dichlorobenzene | ppbv | 0.039 ^e | 0.025–0.053 | 2.58 |
| Tetrachloroethylene | ppbv | 0.038 ^f | 0.024–0.052 | 1.52 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA. LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include 20 detections that ranged from 0.135 to 0.563 ppbv.

^c The mean of measurements for 1,3-butadiene is the average of all sample results, which include 18 detections that ranged from 0.01 to 0.137 ppbv, as well as two samples in which no chemical was registered by the laboratory analytical equipment.

^d The mean of measurements for carbon tetrachloride is the average of all sample results, which include 20 detections that ranged from 0.083 to 0.139 ppbv.

^e The mean of measurements for *p*-dichlorobenzene is the average of all sample results, which include 17 detections that ranged from 0.013 to 0.118 ppbv, as well as three samples in which no chemical was registered by the laboratory analytical equipment.

^f The mean of measurements for tetrachloroethylene is the average of all sample results, which include 17 detections that ranged from 0.015 to 0.109 ppbv, as well as three samples in which no chemical was registered by the laboratory analytical equipment.

Table 2.5-13. Site S-2 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|---------------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.300 ^b | 0.257–0.343 | 7.48 |
| 1,3-Butadiene | ppbv | 0.057 ^c | 0.040–0.073 | 3.75 |
| Carbon Tetrachloride | ppbv | 0.117 ^d | 0.112–0.122 | 4.36 |
| <i>p</i> -Dichlorobenzene | ppbv | 0.051 ^f | 0.004–0.098 | 3.38 |
| Tetrachloroethylene | ppbv | 0.061 ^g | 0.032–0.090 | 2.44 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA.

LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include 18 detections that ranged from 0.180 to 0.501 ppbv.

^c The mean of measurements for 1,3-butadiene is the average of all sample results, which include 18 detections that ranged from 0.024 to 0.147 ppbv.

^d The mean of measurements for carbon tetrachloride is the average of all sample results, which include 18 detections that ranged from 0.090 to 0.133 ppbv.

^e The mean of measurements for *p*-dichlorobenzene is the average of all sample results, which include 15 detections that ranged from 0.014 to 0.416 ppbv, as well as three samples in which no chemical was registered by the laboratory analytical equipment.

^f The mean of measurements for tetrachloroethylene is the average of all sample results, which include 18 detections that ranged from 0.012 to 0.218 ppbv.

Table 2.5-14. Site S-3A Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|---------------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.301 ^b | 0.173–0.428 | 7.50 |
| 1,3-Butadiene | ppbv | 0.049 ^c | 0.016–0.082 | 3.23 |
| Carbon Tetrachloride | ppbv | 0.118 ^d | 0.111–0.125 | 4.38 |
| <i>p</i> -Dichlorobenzene | ppbv | 0.030 ^e | 0.017–0.043 | 2.01 |
| Tetrachloroethylene | ppbv | 0.025 ^f | 0.011–0.039 | 1.00 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA.

LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include nine detections that ranged from 0.157 to 0.636 ppbv.

^c The mean of measurements for 1,3-butadiene is the average of all sample results, which include eight detections that ranged from 0.023 to 0.123 ppbv, as well as one sample in which no chemical was registered by the laboratory analytical equipment.

^d The mean of measurements for carbon tetrachloride is the average of all sample results, which include nine detections that ranged from 0.104 to 0.134 ppbv.

^e The mean of measurements for *p*-dichlorobenzene is the average of all sample results, which include nine detections that ranged from 0.011 to 0.056 ppbv.

^f The mean of measurements for tetrachloroethylene is the average of all sample results, which include seven detections that ranged from 0.013 to 0.056 ppbv, as well as two samples in which no chemical was registered by the laboratory analytical equipment.

Table 2.5-15. Site S-3B Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|----------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.165 ^b | 0.137–0.193 | 4.11 |
| Carbon Tetrachloride | ppbv | 0.115 ^c | 0.107–0.122 | 4.26 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA. LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include six detections that ranged from 0.132 to 0.214 ppbv.

^c The mean of measurements for carbon tetrachloride is the average of all sample results, which include six detections that ranged from 0.103 to 0.122 ppbv.

Table 2.5-16. Site S-4 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|---------------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Acetaldehyde | ppbv | 3.802 ^b | 2.677–4.927 | 15.07 |
| Benzene | ppbv | 0.686 ^c | 0.465–0.906 | 17.08 |
| 1,3-Butadiene | ppbv | 0.092 ^d | 0.051–0.132 | 6.08 |
| Carbon Tetrachloride | ppbv | 0.113 ^e | 0.107–0.118 | 4.19 |
| <i>p</i> -Dichlorobenzene | ppbv | 0.060 ^f | 0.038–0.083 | 3.99 |
| Formaldehyde | ppbv | 1.140 ^g | 0.731–1.548 | 17.50 |
| Tetrachloroethylene | ppbv | 0.048 ^h | 0.034–0.061 | 1.90 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA. LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for acetaldehyde is the average of all sample results, which include 20 detections that ranged from 1.35 to 9.06 ppbv.

^c The mean of measurements for benzene is the average of all sample results, which include 20 detections that ranged from 0.200 to 1.83 ppbv.

^d The mean of measurements for 1,3-butadiene is the average of all sample results, which include 18 detections that ranged from 0.015 to 0.304 ppbv.

^e The mean of measurements for carbon tetrachloride is the average of all sample results, which include 20 detections that ranged from 0.094 to 0.142 ppbv.

^f The mean of measurements for *p*-dichlorobenzene is the average of all sample results, which include 19 detections that ranged from 0.019 to 0.178 ppbv, as well as one sample in which no chemical was registered by the laboratory analytical equipment.

^g The mean of measurements for formaldehyde is the average of all sample results, which include 20 detections that ranged from 0.412 to 4.45 ppbv.

^h The mean of measurements for tetrachloroethylene is the average of all sample results, which include 20 detections that ranged from 0.015 to 0.116 ppbv.

Table 2.5-17. Site S-5 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|----------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Acetaldehyde | ppbv | 1.824 ^b | 1.416–2.231 | 7.23 |
| Benzene | ppbv | 0.197 ^c | 0.162–0.232 | 4.90 |
| 1,3-Butadiene | ppbv | 0.018 ^d | 0.011–0.025 | 1.20 |
| Carbon Tetrachloride | ppbv | 0.108 ^e | 0.097–0.119 | 4.03 |
| Formaldehyde | ppbv | 0.723 ^f | 0.626–0.819 | 11.09 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA.

LCLs for this study are presented in Appendix 2-G. "Factor of LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for acetaldehyde is the average of all sample results, which include 20 detections that ranged from 0.831 to 4.93 ppbv.

^c The mean of measurements for benzene is the average of all sample results, which include 19 detections that ranged from 0.104 to 0.359 ppbv.

^d The mean of measurements for 1,3-butadiene is the average of all sample results, which include 15 detections that ranged from 0.011 to 0.051 ppbv, as well as four samples in which no chemical was registered by the laboratory analytical equipment.

^e The mean of measurements for carbon tetrachloride is the average of all sample results, which include 19 detections that ranged from 0.053 to 0.140 ppbv.

^f The mean of measurements for formaldehyde is the average of all sample results, which include 20 detections that ranged from 0.474 to 1.32 ppbv.

Table 2.5-18. Site S-6 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|----------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.097 ^b | 0.061–0.134 | 2.42 |
| Carbon Tetrachloride | ppbv | 0.097 ^c | 0.083–0.110 | 3.59 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA.

LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include 15 detections that ranged from 0.070 to 0.263 ppbv, as well as four samples in which no chemical was registered by the laboratory analytical equipment.

^c The mean of measurements for carbon tetrachloride is the average of all sample results, which include 18 detections that ranged from 0.071 to 0.127 ppbv, as well as one sample in which no chemical was registered by the laboratory analytical equipment.

Table 2.5-19. Site S-7 Key Pollutant Averages

| Pollutant | Units | Mean of Measurements | 95% Confidence Interval on the Mean | Factor of EPA LCL ^a |
|----------------------|-------|----------------------|-------------------------------------|--------------------------------|
| Benzene | ppbv | 0.109 ^b | 0.066–0.152 | 2.71 |
| Carbon Tetrachloride | ppbv | 0.098 ^c | 0.079–0.117 | 3.65 |

^a LCL refers to the Lowest Comparison Level of cancer and/or noncancer values, as used in EPA's NATA. LCLs for this study are presented in Appendix 2-G. "Factor of EPA LCL" is the pollutant study average (or mean of measurements) divided by its LCL.

^b The mean of measurements for benzene is the average of all sample results, which include 14 detections that ranged from 0.064 to 0.282 ppbv, as well as four samples in which no chemical was registered by the laboratory analytical equipment.

^c The mean of measurements for carbon tetrachloride is the average of all sample results, which include 16 detections that ranged from 0.077 to 0.142 ppbv, as well as two samples in which no chemical was registered by the laboratory analytical equipment.

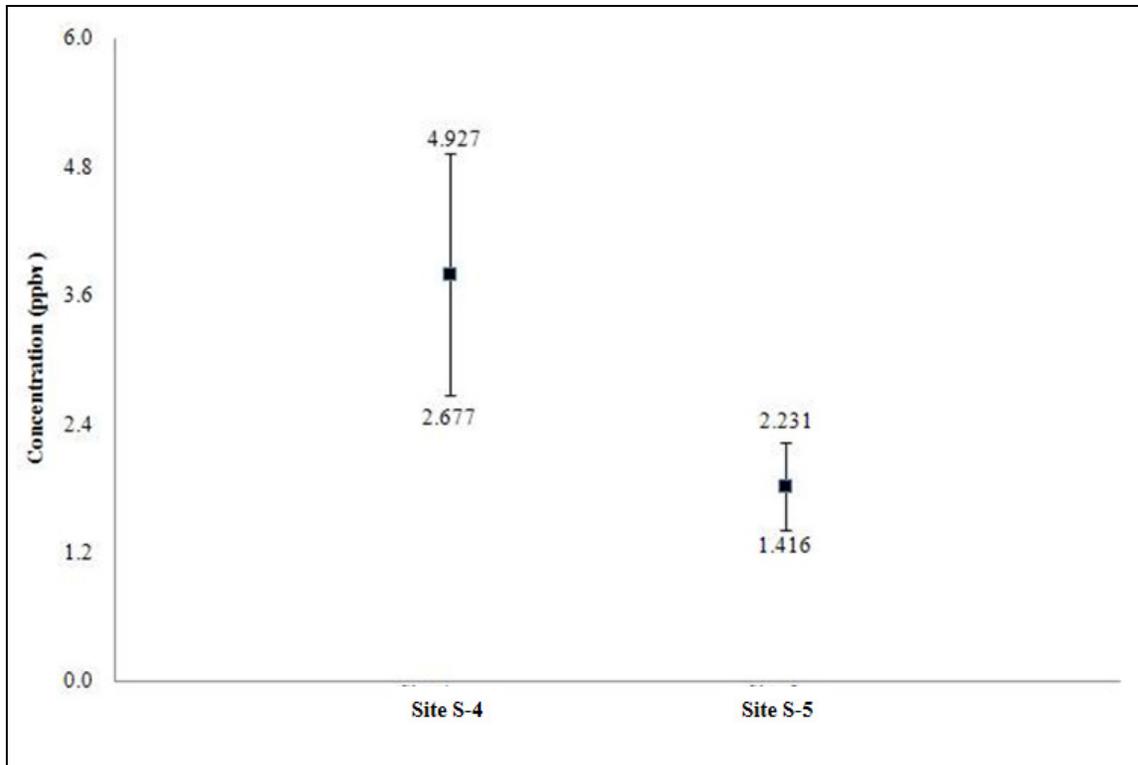


Figure 2.5-1. Acetaldehyde Average Concentrations by Site

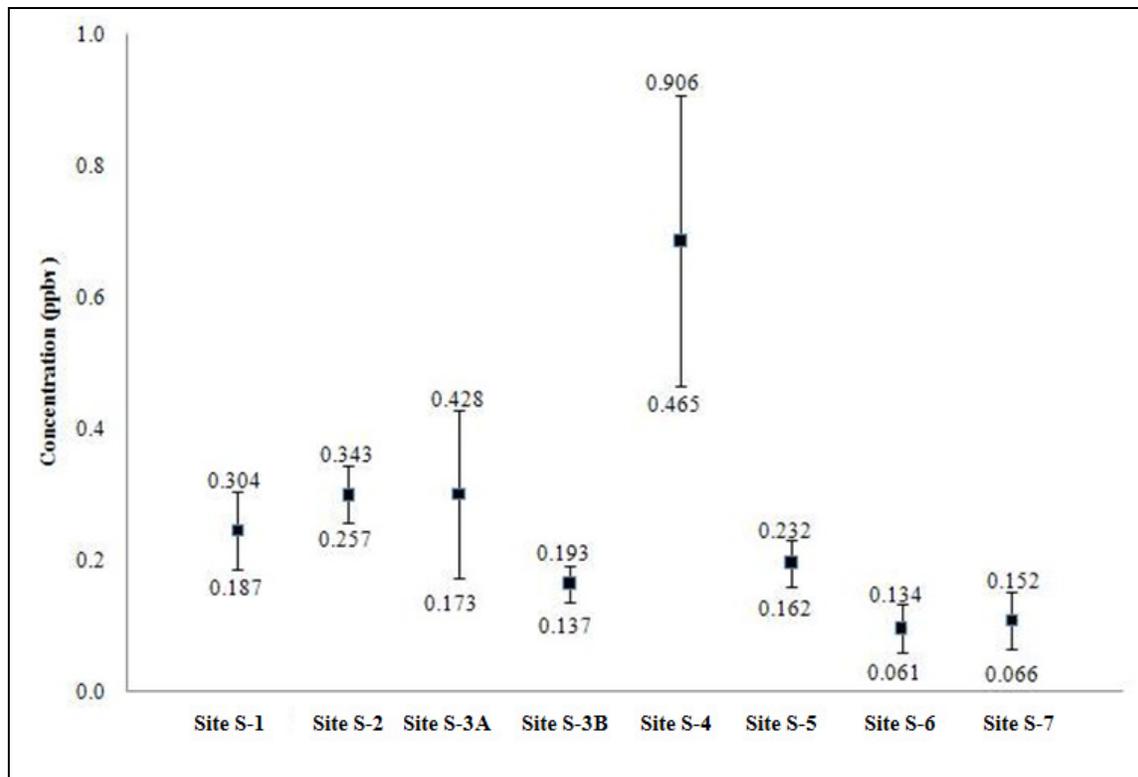


Figure 2.5-2. Benzene Average Concentrations by Site

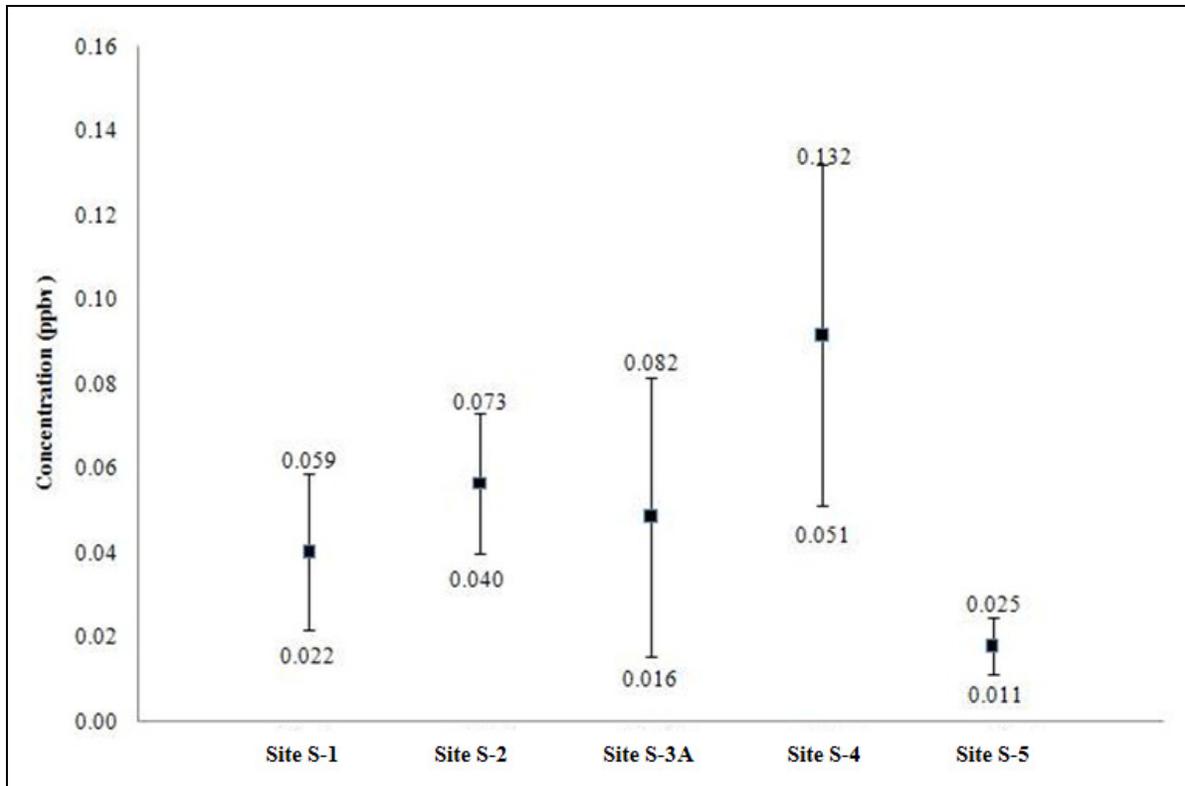


Figure 2.5-3. 1,3-Butadiene Average Concentrations by Site

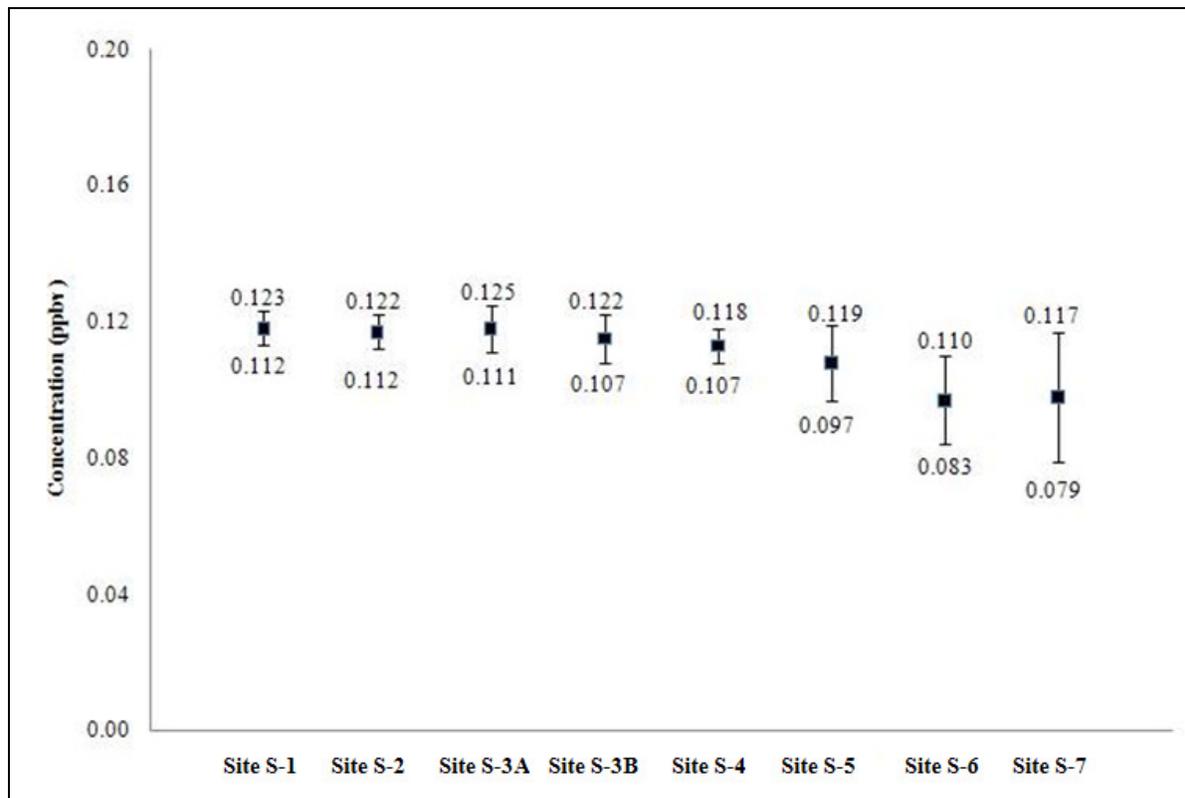


Figure 2.5-4. Carbon Tetrachloride Average Concentrations by Site

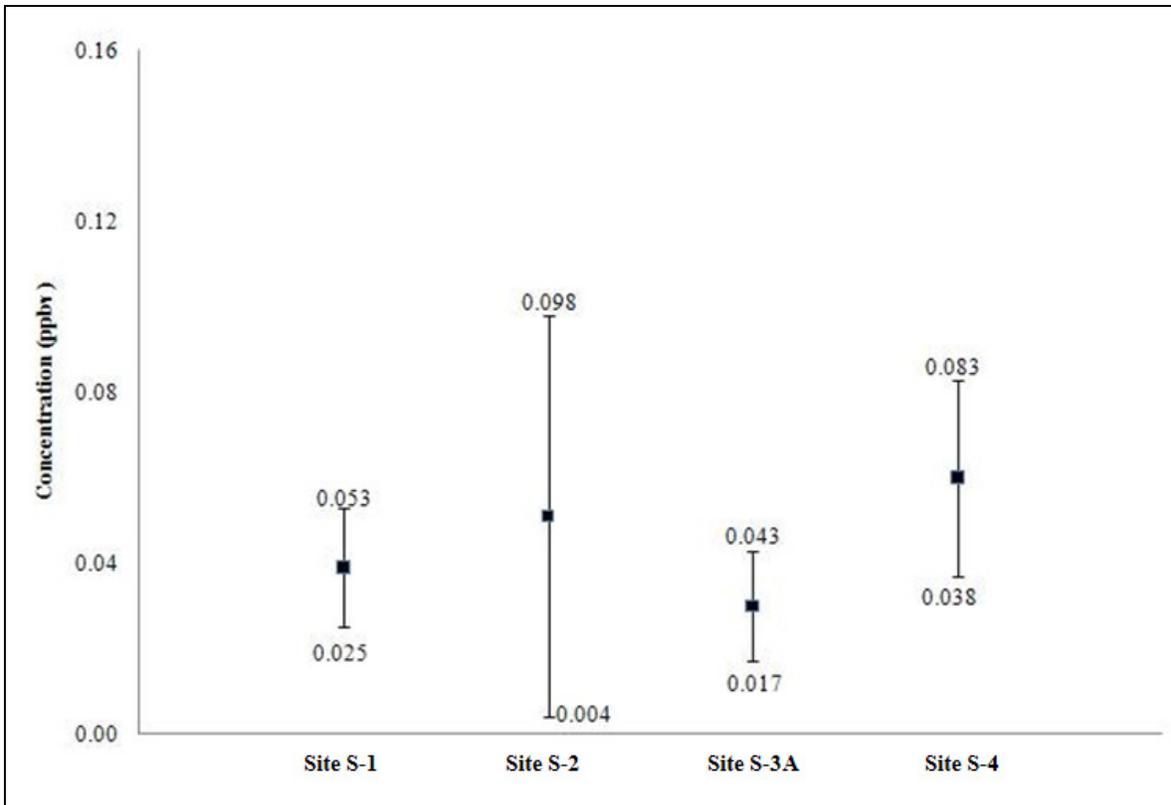


Figure 2.5-5. *p*-Dichlorobenzene Average Concentrations by Site

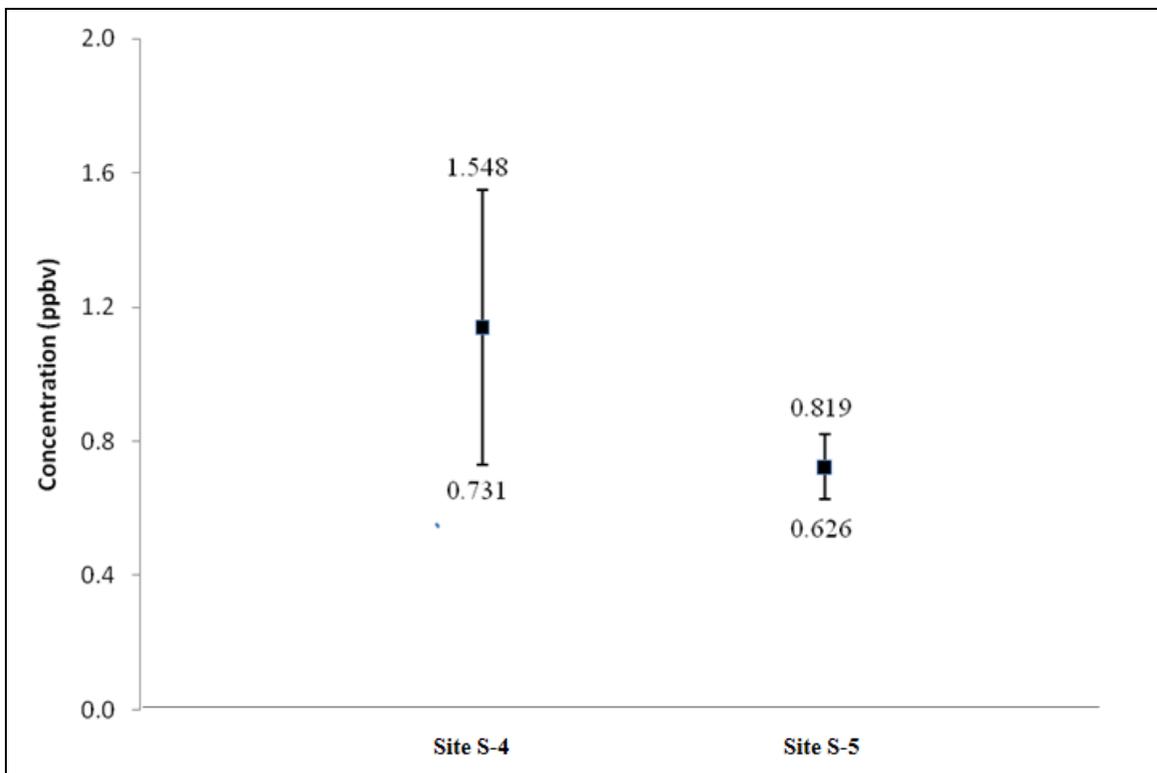


Figure 2.5-6. Formaldehyde Average Concentrations by Site

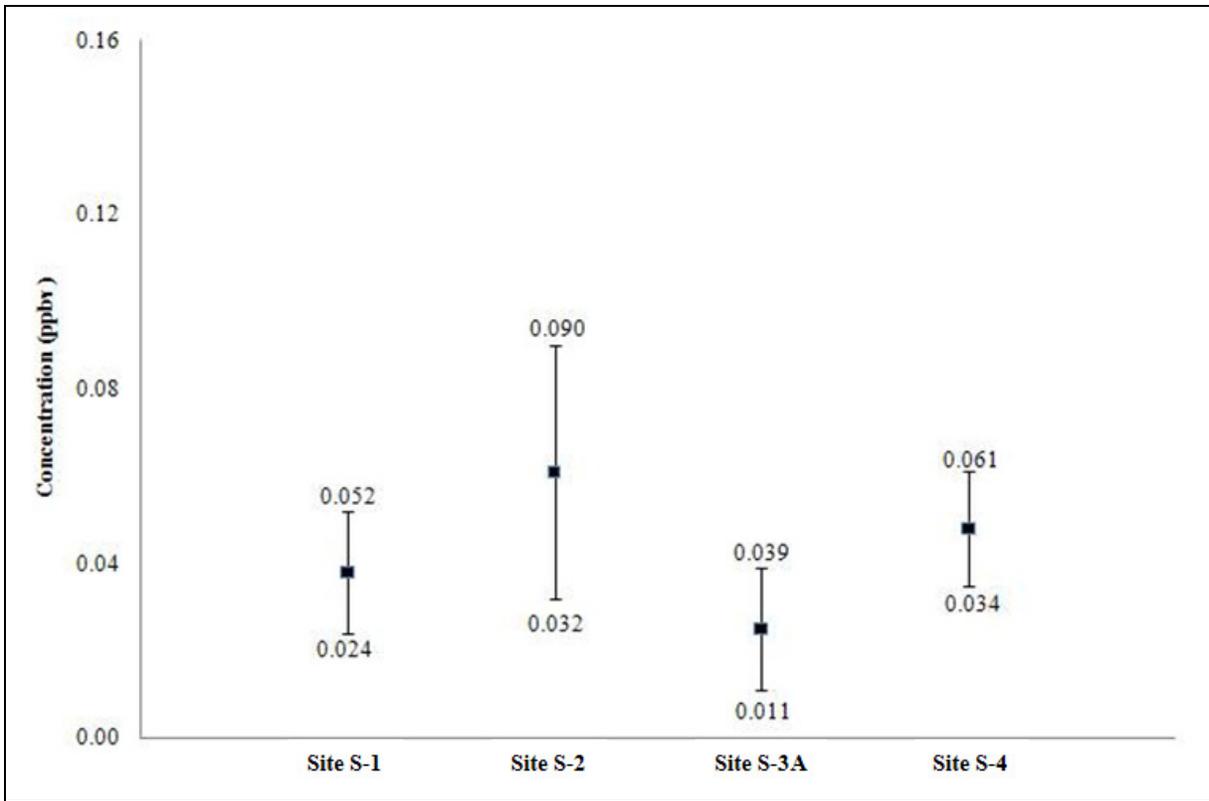


Figure 2.5-7. Tetrachloroethylene Average Concentrations by Site

Table 2.5-20. Meteorological Stations Used in This Study

| Site | Closest Meteorological Station | Distance/ Orientation from Site | Type | Alternate Meteorological Station | Distance/ Orientation from Site | Type |
|------|--|------------------------------------|--------------------------|-----------------------------------|------------------------------------|--------------------------|
| S-1 | Dallas–Ft. Worth International (03927) | 5.29 miles/ north | National Weather Service | Oakwood Terrace Elementary School | 2.75 miles/ west | Weatherbug |
| S-2 | Nolan High School (NOLAN) | 2.22 miles/ west | Weatherbug | Arlington Municipal Airport | 10.30 miles/ southeast | National Weather Service |
| S-3A | Nolan High School (NOLAN) | 0.50 miles/ southeast | Weatherbug | Arlington Municipal Airport | 12.15 miles/ southeast | National Weather Service |
| S-3B | Ft. Worth Naval Air Station/Carswell Field (13911) | 3.11 miles/ east | National Weather Service | Ft. Worth Northwest (48-439-1002) | 8.23 miles/ east-northeast | TCEQ |
| S-4 | Ft. Worth Meacham Airport (13961) | 2.98 miles/ northwest | National Weather Service | Ft. Worth Northwest (48-439-1002) | 2.21 miles/ northwest | TCEQ |
| S-5 | Ft. Worth Alliance Airport (53909) | 3.88 miles/ east | National Weather Service | Eagle Mountain Lake (48-439-0075) | 5.40 miles/ west | TCEQ |
| S-6 | Spinks Airport (03985) | 0.69 miles/ north-northeast | National Weather Service | Wm. Stribling Elementary School | 2.75 miles/ southeast | Weatherbug |
| S-7 | Spinks Airport (03985) | 0.40 miles/ southeast | National Weather Service | Wm. Stribling Elementary School | 3.50 miles/ southeast | Weatherbug |

Figure 2.5-8 presents an overview of the monitoring sites and their nearest meteorological stations.

Windrose Analysis

In this set of analyses, ERG compared wind patterns on sample days to patterns for the whole sampling period, as well as comparing the sampling period's wind patterns to historical wind patterns. The purpose of these analyses was to confirm that sampling occurred under typical conditions. Finally, the historical two-month patterns were compared to the long-term annual patterns that were generated at onset of this study.

Key Point: Windrose Analysis
Based on the windrose profiles associated with each monitoring site during the sampling period, the locations of the monitoring sites were accurately sited relative to wind direction.

Windroses were created for several time periods (historical, annual for 2009, sample days, and sample period) for each sampling site. The data for the windroses came from the NWS stations, EPA's Air Quality System (AQS), and the Fort Worth Weatherbug Network; the windroses were created using Lakes Environmental's WRPlot[®] View (version 6.5.1) software.

The following observations are made for each site:

- *Site S-1:* As presented in Table 2.5-20, the closest meteorological station is located at Dallas–Fort Worth International Airport, approximately 5 miles north of Site S-1. As shown in Figure 2.5-9, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.
- *Site S-2:* As presented in Table 2.5-20, the closest meteorological station is located at Nolan High School, which is approximately 2 miles west of Site S-2. For historical comparisons, ERG used the meteorological data from Arlington Municipal Airport, a station approximately 10 miles to the southeast. As shown in Figure 2.5-10, the sample day and sample period windroses at Nolan High School are from the south, south-southeast, and southeast, while the windroses at Arlington Municipal Airport are predominantly southerly.
- *Site S-3A:* Similar to Site S-2, the closest meteorological station is located at Nolan High School, which is approximately one-half mile southwest of Site S-3A. For historical comparisons, ERG used the meteorological data from Arlington Municipal Airport, a station approximately 12 miles to the southeast. As shown in Figure 2.5-11, the sample day and sample period windroses at Nolan High School are from the south, south-southeast, and southeast, while the windroses at Arlington Municipal Airport are predominantly southerly.
- *Site S-3B:* As presented in Table 2.5-20, the closest meteorological station is located at Fort Worth Naval Air Station/Carswell Field, approximately 3 miles east of Site S-3B. As shown in Figure 2.5-12, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.
- *Site S-4:* As presented in Table 2.5-20, the closest meteorological station is located at Fort Worth Meacham Airport, approximately 3 miles northeast of Site S-4. As shown

- in Figure 2.5-13, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.
- *Site S-5*: As presented in Table 2.5-20, the closest meteorological station is located at Fort Worth Alliance Airport, approximately 4 miles east of Site S-5. As shown in Figure 2.5-14, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.
 - *Site S-6*: As presented in Table 2.5-20, the closest meteorological station is located at Spinks Airport, less than 0.75 miles north-northeast of Site S-6. As shown in Figure 2.5-15, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.
 - *Site S-7*: Similar to Site S-6, the closest meteorological station is located at Spinks Airport, less than half a mile southeast of Site S-7. As shown in Figure 2.5-16, all five time-period windroses appear similar, with winds predominantly from the south-southeast and south.

As described in the Ambient Air Monitoring Plan, the monitoring network was designed in part after understanding typical wind patterns in and around the City of Fort Worth through the use of historical windroses. Monitoring sites were placed to capture ambient air downwind of the target areas of interest. The general conclusion from the above windrose comparisons at each monitoring site during the study period is that wind patterns on sample days were generally typical of year-round and long-term historical wind patterns, indicating that the monitoring sites were able to collect samples from the target direction.

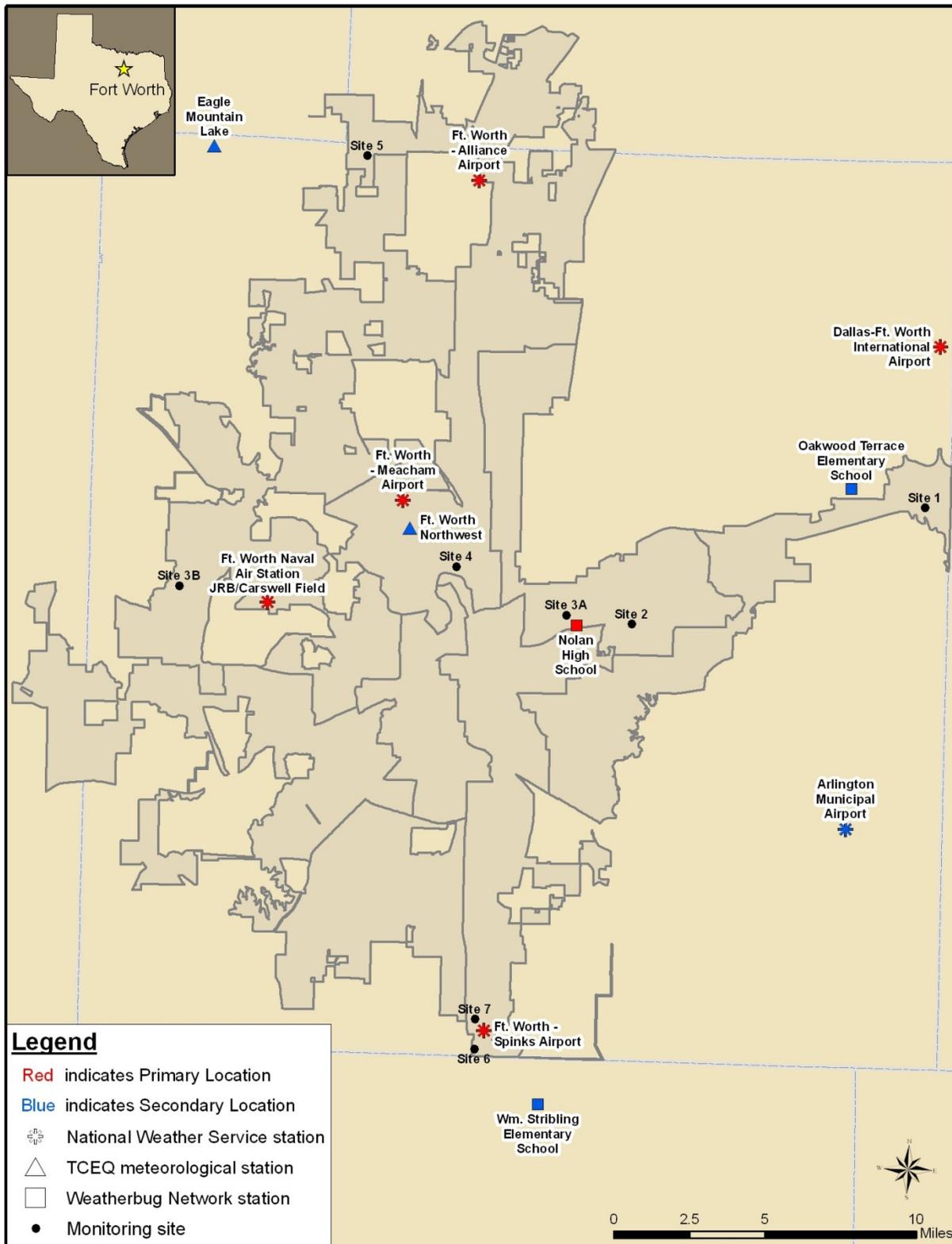


Figure 2.5-8. Meteorological Stations and Monitoring Site Locations

NWS WBAN 03927

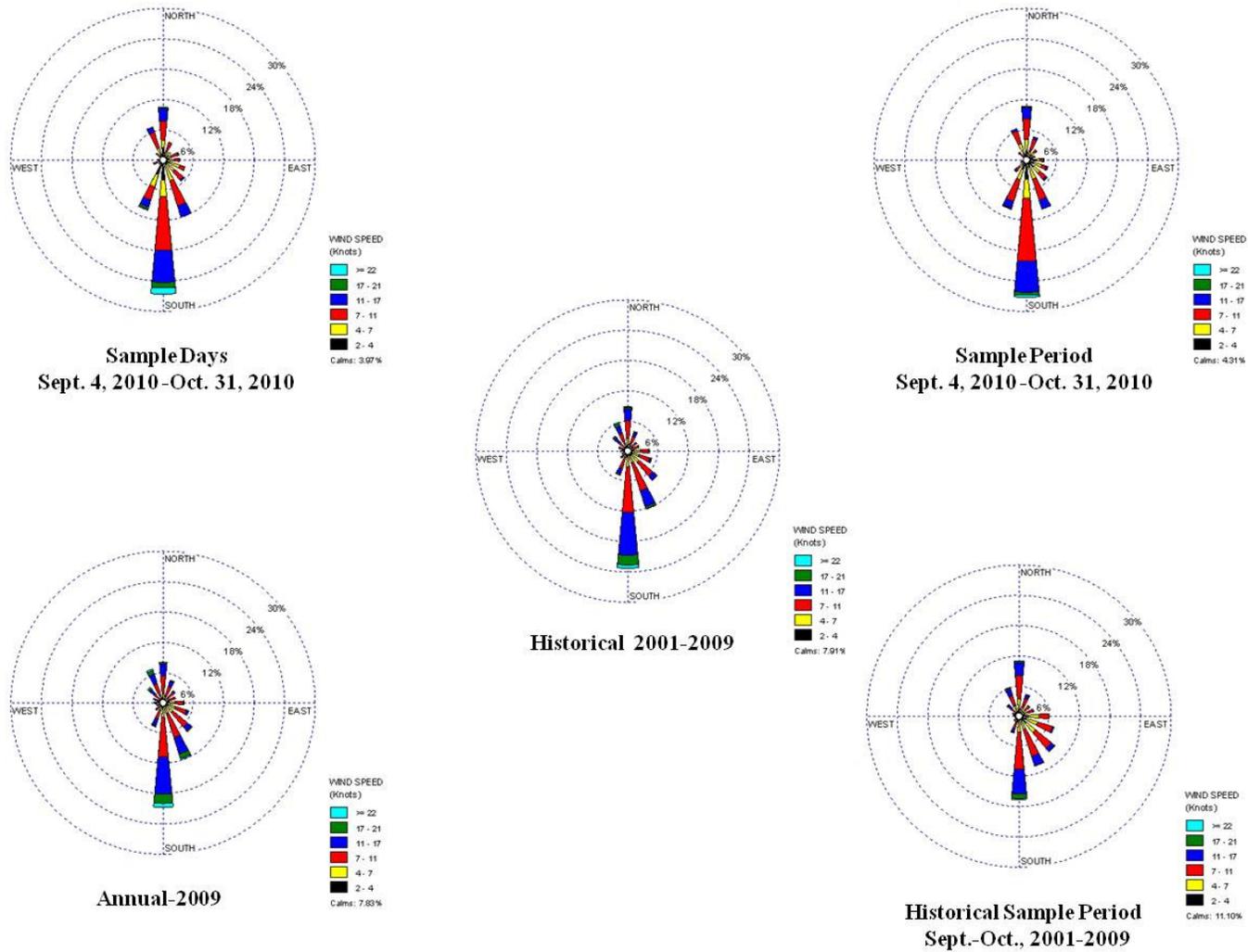
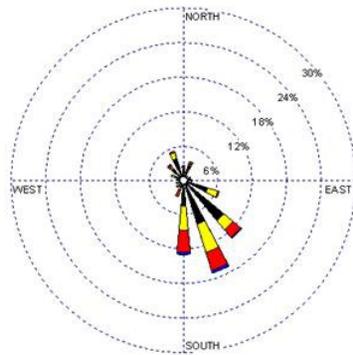


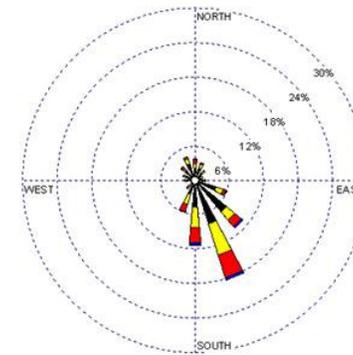
Figure 2.5-9. Site S-1 Windrose Comparisons

Nolan High School



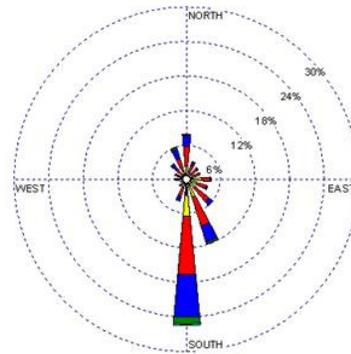
Sample Days
Sept. 4, 2010-Oct. 31, 2010

WIND SPEED
(Knots)
 ≥ 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 20.94%



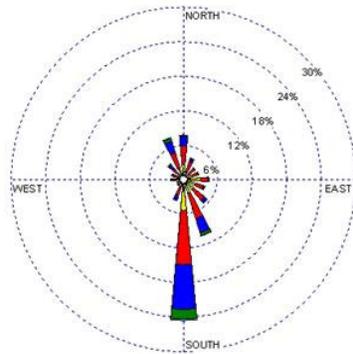
Sample Period
Sept. 4, 2010-Oct. 31, 2010

WIND SPEED
(Knots)
 ≥ 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 20.28%



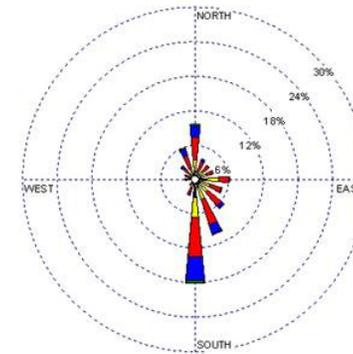
Historical 2001-2009
(WBAN 53907)

WIND SPEED
(Knots)
 ≥ 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 11.00%



Annual 2009
(WBAN 53907)

WIND SPEED
(Knots)
 ≥ 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 11.30%



Historical Sample Period
Sept.-Oct., 2001-2009
(WBAN 53907)

WIND SPEED
(Knots)
 ≥ 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 15.81%

Figure 2.5-10. Site S-2 Windrose Comparisons

Nolan High School

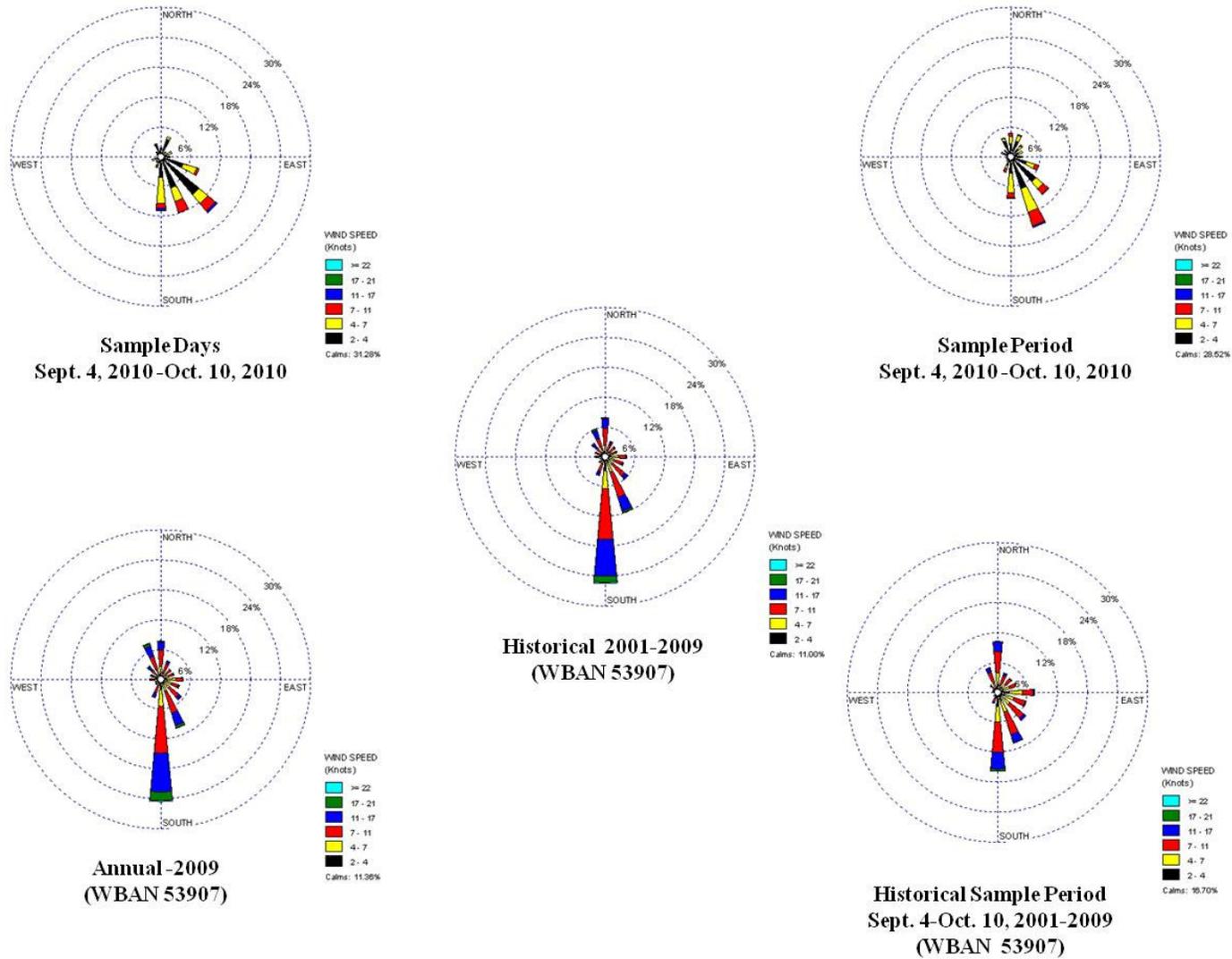
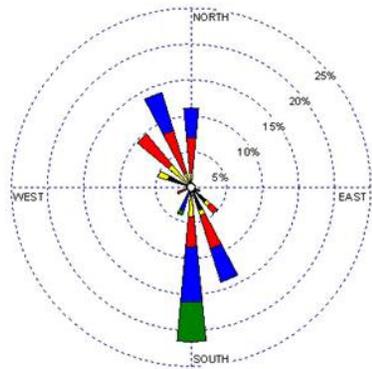


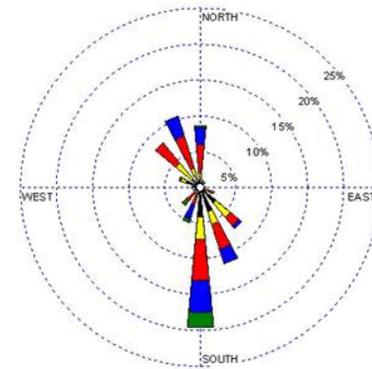
Figure 2.5-11. Site S-3A Windrose Comparisons

NWS WBAN 13911



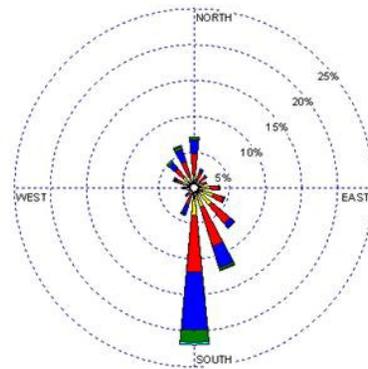
Sample Days
Oct. 13, 2010-Oct. 31, 2010

WIND SPEED (Knots)
 >= 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 9.72%



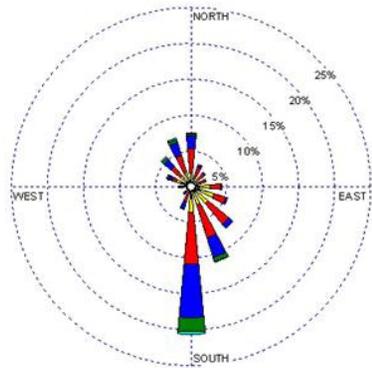
Sample Period
Oct. 13, 2010-Oct. 31, 2010

WIND SPEED (Knots)
 >= 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 15.10%



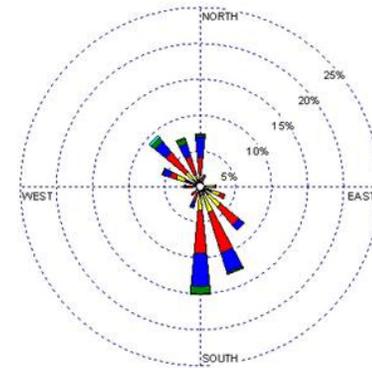
Historical 2005-2009

WIND SPEED (Knots)
 >= 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 13.22%



Annual-2009

WIND SPEED (Knots)
 >= 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 11.41%



Historical Sample Period
Oct. 13-Oct. 31, 2005-2009

WIND SPEED (Knots)
 >= 22
 17 - 21
 11 - 17
 7 - 11
 4 - 7
 2 - 4
 Calms: 17.58%

Figure 2.5-12. Site S-3B Windrose Comparisons

NWS WBAN 13961

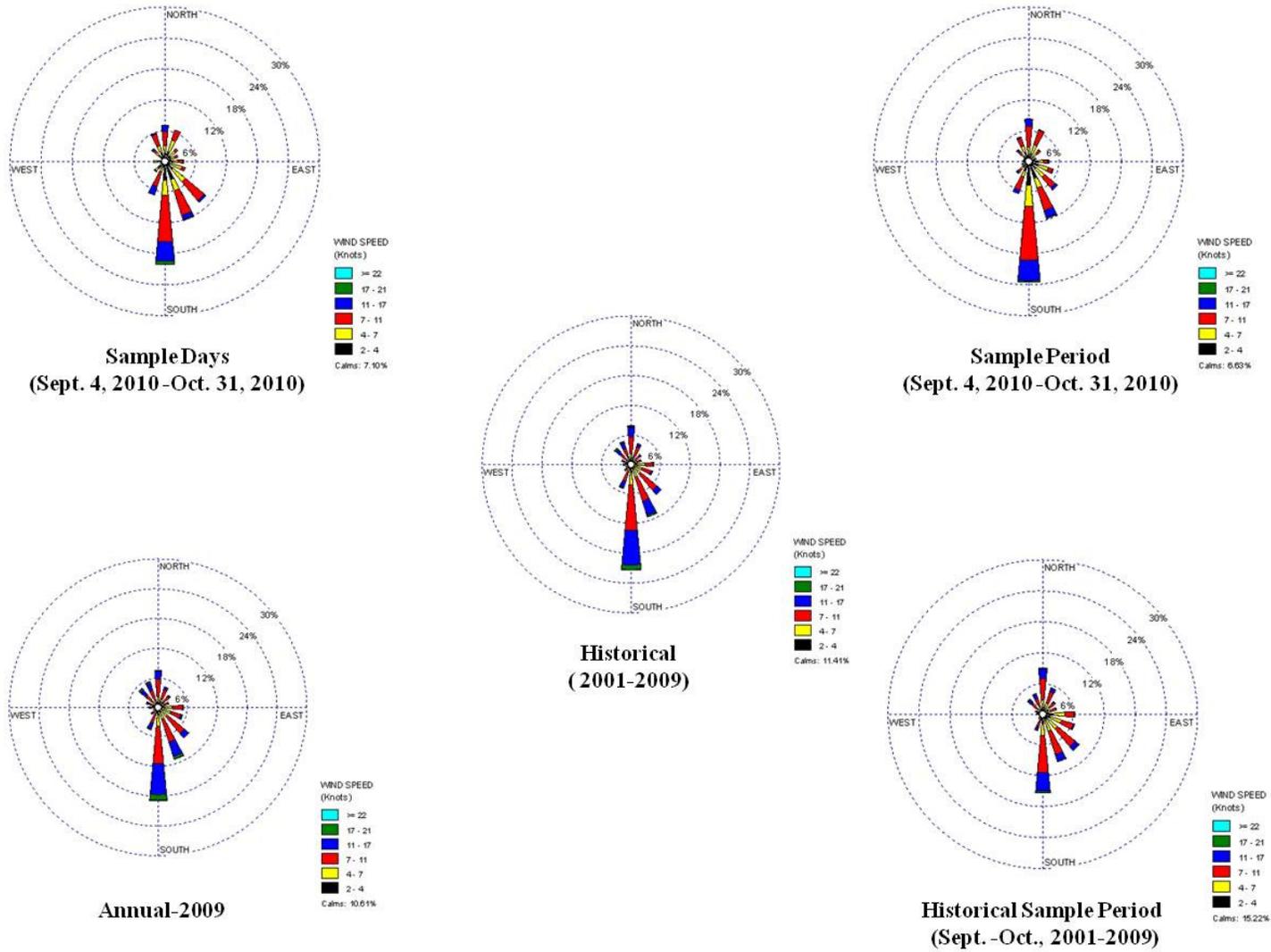


Figure 2.5-13. Site S-4 Windrose Comparisons

NWS WBAN 53909

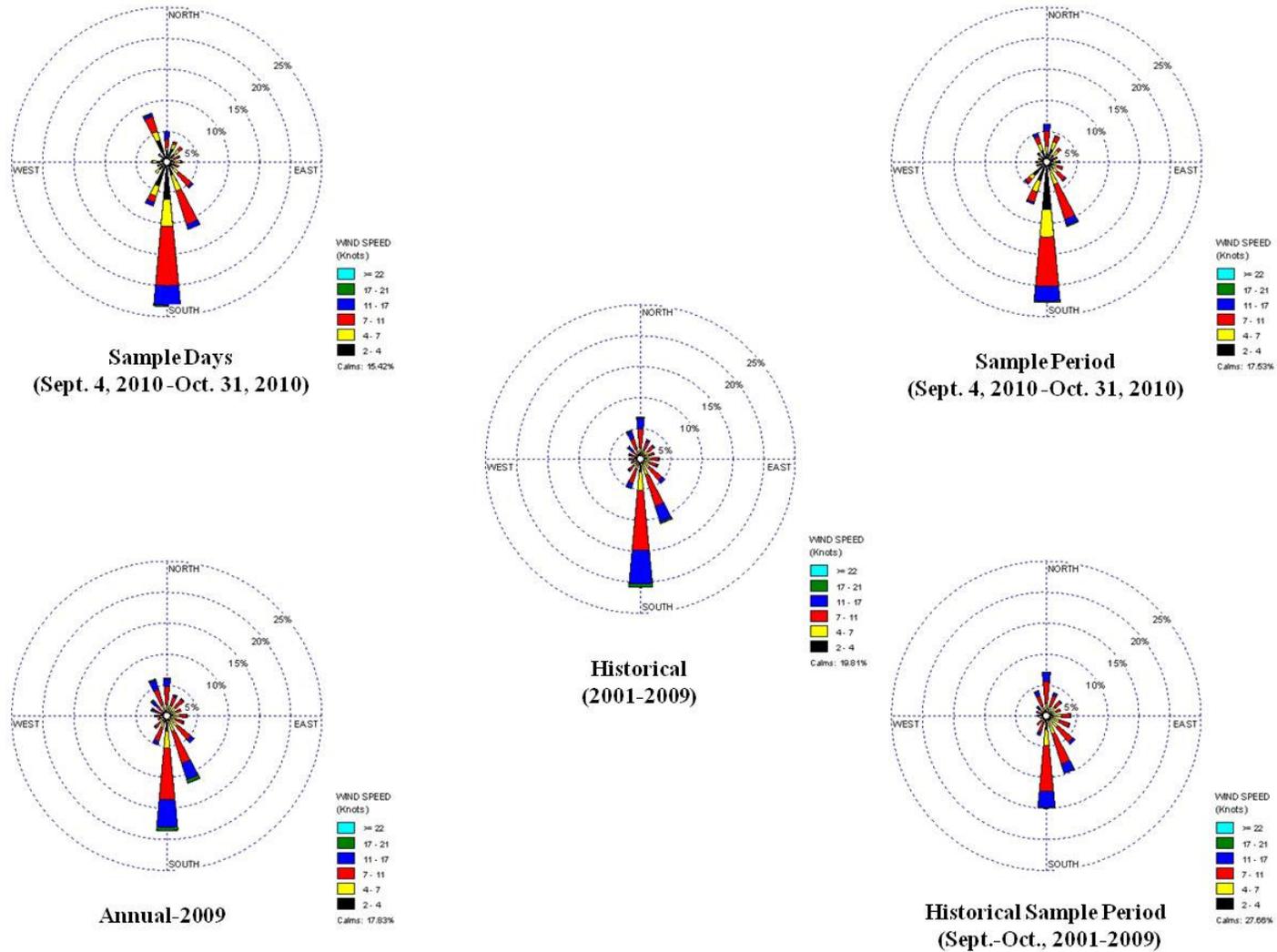


Figure 2.5-14. Site S-5 Windrose Comparisons

NWS WBAN 03985

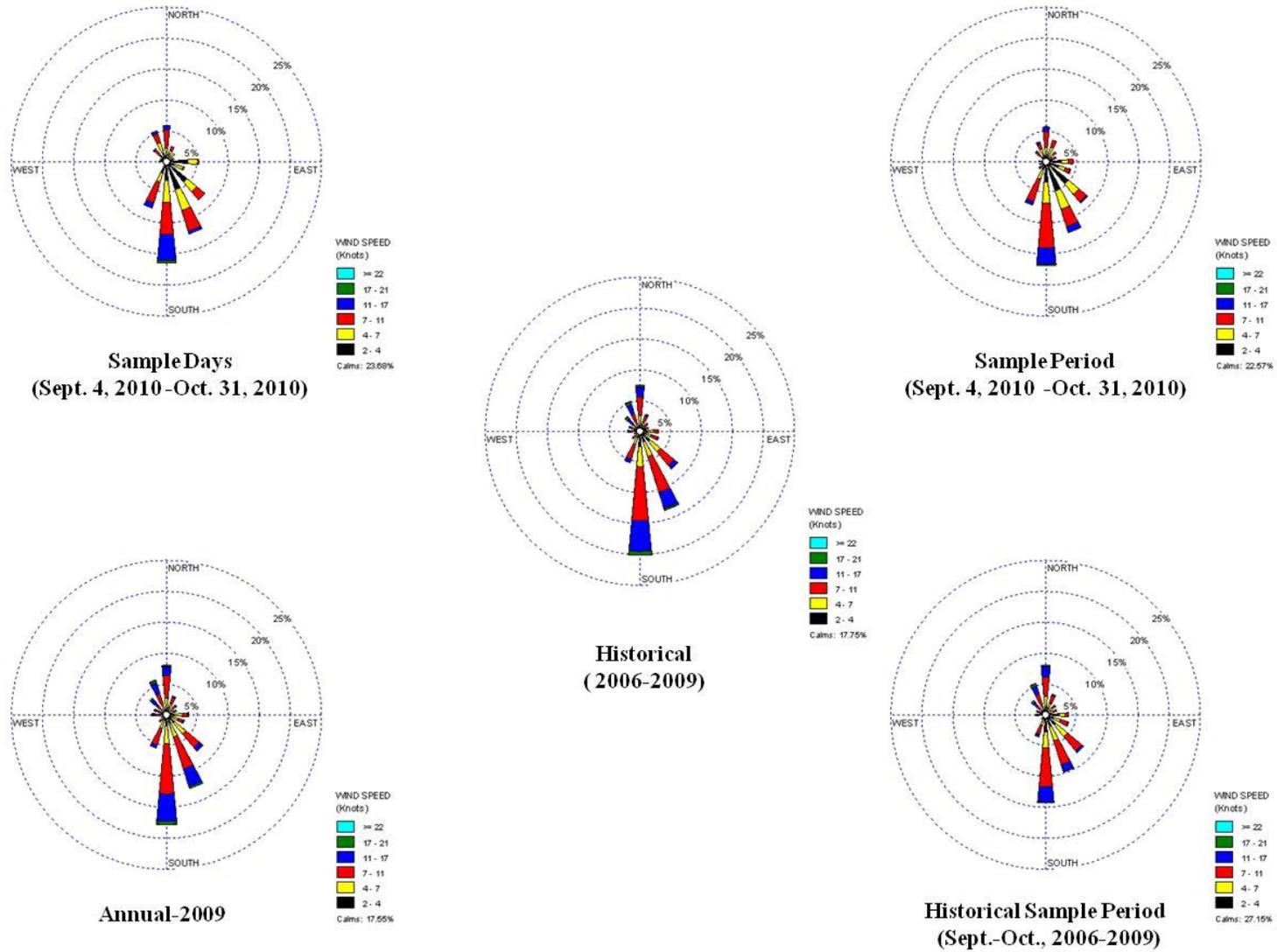


Figure 2.5-15. Site S-6 Windrose Comparisons

NWS WBAN 03985

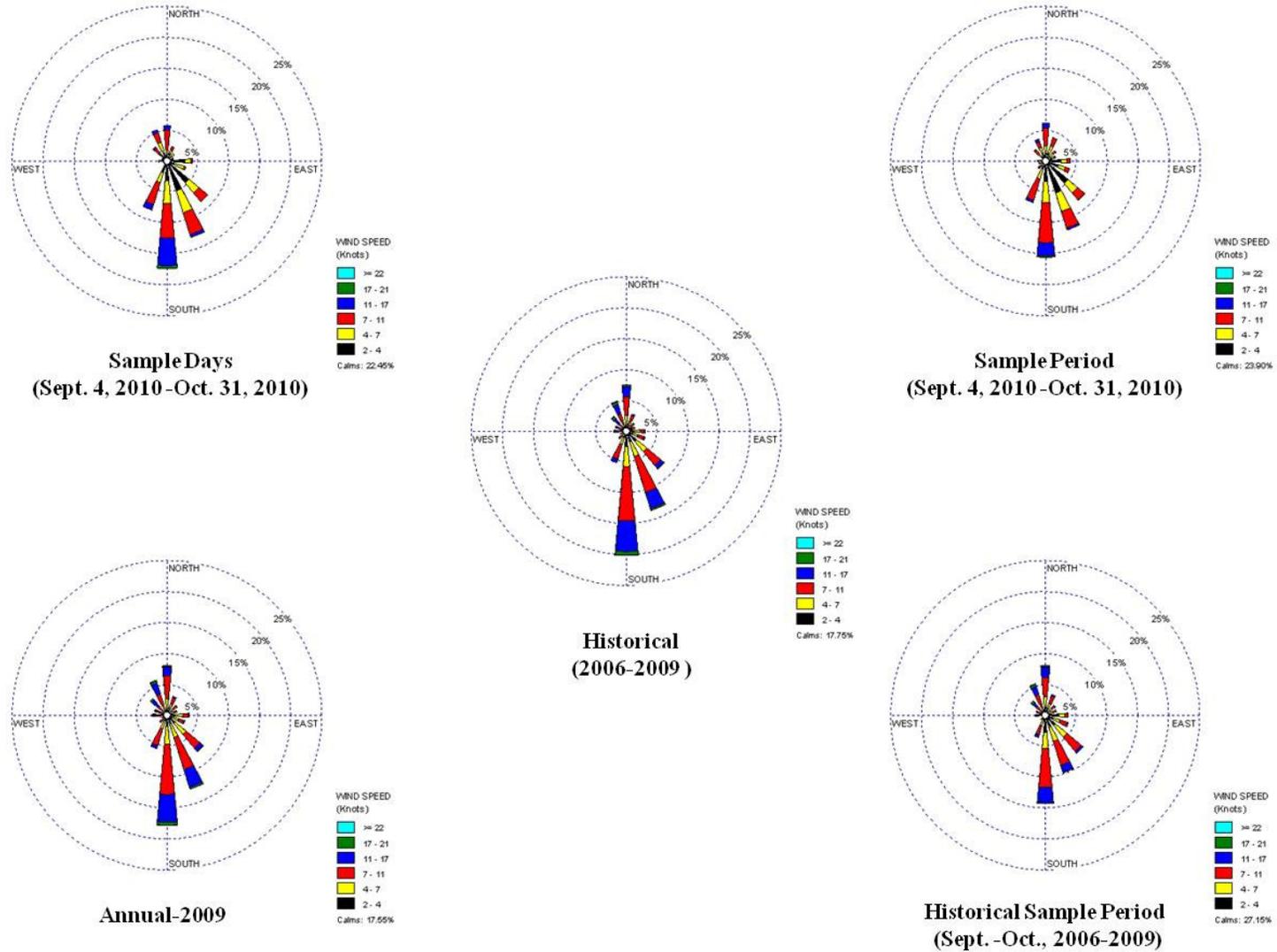


Figure 2.5-16. Site S-7 Windrose Comparisons

2.6 Ambient Air Monitoring Conclusions

Ambient air monitoring sampling at eight monitoring sites for nearly 140 pollutants yielded over 15,000 data points for this study. The ambient monitoring data presented in this report is based on air samples collected during a two-month timeframe at eight locations. The data should not be used to make inferences about air quality during times when, and locations where, samples were not collected. Insights from the dispersion modeling analysis have been used to help address this inherent limitation of the ambient air monitoring program, and a full discussion of the health implications of this study are presented in Section 5 of this report.

Key findings from the ambient monitoring study are as follows:

- 169 ambient air samples from 8 locations in Fort Worth were collected and analyzed, resulting in over 15,000 ambient air data points generated for this study.
- ERG found little variability across the sampling network for certain pollutants, such as carbon tetrachloride, chloroform, chloromethane, crotonaldehyde, dichlorodifluoromethane, dichlorotetrafluoroethane, ethylene, 1-hexene, isoprene, propylene, trichlorotrifluoromethane, and trichlorotrifluoroethane. The low variability across the entire network suggests that these pollutants are not affected by localized, anthropogenic sources, but rather exist as background pollutants.
- Benzene and carbon tetrachloride were identified as key VOCs at each site.
- Acetaldehyde and formaldehyde were identified as key carbonyls at Sites S-4 and S-5.
- No SNMOCs were identified as key pollutants.
- Concentrations measured at Site S-4 (located in a high-level activity area near compressor stations, well pads, and mobile sources) were generally higher than at other sites. For some of the key pollutants (acetaldehyde and benzene), concentrations at this site were considerably higher.
- Pollutant concentrations at Sites S-6 and S-7 (located in a medium-level activity area) were surprisingly low relative to other sites, especially given their close proximity to active well pad locations.
- Concentrations at Site S-1 (“background” site with no nearby natural gas well pads upwind) were generally similar to Site S-2 (“mobile sources” site). Concentrations at these two sites were slightly higher than Sites S-6 and S-7.
- Concentrations at the two “preproduction” sites did not display higher pollutant concentrations than the two monitoring stations designated as “background” and “mobile source” sites.
- Wind patterns observed during the sampling period were consistent with historical wind patterns, indicating proper placement of the ambient air monitors.

3.0 Point Source Testing

ERG subcontracted the point source testing task to Sage Environmental Consulting LP (Sage). This section discusses how the point source testing task was conducted and the results that were obtained.

This section has seven sub-sections:

- 3.1 Introduction – Provides a summary of the purpose of the point source study, the scope of work, and the project timeline.
- 3.2 Point Source Survey Sampling Equipment – This section describes the field instrumentation.
- 3.3 Point Source Survey and Sampling Procedures – This section discusses survey procedures, documentation of emission points, the collection of emission data, canister sampling, and data archival procedures.
- 3.4 Emissions Calculation Procedures – The development of canister-derived emissions, the application of correlation equations, the creation of surrogate tank and non-tank emissions profiles, the use of EPA default-zero emissions factors, the use of engine emissions tables, and the calculation of Screening Emissions Factors are discussed in this section.
- 3.5 Point Source Emissions Results – The results of the point source study are provided in the charts and tables of this section.
- 3.6 Quality Control (QC) Results – This section contains the results of the QC procedures specified in the Final Point Source Test Plan including instrument calibration checks, canister sample collection procedures, and laboratory analytical checks.
- 3.7 Point Source Testing Conclusions – This section presents conclusions of the point source testing task.
- Appendix 3-A: Emissions summary for each point source site surveyed.
- Appendix 3-B: Two DVD discs containing the emissions calculation workbook, “MASTER - Well Char Emission Data 2011-07-13_FINAL” together with the data collected for each point source site.
- Appendix 3-C: One DVD containing the canister sample logbooks and the canister analytical results, the laboratory quality control results and the canister chain-of-custody documentation.

3.1 Introduction

The purpose of the point source emissions study was to characterize emissions from natural gas-related point sources located within the Fort Worth city limits. These sources are categorized in seven groups:

- Well Pads – Comprising the largest group of sites visited, natural gas well pads typically contained several active wells, produced water storage tanks, separators, and

- metering runs (piping). Approximately one-third (123) of the well pads also had lift compressors used to increase a well's gas production rate. Emission sources typically related with well pads include equipment leaks, produced water and condensate storage and loading, and lift compressors. The amount of condensate production and related emissions are usually dependant on whether the produced gas is wet or dry gas.
- Compressor Stations – Compressor stations contain one or more large (generally 250 horsepower (hp) or greater) line compressors which provide the necessary pressure to move the natural gas through many miles of transmission lines. The most significant emissions from compressor stations are usually from combustion at the compressor engines or turbines. Other emissions sources may include equipment leaks, storage tanks, glycol dehydrators, flares, and condensate and/or wastewater loading. None of the compressor stations visited included turbines.
 - Processing Facilities – Processing facilities generally remove impurities from the natural gas, such as carbon dioxide, water, and hydrogen sulfide. These facilities may also be designed to remove ethane, propane, and butane fractions from the natural gas for downstream marketing. Processing facilities are usually the largest emitting natural gas-related point sources including multiple emission sources such as, but not limited to equipment leaks, storage tanks, separator vents, glycol dehydrators, flares, condensate and wastewater loading, compressors, amine treatment and sulfur recovery units. The Processing Plant visited included most of these sources except for sulfur recovery units.
 - Saltwater Treatment Facility – The single saltwater treatment facility permitted for operation within the City's boundaries uses underground injection to dispose of well production liquids such as oilfield brine, drilling mud, fracture materials, and well treatment fluids. Emission sources typically related with salt water treatment facilities include equipment leaks, storage tanks, and generators.
 - Drilling Operation – Drilling of a new well is typically a two to three week process from start to finish and involves several large diesel-fueled generators. Other emission sources related to drilling operations may include equipment leaks and waste storage.
 - Fracking Operation – Fracking is the high pressure injection of water mixed with sand and a variety of chemical additives into the well to fracture the shale and stimulate natural gas production from the well. Fracking operations can last for several weeks and involve many large diesel-fueled generators. Other emission sources related to fracking operations may include equipment leaks and waste storage.
 - Flowback – Flowback is a well completion activity that occurs following the conclusion of a fracking operation. Flowback thus entails the removal of fracking fluids from the well in preparation either for a subsequent phase of treatment or for cleanup and returning the well to production. Similar to fracking operations, other related emission sources may include equipment leaks and waste storage.

The point source teams surveyed a total of 388 sites (including repeat visits at two sites). The sites are identified by owner and type in Table 3.1-1. Figure 3.1-1 locates each site on an overlay map of Fort Worth. Figure 3.1-2 indicates which well pads were considered to be wet gas, and which were considered to be dry gas. For purposes of this study, a site was considered to be a wet gas site if it produced more than 1 barrel of condensate/day as indicated by the Texas Railroad Commission records.

Key Point: Sites Surveyed

This study included surveying a total of 388 sites comprised of well pads, compressor stations, processing facilities, a salt water treatment facility, drilling operations, fracking operations, and completion operations.

The point source emissions survey occurred in two phases. Phase I was completed in the fall of 2010 (August 30 – October 21, 2010). Phase II took place during the beginning months of 2011 (January 4 – February 16, 2011). There were no significant differences in methodology or scope between the two phases. Any slight differences between the methodologies are discussed below. During Phase I, 199 point source sites were surveyed and are identified using Point Source ID's PS-001 through PS-201. An additional 189 sites were completed in Phase II and are identified as Point Source ID's 6 through 487.

Quality Control results indicate that the field and the laboratory equipment were in a state of control during the point source survey and that project quality control checks were followed. Site-by-site emission summaries are provided in Appendix 3-A of this report. Appendix 3-B provides the field data and emission calculation workbook on two DVD discs. Appendix 3-C contains the canister analytical data on one DVD disc.

3.2 Point Source Emissions Survey Sampling Equipment

The point source surveys were carried out by two teams of two persons each. In Phase I each team was staffed by a Sage employee and an employee from Hicks & Co. Environmental (Hicks). This changed in Phase II to one team of two Sage employees while the other team remained a Sage and a Hicks employee. The point source teams were equipped with the following test equipment:

- FLIR™ Infrared (IR) Camera.
- Thermo Environmental™ Toxic Vapor Analyzer.
- Bacharach™ Hi Flow Sampler.
- Summa Passivated Stainless Steel Canisters from TestAmerica™.
- Miscellaneous Support Equipment (Global Positioning System (GPS) Finder, Laser Distance Finder, Weather meter, Digital Camera).

Table 3.1-1. Point Source Sites by Owner and Type

| Owners | Well Pad | Compressor Station | Processing Facility | Saltwater Treatment Facility | Drilling Operation | Fracking Operation | Completion Operation (Flowback) | Total |
|----------------------------|-----------------|--------------------|---------------------|------------------------------|--------------------|--------------------|---------------------------------|------------|
| Burnett Oil Production | 2 | | | | | | | 2 |
| Chesapeake Operating Inc. | 84 ^a | 2 | | 1 | | | | 87 |
| Crosstex | | | 1 | | | | | 1 |
| Crow Creek Operating Inc | 3 | | | | | | | 3 |
| Devon Energy Production Co | 105 | | | | | | | 105 |
| Eagle Oil And Gas | 1 | | | | | | | 1 |
| Encana Oil & Gas (USA) Inc | 18 ^b | | | | | | | 18 |
| Finley | 2 | | | | | | | 2 |
| Frost Brothers | 2 | | | | | | | 2 |
| Grand Operating Inc | 1 | | | | | | | 1 |
| Lakota Energy LTD | 1 | | | | | | | 1 |
| Newark Energy | 1 | | | | | | | 1 |
| Proven Resources | 3 | | | | | | | 3 |
| Quicksilver Resources | 28 | 1 | | | | 1 | 1 | 31 |
| Range Production Co | 16 | 3 | | | | | | 19 |
| Vargus Energy LTD | 1 | | | | | | | 1 |
| Williams Production | 5 | | | | | | | 5 |
| XTO Energy Inc | 102 | 2 | | | 1 | | | 105 |
| Grand Total | 375 | 8 | 1 | 1 | 1 | 1 | 1 | 388 |

^a Includes repeat visits to the same site i.e., Site IDs: PS-192 and 294.

^b Includes repeat visits to the same site i.e., Site IDs: PS-086 and 260.

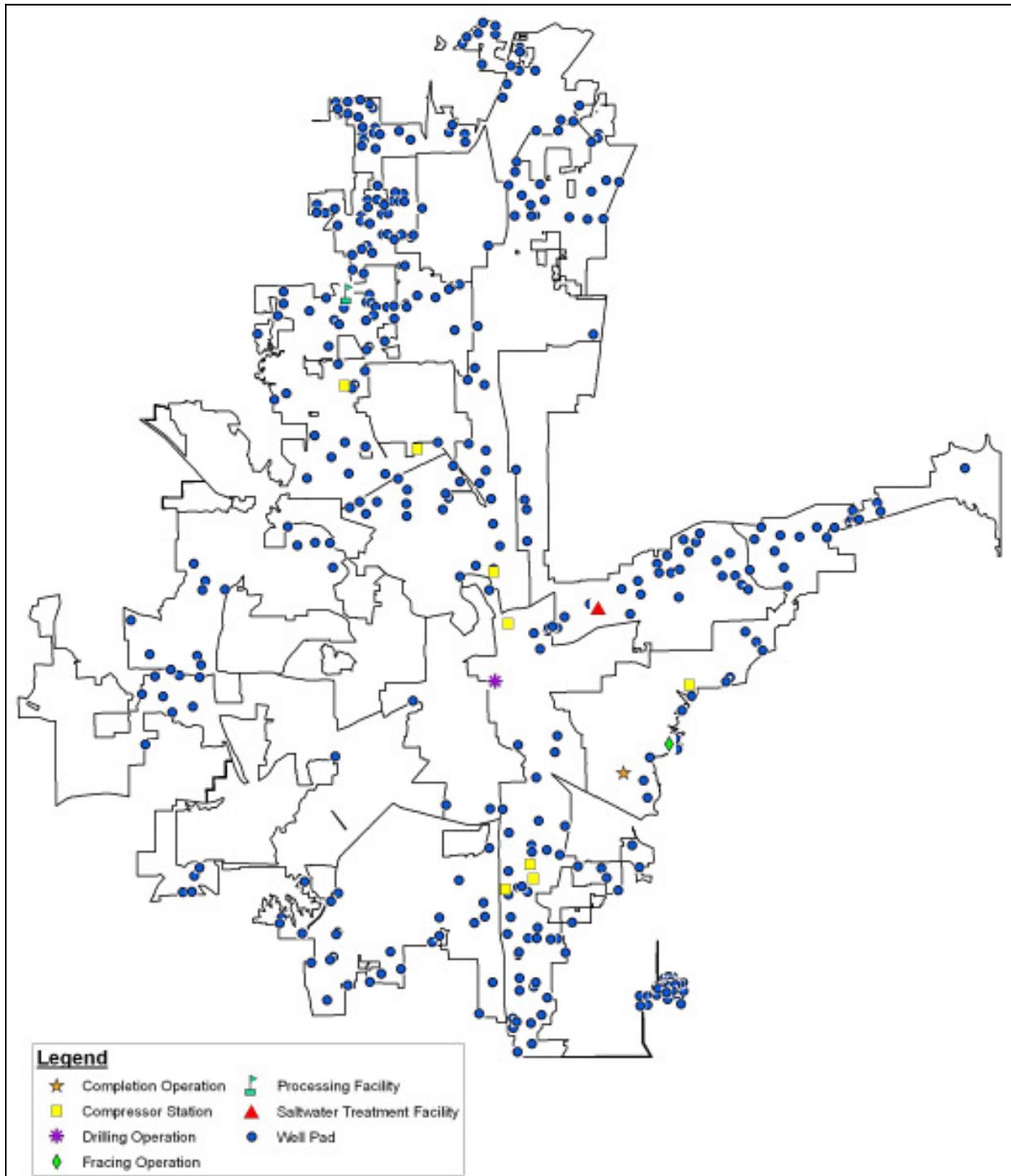


Figure 3.1-1. Point Source Survey Sites (August 2010 – February 2011)

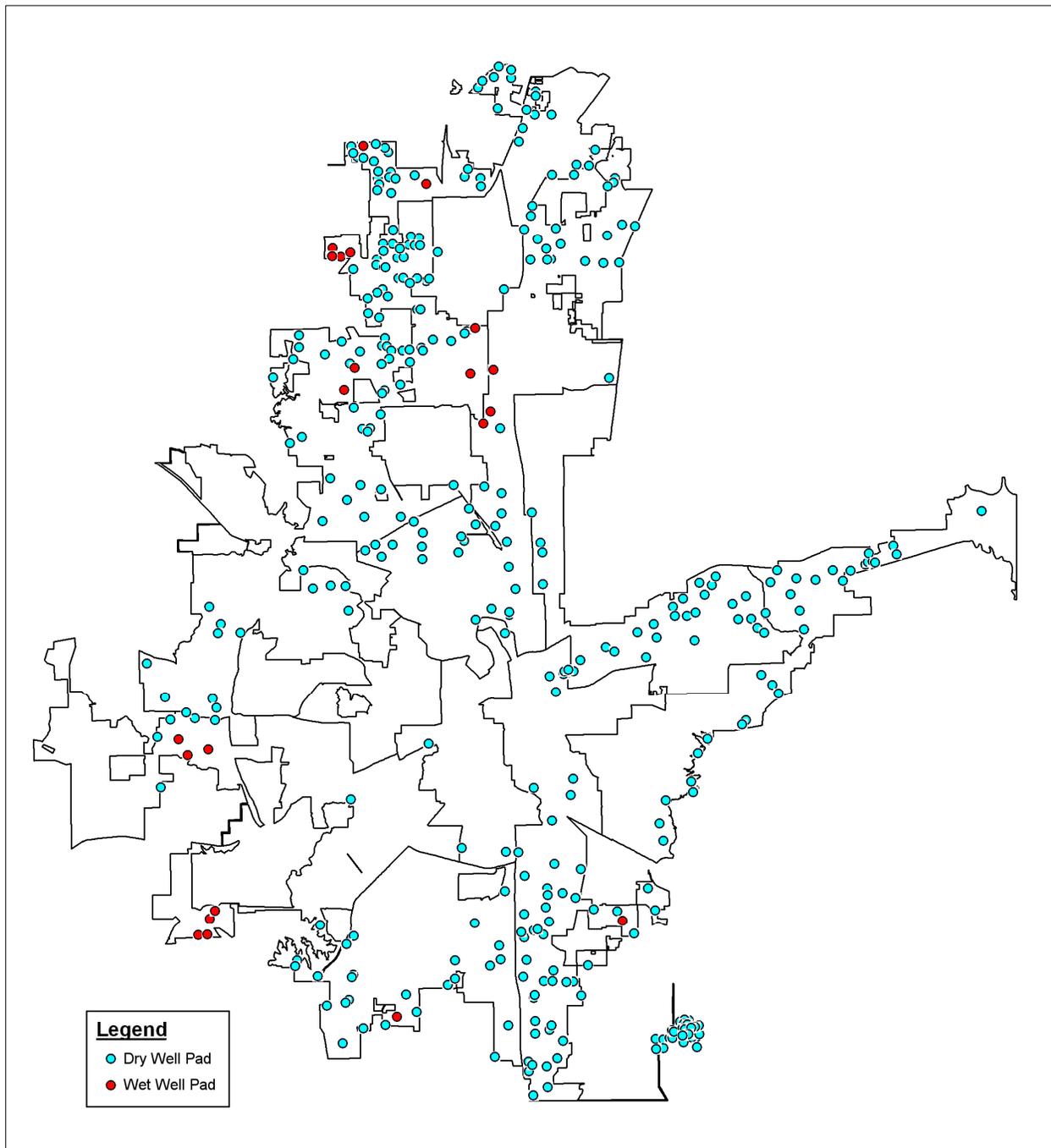


Figure 3.1-2. Wet Gas and Dry Gas Well Pads

3.2.1 The FLIR™ Infrared Camera

FLIR™ infrared cameras were used to survey all equipment in natural gas service at each point source site visited. The IR camera enables rapid detection of large emission sources (for instance, sources with concentrations > 10,000 parts per million by volume (ppmv)). Moreover, the infrared camera is well suited to detecting methane emissions, the largest constituent of

natural gas, as well as ethane, propane, and butane. Figure 3.2-1 illustrates the use of a FLIR™ infrared camera at a well site.



Figure 3.2-1. IR Camera Imaging at a Well Site

Two models of infrared camera were used on this project. One team used the GasFindIR™ camera equipped with a 50 mm lens and an external COWAN™ video recorder. The second team used the FLIR™ Model GF-320 infrared camera. While the two cameras share identical performance characteristics, the GF-320 has more user-friendly features (such as built-in video recorder and digital camera). All infrared camera imaging was performed by trained Level 1 or Level 2 Thermographers.

3.2.2 The Toxic Vapor Analyzer (TVA)

The TVA is a portable, battery-powered, intrinsically safe, hydrocarbon analyzer with a measurement range extending from 0.5 ppmv (parts per million by volume) to 50,000 ppmv hydrocarbon. This instrument was used to screen a random selection of site valves and connectors for leaks below the detection limit of the IR camera. It was also used to measure emissions detected with the camera, although in most cases these measurements resulted in a “flame-out” of the analyzer (that is, a reading greater than 50,000 ppmv). Figure 3.2-2 illustrates the use of a TVA at a well site.

***Key Point: IR Camera and TVA
Detection Limits***

The Infrared camera is typically used to detect large emission sources at concentrations >10,000 ppmv whereas the TVA can detect emissions with concentrations as low as 0.5 ppmv.



Figure 3.2-2. Method 21 Screening with the TVA at a Well Site

Use of the TVA followed EPA Method 21 procedures (40 CFR 60 Appendix A), which prescribes how to screen various components for fugitive emissions. Each TVA was calibrated daily prior to use with methane-in-air calibration standards.

3.2.3 The Hi Flow Sampler

The Hi Flow Sampler is a portable, intrinsically safe instrument designed to measure the rate of gas leakage around various pipe fittings, valve packings and compressor seals found at natural gas facilities. Because of its high flow rate (8 to 10 standard cubic feet per minute (SCFM)) the Hi Flow Sampler is able to completely capture any gas emitting from a component. The rate of the gas leak is determined by accurately measuring the flow rate of the sampling stream and the natural gas concentration. Figure 3.2-3 illustrates the sampling of a tank vent with the Hi Flow sampler.



Figure 3.2-3. Sampling a Tank Vent with the Hi Flow Sampler

To make an emission measurement with the Hi Flow Sampler, an attachment is chosen that is suitable for capturing the entire leak. An assortment of attachments are available to enable testing of a wide variety of components. For instance, for thief hatches or tank vents, a large nylon bag attachment was used. A plunger-style attachment was used to enclose small valves. Flanges were enclosed with a plastic strap and secured with Velcro™. For equipment that could not be enclosed with the standard Hi Flow Sampler attachments, plastic wrapping was used. With one end of the attachment enclosing the emission source and the other end attached to the instrument's main sampling hose, the Sampler was switched on and sampling initiated using the menu options available through the unit's controller. An entire Hi Flow Sampler test run lasted approximately 3 to 5 minutes.

For the point source surveys the Hi Flow Sampler was operated in its Automatic 2-Stage Mode, performing a leak rate measurement first at a high flow rate setting for one minute, and then automatically switching to a lower flow rate for a second minute of additional sampling. The unit calculated the degree of comparison between two measurements and displayed the total sample flow rate in cubic feet per minute (CFM) and the leak as percent methane and as the percent of the sample flow rate (% CFM).

3.2.4 Summa Canisters

Evacuated, six-liter, canisters provided by TestAmerica's™ Austin, Texas laboratory, were used to collect gas samples from selected emission points for VOC and HAP analysis by Gas chromatograph/Mass spectrometer (GC/MS) and for methane analysis by gas chromatography with a thermal conductivity detector (TCD). Canisters were shipped to the field office in a pre-cleaned, evacuated condition. Completed canisters were returned within several days of sample collection, together with chain-of-custody documentation, to TestAmerica™ for analysis. Unused canisters were kept securely stored in the project field office. Figure 3.2-4 illustrates how a canister sample was collected from the exhaust port of the Hi Flow Sampler.



Figure 3.2-4. Collecting a Canister Sample from the Exhaust Port of the Hi Flow Sampler

3.2.5 Miscellaneous Equipment

In addition to the equipment described above the point source teams also employed:

- A GPS receiver to document a site's North and West coordinates.
- A Kestrel Weathermeter™ to measure wind speed, temperature, relative humidity, and barometric pressure during a site visit.
- A laser distance finder to measure heights of emission points.
- An Archer™ field computer to record site data.
- A digital camera for site and equipment photos.

3.3 Point Source Survey and Sampling Procedures

This section discusses pre-test equipment preparation, site survey procedures, and data retrieval/archiving activities. The point source survey and sampling procedures followed were consistent with the Point Source Test Plan previously submitted and approved by the City of Fort Worth. Any deviations from this plan are discussed in the following sections as applicable.

3.3.1 Pre-Test Equipment Preparation

Equipment was prepared for use each morning prior to the first site visit. Preparations included:

- The IR Camera Daily Demo.
- A calibration check of the Hi Flow Sampler.
- A multipoint calibration of the TVA.

IR Camera Daily Demo Quality Assurance Check

The IR Camera Daily Demo provides a validation of the camera's operation by releasing a known mass emission rate of gas (100% propane) and measuring the distance from which the release can be reliably viewed. This validation was performed first thing each morning with both cameras at two mass emission rates: a low emission rate of 10 grams/hour propane and a higher emission rate of 31 grams/hour propane. The distance from which each emission rate could be detected (i.e. sighting distance) was recorded, together with wind direction, wind speed, temperature, relative humidity, barometric pressure, and percent cloud cover information. The equipment used to perform the daily demo included a steel compressed gas cylinder of 100% propane gas, a single stage gas regulator, a calibrated rotameter, flow control valves and tubing to position the emission flow at eye-level. The results of the daily demos are provided in Section 3.6 of this report and further documented in the field log notes included in Appendix 3-B.

Calibration Check of the Hi Flow Samplers

The Hi Flow Sampler contains two sensors – a background sensor and a leak sensor. Both sensors were calibrated at the start of Phase I and at the start of Phase II using certified standards of 2.5% methane-in-air and 100% methane. On a daily basis, prior to testing, the background and leak sensors of each Sampler were calibration-checked with the 2.5% methane standard. If an error greater than 10% resulted, the instrument was re-calibrated. Each Monday, the background and leak sensors of both instruments were calibration-checked with both the 2.5% and the 100% methane standards. Again, errors above 10% required re-calibration of the instrument.

The results of the Hi Flow Sampler daily calibration checks are provided in Section 3.6 of this report and further documented in the field log notes included in Appendix 3-B.

Multipoint Calibration of the TVAs

A multipoint calibration of each TVA was performed daily prior to testing with the following gases:

- Zero gas (<0.1 ppmv total hydrocarbon).
- Low Level Span gas (nominally 500 ppmv methane-in-air).
- Mid Level Span gas (nominally 1,000 ppmv methane-in-air).
- High Level Span gas (nominally 10,000 ppmv methane-in-air).

Following the calibration, each TVA would be re-checked with the same gases. The instrument was considered to be in a state of control if its response to each gas was accurate to within +/- 10%. Failure to meet this criterion required recalibration, repair, or replacement of the instrument.

3.3.2 Final Preparations

Following the instrument performance checks, data from the previous day would be reviewed for completeness and accuracy, the City Chief Gas Inspector would be called with the addresses of the first sites to be visited, and the vans would be loaded with the instrumentation and canisters. There would be a brief group safety discussion, the field office would then be locked, and the each team would depart to the first of their assigned sites for the day.

KeyPoint: Random Site Selection

To reduce bias in the survey relative to owner, operator, location, or any other variable, sites were selected for surveying on a random basis.

Sites were selected for surveying on a random basis. During the day, City Gas Inspectors were only told of the next scheduled site upon departure. These procedures were followed to avoid the possibility of site owners learning of the survey schedule in advance.

3.3.3 Site Arrival

Upon arrival at the designated point source site, the survey team met with the City Gas Inspector who unlocked the site gate to allow entrance to the site. On no occasion did the team enter a site without the City Gas Inspector also being present. Customarily at this time, a picture was taken of the front gate signage as part of the site documentation (Figure 3.3-1 shows an example of front gate signage).



Figure 3.3-1. Front Gate Signage

Immediately after arrival, a brief safety screening of the site would be conducted with the TVA to avoid entering an area of potentially dangerous pollutant concentrations.

One objective of each point source site visit was to document important site parameters such as the number of wells, storage tanks, and compressors, the site's GPS coordinates, the site's Railroad Commission (RRC) postings, and site throughput. Much of this information would be collected on preformatted data forms at the start of the survey. The use of preformatted forms helped to ensure a consistent data collection effort between the two teams as well as between sites. Figure 3.3-2 illustrates the site characterization form on which much of this information was recorded. In the "SITE LAYOUT" section of the form a sketch illustrating the positions of all major pieces of equipment would be drawn. All forms completed during the site surveys are included in Appendix 3-B.

| SITE CHARACTERIZATION FORM | |
|----------------------------|--|
| TEAM: | |
| SITE ID: | |
| OWNER: | |
| ADDRESS: | |
| DATE: | |
| ARRIVE: | |
| DEPART: | |
| RRC: | |
| THRUPUT (MCF): | |
| GPS: North | |
| GPS: West | |
| #WELLS | |
| #VALVES | |
| #CONNECTORS: | |
| #TANKS: | |
| #COMPRESSORS: | |
| OTHER EQUIP: | |

SITE LAYOUT:

| SITE PHOTOS | |
|-------------|-------------|
| Picture ID | Description |
| | |
| | |
| | |
| | |

| COMPRESSORS | | | | | | |
|-------------|-----------------|---------------|--------------|-------|----|----------------|
| ID# | Use (Lift/Line) | Type (NG-D-E) | Manufacturer | Model | HP | Duty Cycle (%) |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| SUMMARY: | |
|---------------------------|--|
| #M21 Valves | |
| #M21 Connect. | |
| #M21 ₂ 500 ppm | |
| # HiFlows | |
| #IRs | |
| # Canisters | |

NOTES:

Figure 3.3-2. Point Source Site Characterization Form

3.3.4 IR Camera Survey

The IR camera survey of a site began with the thermographer starting at one end of the site and working his way in logical fashion to the opposite end so that all equipment was surveyed. In a typical route, for instance, the thermographer would begin at the well pads, carefully surveying all of the valves and connectors associated with each well. From the well pads he would proceed to the compressor if one was present. Next, he might image the metering run and from there proceed to the piping and separators inside the tank battery. Finally he would finish the survey with a careful imaging of each storage tank, climbing up the stairs to the tank walkway in order to view each thief hatch and pressure relief valve (PRV) vent line. Depending on circumstances, such as the size and amount of equipment on the site and the number of

detected emission points, an IR camera site survey of a typical well pad might last from one to several hours.

When an emission was detected with the IR camera, a video recording of the IR imaging would be made, a photograph of the emission source would be taken and the following data documented:

- Date and time.
- Equipment description and size.
- Emission point height above ground (feet).
- GPS coordinates of emission point (Phase II only).
- Sighting distance (feet).
- TVA reading of emission (ppmv).
- Tank height and radius if tank emission (feet).
- Video file name.
- Maximum sighting distance (feet) – The maximum sighting distance is the distance from which the emission can be reliably detected with the IR camera and provides a measure of the emission’s magnitude (i.e. large emissions can be detected from further away).
- Weather conditions (Wind Direction, Wind Speed, Temperature, Relative Humidity, Barometric Pressure, and Cloud Cover).

As standard practice, the thermographer would image equipment from different angles. This is necessary since environmental conditions such as sunlight, wind, and background (i.e. air, piping, concrete or heat profiles) can cause an emission stream to be difficult to see from one angle, but easily detected from another.

With the GasFindIR™ camera integration settings would be switched to enable viewing of very hot surfaces (typically found at compressors), manual mode would be used on occasion to verify the absence or presence of a subtle emission, and “nuking” would be employed as required to eliminate optical background noise. Nuking adjusts the GasFindIR’s background so that a more uniform pixel response is obtained.

With the GF-320 camera the thermographer would frequently shift to High Sensitivity mode to confirm or detect a more subtle emission that was hard to see. All field data forms, digital photographs and videos are provided in electronic form in Appendix 3-B.

3.3.5 Method 21 Site Survey with the Toxic Vapor Analyzer

While one team member conducted the IR camera site survey, the second member calculated the total number of site valves and connectors. This was done by first determining the valve count and then applying a multiplying factor to arrive at the number of connectors. For this

project, a connector multiplier of 7 was conservatively used, based upon detailed connector counts performed at the beginning of both Phase I and Phase II. Thus if it was determined that a site contained 245 valves, then a connector count of 1,715 (7×245) was assumed. The 7:1 connector to valve ratio held true for all equipment except at compressor skids where a higher ratio was often noted. Consequently the number of connectors at compressor skids was estimated separately by multiplying the number of compressor valves by factors ranging from 10 to 15, depending on the size and complexity of the compressor.

These component counts were necessary since one objective of the point source testing was to estimate low level emissions (i.e. emissions below the detection limits of the IR camera) from fugitive equipment leaks. This objective was accomplished by screening at least ten percent of the valve and

Key Point: Method 21 Screening

To estimate low level emissions from fugitive equipment leaks, at least 10% of the valve and connector population at each site surveyed was screened.

connector population at each point source site with the TVA. Thus while the IR camera survey was in progress, Method 21 screening of the site's valves and connectors was performed with the TVA on one of every ten valves and one of every ten connectors until ten percent of the total valve and connector counts was reached. This procedure ensured that the required number of components was screened and that the screening population was evenly distributed across all areas of the site. This screening was conducted independent of the IR camera survey. Once it was completed, the TVA was then used to screen any emission points identified by the IR camera.

Following Method 21 procedures, valves were screened at their three primary leak areas: the stem, the packing, and the bonnet flange. Method 21 screening entails placing the TVA's probe at the various leak interfaces and sampling the complete circumference. Flanges were screened by placing the TVA probe at the edge of the flange-gasket interface. Connectors were screened by sampling the circumference of the threaded sections. All other components were monitored through a peripheral traverse of the seal interface. Whenever an elevated reading was obtained the sample probe was left at this elevated point for at least twice the instrument's response time (i.e. at least for 8 seconds) to ensure that the maximum concentration was measured.

When an emission at or above 500 ppmv was detected with the TVA the following data would be recorded:

- Date and time.
- Screening concentration (ppmv).
- Equipment Description.
- Equipment Location (GPS coordinates in Phase II only).

3.3.6 Hi Flow Sampler Emissions Testing

The Hi Flow Sampler, as discussed previously, provides a quick and effective means of quantifying emissions by sampling at a high enough flow rate to capture all the emissions escaping from a component. By accurately measuring the flow rate of the sample stream and the natural gas concentration within the stream, the instrument is able to determine the gas leak rate expressed both as percent methane and percent CFM. When this data is combined with canister analytical data, mass emission rates for individual compounds can be calculated as explained in Section 3.4.

Hi Flow Sampler testing was conducted at all emission points identified with the IR Camera (high level emissions) as well as at each emission point identified through Method 21 screening with a concentration ≥ 500 ppmv (low level emissions). A number of low level emissions in Phase I were below the detection capability of the Hi Flow Sampler. Emissions from these points have had to be subsequently estimated. In Phase II this was remedied by sampling the exhaust stream of the Hi Flow Sampler with the TVA and using the resulting TVA concentration to calculate the low level emission rate.

The following data was documented for each Hi Flow Sampler test:

- Date and time.
- The percent difference in leak rate between the sample flow rates.
- Total sample flow (CFM).
- Background concentration (%).
- Leak rate as % methane (% CH₄).
- Leak rate as % of total sample flow (% CFM).

3.3.7 Canister Sampling

As documented in the Point Source Test Plan, it was originally intended that a canister sample be collected at each emission point identified by the IR camera. However, as Phase I testing commenced, it became apparent that the sampling teams were observing an unexpectedly high frequency of camera-detected emission points. Therefore,

an alternative canister sampling strategy was needed; neither the project budget nor laboratory resources would be able to keep up with the canister demand otherwise. A revised canister sampling plan was developed and subsequently approved by the City of Fort Worth. The revised canister sampling plan was based upon three criteria.

Key Point: Canister Sampling

164 canister samples were collected throughout Fort Worth during the study. Data obtained from the 164 canister samples were used to develop surrogate canister emission profiles and correlation equations to characterize emissions from those points not directly sampled.

A canister sample would be collected from an emission point only if:

1. The % CFM reading obtained with the Hi Flow Sampler from that point exceeded the daily rolling average % CFM for all Hi Flow Sampler tests conducted thus far. In other words, the emission rate had to equal or exceed the average emission rate. The average emission rate was originally expressed as the rolling average of the third quartile % CFM; this was later changed to the rolling average % CFM.
2. Less than three canister samples have been collected from a similar component at other sites.
3. Less than three canister samples had been collected in the general geographical region. Geographical regions will be defined as the north, east, south, and west quadrants of the City of Fort Worth as well as any particular region in which the characteristics of the natural gas are substantially different from other regions (for instance, regions with wet gas and regions with dry gas).

If all of these conditions were not met, a canister sample was not collected. This approach succeeded in reducing the canister demand to a manageable level and was followed through the remainder of Phase I and through all of Phase II (a total of 164 canister samples were collected, not including 8 duplicate canister samples). Data obtained from these 164 canister samples were then used to develop surrogate canister emission profiles and correlation equations to characterize points for which no canister sample was taken.

Figure 3.3-3 provides a map of Fort Worth indicating the locations where canister samples were collected, as well as those locations where no samples were taken. As indicated in the map, the locations where canister samples were collected provide a well distributed characterization of canister samples. In other words, there were no large geographic locations in which there were no canister samples taken.

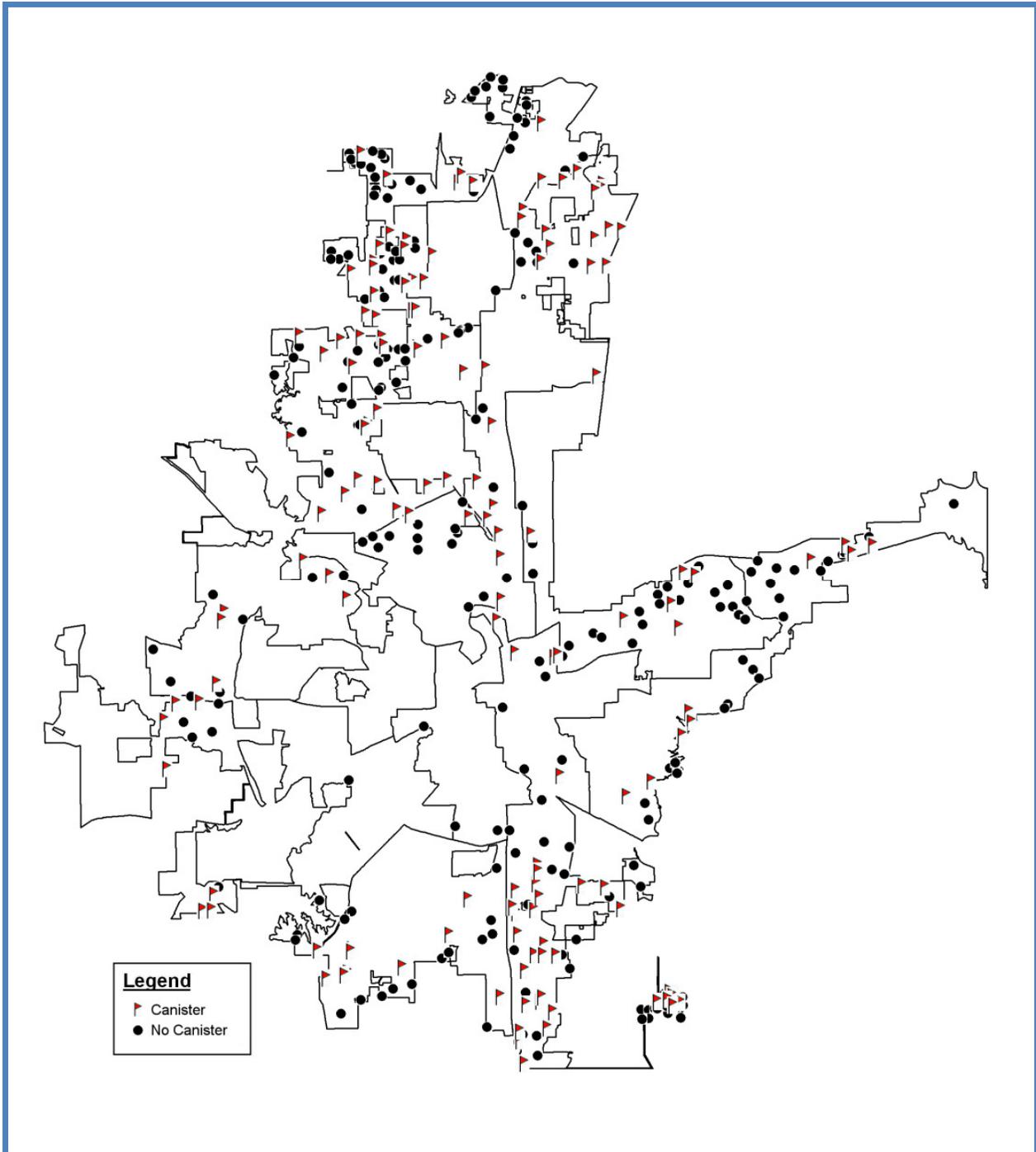


Figure 3.3-3. Canister Sample Locations

Whenever a canister sample was to be collected, the collection process followed specific protocols. A canister sampling manifold (Figure 3.3-4) consisting of a flow control valve and vacuum gauge was connected to the canister inlet port, and the canister's initial vacuum was checked. If less than 25-inches Hg vacuum was measured the canister was not used for sampling and was returned to the laboratory (this occurred only once).

To collect a sample, the canister's sample probe was directed into the exhaust port of the Hi Flow Sampler. Since it was possible, if the canister was opened very quickly, for the canister inlet flow to exceed the exhaust flow of the Hi Flow and thereby dilute the sample with ambient air, the sampling flow was carefully controlled. This was accomplished by adjusting the sample valve located upstream of the vacuum gauge (Figure 3.3-4) to ensure a slow but steady decrease in the canister vacuum. In practice, canister fill times were never less than 20 seconds and more typically, were between 30 seconds and 1 minute, far longer than the less than 2 second fill rate required to overcome the Hi Flow's exhaust rate.

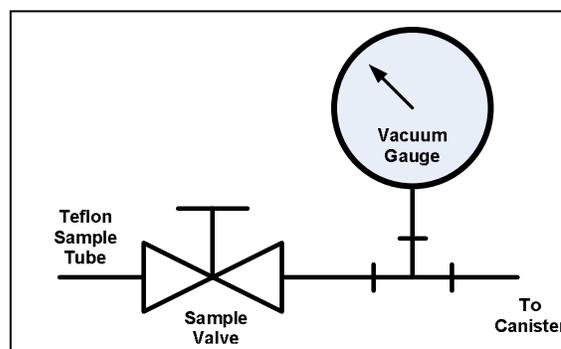


Figure 3.3-4. Canister Sampling Manifold

A canister was never filled completely but rather enough sample was collected to bring the canister vacuum up between 10 to 5 inches Hg. Following the collection of a canister sample the following data was documented both in a canister collection logbook and in the site's data form:

- Sample ID Number.
- Site Address.
- Date and Time.
- Initial Vacuum (inches Hg).

Similar information was also recorded on the canister's tag. Copies of the canister collection logbook entries are provided in Appendix 3-C.

3.3.8 Completion of the Site Survey

Following completion of the IR camera survey, the Method 21 screening, the Hi Flow Sampler testing of low level and high level emission points, and the canister sampling, the major equipment-containing areas of the site were documented both in photographs and with a site layout sketch. Figures 3.3-5, 3.3-6, and 3.3-7 provide typical examples of site photographs. Figure 3.3-8 illustrates a completed site layout sketch. Copies of all field data including site photos and site videos are provided in Appendix 3-B.



Figure 3.3-5. Site Documentation – Wells



Figure 3.3-6. Site Documentation – Tanks and Separators



Figure 3.3-7. Site Documentation – Lift Compressor

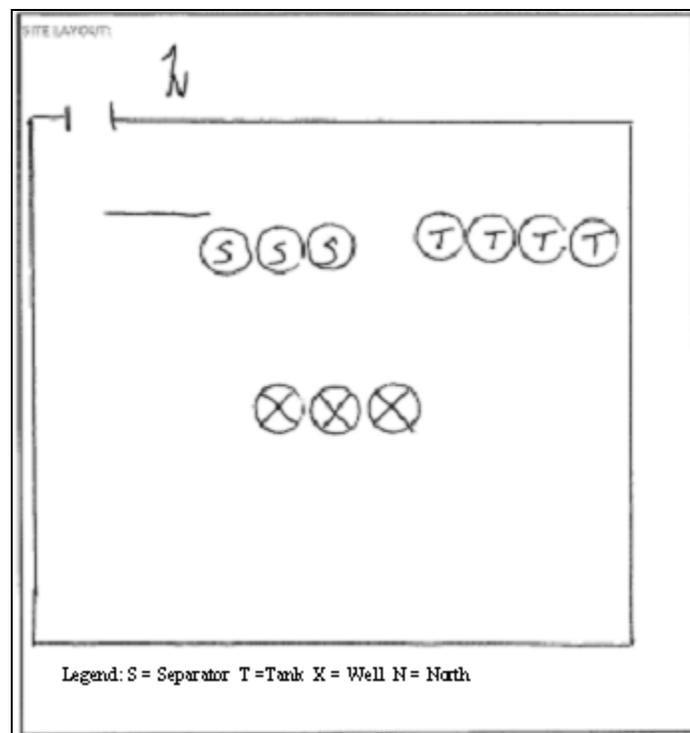


Figure 3.3-8. Example Site Sketch

Following this, the point source team prepared to depart from the site. The site data forms were checked for completeness and accuracy, any temporary flagging was removed the site’s equipment, all well and tank battery gates were closed and secured, and the departure time was documented. The gas inspector was then told the address of the next site to visit, and the facility’s main gate was locked behind the departing vehicles.

At the end of the day both teams returned to the field office where the equipment was off loaded from the project vans. Any canister samples taken that day were securely stored. The collected field data for that day was downloaded to a computer, printed out, and backed up.

Data archiving consisted of setting up separate computer site folders for the site's visited that day. Each folder was populated with the completed data forms, the site IR videos, and the site photos. Each team stored their data on the team computer and backed it up on dedicated hard drives. In addition, hardcopy printouts of the completed data forms were kept in large loose-leaf binders organized in chronological order. While one team member handled the data archiving, the other team member unloaded the van and prepared for the next work day. IR Camera, Hi Flow Sampler, TVA, digital camera and Archer data logger batteries were set up for overnight charging and facility field sketches were copied onto the printed out data forms. The completed data forms were quality control reviewed on a regular basis, either at the end of the day, the first thing the next day, or on the following weekend.

3.4 Emissions Calculation Procedures

This section describes the emissions calculation procedures used to derive a total emissions profile for each point source site. It is important to understand that for this study, not all of the site's emissions were calculated and/or characterized. For purposes of this study, in most cases, the emissions were calculated from only those sources in which emissions were detected and/or could be measured following the procedures described in the previous section. Hence, emissions were only estimated from piping and instrumentation equipment leaks, storage tanks, and compressors, which contribute the majority of emissions from natural gas-related facilities. Other sources of emissions, including but not limited to, storage tank breathing and standing losses, glycol dehydrator reboiler vents, wastewater and/or condensate loading, and flaring were not calculated. Non-routine emissions such as those generated during upsets or from maintenance, startup, and shutdown activities were also not measured or calculated as part of this study unless they were observed at the time of the site visit.

Annual emission estimates for each site were derived based on data obtained during the site visit and by assuming that conditions during the visit were representative of site conditions throughout the year. While it is important to note that emissions at any individual site can fluctuate depending on day-to-day operating and equipment conditions, the variation in emissions over the entire population were captured as a whole and are encompassed in this study as a result of breadth and depth of the point source testing and the use of surrogate emission profiles.

3.4.1 Well Pad, Compressor Station, Gas Plant, and Salt Water Disposal Facility Emissions

Total speciated emissions were calculated for each well pad, compressor station, gas plant and salt water disposal facility visited by the point source teams. These calculations fall into two categories: 1) Direct and 2) Indirect. Direct emission calculations were based upon the analytical results of the canister samples. Indirect emission measurements were derived from

several sources including the emission results from the canister sampling, correlation equations, calculated surrogate emission rates, EPA emission factors, and engine emission data for both natural gas and diesel powered engines. Each site's total emissions were calculated as a combination of direct and indirect emissions results. Figure 3.4-1 illustrates the overall approach followed in calculating total site emissions.

3.4.2 Direct Emission Calculations

Direct calculation of speciated emissions from a canister result was accomplished in 3 steps:

- Step 1: Convert the ppmv canister result to mg/m³ using Equation 5-1:

$$C = \frac{ppmv * MW}{24.45}$$

Where:

- C = Concentration in mg/m³
- ppmv = Parts per million by volume
- MW = Molecular Weight of analyte in gram/mols
- 24.45 = Molar Volume @ 25°C and 1 atmosphere in L/mols.

- Step 2: Convert the actual Hi Flow Sampler gas flow to standard gas flow using Equation 5-2:

$$CFM_{std} = (CFM_{act}) \left(\frac{T_{std}}{T_{act}} \right) \left(\frac{P_{act}}{P_{std}} \right)$$

Where:

- CFM_{std} = Flow rate corrected for standard conditions (ft³/min)
- CFM_{act} = Flow rate at actual conditions (ft³/min)
- T_{std} = Absolute gas temperature at standard conditions (°R)
- T_{act} = Absolute gas temperature at actual conditions (°R)
- P_a = Absolute gas pressure at actual conditions (psia)
- P_{std} = Absolute gas pressure at standard conditions (psia).

- Step 3: Calculate the emission rate using Equation 5-3:

$$ER = C * CFM_{std} * CF * 8760$$

Where:

- ER = Emission Rate (lb/yr)
- C = Analyte Concentration (mg/m³)
- CFM_{std} = Flow rate (ft³/min) corrected to standard conditions
- CF = Units Conversion Factor = 3.75E-06 (1 m³/35.32147 ft³) x 60 minutes/hour x (1 pound/453592.37 mg)
- 8760 = Hours per year

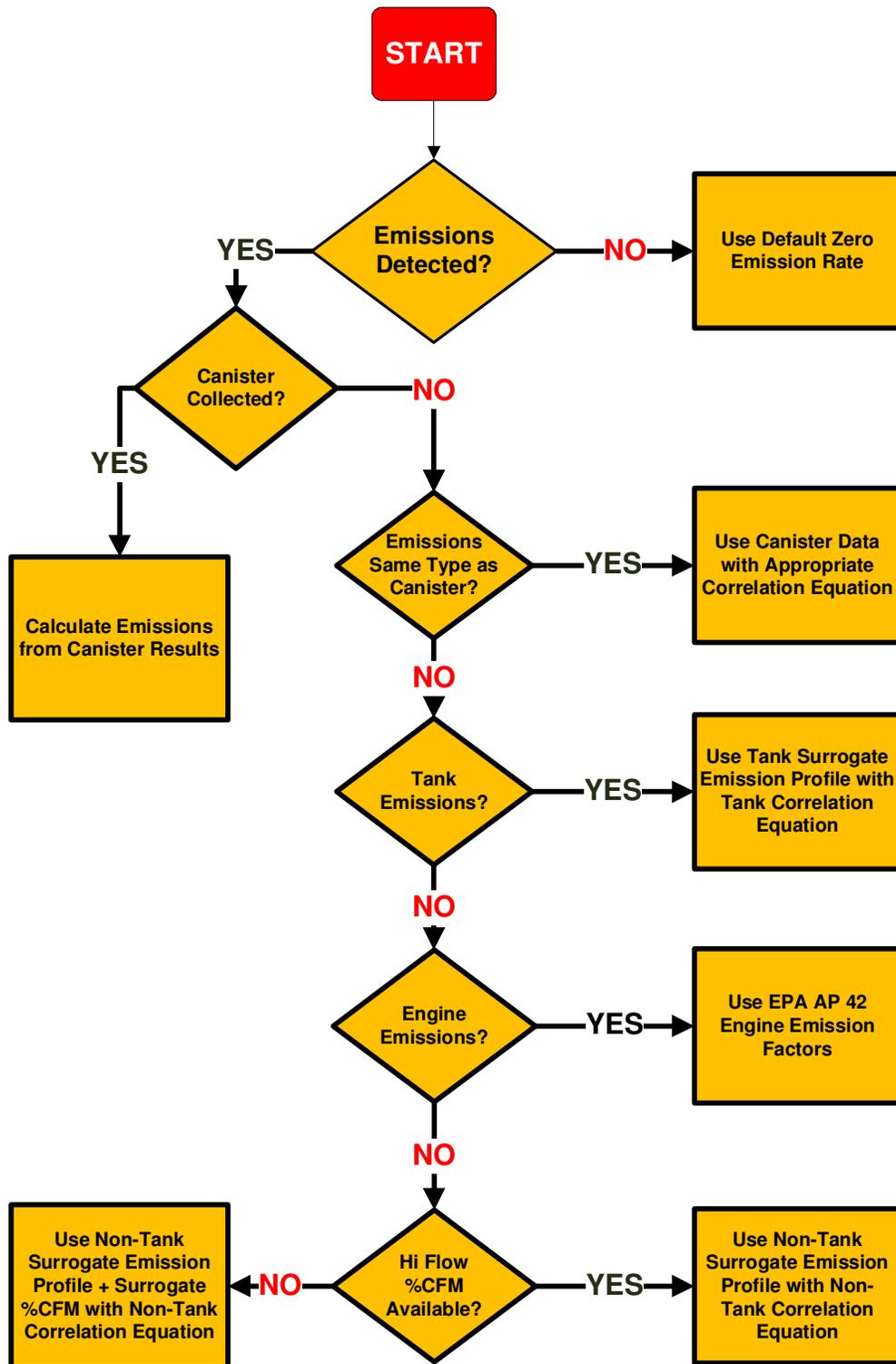


Figure 3.4-1. Emissions Calculation Flowchart

3.4.3 Indirect Emission Calculations -- Correlation Equation Development

The results of the canister samples were used to estimate emissions from those emission points that did not have a canister sample through the use of correlation equations. Two correlation equations, one for tank emissions and one for non-tank emissions, were developed based upon guidance from Section 2 and Appendix B of EPA's 1995 *Protocol for Equipment Leak Emission Estimates*.⁷

The first step in the development of the tank and non-tank correlation equations was the calculation of the natural logarithm of each canister's mass emission of total organic compounds (TOC) (lbs/yr) and its corresponding % CFM value.

The second step performed a linear regression in log space with the TOC values as the dependent variable (Y) and the % CFM values as the independent variable (X). The resulting regression line took the following form:

KeyPoint: Normality Correction

To estimate emissions from those sources not directly sampled with a canister, a correlation equation was developed between the calculated TOC (lb/yr) and the corresponding measured % CFM from those sources that were sampled. Since the data used to develop the correlation was not normally distributed, it was necessary to normalize the data by taking the natural logarithm of the data. A scale bias correction factor was then used to convert back to the arithmetic space.

$$\text{Emission Rate} = \beta_0 + \beta_1(\% \text{ CFM})$$

Where:

Emission Rate = Natural log of the leak rate determined by the canister results;

% CFM_i = Natural log of the % CFM_i;

β_0 = Intercept of regression line, and

β_1 = Slope of regression line.

The Mean Square Error (MSE) was then calculated by:

$$\text{MSE} = \frac{1}{n-2} \sum_{i=1}^n r_i^2$$

Where:

$$r_i = Y_i - \beta_0 - \beta_1 x_i$$

In the final step, the slope and intercept and a scale bias correction factor (SBCF) were used to transform the regression equations from log space to arithmetic space resulting in the tank and non-tank correlation equations:

$$\text{Leak Rate} = \text{SBCF} \times e^{\beta_0} \times \% \text{ CFM}^{\beta_1}$$

Where:

Leak Rate = Emission rate of TOC's from the individual source (lb/yr)

SBCF = Scale Bias Correction Factor

β_0, β_1 = Regression constants, and

% CFM = Cubic feet per minute measured by the Hi Flow Sampler.

The SBCF corrects for the variability of the log space data. It was calculated by summing 15 significant numbers of the terms from the infinite series:

$$SBCF = 1 + \frac{(m-1) * T}{m} + \frac{(m-1)^3 * T^2}{m^2 * 2! * (m+1)} + \frac{(m-1)^5 * T^3}{m^3 * 3! * (m+1) * (m+3)} + \dots$$

Where:

T = MSE/2.

MSE = mean square error from the regression.

m = number of data pairs.

3.4.4 Applying Canister Results to Non-Canister Emission Points

Canister-derived emission profiles were used to characterize non-canister emission points if 1) the non canister emission point was from the same site as the canister sample and 2) if the emission source types were the same (i.e. tank or non-tank).

For instance, if non-canister emissions were detected from a tank source, and if a canister had been collected at that site from another tank source, then that canister's data would be used to characterize the non-canister emission point. If the reverse was true, if the emissions were from a non-tank component, then a surrogate non-tank canister profile was used.

The distinction between tank and non-tank emission sources was made due to the differences in emissions characteristics observed between these two emission types. Tank emissions develop from the volatilization of heavier hydrocarbons entrained in the liquids produced by the facility separators, whereas non-tank emissions (i.e., particularly fugitive equipment leaks) are generally lighter gas emissions. Consequently, the chemical profile of each is somewhat different. For example, Table 3.4-1 provides a comparison of the average TOC, VOC, and HAP emissions resulting from a tank and non-tank canister sample collected during the study.

Table 3.4-1. Comparison of Emissions Between Tank and Non-Tank Emission Sources

| Source Type (Canister Site ID) | TOC (tons/yr) | VOC (tons/yr) | HAP (tons/yr) |
|-----------------------------------|------------------|------------------|------------------|
| Non-Tank (PS-126) | 6.65 | 0.01 | 0.00 |
| Tank (295) | 18.18 | 0.21 | 0.19 |

As indicated by the above comparison, tank emissions commonly exceed fugitive gas emissions.

Pairing a canister sample with a non-canister emission point provides the latter with a chemical composition. To calculate its emission rate, the Hi Flow Sampler results were used as follows:

1. The % CFM for the sample was entered into the correlation equation developed for the emission type (tank or non-tank) to determine the TOC mass emission rate.
2. The constituent contribution for each compound was determined from the weight percentages of the canister sample result.

This was done for each constituent so that the resulting products represented the speciated emission profile for the non-canister component.

For example, in Table 3.4-2 a canister sample (#A002) was collected from a leaking ¼-inch tubing connector – a non-tank sample type. Two other non-tank emission sources were detected at this site – a tee union connector and a pneumatically actuated valve. Since canister samples were not collected from these two sources, their emission profiles were derived as follows:

1. The non-canister total organic compound emission rate was calculated by the non-tank correlation equation. For the tee union with a % CFM of 0.39 the TOC emission rate was 11,644.25 lb/yr calculated as:

$$LR = 2.3759 * e^{9.674501743} * 0.39^{1.250318323} = 11,644.25 \text{ lbs / year .}$$

Where:

LR = TOC Leak Rate.

2.3759 = SBCF

9.674502= non-tank correlation equation intercept.

1.250318 = non-tank correlation equation slope.

2. Similarly, for the pneumatic valve which had a % CFM of 0.05 the TOC emission rate was 892.71 lb/yr calculated as:

$$LR = 2.3443 * e^{9.674501743} * 0.05^{1.2502318323} = 892.71 \text{ lbs / year .}$$

3. The non-canister emissions were assumed to have the same composition as the canister sample since they are both from the same site and from non-tank sources.
4. The speciated emissions of the non-canister were generated by multiplying the canister's speciated results by product of the ratio of each canister compound's emission to the canister TOC emission and the correlation equation TOC emission. The Tee union's methane emission rate, for instance, was 11,643.77 lbs/yr calculated as:

$$\frac{13,993.20}{13,993.78} * 11,644.25 = 11,643.77 \text{ lbs/yr methane.}$$

Where:

13,993.20 = Canister CH₄ lbs/yr.

13,993.78 = Canister TOC lbs/yr.

11,644.25 = Correlation Equation TOC lbs/yr.

Table 3.4-2. Non-Canister Methane Emissions Calculation Example

| Emission Pt. | HF % CFM | Canister ID | Methane (lbs/yr) | Methane (tons/yr) |
|-----------------|----------|-------------|------------------|-------------------|
| ¼-inch tubing | 1.01 | A002 | 13,993 | 6.99 |
| Tee Union | 0.39 | -- | 11,644 | 5.82 |
| Pneumatic Valve | 0.05 | -- | 893 | 0.45 |

3.4.5 Surrogate Canister Profiles

For emission points which could not be directly tied to a canister profile, either because a canister was not collected at the site or because the canister sample from the site was from a non-matching source (i.e. tank vs. non-tank), then a surrogate canister profile was used in the emissions calculations. Two canister surrogate emission profiles with the units of pounds/yr were developed: 1) a non-tank surrogate emission profile and 2) a tank surrogate emission profile (Table 3.4-3). The non-tank surrogate emission profile was used for components associated with valves, connectors, and other piping and instrumentation equipment located at well heads, metering runs, separator pads and compressor skids. The tank surrogate emission profile was used to characterize emissions primarily from tank thief hatches and tank relief vents.

Table 3.4-3. Surrogate Tank and Non-Tank Emission Profiles

| Category | Type | TOC (pounds/yr) | Non-VOC (pounds/yr) | VOC (pounds/yr) | HAP (pounds/yr) |
|-------------|----------|-----------------|---------------------|-----------------|-----------------|
| Wet/Dry Gas | Non-Tank | 13,256 | 13,252 | 4.12 | 0.78 |
| Wet/Dry Gas | Tank | 27,786 | 27,768 | 17.20 | 4.12 |

An attempt was made to further distinguish between emissions from sites in wet gas service versus sites in dry gas service for both tank and non-tank sources, but the number of emission sources in wet gas service turned out to be too small to draw statistically reliable inferences. At wet gas sites, emissions were detected from only 3 tank component types and 6 non-tank component types. At least 30 data points are needed to form reliable statistical conclusions.

The two surrogate emission profiles were developed using standard statistical procedures referenced in EPA's 1995 *Protocol for Equipment Leak Emission Estimates*:

1. The canister data for each emission type was checked for normality using probability plots to evaluate the correlation between the data and a normal distribution.
2. Since, in both cases, the data turned out to be non-normal, a natural logarithmic transformation of both sets of canister data was performed.
3. The normality of the transformed data was again checked using probability plots and found to be sufficiently linear.
4. The surrogate compositions were determined as the anti-logarithmic mean of the transformed data.

For summary purposes, Table 3.4-2 indicates the surrogate emission profiles only for categories of compounds (i.e. TOC, VOC, etc.). It is important to note that each surrogate profile also contains the emission rates for all of the individual compounds found in the aggregate canister samples used to generate the surrogate emission profiles.

Once the use of a surrogate canister profile was applied to an emission point, the emission calculation was performed according to the procedures described above in Section 3.4.3.

In Phase I there were several instances in which a low level emission fell below the detection limit of the Hi Flow Sampler (this limitation was overcome in Phase II by measuring the hydrocarbon concentration of the Hi Flow Sampler's exhaust stream with the TVA). For these occasions a surrogate % CFM was derived as the anti-log mean value of the normalized % CFM readings recorded in Phase II with the TVA.

3.4.6 Calculation of Non-Sampled Low Level Emission Points

While all site piping and instrumentation equipment was surveyed with the IR camera for high level emissions, only ten percent of the components at a site were sampled for low level emissions using a TVA following Method 21 screening procedures. Two separate emission calculations were used to arrive at emission rate estimates for the ninety percent not screened with the TVA:

1. The percent of components found leaking in the Method 21 screening was applied to the total non-sampled population of valves and connectors at the site and the non-tank correlation equation was used to estimate their emissions.
2. The remaining components were assumed to be non-leaking and their emissions were calculated using the Synthetic Organic Chemical Manufacturing Industry (SOCMI) default zero values listed in EPA's 1995 *Protocol for Equipment Leak Emission Estimates* (Figure 3.4-2). Studies by EPA have demonstrated that non-leaking equipment actually have low level emissions. These emission values are termed "default zeros" and are routinely used across the petroleum industry in the calculation of emission inventories.

TABLE 2-12. DEFAULT-ZERO VALUES: PETROLEUM INDUSTRY

| Equipment type/service | Default-zero emission rates ^{a,b} (kg/hr/source) |
|--------------------------|--|
| Valves/all | 7.8E-06 |
| Pump seals/all | 2.4E-05 |
| Others ^c /all | 4.0E-06 |
| Connectors/all | 7.5E-06 |
| Flanges/all | 3.1E-07 |
| Open-ended lines/all | 2.0E-06 |

^aDefault zero emission rates were based on the combined 1993 refinery and marketing terminal data only (default zero data were not collected from oil and gas production facilities).

^bThese default zero emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

^cThe "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Figure 3.4-2. Default-Zero Values

As an example, a site component count indicates a site contains 150 valves and 1,050 connectors. Method 21 screening is therefore performed on 15 of the valves and 105 connectors (i.e. 10%). Emissions at or above 500 ppmv are detected on 3 of the valves (20%) and 2 of the connectors (1.9%). The remaining 135 valves and 945 connectors that were not monitored are assumed to have the same leak percentages. Accordingly an additional 27 valves (20% of 135) and 18 connectors (1.9% of 945) would be assumed to be leaking at this site. The emission rates of these components would be determined as follows:

1. For valves, the valve minor emission % CFM would be multiplied by 27. For connectors a multiplier of 18 would be used.
2. The resulting % CFMs would be entered into the non-tank correlation equation to calculate a single TOC emission for the additional 27 valves and a single TOC emission for the additional 18 connectors presumed leaking.
3. The calculated weight percentages from the non-tank surrogate profile would be applied to derive speciated emissions for each result.

The remaining 108 valves (135-27) and 927 connectors (945-18) would have the valve and connector default zero emission rates applied to them. This would be done by converting the default zero kg/hr emission rates to % CFM as methane. The resulting value would be then entered into the non-tank correlation equation to calculate TOC emissions. Speciated results would be obtained using the calculated weight percentages from the non-tank surrogate profile.

3.4.7 Compressor Engine Emissions

A total of 186 natural gas compressor engines were encountered during the site surveys. Of these, 150 were located at 123 well pad sites, 12 were located at the gas processing facility, 1 was located at the salt water treatment facility, and 23 were located at the eight line compressor stations. The majority of the compressor engines located on well pads functioned as lift compressors.

Emissions from compressor engines were derived from field data collected during the site surveys, vendor specification sheets and published emission factors. In calculating emissions for compressor engines, a 100% compressor duty cycle was conservatively assumed (i.e. 24 hours/day/ for 365 days/year). In addition, it was conservatively assumed that these engines were uncontrolled. Multiple XTO facilities were noted as having catalyst controls on their engines, but as stack testing of the exhaust from compressor engines was not included in the scope of this study, the control efficiency of these engines is unknown.

Key Point: Compressor Engine Controls

Emissions from compressor engines were estimated using the best available data collected during the point source testing. Where data was limited, conservative assumptions were used including but not limited to, the use of uncontrolled emission factors where controls were known to be present but no control efficiency data was readily available.

3.4.8 Well Drilling and Fracking Engine Emissions

Criteria pollutant, VOC and HAP emissions from natural gas and diesel engines used in well drilling and fracking operations were conservatively estimated based upon vendor specifications and published emission factors. Engine emissions from well drilling assume 504 hours of continuous operation (3 weeks, 7 days/week, 24 hours/day). Engine emissions associated with a fracking operation are based upon 120 hours of non-continuous operation (3 weeks, 5 days/week, 8 hours/day).

3.4.9 Calculation of Method 21 TOC Screening Emission Factors

Method 21 screening results were used to calculate VOC emission factors for non-tank equipment in natural gas service so that emissions due to future build out can be predicted based upon Method 21 monitoring results. Emission factors were calculated for the following equipment /screening categories:

- Valves: 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv.
- Connectors: 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv

- Other (sump pumps, pneumatic valve controllers, regulators, flow meters, knock-out pots, vents, etc.): 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv.

The emission factors were derived in a five step procedure:

1. Step 1: Filter for Phase II data since this data contained a larger data set of Hi Flow Sampler emission measurements for low level emissions.
2. Step 2: Sequentially filter the result of Step 1 by component type (valve, connector or other).
3. Step 3: Sequentially filter the result of Step 2 by the desired range of screening values (500 – 999 ppmv or 1000 – 10,000 ppmv).
4. Step 4: Sum the individual TOC emissions for the filtered results to produce total TOC emissions (lbs/hr) for each.
5. Calculate the emission factor for the selected component type and screening value range as the median of the Step 5 results and convert from pounds per hour to kilograms per hour.

3.5 Point Source Emissions Results

A total of 388 point source emissions sites were surveyed, including two repeated sites, for natural gas emissions in the point source study. Of these, 375 well pads and 8 compressor stations were visited, which comprised approximately 75% of the population. This section provides the point source survey results as TOC, VOC, HAP and Criteria Pollutant emissions in tons/yr. TOC are the sum of non-VOCs and VOCs. VOCs are the sum of non-HAP VOCs and HAPs. Criteria pollutants are VOCs, particulate matter (PM), Oxides of Nitrogen (NO_x), Carbon Monoxide (CO), and sulfur dioxide (SO₂).

Table 3.5-1 lists the average and maximum emission rates by site type. Emissions are extrapolated over a one year period (i.e. tons per year) for different site types. The average and maximum values are the same for processing and saltwater treatment facilities because only one of each was surveyed.

Table 3.5-1. Average and Maximum Point Source Emission Rates by Site Type^a

| Site Type | TOC (tons/yr) | | VOC (tons/yr) | | HAP (tons/yr) | |
|------------------------------|---------------|-------|---------------|------|---------------|-----|
| | Average | Max | Average | Max | Average | Max |
| Well Pad | 16 | 445 | 0.07 | 8.6 | 0.02 | 2 |
| Well Pad with Compressor(s) | 68 | 4433 | 2 | 22 | 0.9 | 8.8 |
| Compressor Station | 99 | 276 | 17 | 43 | 10 | 25 |
| Processing Facility | 1,293 | 1,293 | 80 | 80 | 47 | 47 |
| Saltwater Treatment Facility | 1.5 | 1.5 | 0.65 | 0.65 | 0.4 | 0.4 |

^a For values reported as <0.01 see Appendix 3-A for actual emissions expressed in scientific notation.

Table 3.5-2 summarizes the average emission volumes for each site type as measured by the Hi Flow Sampler. Note that engine emission volumes are not included in this table.

Table 3.5-2. Average Point Source Emission Volumes by Site Type

| Site Type | TOC (cubic feet/yr) |
|------------------------------|------------------------|
| Well Pad | 148,552 |
| Well Pad with Compressor(s) | 218,035 |
| Compressor Station | 188,236 |
| Processing Facility | 372,019 |
| Saltwater Treatment Facility | 526 |

Table 3.5-1 shows the contribution compressor engines make to total site-wide emissions. In addition to increasing TOC, VOC and HAP emissions, the exhaust from a compressor engine contains the criteria pollutants (PM, SO₂, CO and NO_x). By way of illustration, Figure 3.5-1 compares the average annual emissions from a well pad without a compressor to one with a compressor. Clearly, compressor engines are a significant contributor of emissions at natural gas-related facilities.

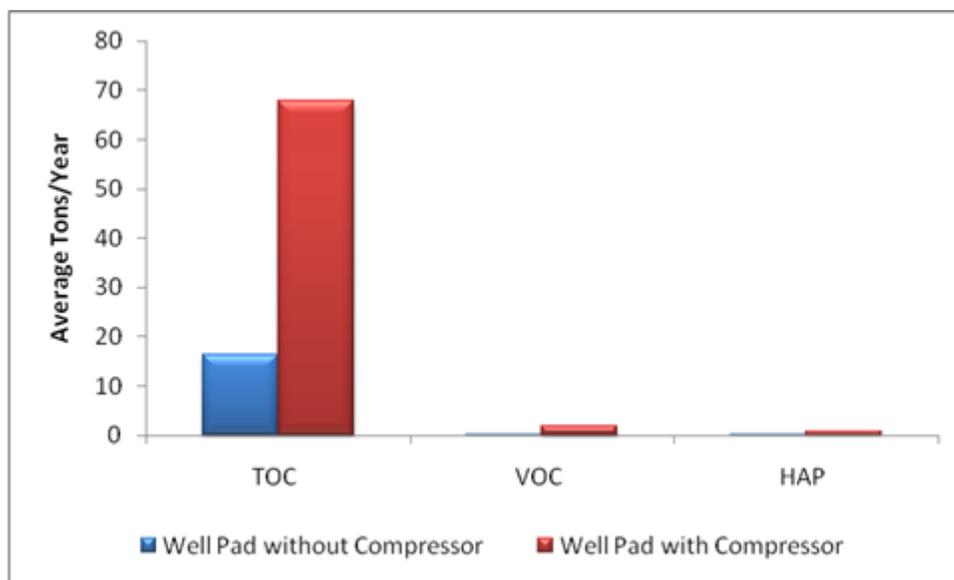


Figure 3.5-1. The Effect of Compressors on Site Emissions

Table 3.5-3 summarizes the emissions rates for all criteria pollutants and HAPs per each site surveyed during the point source testing. For each site, the summary provides the number of emission sources by type (e.g., compressor engines, storage tanks, fugitive leaks) and their contribution to total site-wide VOCs. Furthermore, the table provides for each site surveyed, the number of leaks detected by the IR camera and the number of leaks detected above 500 ppm using Method 21 screening.

Table 3.5-3. Point Source Emissions Summary by Site ^a

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-001 | 16791 WOODSIDE DR | WELL PAD | 2 | 89 | 384 | 2 | 0 | 6 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-002 | 2098 BRENNAN; F6 | WELL PAD | 3 | 347 | 2040 | 10 | 1 | 7 | 4 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-003 | 16616 FORD OAKS LN; F1 | WELL PAD | 1 | 65 | 320 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-004 | 2033 J CHESHEIR RD; F1 | WELL PAD | 1 | 73 | 286 | 1 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-005 | SAM REYNOLDS; F1 | WELL PAD | 1 | 76 | 710 | 2 | 0 | 4 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-006 | 1101 HWY 114; F1 | WELL PAD | 1 | 59 | 590 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-007 | 1850 BLK HWY 114; F1 | WELL PAD | 1 | 22 | 220 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-008 | 2690 HWY 114 (BEECH) (C-PAD); F1 | WELL PAD | 3 | 214 | 2140 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-009 | 2690 HWY 114 (BEECH) (B-PAD); F1 | WELL PAD | 2 | 198 | 1386 | 2 | 0 | 5 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-010 | 2598 HWY 114 (BEECH) (A-PAD); F1 | WELL PAD | 2 | 109 | 388 | 1 | 0 | 4 | 3 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-011 | 15096 AMERICAN WAY (A-COMMERCE) (B-PAD); F1 | WELL PAD | 2 | 128 | 984 | 6 | 0 | 4 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-012 | 12601 KATY RD; G1 | WELL PAD | 1 | 207 | 1149 | 2 | 1 | 0 | 3 | 0.01 | 3.18 | 5.21 | <0.01 | 0.17 | 0.17 | <0.01 | <0.01 | 0.10 | 0.07 | <0.01 |
| PS-013 | CAYLOR RD; G3 | WELL PAD | 1 | 65 | 390 | 1 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-014 | 12497 OLD DENTON RD POWELL 1; G3 | WELL PAD | 1 | 8 | 48 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-015 | 12497 OLD DENTON RD POWELL 2; G3 | WELL PAD | 2 | 113 | 791 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-016 | 12698 OLD DENTON RD; G3 | WELL PAD | 1 | 9 | 56 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-017 | 12498 ALTA VISTA ; G3 | WELL PAD | 1 | 105 | 735 | 1 | 1 | 1 | 4 | 0.04 | 0.57 | 11.17 | <0.01 | 0.58 | 0.58 | <0.01 | <0.01 | 0.34 | 0.23 | <0.01 |
| PS-018 | 3897 LITSEY RD; G1 | WELL PAD | 3 | 234 | 1190 | 6 | 1 | 4 | 0 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-019 | 15695 NORTH FWY (BEECH) (E-PAD); G3 | WELL PAD | 5 | 298 | 1888 | 5 | 0 | 3 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|----------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-020 | 2660 PETTY PLACE; G1 | WELL PAD | 1 | 77 | 548 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-021 | 16280 3 WILD DRIVE; G1 | WELL PAD | 3 | 172 | 1204 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-022 | 2898 HWY 114; G1 | WELL PAD | 2 | 87 | 609 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-023 | 2297 SILVER CREEK RD; C6 | WELL PAD | 1 | 53 | 371 | 2 | 0 | 1 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-024 | 2297 SILVER CREEK RD (PAD 2); C6 | WELL PAD | 2 | 82 | 574 | 3 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-025 | 3193 JIMISONS LN (XTO) (SURBER CA/CWS); J6 | WELL PAD | 3 | 209 | 1254 | 4 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-026 | 11494 MOSIER VALLEY RD (XTO) (REGAN); J6 | WELL PAD | 1 | 77 | 440 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-027 | 11468 MOSIER VALLEY RD (XTO) (KNAPP); J6 | WELL PAD | 1 | 84 | 500 | 1 | 0 | 0 | 3 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-028 | 11693 MOSIER VALLEY RD (XTO) (EULESS A); J6 | WELL PAD | 4 | 273 | 1530 | 4 | 0 | 3 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-028.1 | 14193 JOHN DAY RD (H-PAD); E1 | WELL PAD | 2 | 96 | 672 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-029 | 14193 JOHN DAY RD (G-PAD); E1 | WELL PAD | 4 | 209 | 1449 | 4 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-030 | 14193 JOHN DAY RD (F-PAD); E1 | WELL PAD | 3 | 136 | 952 | 3 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-031 | 14193 JOHN DAY RD (D-PAD); E1 | WELL PAD | 1 | 48 | 336 | 1 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-032 | 11591 TRINITY BLVD (XTO) (EULESS C); J6 | WELL PAD | 1 | 78 | 468 | 1 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-033 | 11696 MOSIER VALLEY RD (XTO) (JW ARLINGTON); J6 | WELL PAD | 4 | 255 | 1300 | 4 | 0 | 2 | 3 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-034 | 12196 TRINITY BLVD (XTO) (EULESS B); J6 | WELL PAD | 5 | 214 | 1284 | 5 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-035 | 141931 JOHN DAY RD (C-PAD); E1 | WELL PAD | 1 | 50 | 350 | 1 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-036 | 14193 JOHN DAY RD (A-PAD); E1 | WELL PAD | 2 | 117 | 819 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-037 | 14193 JOHN DAY RD (E-PAD); E1 | WELL PAD | 2 | 105 | 735 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-038 | 14193 JOHN DAY RD (B-PAD); E1 | WELL PAD | 1 | 65 | 455 | 1 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-039 | 493 AVONDALE HASLET RD (DEVON) (GARNETT-LAPRELLE); E2 | WELL PAD | 2 | 194 | 1620 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-040 | 493 AVONDALE HASLET RD (XTO) (HUFFMAN); E2 | WELL PAD | 2 | 137 | 1218 | 3 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-041 | 1701 AVONDALE HASLET RD (DEVON) (MOSS) (A-PAD); E2 | WELL PAD | 2 | 140 | 840 | 1 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-042 | 1701 AVONDALE HASLET RD (DEVON) (MOSS) (B-PAD); E2 | WELL PAD | 2 | 150 | 1244 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-043 | 1502 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (F-PAD); E2 | WELL PAD | 2 | 131 | 917 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-044 | 1400 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (C-PAD); E2 | WELL PAD | 1 | 57 | 342 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-045 | 4594 HWY 360 SOUTH PAD; K5 | WELL PAD | 1 | 160 | 1120 | 3 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-046 | 10896 TRINITY BLVD; J6 | WELL PAD | 2 | 255 | 1785 | 3 | 0 | 1 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-047 | 1480 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (E-PAD); E2 | WELL PAD | 3 | 203 | 1421 | 3 | 0 | 0 | 4 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-048 | 13800 SENDERA RANCH BLVD (DEVON) (MORRIS HARMONSON) (A-PAD); E2 | WELL PAD | 3 | 178 | 1176 | 3 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-049 | 694 AVONDALE HASLET (DEVON) (LBJ) (B-PAD); E2 | WELL PAD | 1 | 60 | 420 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-050 | 694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (A-PAD); E2 | WELL PAD | 2 | 68 | 340 | 0 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-051 | 694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (B-PAD); E2 | WELL PAD | 1 | 22 | 154 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-052 | 694 AVONDALE HASLET (DEVON) (LBJ) (K-PAD); E2 | WELL PAD | 2 | 127 | 889 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-053 | 694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (C-PAD); E2 | WELL PAD | 1 | 86 | 516 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-054 | 694 AVONDALE HASLET (BOAZ) (N-PAD); E2 | WELL PAD | 3 | 196 | 1332 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-055 | 12494 HWY 287 (DEVON) (PHASE 3) (A-PAD); E2 | WELL PAD | 1 | 63 | 441 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-056 | 290 BLUE MOUND RD (DEVON) (GARNETT-LAPRELLE) (B-PAD); E2 | WELL PAD | 2 | 137 | 822 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-057 | 4950 PAINT HORSE DR; G6 | WELL PAD | 6 | 291 | 2037 | 3 | 0 | 7 | 8 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-058 | 2796 PREMIER ST; G6 | WELL PAD | 1 | 197 | 1429 | 4 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-059 | 694 AVONDALE HASLET (DEVON) (LBJ) (A-PAD); E2 | WELL PAD | 1 | 62 | 434 | 1 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-060 | 694 AVONDALE HASLET (DEVON) (LBJ) (D-PAD); E2 | WELL PAD | 2 | 137 | 959 | 4 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-061 | 694 AVONDALE HASLET (DEVON) (LBJ) (E-PAD); E2 | WELL PAD | 1 | 69 | 414 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-062 | 1400 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (D-PAD); E2 | WELL PAD | 1 | 63 | 441 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-064 | 694 AVONDALE HASLET (DEVON) (LBJ) (F-PAD); E2 | WELL PAD | 2 | 120 | 840 | 4 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-065 | 694 AVONDALE HASLET (DEVON) (LBJ) (J-PAD); E2 | WELL PAD | 2 | 126 | 882 | 4 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-066 | 3399 E LONG AVE; G6 | WELL PAD | 5 | 472 | 5345 | 3 | 3 | 11 | 18 | 0.32 | 4.71 | 47.67 | 0.02 | 4.74 | 4.71 | 0.01 | 0.01 | 2.80 | 1.89 | 0.07 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-067 | 694 AVONDALE HASLET (DEVON) (LBJ) (G-PAD); E2 | WELL PAD | 2 | 118 | 708 | 3 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-068 | 694 AVONDALE HASLET (DEVON) (LBJ) (H-PAD); E2 | WELL PAD | 1 | 62 | 372 | 1 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-069 | 694 AVONDALE HASLET (DEVON) (LBJ) (I-PAD); E2 | WELL PAD | 1 | 47 | 329 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-070 | 694 AVONDALE HASLET (DEVON) (LBJ) (M-PAD); E2 | WELL PAD | 3 | 200 | 1230 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-071 | 694 AVONDALE HASLET (DEVON) (LBJ) (L-PAD); E2 | WELL PAD | 1 | 62 | 434 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-072 | 2292 N TARRANT PKWY; F4 | WELL PAD | 4 | 438 | 3456 | 8 | 1 | 14 | 9 | 0.10 | 1.50 | 17.21 | <0.01 | 1.39 | 1.38 | 0.01 | <0.01 | 0.82 | 0.55 | 0.02 |
| PS-073 | 693 AVONDALE HASLET (DEVON) (LBJ) (O-PAD); E2 | WELL PAD | 1 | 59 | 416 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-074 | 693 AVONDALE HASLET (DEVON) (LBJ) (N-PAD); E2 | WELL PAD | 1 | 65 | 390 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-075 | 693 AVONDALE HASLET (DEVON) (LBJ) (Q-PAD); E2 | WELL PAD | 2 | 126 | 882 | 4 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | 3.57 | <0.01 | <0.01 | 3.57 | 0.72 | -0- | <0.01 |
| PS-076 | 693 AVONDALE HASLET (DEVON) (LBJ) (R-PAD); E2 | WELL PAD | 1 | 85 | 425 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-077 | 693 AVONDALE HASLET (DEVON) (LBJ) (S-PAD); E2 | WELL PAD | 2 | 147 | 735 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-078 | 1300 BLUFF SPRINGS RD (DEVON) (BOAZ) (B-PAD); E2 | WELL PAD | 1 | 54 | 324 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-079 | 1301 BLUFF SPRINGS RD (DEVON) (BOAZ) (C-PAD); E2 | WELL PAD | 1 | 60 | 360 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-080 | 1101 DURANGO SPRINGS DR (DEVON) (BOAZ) (A-PAD); E2 | WELL PAD | 1 | 61 | 376 | 1 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-081 | 1417 WHISPER WILLOWS (DEVON) (BOAZ) (D-PAD); E2 | WELL PAD | 1 | 50 | 315 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-082 | 8191 HORSEMAN RD; F4 | WELL PAD | 4 | 508 | 3646 | 6 | 1 | 8 | 3 | 0.15 | 2.00 | 6.38 | <0.01 | 2.18 | 2.18 | <0.01 | <0.01 | 1.29 | 0.87 | 0.03 |
| PS-083 | 9191 BLUE MOUND RD; F4 | WELL PAD | 1 | 152 | 1064 | 3 | 1 | 4 | 4 | 0.04 | 0.57 | 11.17 | <0.01 | 0.59 | 0.58 | <0.01 | <0.01 | 0.35 | 0.23 | <0.01 |
| PS-084 | 7598 BLUE MOUND RD; F4 | WELL PAD | 1 | 109 | 763 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-085 | 2591 BASSWOOD BLVD; F4 | WELL PAD | 4 | 368 | 2100 | 5 | 1 | 4 | 5 | 0.10 | 1.57 | 5.02 | <0.01 | 1.38 | 1.38 | <0.01 | <0.01 | 0.82 | 0.55 | 0.02 |
| PS-086 | 11398 WEST FWY; B8 | WELL PAD | 3 | 217 | 1519 | 6 | 0 | 4 | 8 | -0- | -0- | -0- | -0- | 8.65 | <0.01 | 8.65 | <0.01 | 1.99 | -0- | 0.02 |
| PS-087 | 4496 LOST CREEK BLVD; B8 | WELL PAD | 1 | 83 | 581 | 4 | 0 | 4 | 2 | -0- | -0- | -0- | -0- | 0.20 | <0.01 | 0.20 | <0.01 | 0.02 | -0- | <0.01 |
| PS-088 | 10293 OLD WEATHERFORD RD; C7 | WELL PAD | 2 | 130 | 910 | 4 | 0 | 2 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-090 | 14193 JOHN DAY RD (DEVON) (I-POOL PAD); E2 | WELL PAD | 2 | 101 | 707 | 2 | 0 | 3 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-091 | 14193 JOHN DAY RD (DEVON) (L-POOL PAD); E2 | WELL PAD | 1 | 62 | 372 | 1 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-092 | 14193 JOHN DAY RD (J-POOL PAD); E2 | WELL PAD | 1 | 68 | 476 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-093 | 14193 JOHN DAY RD (K-BLAKLEY PAD); E2 | WELL PAD | 4 | 198 | 1336 | 3 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-094 | 14193 JOHN DAY RD (M-BLAKLEY PAD); E2 | WELL PAD | 2 | 122 | 732 | 2 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-095 | 14193 JOHN DAY RD (N-BLAKLEY PAD); E2 | WELL PAD | 5 | 216 | 1512 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-096 | 14193 JOHN DAY RD (W-BLAKLEY PAD); E2 | WELL PAD | 4 | 283 | 1698 | 4 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-097 | 14193 JOHN DAY RD (O-POOL PAD); E2 | WELL PAD | 2 | 134 | 1164 | 2 | 0 | 1 | 9 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-098 | 14193 JOHN DAY RD (P-BLAKLEY PAD); E2 | WELL PAD | 5 | 225 | 1870 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-099 | 14293 SNAFFLE BIT TRL (Q-BLAKLEY PAD); E2 | WELL PAD | 4 | 258 | 2020 | 4 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-100 | 14193 JOHN DAY RD (U-BLAKLEY PAD); E2 | WELL PAD | 7 | 480 | 4016 | 7 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-101 | 14193 JOHN DAY RD (V-BLAKLEY PAD); E2 | WELL PAD | 5 | 131 | 1870 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-102 | 9767 VERNA TRAIL N; C7 | WELL PAD | 4 | 288 | 1816 | 4 | 0 | 5 | 4 | -0- | -0- | -0- | -0- | 0.53 | <0.01 | 0.53 | <0.01 | 0.07 | -0- | 0.02 |
| PS-103 | 1299 W LOOP 820; C7 | WELL PAD | 1 | 65 | 455 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-104 | 9798 WESTPOINT DR; C7 | WELL PAD | 2 | 203 | 1550 | 2 | 1 | 0 | 8 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| PS-105 | 9596 OLD WEATHERFORD; C7 | WELL PAD | 1 | 103 | 721 | 2 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-106 | 10590 OLD WEATHERFORD; B7 | WELL PAD | 2 | 142 | 994 | 4 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|--------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-107 | 5291 EVERMAN KENNEDALE BURLESON RD (CFW SOUTH); H10 | WELL PAD | 4 | 286 | 2002 | 4 | 1 | 0 | 3 | 0.07 | 0.98 | 32.48 | <0.01 | 1.22 | 0.99 | 0.23 | <0.01 | 0.64 | 0.40 | 0.03 |
| PS-108 | 7196 WICHITA (GARRETT); G9 | WELL PAD | 2 | 105 | 805 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | <0.01 | 0.02 | <0.01 | -0- | <0.01 |
| PS-109 | 5691 CA ROBERSON BLVD (FWISD); G9 | WELL PAD | 8 | 547 | 3329 | 10 | 2 | 3 | 1 | 0.09 | 1.40 | 37.69 | <0.01 | 1.40 | 1.36 | <0.01 | 0.04 | 0.81 | 0.55 | 0.02 |
| PS-110 | 2400 BLK CAMPUS ST (SMP); G9 | WELL PAD | 1 | 68 | 476 | 2 | 1 | 2 | 1 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-111 | 11495 WHITE SETTLEMENT RD (B-PAD); B7 | WELL PAD | 3 | 224 | 1568 | 4 | 0 | 3 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-112 | 10595 WEST CLEBURNE RD; E11 | WELL PAD | 6 | 549 | 4480 | 8 | 1 | 9 | 8 | 0.05 | 0.70 | 18.85 | <0.01 | 0.69 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-113 | 10495 W CLEBURNE; E11 | WELL PAD | 3 | 236 | 2744 | 3 | 2 | 5 | 7 | 0.09 | 1.40 | 37.69 | <0.01 | 1.38 | 1.36 | <0.01 | 0.01 | 0.81 | 0.55 | 0.02 |
| PS-114 | 6599 OAK GROVE RD (CARTER TRUST); G9 | WELL PAD | 3 | 316 | 2212 | 3 | 2 | 6 | 10 | 0.82 | 13.33 | 69.56 | 0.05 | 11.99 | 11.93 | 0.02 | 0.03 | 7.10 | 4.79 | 0.17 |
| PS-115 | 10296 OLD CLEBURNE CROWLEY RD; E11 | WELL PAD | 1 | 146 | 1399 | 2 | 1 | 5 | 7 | 0.05 | 0.70 | 18.85 | <0.01 | 0.69 | 0.68 | <0.01 | <0.01 | 0.41 | 0.27 | 0.01 |
| PS-116 | 10699 OLD GRANDBURY RD; D11 | WELL PAD | 6 | 632 | 5022 | 8 | 1 | 9 | 12 | 0.05 | 0.70 | 18.85 | <0.01 | 0.69 | 0.68 | <0.01 | <0.01 | 0.41 | 0.27 | <0.01 |
| PS-117 | 3595 ANGLE RD | WELL PAD | 7 | 31 | 207 | 6 | 1 | 0 | 4 | 0.05 | 0.70 | 18.85 | <0.01 | 0.70 | 0.68 | <0.01 | 0.02 | 0.41 | 0.27 | 0.01 |
| PS-118 | 590 NW LOOP 820; KS | COMPRESSOR STATION | 0 | 1414 | 9888 | 3 | 6 | 2 | 7 | 0.02 | 51.42 | 269.95 | 0.18 | 42.69 | 42.59 | <0.01 | 0.11 | 25.31 | 17.08 | 0.60 |
| PS-119 | 6900 E ROSEDALE; I8; KS | COMPRESSOR STATION | 0 | 985 | 6895 | 8 | 7 | 5 | 9 | 0.02 | 45.77 | 240.30 | 0.16 | 37.80 | 37.79 | <0.01 | 0.01 | 22.46 | 15.16 | 0.53 |
| PS-120 | 2298 E 4TH ST; F7; KS | COMPRESSOR STATION | 0 | 325 | 2548 | 1 | 1 | 2 | 11 | 0.05 | 0.70 | 18.85 | <0.01 | 0.72 | 0.68 | <0.01 | 0.03 | 0.41 | 0.27 | 0.01 |
| PS-121 | 7091 OAK GROVE; G10; KS | COMPRESSOR STATION | 0 | 208 | 1456 | 0 | 1 | 0 | 3 | <0.01 | 5.07 | 11.76 | 0.02 | 4.88 | 4.87 | <0.01 | <0.01 | 2.90 | 1.95 | 0.07 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|-----------------------------------|----------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-122 | 7091 OAK GROVE; G10 | WELL PAD | 4 | 208 | 1456 | 4 | 0 | 3 | 5 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-123 | 7695 OAK GROVE; G10 | WELL PAD | 5 | 204 | 1408 | 6 | 0 | 5 | 6 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-124 | 7695 OAK GROVE; G10; KS | COMPRESSOR STATION | 5 | 242 | 1694 | 6 | 2 | 1 | 5 | <0.01 | 10.14 | 23.52 | 0.04 | 9.76 | 9.75 | <0.01 | 0.01 | 5.79 | 3.91 | 0.14 |
| PS-125 | 7997 SOUTH FWY; G10; KS | COMPRESSOR STATION | 2 | 357 | 4020 | 4 | 1 | 7 | 13 | 0.41 | 6.66 | 34.78 | 0.03 | 6.42 | 5.97 | <0.01 | 0.45 | 3.56 | 2.39 | 0.09 |
| PS-126 | 7997 SOUTH FWY; G10 | WELL PAD | 2 | 128 | 896 | 4 | 0 | 1 | 4 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-127 | 5296 BAILEY BOSWELL; E4; KS | COMPRESSOR STATION | 0 | 414 | 2898 | 4 | 3 | 6 | 11 | 1.61 | 24.33 | 545.08 | 0.10 | 23.70 | 23.56 | 0.11 | 0.04 | 14.02 | 9.45 | 0.34 |
| PS-128 | 580 E ROSEDALE | DRILLING OPERATION | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.37 | 11.74 | 6.42 | 4.51 | 0.04 | 0.04 | <0.01 | <0.01 | 0.01 | <0.01 | <0.01 |
| PS-129 | 10091 OLD GRANBURY RD; D11 | WELL PAD | 3 | 212 | 1913 | 4 | 1 | 2 | 9 | 0.05 | 0.70 | 18.85 | <0.01 | 0.92 | 0.68 | 0.21 | 0.03 | 0.42 | 0.27 | 0.02 |
| PS-130 | 6597 OAK GROVE (CARTER ALCON); G9 | WELL PAD | 5 | 517 | 3619 | 5 | 0 | 1 | 7 | -0- | -0- | -0- | -0- | 0.29 | <0.01 | 0.25 | 0.04 | 0.06 | -0- | 0.03 |
| PS-131 | 6799 OAK GROVE (CARTER TRUST); G9 | WELL PAD | 3 | 244 | 2458 | 3 | 1 | 1 | 3 | 0.07 | 0.98 | 32.48 | <0.01 | 0.99 | 0.99 | <0.01 | <0.01 | 0.59 | 0.40 | 0.01 |
| PS-132 | 2795 QUAIL RD (EXELON); H8 | WELL PAD | 4 | 338 | 2296 | 4 | 0 | 3 | 3 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | <0.01 | 0.02 | <0.01 | -0- | <0.01 |
| PS-133 | 6099 WILBARGER (OLCOTT SOUTH); H8 | WELL PAD | 8 | 613 | 4291 | 6 | 0 | 6 | 5 | -0- | -0- | -0- | -0- | 0.27 | <0.01 | 0.27 | <0.01 | 0.07 | -0- | 0.02 |
| PS-134 | 5199 VILLAGE CREEK RD; H9 | COMPLETION OPERATION | 4 | 0 | 0 | 0 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-135 | 6293 HATCHERY RD; D6 | WELL PAD | 5 | 279 | 1953 | 5 | 1 | 1 | 17 | 0.05 | 0.70 | 18.85 | <0.01 | 1.42 | 0.68 | 0.04 | 0.70 | 0.44 | 0.27 | 0.02 |
| PS-136 | 6497 SHADY OAKS MANOR RD; D6 | WELL PAD | 3 | 232 | 2027 | 3 | 1 | 3 | 12 | 0.05 | 0.70 | 23.20 | <0.01 | 1.06 | 0.71 | 0.05 | 0.31 | 0.45 | 0.28 | 0.02 |
| PS-137 | 6791 NW LOOP 820; D6 | WELL PAD | 3 | 161 | 1127 | 3 | 0 | 1 | 6 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-138 | 4993 FREEMAN DR (KATES); H9 | WELL PAD | 1 | 84 | 588 | 1 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-139 | 7797 E LANCASTER AVE (GREEN OAKS); I8 | WELL PAD | 6 | 603 | 4219 | 6 | 2 | 6 | 6 | 0.09 | 1.40 | 37.69 | <0.01 | 1.37 | 1.36 | <0.01 | 0.01 | 0.81 | 0.55 | 0.02 |
| PS-140 | 6896 NW LOOP 820; D6 | WELL PAD | 4 | 227 | 1589 | 4 | 0 | 2 | 5 | -0- | -0- | -0- | -0- | 0.05 | <0.01 | 0.01 | 0.04 | <0.01 | -0- | <0.01 |
| PS-141 | 2693 ROBERTS CUT-OFF RD; D6 | WELL PAD | 2 | 123 | 861 | 2 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-142 | 3291 NW LOOP 820; E6 | WELL PAD | 2 | 158 | 1706 | 2 | 1 | 0 | 11 | 0.05 | 0.70 | 23.20 | <0.01 | 0.76 | 0.71 | 0.04 | 0.01 | 0.43 | 0.28 | 0.01 |
| PS-143 | 3091 NW LOOP 820; E6 | WELL PAD | 3 | 116 | 813 | 3 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-144 | 2399 DOTTIE LYNN (SOWELL N); I7 | WELL PAD | 4 | 419 | 2933 | 4 | 2 | 9 | 5 | 0.11 | 1.74 | 21.75 | <0.01 | 1.70 | 1.69 | <0.01 | 0.01 | 1.01 | 0.68 | 0.02 |
| PS-145 | 6093 WILBARGER (OLCOTT NORTH); H8 | WELL PAD | 12 | 366 | 2562 | 0 | 0 | 7 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-146 | 5693 E LOOP 820 S (DUKE); H9 | WELL PAD | 2 | 199 | 1393 | 2 | 0 | 4 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-147 | 5195 E LOOP 820 S (820 MARTIN); H9 | WELL PAD | 8 | 536 | 3752 | 4 | 1 | 9 | 8 | 0.05 | 0.70 | 18.85 | <0.01 | 0.83 | 0.68 | 0.14 | 0.02 | 0.44 | 0.27 | 0.02 |
| PS-148 | 3093 NW LOOP 820; E6 | WELL PAD | 2 | 202 | 1817 | 2 | 1 | 2 | 13 | 0.07 | 0.98 | 32.48 | <0.01 | 1.14 | 0.99 | 0.12 | 0.03 | 0.62 | 0.40 | 0.02 |
| PS-149 | 7500 RANDOL MILL RD (BLAKEMAN); I7 | WELL PAD | 1 | 129 | 903 | 1 | 1 | 0 | 2 | 0.07 | 0.98 | 32.48 | <0.01 | 1.01 | 0.99 | 0.02 | <0.01 | 0.59 | 0.40 | 0.02 |
| PS-150 | 7891 RANDOL MILL RD (MORRIS); I7 | WELL PAD | 1 | 121 | 847 | 1 | 1 | 1 | 0 | 0.05 | 0.70 | 23.20 | <0.01 | 0.71 | 0.71 | <0.01 | <0.01 | 0.42 | 0.28 | <0.01 |
| PS-151 | 8096 RANDOL MILL RD (DOREX); I7 | WELL PAD | 1 | 121 | 847 | 2 | 1 | 0 | 2 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-152 | 8390 RANDOL MILL RD (BUZZYS); I7 | WELL PAD | 2 | 143 | 1001 | 2 | 1 | 1 | 4 | 0.01 | 3.18 | 5.21 | <0.01 | 0.18 | 0.17 | <0.01 | <0.01 | 0.10 | 0.07 | <0.01 |
| PS-153 | 2298 PRECINCT LINE (DUCK LAKE) (D-PAD); I7 | WELL PAD | 2 | 151 | 1057 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|----------|--|---------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-153.1 | 2298 PRECINCT LINE (DUCK LAKE) (B-PAD); I6 | WELL PAD | 4 | 0 | 0 | 3 | 1 | 0 | 0 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-154 | 8091 BRENTWOOD STAIR RD (CLANECO); I7 | WELL PAD | 1 | 154 | 1078 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-155 | 3598 ANGLE AVE; E6 | WELL PAD | 2 | 108 | 756 | 1 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-156 | 2095 NW LOOP 820; E6 | WELL PAD | 4 | 234 | 1638 | 4 | 0 | 3 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-157 | 4592 ANGLE AVE (LS); E6 | WELL PAD | 4 | 198 | 1386 | 2 | 0 | 2 | 6 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-158 | 3491 LINCOLN AVE (A-PAD); E6 | WELL PAD | 2 | 107 | 749 | 2 | 0 | 1 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-159 | 10488 HICKS FIELD RD (CROSSTEX AMINE TREATMENT CENTER) | PROCESSING FACILITY | 0 | 1800 | 12590 | 10 | 12 | 10 | 67 | 1.00 | 87.74 | 1038.90 | 0.34 | 79.93 | 79.58 | <0.01 | 0.34 | 47.32 | 31.93 | 1.14 |
| PS-160 | 7595 E LANCASTER AVE (BOSWELL); I8 | WELL PAD | 7 | 429 | 3007 | 0 | 0 | 4 | 6 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | <0.01 | 0.02 | <0.01 | -0- | <0.01 |
| PS-161 | 7397 RANDOL MILL RD (DUCKHEAD); I6 | WELL PAD | 3 | 256 | 2176 | 0 | 1 | 4 | 4 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| PS-162 | 1999 PRECINCT RD (RIVERBEND); I6 | WELL PAD | 2 | 226 | 1869 | 6 | 1 | 1 | 2 | 0.05 | 0.70 | 18.85 | <0.01 | 0.69 | 0.68 | <0.01 | <0.01 | 0.41 | 0.27 | <0.01 |
| PS-163 | 490 E RENDON CROWLEY RD (N SPINKS); G11 | WELL PAD | 3 | 212 | 1484 | 4 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-164 | 14091 STONE RD (S SPINKS); G11 | WELL PAD | 4 | 260 | 1820 | 4 | 2 | 5 | 6 | 0.09 | 1.40 | 37.69 | <0.01 | 1.36 | 1.36 | <0.01 | <0.01 | 0.81 | 0.55 | 0.02 |
| PS-165 | 7996 TRAMMEL DAVIS RD (DUCK LAKE) (A-PAD); I6 | WELL PAD | 6 | 356 | 2492 | 2 | 1 | 1 | 4 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-166 | 9799 TRAMMEL DAVIS RD (TXI A); I6 | WELL PAD | 1 | 140 | 973 | 2 | 1 | 0 | 3 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-167 | 3198 S NORWOOD DR (TXI); I6 | WELL PAD | 1 | 144 | 1008 | 2 | 1 | 1 | 5 | 0.05 | 0.70 | 18.85 | <0.01 | 0.78 | 0.68 | 0.10 | <0.01 | 0.43 | 0.27 | 0.02 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|------------------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-168 | 9992 TRINITY BLVD (BELL) (B-PAD); I6 | WELL PAD | 3 | 264 | 1848 | 6 | 1 | 2 | 3 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-169 | 10190 TRINITY BLVD (BELL) (A-PAD); I6 | WELL PAD | 3 | 264 | 1848 | 4 | 1 | 1 | 2 | 0.05 | 0.70 | 18.85 | <0.01 | 0.68 | 0.68 | <0.01 | <0.01 | 0.40 | 0.27 | <0.01 |
| PS-170 | 4697 ENON RD (KARANGES); G10 | WELL PAD | 3 | 273 | 1911 | 3 | 1 | 0 | 6 | 0.07 | 0.98 | 32.48 | <0.01 | 1.09 | 0.99 | <0.01 | 0.09 | 0.61 | 0.40 | 0.02 |
| PS-171 | 3892 LON STEVENSON RD (WALLS COLEMAN); G10 | WELL PAD | 4 | 433 | 3031 | 4 | 2 | 3 | 6 | 0.14 | 1.96 | 64.96 | <0.01 | 2.02 | 1.98 | 0.04 | <0.01 | 1.19 | 0.79 | 0.03 |
| PS-172 | 8290 ANGLIN CR (MOORE); G10 | WELL PAD | 3 | 161 | 1127 | 3 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-173 | 2999 LANA LN (HOSLER); G10 | WELL PAD | 3 | 183 | 1281 | 5 | 0 | 3 | 1 | -0- | -0- | -0- | -0- | 0.03 | <0.01 | <0.01 | 0.03 | <0.01 | -0- | <0.01 |
| PS-174 | 5591 E 1ST ST (CARTER STATE) (SALT WATER DISPOSAL SITE); G7 | SALTWATER TREATMENT FACILITY | 3 | 211 | 1477 | 8 | 1 | 3 | 0 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| PS-176 | 1375 OAK GROVE SHELBY RD (SHULTZ); G10 | WELL PAD | 1 | 54 | 378 | 1 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-177 | 9499 SOUTH RACE ST (HARRISON); G10 | WELL PAD | 1 | 88 | 616 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-178 | 10198 FOREST HILL EVERMAN RD (MISSION) (A-PAD); G10 | WELL PAD | 2 | 183 | 1775 | 2 | 1 | 1 | 2 | 0.07 | 0.98 | 32.48 | <0.01 | 1.01 | 0.99 | 0.02 | <0.01 | 0.59 | 0.40 | 0.01 |
| PS-179 | 3691 MOPAC (PEARSON); E8 | WELL PAD | 4 | 30 | 210 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-180 | 695 E NORTHSIDE DR (STOCKYARDS); F7 | WELL PAD | 3 | 70 | 490 | 4 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-181 | 3298 VAN HORN AVE (CRAIN); G7 | WELL PAD | 1 | 75 | 525 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.02 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--|--------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-182 | 691 BEACH ST (FROST); G7 | WELL PAD | 3 | 115 | 705 | 4 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-184 | 10590 CHAPIN RD (CHAPEL CREEK); E9 | WELL PAD | 1 | 144 | 2408 | 2 | 1 | 0 | 12 | 0.30 | 4.01 | 12.76 | 0.02 | 22.32 | 4.36 | <0.01 | 17.95 | 4.09 | 1.75 | 0.16 |
| PS-185 | 10199 OAK GROVE RD (BEAN) (A-PAD); G10 | WELL PAD | 3 | 143 | 1001 | 3 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-186 | 394 EVERMAN PKWY (MARITZ); F10 | WELL PAD | 4 | 207 | 1449 | 4 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-187 | 9198 FORUM WAY (UNION PACIFIC); F10 | WELL PAD | 3 | 166 | 1162 | 3 | 0 | 3 | 4 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-188 | 1298 W RISINGER RD (HOLT HICKMAN); F10 | WELL PAD | 2 | 117 | 819 | 2 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-189 | 2990 BRASWELL DR (RP STEPHENS); F6 | WELL PAD | 1 | 83 | 797 | 1 | 1 | 0 | 0 | 0.01 | 3.18 | 5.21 | <0.01 | 0.17 | 0.17 | <0.01 | <0.01 | 0.10 | 0.07 | <0.01 |
| PS-190 | 796 MEACHAM BLVD (PRIME RAIL); F6 | WELL PAD | 3 | 146 | 1022 | 3 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-191 | 3592 DEEN RD; F6 | WELL PAD | 3 | 173 | 1211 | 3 | 0 | 3 | 4 | -0- | -0- | -0- | -0- | 0.05 | <0.01 | 0.04 | <0.01 | <0.01 | -0- | <0.01 |
| PS-192 | 2299 MERCADO DRIVE; F6 | WELL PAD | 10 | 616 | 4312 | 13 | 2 | 6 | 12 | 0.13 | 2.08 | 5.81 | <0.01 | 2.20 | 2.01 | 0.15 | 0.03 | 1.26 | 0.81 | 0.06 |
| PS-193 | 5900 WILLBARGER (FRACKING JOB) | FRACKING OPERATION | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0.51 | 16.37 | 8.26 | 5.82 | 0.05 | 0.05 | <0.01 | <0.01 | 0.02 | <0.01 | <0.01 |
| PS-194 | 10395 CAMP BOWIE W (JOHNSON HUBBELL); E9 | WELL PAD | 1 | 93 | 652 | 2 | 0 | 0 | 4 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.02 | <0.01 | <0.01 | -0- | <0.01 |
| PS-195 | 3497 LONGVUE (HAVENER); E9 | WELL PAD | 2 | 134 | 938 | 4 | 0 | 2 | 9 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-196 | 792 DE COSTA (EASTSIDES); G7 | WELL PAD | 4 | 215 | 1405 | 3 | 2 | 0 | 8 | 0.16 | 4.83 | 16.69 | 0.02 | 4.98 | 4.85 | 0.09 | 0.03 | 2.94 | 1.95 | 0.09 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| PS-197 | 692 BEACH ST (FROST); G7 | WELL PAD | 1 | 228 | 1596 | 3 | 1 | 2 | 7 | 0.07 | 1.04 | 2.91 | <0.01 | 1.10 | 1.01 | 0.09 | 0.01 | 0.63 | 0.40 | 0.03 |
| PS-198 | 5699 RANDOL MILL RD (GOODMAN); H7 | WELL PAD | 3 | 260 | 1824 | 4 | 1 | 4 | 2 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| PS-199 | 7094 JACK NEWELL BLVD S (TRIMBLE); H7 | WELL PAD | 2 | 118 | 826 | 4 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-200 | 7092 ENTERPRISE AVE (PARROT) (B-PAD); H7 | WELL PAD | 2 | 41 | 294 | 0 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| PS-201 | 5895 MARINE CREEK PKWY (MARINE CREEK) (A-PAD); E5 | WELL PAD | 2 | 183 | 1645 | 3 | 1 | 2 | 6 | -0- | -0- | -0- | -0- | 1.11 | 0.99 | 0.11 | 0.01 | 0.60 | 0.40 | 0.02 |
| 6 | HWY 114 | WELL PAD | 1 | 62 | 134 | 1 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 20 | 4190 LITSEY RD | WELL PAD | 2 | 103 | 960 | 8 | 0 | 5 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 23 | 4192 LITSEY RD | WELL PAD | 6 | 448 | 3584 | 0 | 1 | 2 | 6 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 24 | 3596 ELIZABETHTOWN CEMETERY RD | WELL PAD | 6 | 434 | 2738 | 6 | 1 | 3 | 2 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 25 | 14797 ELIZABETHTOWN CEMETERY RD | WELL PAD | 5 | 206 | 1650 | 4 | 1 | 4 | 6 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | 0.01 | 0.39 | 0.26 | <0.01 |
| 26 | 14798 ELIZABETHTOWN CEMETERY RD | WELL PAD | 6 | 463 | 4270 | 6 | 1 | 3 | 9 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 27 | 4791 HENRIETTA CREEK RD | WELL PAD | 1 | 99 | 996 | 2 | 1 | 3 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 28 | 4794 HENRIETTA CREEK RD | WELL PAD | 1 | 76 | 768 | 2 | 1 | 3 | 5 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 29 | 14404 CHAPARRAL | WELL PAD | 2 | 154 | 1482 | 4 | 1 | 2 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 32 | 13794 NORTH FWY | WELL PAD | 8 | 506 | 3542 | 8 | 1 | 1 | 8 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | 0.01 | <0.01 | 0.39 | 0.26 | 0.01 |
| 33 | 13593 NORTH FWY | WELL PAD | 8 | 539 | 4672 | 6 | 2 | 6 | 8 | 0.09 | 1.40 | 3.92 | <0.01 | 1.34 | 1.31 | 0.03 | <0.01 | 0.78 | 0.52 | 0.02 |
| 35 | 2890 WESTPORT PKWY | WELL PAD | 1 | 68 | 476 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|-------------------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 36 | 3397 ALLIANCE GATEWAY | WELL PAD | 8 | 549 | 4747 | 1 | 1 | 4 | 15 | 0.07 | 1.04 | 2.91 | <0.01 | 1.04 | 1.01 | <0.01 | 0.03 | 0.60 | 0.40 | 0.02 |
| 37 | 5198 WESTPORT PKWY | WELL PAD | 2 | 128 | 1256 | 4 | 1 | 0 | 1 | 0.07 | 0.98 | 2.76 | <0.01 | 1.00 | 1.00 | <0.01 | <0.01 | 0.59 | 0.40 | 0.01 |
| 38 | 5290 WESTPORT PKWY | WELL PAD | 1 | 74 | 662 | 2 | 1 | 2 | 4 | 0.03 | 0.48 | 12.87 | <0.01 | 0.45 | 0.45 | <0.01 | <0.01 | 0.26 | 0.18 | <0.01 |
| 39 | 13195 PARK VISTA BLVD | WELL PAD | 3 | 166 | 1282 | 3 | 1 | 4 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 41 | 3398 ALLIANCE GATEWAY | WELL PAD | 12 | 801 | 7041 | 1 | 1 | 4 | 25 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | 0.01 |
| 44 | 12695 OLD DENTON | WELL PAD | 1 | 193 | 1331 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 50 | 11498 HARMON RD | WELL PAD | 2 | 218 | 1526 | 3 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 55 | 5696 N TARRANT PKWY | WELL PAD | 2 | 275 | 2181 | 3 | 1 | 2 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | 0.01 | 0.39 | 0.26 | 0.01 |
| 57 | 1098 BLK EAST BONDS RANCH RD S SIDE | WELL PAD | 2 | 164 | 1099 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 59 | 1392 BLK E BONDS RANCH RD S-SIDE | WELL PAD | 1 | 24 | 175 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 62 | 1098 E BONDS RANCH RD | WELL PAD | 1 | 6 | 42 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 63 | 1096 EAST BONDS RANCH RD | WELL PAD | 1 | 59 | 413 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 98 | 13393 SENDERA RANCH BLVD | WELL PAD | 2 | 102 | 816 | 2 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 110 | 12595 WILLOW SPRINGS | WELL PAD | 1 | 60 | 420 | 1 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 111 | 12591 BLK WILLOW SPRINGS RD W-SIDE | WELL PAD | 1 | 74 | 518 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 125 | 12690 WILLOW SPRINGS RD | WELL PAD | 1 | 53 | 371 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 126 | 693 AVONDALE HASLET RD | WELL PAD | 3 | 220 | 1540 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 130 | 290 BLUE MOUND RD WEST | WELL PAD | 2 | 133 | 931 | 3 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 132 | 12294 NW HWY 287 CFW | WELL PAD | 2 | 151 | 1057 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 134 | 12290 NW HWY 287 | WELL PAD | 2 | 75 | 525 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 136 | 998 BLUE MOUND RD WEST | WELL PAD | 7 | 421 | 2947 | 3 | 0 | 6 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 138 | 1096 BLK W BLUE MOUND AT HWY-287 N-SIDE | WELL PAD | 3 | 245 | 1855 | 3 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 139 | 1099 BLUE MOUND RD W | WELL PAD | 2 | 160 | 1120 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 141 | 692 BLUE MOUND RD | WELL PAD | 1 | 60 | 420 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 142 | 392 BLUE MOUND RD WEST | WELL PAD | 3 | 191 | 1337 | 3 | 0 | 3 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 143 | 893 BLUE MOUND RD W | WELL PAD | 2 | 167 | 1169 | 3 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 147 | 12890 BLK SAGINAW BLVD | WELL PAD | 2 | 162 | 1079 | 3 | 1 | 2 | 0 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 147A | 12700 BLK HWY 287 & 81 S-SIDE | WELL PAD | 1 | 60 | 420 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 149 | 12700 SAGINAW RD | WELL PAD | 1 | 38 | 266 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 150 | 12700 SAGINAW RD | WELL PAD | 1 | 42 | 294 | 1 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 153 | 2492 BLUE MOUND RD W | WELL PAD | 2 | 128 | 896 | 3 | 0 | 5 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 154 | 11996 WILLOW SPRINGS RD | WELL PAD | 1 | 87 | 609 | 1 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 155 | 11693 WILLOW SPRINGS RD | WELL PAD | 4 | 315 | 2205 | 4 | 0 | 1 | 4 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.02 | <0.01 | <0.01 | -0- | <0.01 |
| 156 | 11498 WILLOW SPRINGS RD | WELL PAD | 3 | 217 | 1519 | 3 | 0 | 0 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 159 | LPA BONDS RANCH RD | WELL PAD | 4 | 314 | 2198 | 3 | 0 | 5 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 160 | 1892 W BONDS RANCH RD | WELL PAD | 5 | 377 | 2639 | 4 | 0 | 1 | 7 | -0- | -0- | -0- | -0- | 0.26 | <0.01 | 0.26 | <0.01 | 0.06 | -0- | 0.02 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|---------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 161 | 10999 WILLOW SPRINGS RD | WELL PAD | 4 | 330 | 2310 | 4 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 164 | 11300 BLK HWY 287 & 81 | WELL PAD | 4 | 309 | 2163 | 3 | 0 | 3 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 165 | 452 WEST BONDS RANCH RD | WELL PAD | 5 | 328 | 2672 | 2 | 1 | 5 | 1 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 167 | 4099 W BONDS RANCH RD | WELL PAD | 2 | 76 | 725 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 168 | 3091 W BONDS RANCH RD | WELL PAD | 4 | 245 | 1715 | 4 | 0 | 2 | 5 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 171 | 11593 SAGINAW BLVD | WELL PAD | 7 | 286 | 2288 | 4 | 0 | 3 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 172 | 4099 W BONDS RANCH RD | WELL PAD | 4 | 264 | 3248 | 8 | 0 | 5 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 174 | 9698 BOAT CLUB ROAD | WELL PAD | 1 | 70 | 490 | 1 | 1 | 1 | 2 | 0.02 | 3.74 | 6.13 | <0.01 | 0.20 | 0.20 | <0.01 | <0.01 | 0.12 | 0.08 | <0.01 |
| 176 | 11593 SAGINAW BLVD | WELL PAD | 5 | 371 | 2597 | 3 | 1 | 2 | 2 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 178 | 11601 BLK SAGINAW BLVD | WELL PAD | 5 | 374 | 2597 | 3 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 182 | 1898 W BONDS RANCH RD | WELL PAD | 3 | 189 | 1323 | 1 | 0 | 3 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 187 | 10398 HICKS FIELD RD | WELL PAD | 5 | 200 | 1400 | 5 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.02 | <0.01 | <0.01 | -0- | <0.01 |
| 188 | 10398 HICKS FIELD RD | WELL PAD | 1 | 53 | 371 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 189 | 10398 HICKS FIELD RD | WELL PAD | 2 | 119 | 833 | 2 | 0 | 0 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 191 | 10094 HICKS FIELD RD | WELL PAD | 2 | 130 | 910 | 3 | 0 | 2 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 192 | LPA WAGLEY ROBERTSON RD | WELL PAD | 1 | 167 | 1170 | 4 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 193 | 10197 WAGLEY ROBERTSON RD | WELL PAD | 3 | 66 | 462 | 0 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|-------------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 194 | LPA WAGLEY ROBERTSON RD | WELL PAD | 1 | 92 | 930 | 1 | 1 | 0 | 5 | 0.05 | 0.79 | 21.19 | <0.01 | 0.76 | 0.76 | <0.01 | <0.01 | 0.45 | 0.31 | 0.01 |
| 195 | 10094 HICKS FIELD RD | WELL PAD | 1 | 55 | 385 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 196 | 10000 BLK HICKS FIELD RD | WELL PAD | 1 | 52 | 364 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 197 | 10200 BLK WAGLEY ROBERTSON RD | WELL PAD | 3 | 170 | 1190 | 3 | 0 | 3 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 198 | 10196 EVENING VIEW DR | WELL PAD | 4 | 162 | 1134 | 1 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 199 | 293 W BONDS RANCH RD | WELL PAD | 3 | 184 | 1288 | 2 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 201 | 10191 NW HIGHWAY 287 | WELL PAD | 2 | 124 | 868 | 1 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 207 | 8799 WAGLEY ROBERTSON RD | WELL PAD | 1 | 101 | 716 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 208 | 7999 WAGLEY ROBERTSON RD | WELL PAD | 1 | 78 | 555 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 209 | 9491 SAGINAW BLVD | WELL PAD | 2 | 187 | 1790 | 2 | 1 | 4 | 4 | 0.01 | 3.58 | 5.87 | <0.01 | 0.19 | 0.19 | <0.01 | <0.01 | 0.11 | 0.08 | <0.01 |
| 213 | 10999 SAGINAW RD | WELL PAD | 1 | 80 | 560 | 2 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 214 | 9500 BLK PARK DR | WELL PAD | 1 | 173 | 1211 | 2 | 1 | 4 | 1 | 0.03 | 0.46 | 12.35 | <0.01 | 0.43 | 0.43 | <0.01 | <0.01 | 0.26 | 0.17 | <0.01 |
| 216 | 9098 PARK DR | WELL PAD | 1 | 51 | 357 | 1 | 0 | 0 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 217 | 8793 OLD DECATUR RD | WELL PAD | 4 | 247 | 2262 | 3 | 1 | 4 | 11 | 0.05 | 0.70 | 1.96 | <0.01 | 0.68 | 0.65 | 0.01 | 0.01 | 0.39 | 0.26 | 0.01 |
| 222 | 5299 W BAILEY BOSWELL RD | WELL PAD | 2 | 73 | 511 | 3 | 0 | 3 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 223 | 5293 W BAILEY BOSWELL RD | WELL PAD | 3 | 134 | 938 | 3 | 0 | 1 | 5 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 225 | 5696 W J BOAZ RD | WELL PAD | 2 | 69 | 490 | 2 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | 0.18 | <0.01 | 0.18 | <0.01 | <0.01 | -0- | <0.01 |
| 227 | 6325 CROMWELL MARINE CREEK RD | WELL PAD | 1 | 82 | 572 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 228 | 5693 CROMWELL MARINE CREEK RD | WELL PAD | 1 | 108 | 920 | 2 | 1 | 0 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 230 | 5996 BOWMAN ROBERTS RD | WELL PAD | 2 | 163 | 1615 | 2 | 1 | 3 | 4 | 0.07 | 0.98 | 2.74 | <0.01 | 1.01 | 0.99 | <0.01 | 0.02 | 0.59 | 0.40 | 0.01 |
| 234 | 5492 TEN MILE BRIDGE RD | WELL PAD | 1 | 48 | 320 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 235 | 6493 TEN MILE BRIDGE RD | WELL PAD | 1 | 71 | 491 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 238 | 798 INDUSTRIAL ROAD | WELL PAD | 2 | 691 | 5185 | 4 | 2 | 4 | 10 | 0.53 | 15.71 | 219.33 | 0.06 | 14.24 | 14.12 | 0.11 | <0.01 | 8.42 | 5.67 | 0.21 |
| 240 | 1392 CANELL SAMPSON RD | WELL PAD | 2 | 298 | 2586 | 2 | 1 | 0 | 5 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | 0.02 | <0.01 | 0.39 | 0.26 | 0.01 |
| 241 | 1895 NORTHEAST LOOP 820 | WELL PAD | 2 | 218 | 1676 | 2 | 1 | 2 | 1 | 0.07 | 0.99 | 2.77 | <0.01 | 1.00 | 1.00 | <0.01 | <0.01 | 0.59 | 0.40 | 0.01 |
| 247 | 1290 SILVER CREEK RD | WELL PAD | 4 | 478 | 4646 | 4 | 0 | 2 | 4 | -0- | -0- | -0- | -0- | 0.97 | <0.01 | 0.97 | <0.01 | 0.11 | -0- | 0.02 |
| 257 | 10999 OLD WEATHERFORD RD | WELL PAD | 3 | 253 | 2863 | 4 | 2 | 5 | 16 | 0.07 | 1.06 | 11.58 | <0.01 | 20.93 | 1.01 | 19.91 | <0.01 | 4.93 | 0.41 | 0.11 |
| 258 | 9595 OLD WEATHERFORD RD | WELL PAD | 3 | 145 | 1015 | 2 | 0 | 0 | 5 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 260 | 11398 WEST FWY | WELL PAD | 3 | 217 | 1519 | 6 | 0 | 4 | 8 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 261 | 10499 CHAPIN RD | WELL PAD | 2 | 147 | 1029 | 4 | 0 | 1 | 6 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 266 | 11392 TIGER TRL | WELL PAD | 5 | 310 | 1740 | 10 | 1 | 7 | 6 | 0.05 | 0.70 | 1.96 | <0.01 | 1.43 | 0.65 | 0.01 | 0.77 | 0.46 | 0.26 | 0.01 |
| 267 | 11392 TIGER TRL | WELL PAD | 5 | 445 | 3115 | 20 | 1 | 6 | 26 | 0.14 | 1.98 | 24.21 | <0.01 | 19.87 | 2.00 | 17.85 | 0.02 | 3.02 | 0.80 | 0.16 |
| 268 | 11395 TIGER TRL | WELL PAD | 5 | 311 | 3732 | 0 | 1 | 1 | 7 | 0.14 | 1.98 | 24.21 | <0.01 | 4.30 | 2.00 | <0.01 | 2.30 | 1.34 | 0.80 | 0.04 |
| 269 | 11392 TIGER TRL | WELL PAD | 8 | 657 | 4599 | 0 | 0 | 1 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 282 | 4490 OLD DECATUR RD | WELL PAD | 6 | 378 | 2485 | 6 | 1 | 3 | 13 | 0.05 | 0.70 | 1.96 | <0.01 | 0.70 | 0.65 | 0.03 | 0.02 | 0.40 | 0.26 | 0.01 |
| 284 | 998 RAILHEAD RD | WELL PAD | 2 | 138 | 966 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 285 | 4890 BLUE MOUND RD | WELL PAD | 1 | 84 | 588 | 1 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 287 | 4201 BLUE MOUND RD | WELL PAD | 1 | 151 | 357 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 288 | 291 NE 38TH ST | WELL PAD | 4 | 175 | 1225 | 5 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 289 | 4999 MARK IV PKWY | WELL PAD | 2 | 233 | 1781 | 2 | 1 | 3 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|--------------------------------|--------------------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 290 | 1990 GREAT SOUTHWEST PKWY | WELL PAD | 2 | 152 | 1064 | 2 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 291 | 2591 DOWNING DR | WELL PAD | 4 | 181 | 1267 | 4 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 294K | 2299 MERCADO DR | COMPRESSOR STATION | 0 | 436 | 3310 | 0 | 2 | 4 | 6 | 0.80 | 12.94 | 67.54 | 0.05 | 11.59 | 11.59 | <0.01 | <0.01 | 6.89 | 4.65 | 0.16 |
| 294 | 2299 MERCADO DR | WELL PAD | 10 | 616 | 4312 | 13 | 2 | 5 | 22 | 0.13 | 2.08 | 5.81 | <0.01 | 2.16 | 2.01 | 0.13 | 0.02 | 1.21 | 0.81 | 0.03 |
| 295 | 1099 NIXON ST | WELL PAD | 9 | 1010 | 7262 | 11 | 1 | 2 | 7 | 0.40 | 6.47 | 33.77 | 0.02 | 6.02 | 5.79 | 0.21 | 0.01 | 3.63 | 2.32 | 0.13 |
| 302 | 2099 MARTIN LYDON AVE | WELL PAD | 2 | 150 | 1376 | 4 | 1 | 0 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | 0.02 | <0.01 | 0.39 | 0.26 | 0.01 |
| 303 | 5092 SOUTH FWY | WELL PAD | 4 | 437 | 3649 | 5 | 1 | 0 | 1 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 308 | 5990 COLUMBUS TRAIL | WELL PAD | 4 | 368 | 2576 | 4 | 1 | 4 | 0 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 309 | 6091 COLUMBUS TRAIL | WELL PAD | 1 | 75 | 525 | 2 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 310 | 9290 GRANBURY RD | WELL PAD | 4 | 257 | 1799 | 4 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 311 | 9292 GRANBURY RD | WELL PAD | 2 | 173 | 1211 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 312 | 9198 GRANBURY RD | WELL PAD | 2 | 192 | 1344 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | 1.50 | <0.01 | 1.50 | <0.01 | 1.08 | -0- | 0.23 |
| 315 | 5701 W RISINGER RD | WELL PAD | 1 | 184 | 1288 | 2 | 1 | 3 | 1 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 316 | 8699 BREWER BLVD | WELL PAD | 9 | 743 | 5201 | 12 | 0 | 5 | 6 | -0- | -0- | -0- | -0- | 0.05 | <0.01 | <0.01 | 0.05 | <0.01 | -0- | <0.01 |
| 317 | 9991 STEWART FELTZ RD | WELL PAD | 5 | 223 | 1631 | 6 | 0 | 2 | 7 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | <0.01 | 0.02 | <0.01 | -0- | <0.01 |
| 318 | 5892 STEWART FELTZ RD | WELL PAD | 8 | 516 | 4128 | 12 | 0 | 4 | 7 | -0- | -0- | -0- | -0- | 0.07 | <0.01 | <0.01 | 0.07 | <0.01 | -0- | <0.01 |
| 324 | 10193 OLD CROWLEY CLEBURNE RD | WELL PAD | 3 | 300 | 2100 | 4 | 1 | 1 | 1 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 325 | 9599 WEST CLEBURNE | WELL PAD | 1 | 67 | 469 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | 0.02 | <0.01 | 0.02 | <0.01 | <0.01 | -0- | <0.01 |
| 327 | 2998 N CROWLEY CLEBURNE RD | WELL PAD | 3 | 226 | 2193 | 4 | 1 | 3 | 4 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| 328 | 2592 NORTH CROWLEY CLEBURNE RD | WELL PAD | 2 | 176 | 924 | 4 | 1 | 1 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 329 | 2195 CUNNINGHAM | WELL PAD | 1 | 110 | 866 | 1 | 1 | 0 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | 0.02 | <0.01 | 0.39 | 0.26 | 0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|------------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 332 | 9590 TECHNOLOGY RD | WELL PAD | 2 | 95 | 665 | 2 | 0 | 2 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 335 | 7393 CROWLEY RD | WELL PAD | 1 | 95 | 897 | 1 | 1 | 1 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.69 | 0.65 | 0.03 | <0.01 | 0.39 | 0.26 | 0.01 |
| 336 | 293 ALTAMESA BLVD | WELL PAD | 4 | 416 | 2912 | 4 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 338 | 11790 SOUTH FWY | WELL PAD | 3 | 733 | 5805 | 4 | 2 | 8 | 7 | <0.01 | 17.85 | 93.74 | 0.06 | 14.86 | 14.74 | 0.11 | 0.01 | 8.83 | 5.91 | 0.24 |
| 339 | 599 W RENDON CROWLEY RD | WELL PAD | 6 | 492 | 3444 | 7 | 0 | 10 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 341 | 13790 WILDCAT WAY SOUTH | WELL PAD | 3 | 263 | 1641 | 4 | 0 | 3 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 342 | 296 PACE ALSBURY COURT | WELL PAD | 1 | 80 | 560 | 1 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 344 | 12795 SOUTH FWY | WELL PAD | 1 | 223 | 1561 | 4 | 0 | 1 | 3 | -0- | -0- | -0- | -0- | 0.01 | <0.01 | 0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 346 | 13790 WILDCAT WAY SOUTH | WELL PAD | 3 | 198 | 1386 | 4 | 0 | 4 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 348 | 12298 OAK GROVE ROAD SOUTH | WELL PAD | 8 | 553 | 5301 | 10 | 3 | 5 | 15 | 0.12 | 1.86 | 16.27 | <0.01 | 1.77 | 1.74 | 0.02 | <0.01 | 1.04 | 0.70 | 0.03 |
| 349 | 1297 E RENDON CROWLEY | WELL PAD | 5 | 272 | 1904 | 4 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 350 | 495 OLD HWY 1187 | WELL PAD | 5 | 410 | 2870 | 5 | 0 | 6 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 351 | 1099 E RENDON CROWLEY RD | WELL PAD | 4 | 268 | 1966 | 4 | 1 | 2 | 8 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | 0.01 |
| 352 | 1099 E RENDON CROWLEY RD | WELL PAD | 4 | 230 | 1610 | 5 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 353 | 11799 SOUTH FWY | WELL PAD | 2 | 130 | 910 | 2 | 0 | 5 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 354 | 492 GARDEN ACRES DR | WELL PAD | 3 | 432 | 4064 | 3 | 1 | 2 | 1 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 355 | 10598 OAK GROVE RD | WELL PAD | 2 | 224 | 1568 | 4 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 356 | 9798 OLD BURLESON RD | WELL PAD | 3 | 276 | 2308 | 4 | 1 | 4 | 3 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| 357 | 10199 OAK GROVE RD | WELL PAD | 3 | 208 | 1728 | 3 | 1 | 1 | 6 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | 0.01 | 0.39 | 0.26 | <0.01 |
| 360 | 10596 FOREST HILL-EVERMAN RD | WELL PAD | 4 | 288 | 2016 | 5 | 0 | 2 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|------------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 362 | 10196 FOREST HILL EVERMAN RD | WELL PAD | 2 | 84 | 588 | 2 | 0 | 2 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 368 | 8598 WILL ROGERS BLVD | WELL PAD | 1 | 53 | 371 | 1 | 0 | 1 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 369 | 8490 OAK GROVE RD | WELL PAD | 5 | 236 | 1652 | 5 | 0 | 2 | 11 | -0- | -0- | -0- | -0- | 0.04 | <0.01 | <0.01 | 0.04 | <0.01 | -0- | <0.01 |
| 371 | 7893 WILL ROGERS RD | WELL PAD | 2 | 115 | 805 | 3 | 1 | 1 | 1 | 0.08 | 1.23 | 3.45 | <0.01 | 1.13 | 1.13 | <0.01 | <0.01 | 0.67 | 0.45 | 0.02 |
| 373 | 1290 JOHN BURGESS DR | WELL PAD | 4 | 84 | 588 | 0 | 0 | 0 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 374 | 6994 WILL ROGERS BLVD | WELL PAD | 2 | 273 | 2295 | 2 | 1 | 4 | 15 | 0.08 | 1.23 | 3.45 | <0.01 | 1.24 | 1.13 | 0.01 | 0.10 | 0.69 | 0.45 | 0.02 |
| 381 | 1191 INTERMODEL PKWY | WELL PAD | 12 | 759 | 6072 | 12 | 0 | 8 | 19 | -0- | -0- | -0- | -0- | 0.13 | <0.01 | 0.13 | <0.01 | 0.03 | -0- | 0.01 |
| 382 | 6197 SOUTH FWY | WELL PAD | 1 | 119 | 833 | 1 | 0 | 0 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 392 | 5091 SOUTH FREEWAY | WELL PAD | 1 | 69 | 483 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 396 | 2295 E SEMINARY DR | WELL PAD | 10 | 858 | 6144 | 10 | 1 | 8 | 10 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 397 | 1294 E BERRY ST | WELL PAD | 2 | 588 | 4494 | 5 | 3 | 2 | 2 | 0.85 | 13.64 | 69.50 | 0.05 | 12.24 | 12.24 | <0.01 | <0.01 | 7.27 | 4.91 | 0.17 |
| 399 | 4296 MITCHELL BLVD | WELL PAD | 5 | 374 | 2986 | 6 | 1 | 6 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 400 | 3997 MITCHELL BLVD | WELL PAD | 6 | 379 | 2989 | 8 | 1 | 3 | 7 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| 403 | 1999 BOMAR AVE | WELL PAD | 4 | 467 | 3395 | 4 | 1 | 0 | 0 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 405 | 892 BEACH ST | WELL PAD | 5 | 362 | 3619 | 0 | 1 | 1 | 2 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 409 | 4298 EAST FIRST ST | WELL PAD | 3 | 278 | 1946 | 4 | 0 | 0 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 411 | 5391 EAST FIRST ST | WELL PAD | 9 | 1143 | 8136 | 9 | 1 | 3 | 6 | 0.07 | 1.04 | 2.91 | <0.01 | 1.01 | 1.01 | <0.01 | <0.01 | 0.60 | 0.40 | 0.01 |
| 415 | 7092 ENTERPRISE AVE | WELL PAD | 1 | 76 | 670 | 1 | 1 | 2 | 2 | 0.03 | 0.46 | 12.35 | <0.01 | 0.44 | 0.43 | <0.01 | <0.01 | 0.26 | 0.17 | <0.01 |
| 416 | 5290 BOCA RATON BLVD | WELL PAD | 3 | 238 | 1666 | 4 | 0 | 3 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 419 | 7090 ENTERPRISE AVE | WELL PAD | 9 | 389 | 4049 | 12 | 2 | 3 | 19 | 0.13 | 2.08 | 5.81 | <0.01 | 2.02 | 2.01 | <0.01 | 0.01 | 1.20 | 0.81 | 0.03 |
| 420 | 7094 JACK NEWELL BLVD S | WELL PAD | 2 | 159 | 1750 | 4 | 1 | 3 | 3 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

| Site ID | Address | Site Type | No. Wells | No. Valves | No. Connectors | No. Tanks | No. Compressors | No. M21 >500 ppm | No. IRs | PM (tons/yr) | NOx (tons/yr) | CO (tons/yr) | SO2 (tons/yr) | VOCs (tons/yr) | | | | HAPS ^b (tons/yr) | | |
|---------|------------------------|-----------|-----------|------------|----------------|-----------|-----------------|------------------|---------|--------------|---------------|--------------|---------------|----------------|------------|----------|--------------|-----------------------------|--------------|---------|
| | | | | | | | | | | | | | | VOC Total | Engine VOC | Tank VOC | Fugitive VOC | HAP Total | Formaldehyde | Benzene |
| 421 | 2392 AUSTIN RD | WELL PAD | 2 | 146 | 1581 | 2 | 1 | 5 | 6 | 0.05 | 0.70 | 1.96 | <0.01 | 0.66 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 422 | 7213 ATCO DR | WELL PAD | 3 | 137 | 959 | 3 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 423 | 7603 TRINITY BLVD | WELL PAD | 3 | 273 | 2730 | 4 | 0 | 1 | 4 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 424 | 7498 MOSIER VIEW CT | WELL PAD | 4 | 434 | 4510 | 4 | 4 | 4 | 11 | 0.19 | 2.80 | 7.84 | 0.01 | 2.63 | 2.61 | 0.01 | <0.01 | 1.55 | 1.05 | 0.04 |
| 426 | 692 BRIDGEWOOD DR | WELL PAD | 5 | 735 | 5427 | 5 | 2 | 1 | 11 | 0.09 | 1.40 | 3.92 | <0.01 | 1.31 | 1.31 | <0.01 | <0.01 | 0.78 | 0.52 | 0.02 |
| 427 | 7990 TRINITY BLVD | WELL PAD | 6 | 144 | 1008 | 0 | 0 | 0 | 6 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 428 | 7990 TRINITY BLVD | WELL PAD | 5 | 780 | 6015 | 12 | 3 | 6 | 10 | 0.18 | 2.78 | 7.77 | 0.01 | 2.67 | 2.67 | <0.01 | <0.01 | 1.58 | 1.07 | 0.04 |
| 429 | 8097 TRINITY BLVD | WELL PAD | 1 | 143 | 1337 | 2 | 1 | 2 | 4 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 438 | 9290 KEMP ST | WELL PAD | 3 | 301 | 2786 | 5 | 1 | 0 | 2 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 447 | 2598 GREENBELT RD | WELL PAD | 2 | 200 | 1400 | 2 | 1 | 2 | 5 | 0.05 | 0.70 | 1.96 | <0.01 | 0.65 | 0.65 | <0.01 | <0.01 | 0.39 | 0.26 | <0.01 |
| 457 | 1992 EAST CHASE PKWY | WELL PAD | 1 | 119 | 786 | 2 | 0 | 1 | 1 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 462 | 6796 ROSEDALE ST | WELL PAD | 13 | 600 | 4200 | 0 | 0 | 5 | 6 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 468 | 1593 INTERMODEL PKWY | WELL PAD | 12 | 743 | 5201 | 0 | 0 | 2 | 3 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 469 | 7098 ROBERTSON RD | WELL PAD | 11 | 260 | 1820 | 3 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 470 | 7294 ROBERTSON RD | WELL PAD | 2 | 167 | 1570 | 6 | 1 | 1 | 4 | 0.01 | 3.58 | 5.87 | <0.01 | 0.21 | 0.19 | <0.01 | <0.01 | 0.12 | 0.08 | <0.01 |
| 471 | 1597 INTERMODEL PKWY | WELL PAD | 6 | 383 | 2481 | 0 | 0 | 0 | 7 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 472 | 1791 INTERMODEL PKWY | WELL PAD | 7 | 482 | 3374 | 0 | 0 | 5 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 474 | 6593 DIRKS RD | WELL PAD | 1 | 80 | 560 | 1 | 0 | 3 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 480 | 5096 N SYLVANIA AVE | WELL PAD | 3 | 357 | 2499 | 3 | 0 | 1 | 0 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |
| 483 | 4898 MARINE CREEK PKWY | WELL PAD | 1 | 70 | 1095 | 1 | 1 | 0 | 7 | 0.05 | 0.70 | 1.96 | <0.01 | 0.67 | 0.65 | <0.01 | 0.02 | 0.39 | 0.26 | <0.01 |
| 485 | 4691 E LOOP 820 S | WELL PAD | 9 | 447 | 3465 | 6 | 2 | 2 | 19 | 0.09 | 1.40 | 3.92 | <0.01 | 1.36 | 1.31 | 0.01 | 0.04 | 0.79 | 0.52 | 0.02 |
| 487 | 3490 BRYANT IRVIN RD | WELL PAD | 2 | 97 | 679 | 2 | 0 | 0 | 2 | -0- | -0- | -0- | -0- | <0.01 | <0.01 | <0.01 | <0.01 | <0.01 | -0- | <0.01 |

^a For values reported as <0.01, see Appendix 3-A for actual emissions expressed in scientific notation.

^b The HAP Total emissions listed include all HAP emissions that were measured and calculated as part of this study. For a complete list of estimated HAPs emissions, see Appendix 3-A.

Figure 3.5-2 shows the average TOC emissions for the three basic component categories found at the natural gas facilities which were surveyed by the point source team: Valves, Connectors, and Other. Valves include manual valves, automatic actuation valves, and pressure relief valves. Connectors include flanges, threaded unions, tees, plugs, caps and open-ended lines where the plug or cap was missing. The category “Other” consists of all remaining components such as tank thief hatches, pneumatic valve controllers, instrumentation, regulators, gauges, vents, etc.

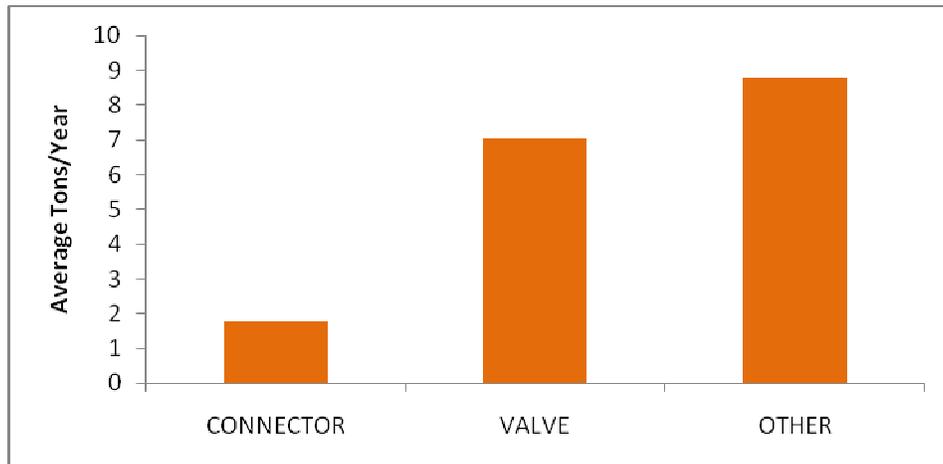


Figure 3.5-2. Average TOC Emissions by Component Category

As indicated in Figure 3.5-2, average TOC emissions from components in the “Other” category exceeded emissions from valves and connectors. Figure 3.5-3 identifies individual equipment types in the “Other” category with the highest average TOC emissions. Among these, tank thief hatches have the largest average TOC emission contribution, followed by miscellaneous equipment, tank vents, pneumatic valve controllers, and gas regulators.

Miscellaneous equipment included a variety of emission sources such as holes and cracks in tank roofs, various types of instrumentation and meters, sumps, compressor shafts, orifice plates, sight glasses, and underground piping.

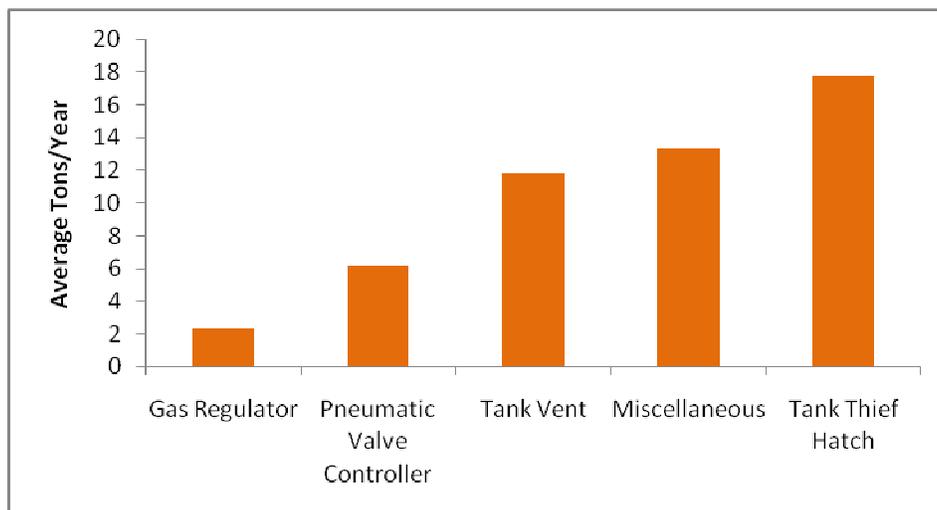


Figure 3.5-3. Average TOC Emissions in Category “Other”

Figure 3.5-4 summarizes the average annual TOC, VOC, HAP, and Criteria Pollutant emissions from compressor engines alone. Criteria pollutant emission data is based upon vendor-provided and published engine emission factors and pertains to those compressors encountered at well pad sites.

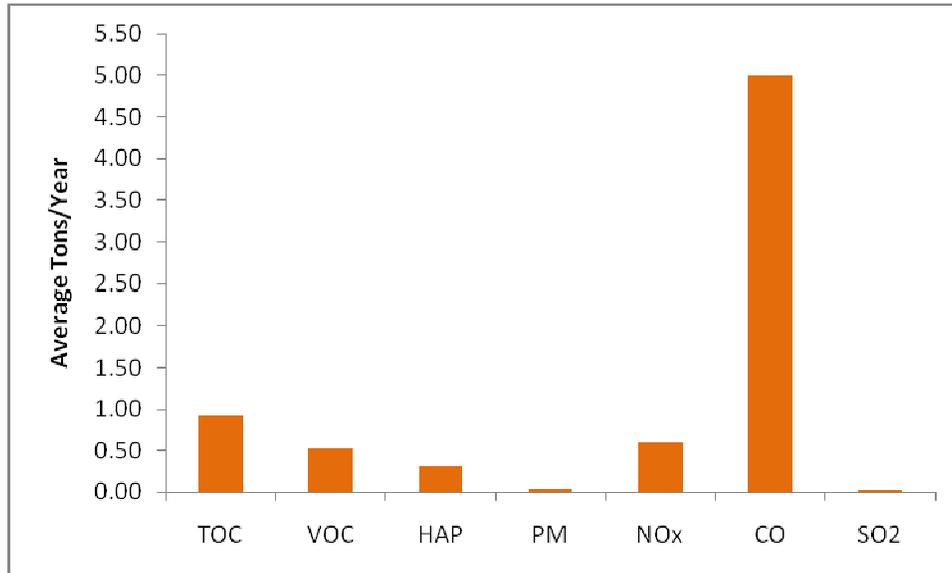


Figure 3.5-4. Average Annual Emissions from Well Pad Compressor Engines

Figure 3.5-5 compares VOC and HAP average annual emissions from Non-Tank and Tank sources.

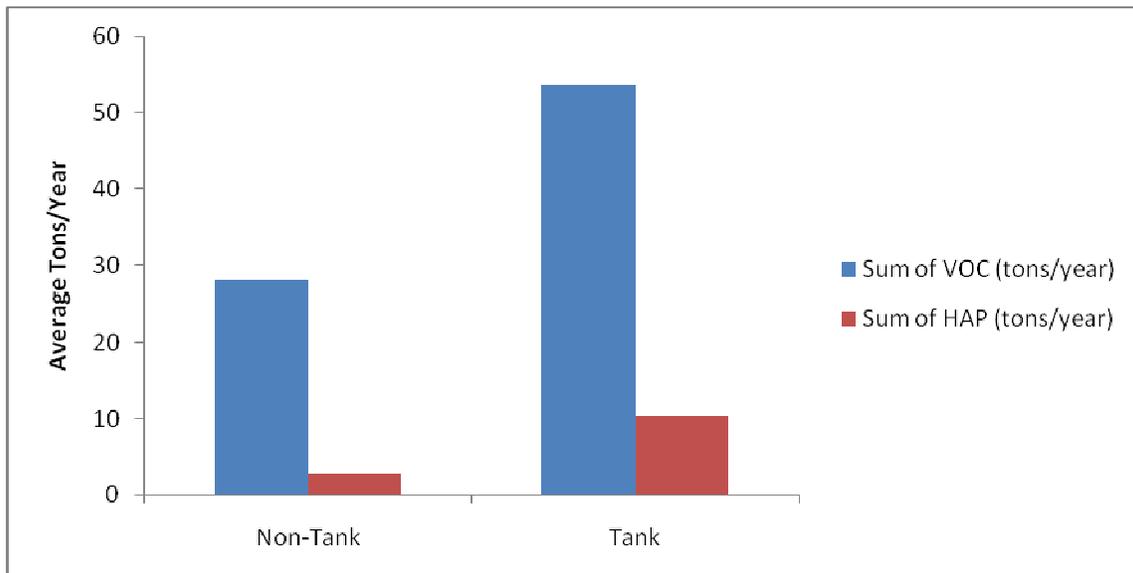


Figure 3.5-5. Non-Tank vs. Tank: Average VOC and HAP Emissions

Figures 3.5-6 and 3.5-7 compare TOC, VOC, and HAP average emissions from dry gas and wet gas sites. For purposes of this study, a site was considered to be a wet gas site if it produced more than 1 barrel of condensate/day as indicated by the Texas Railroad Commission.

Figure 3.5-6 indicates that average TOC emissions from wet gas well pad sites were higher than those from dry gas well pad sites. Also, indicated in Figure 3.5-7, wet gas well pad sites were found to have higher average VOC and HAP emissions.

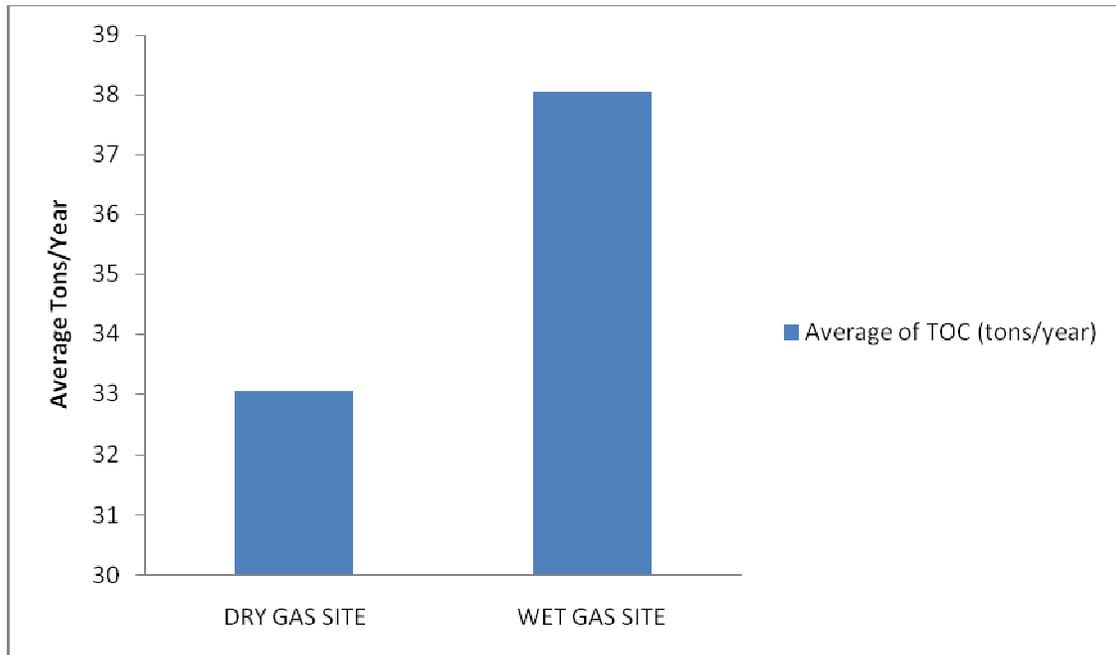


Figure 3.5-6. Average Wet Gas vs. Dry Gas TOC Emissions

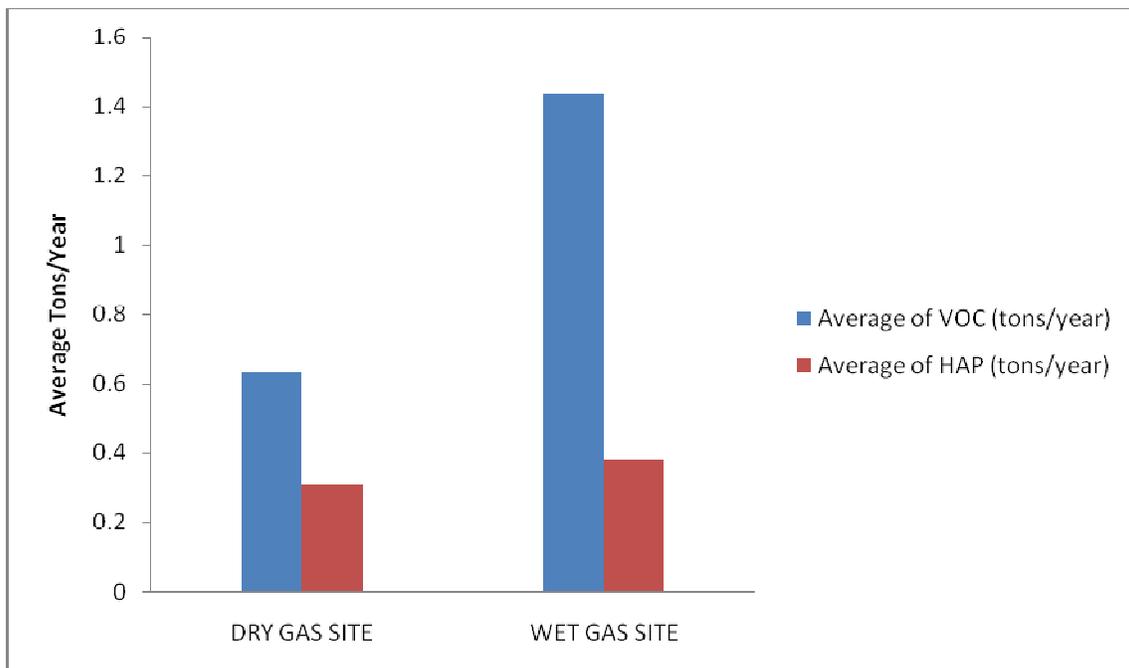


Figure 3.5-7. Average Wet Gas vs. Dry Gas VOC and HAP Emissions

At the City's request, the point source team re-visited two sites in Phase II that had been previously surveyed in Phase I. The Chesapeake site at 2299 Mercado Drive was surveyed on October 20, 2010 (Point Source ID PS -192) and again on February 15, 2011 (Point Source ID 294). The ENCANA site at 11398 West Freeway was surveyed in Phase I on September 21, 2010 (Point Source ID PS -086) and again, in Phase II on February 16, 2011 (Point Source ID 260). Table 3.5-4 summarizes the results of each survey.

Table 3.5-4. Summary of Repeat Surveys^a

| Site/Date | Temp °F ^b | # IR Detects ^c | # M21 Detects ^d | TOC (tons/yr) | VOC (tons/yr) | HAP (tons/yr) |
|---|-------------------------|------------------------------|-------------------------------|------------------|------------------|------------------|
| <i>Chesapeake - 2299 Mercado Drive (Site IDs: PS-192 and 294)</i> | | | | | | |
| 20-Oct-10 | 88 | 12 | 6 | 188 | 2.2 | 1.3 |
| 15-Feb-11 | 64 | 22 | 5 | 181 | 2.15 | 1.2 |
| <i>ENCANA - 11398 West Fwy (Site IDs: PS-086 and 260)^e</i> | | | | | | |
| 21-Sep-10 | 87 | 8 | 4 | 25.7 | 8.7 | 1.9 |
| 16-Feb-11 | 65 | 8 | 4 | 35.7 | <0.1 | <0.1 |

^a For values reported as <0.01 see Appendix 3-A for actual emissions expressed in scientific notation.

^b Ambient site temperature in degrees Fahrenheit

^c Number of emission points detected with the IR camera

^d Number of emission points detected by Method 21 screening procedures.

^e During the first site visit, one canister sample was collected from a tank emission point and the results used to estimate the site's emissions accordingly. During the second site visit, no canister was collected. Therefore, consistent with the point source test plan, a surrogate emission rate was used to estimate the site's emissions during the second visit.

Detailed site-by-site emission results are provided in Appendix 3-A.

3.5.1 Well Activity Emissions

In addition to well pads, compressor stations, a natural gas processing facility and a salt water treatment facility, three types of exploration and stimulation activities were surveyed for emissions:

- Well Drilling.
- Fracking.
- Completion.

Figure 3.5-8 summarizes the hourly emissions from these operations. Since each lasts approximately three weeks or less, emissions are presented on a pounds/hour basis rather than annual basis.

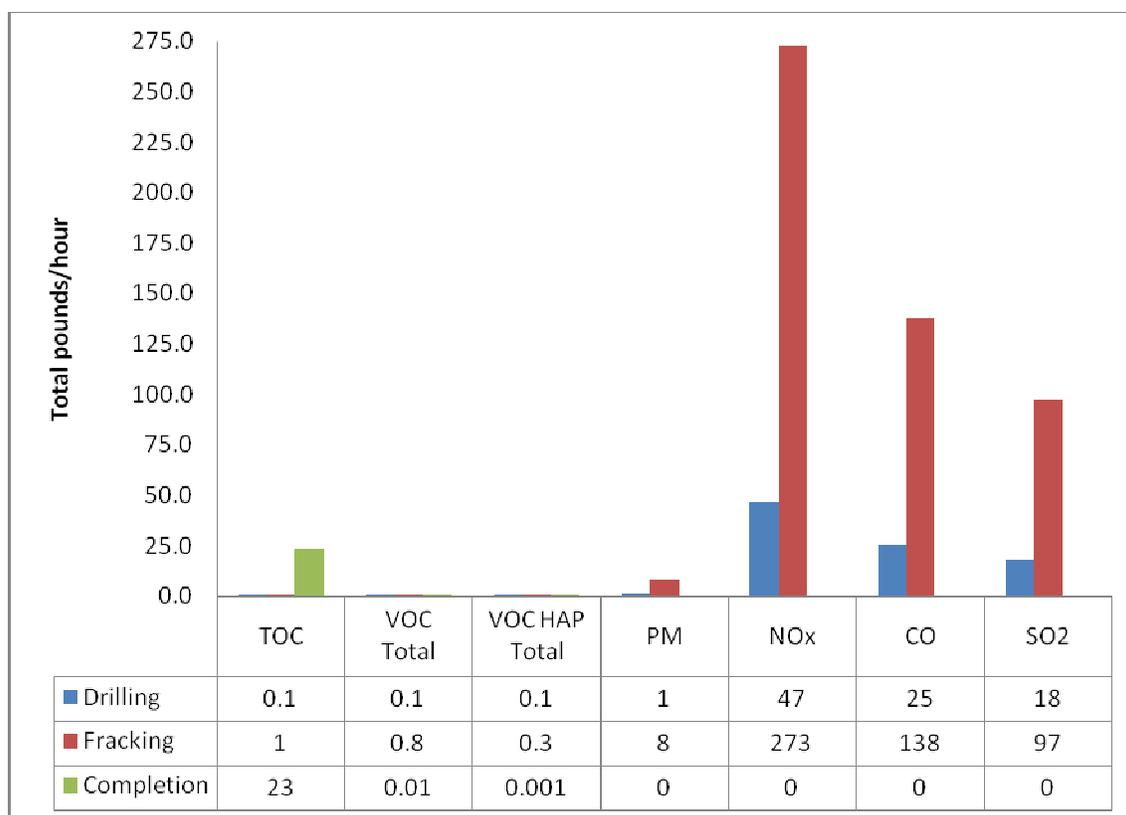


Figure 3.5-8. Well Activity Emissions (lbs/hr)

Well Drilling

A drilling site located at 580 East Rosedale and operated by XTO (Point Source ID PS-128) was surveyed on October 1, 2010. During the time of the site visit, the drilling operation was in process and operating under normal conditions. An IR camera scan was performed on all aspects of the drilling operation. No emissions from leaking components or drilling mud were detected by the camera during this survey. Estimated combustion emissions from the drilling rig engines are based on engine data obtained during the site survey. Detailed combustion emissions are provide in Appendix 3-A.

Fracking

A large fracking operation was surveyed on October 20, 2010 at 5900 Wilbarger (Point Source ID PS-193). During the time of the site visit, the fracking operation was in process and operating under normal conditions. The operation included the following equipment: 8 sand trucks, 11 diesel engine pump trucks, 8 mobile water trucks, 3 sand hoppers, 1 chemical injection flatbed trailer, and 1 chemical injection truck. Two complete IR camera scans were performed on all equipment. No emissions from leaking components or fluids handling were detected by the camera. Combustion emissions from the pump engines have been estimated and are based on engine data obtained during the site survey. Detailed combustion emissions are provide in Appendix 3-A.

Well Completion

A flowback operation was surveyed by the point source team on October 5, 2010 at 5199 Village Creek Road (Point Source ID PS-134). One emission point was detected with the IR camera and five low level emission points were identified with the TVA during Method 21 screening while the flowback operation was in progress. Detailed emissions are provide in Appendix 3-A.

3.5.2 Method 21 TOC Screening Emission Factors

Emission factors for the Method 21 screening ranges 500-999 ppmv and 1,000 to 10,000 ppmv were calculated for the equipment categories valves, connectors, and others according to the procedures explained in Section 3.4.2. Unfortunately, an insufficient number of valves and other equipment were found with emissions in the 500 – 999 ppmv category (two and four respectively) to derive reliable emission factors for this screening range. The remaining categories however were sufficiently populated to enable the derivation of the emission factors provided in Table 3.5-5 below.

Table 3.5-5. TOC Screening Emission Factors

| Concentration Range | Valves | Connectors | Other |
|---------------------|-----------------------------------|------------------------------------|-----------------------------------|
| 500 – 999 ppmv | — | 2.17E-04 kg/hr 4.78E-04 lbs/hr | — |
| 1000 – 10,000 ppmv | 1.10E-03 kg/hr 2.43E-03 lbs/hr | 4.70 E-04 kg/hr 1.04E-03 lbs/hr | 1.60E-02 kg/hr 3.52E-02 lbs/hr |

3.6 Quality Control Results

Point Source project Quality Assurance/Quality Control (QA\QC) was ensured through both field and analytical quality control procedures. Field QC procedures included:

- IR Camera Daily Demo.
- Hi Flow Sampler Daily Calibration Verification.
- TVA Daily Calibration and Drift Checks.
- Regular review of completed field data forms.
- Canister sampling protocols.
- Duplicate canister sample collection.

Analytical QC procedures included:

- Method Blanks.
- Surrogate Recoveries.
- Laboratory Control Samples and Control Sample Duplicates.
- Continuing Calibration Verification.

The results of the field QC checks are provided in the tables following. The results of the analytical QC are provided with the TestAmerica™ laboratory reports in the Appendix 3-C.

3.6.1 IR Camera Daily Demo Results

Three IR cameras were used during this project. IR cameras “GasFindIR” and “GF-320” were used continuously throughout the project. IR camera “Dexter” was used only for one day as a temporary replacement. The sensitivity of each IR camera was evaluated daily prior to testing (i.e. Daily Demo). The Daily Demo was performed at two flow rates: ~10 grams/hour propane and ~30 grams/hour propane. The maximum distance from which the two flow rates could be observed with the cameras was recorded together with current weather data. The results of the IR camera daily demos are provided in Tables 3.6-1 through 3.6-5.

3.6.2 Hi Flow Sampler Calibration Verification

Three Hi Flow Samplers were used during the project. Hi Flow Samplers #QS1002 was used in both Phase I and II. Hi Flow Sampler #QS 1005 was used in Phase I and was replaced in Phase II with Hi Flow Sampler #QX 1007. Each Hi Flow Sampler was calibrated at the start of Phase I and Phase II testing using certified gas cylinders of 2.5% and 99% methane. A calibration verification check of both background and sample sensors was performed daily prior to testing with the 2.5% methane standard. Once each week the calibration verification check of both sensors was performed with the 2.5% and the 99% methane gas standards with an acceptance criterion of +/- 10% agreement. The results of Hi Flow Sampler daily calibration verification checks are summarized in Tables 3.6-6 through 3.6-9.

**Table 3.6-1. IR Camera ID: GasFindIR Daily Demo
September – October, 2010**

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|---------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 9/1/10 9:26 | 27.00 | 100831_002 | 68.01 | 100831_003 | N | 6.5 | 84.5 | 73.4 | 99.4 | 35 |
| 9/2/10 10:15 | 24.16 | 100901_006 | 40.50 | 100901_007 | S | 1.5 | 76.7 | 89.1 | 98.7 | 95 |
| 9/3/10 7:39 | 27.72 | 100902_001 | 39.11 | 100902_002 | W | 5.5 | 72.1 | 61.0 | 99.9 | 100 |
| 9/7/10 7:25 | 50.10 | 100906_001 | 163.70 | 100906_002 | CALM | CALM | 84.2 | 72.0 | 99.6 | 100 |
| 9/8/10 8:33 | 53.25 | 100907_002 | 72.90 | 100907_001 | CALM | CALM | 80.0 | 82.8 | 99.2 | 0 |
| 9/9/10 8:20 | 28.32 | 100908_001 | 53.04 | 100908_002 | N | 2.6 | 91.3 | 86.5 | 99.17 | 100 |
| 9/10/10 8:30 | 39.04 | 100909_001 | 65.21 | 100909_002 | SE | 1.1 | 85.0 | 88.7 | 99.01 | 85 |
| 9/16/10 7:30 | 22.20 | 100915_001 | 36.90 | 100915_003 | W | 1.8 | 81.2 | 75.4 | 99.4 | 4 |
| 9/17/10 7:00 | 26.54 | 100916_001 | 31.16 | 100916_002 | CALM | CALM | 80.2 | 61.5 | 99.5 | 10 |
| 9/20/10 7:20 | 29.90 | 100919_001 | 39.65 | 100919_002 | CALM | 1.0 | 80.3 | 67.2 | 99.7 | 1 |
| 9/21/10 7:30 | 31.90 | 100920_001 | 52.24 | 100920_002 | S | 2.8 | 78.8 | 81.2 | 99.3 | 15 |
| 9/22/10 7:28 | 25.20 | 100921_002 | 42.92 | 100921_003 | SE | 2.3 | 75.7 | 83.8 | 99.5 | 0 |
| 9/23/10 7:20 | 27.10 | 100922_001 | 43.47 | 100922_002 | E | 3.4 | 78.0 | 81.1 | 99.4 | 97 |
| 9/24/10 7:25 | 32.68 | 100923_001 | 59.69 | 100923_002 | SE | 1.4 | 79.9 | 81.0 | 99.8 | 80 |
| 9/27/10 7:28 | 27.07 | 100926_001 | 38.12 | 100926_002 | SW | 1.5 | 57.5 | 65.8 | 99.8 | 0 |
| 9/28/10 7:26 | 26.61 | 100927_002 | 37.54 | 100927_003 | SW | 1.4 | 59.3 | 78.7 | 99.5 | 0 |
| 9/29/10 7:20 | 25.07 | 100928_001 | 35.94 | 100928_002 | NW | 4.0 | 63.8 | 71.0 | 99.1 | 0 |
| 9/30/10 7:45 | 30.92 | 100929_001 | 48.38 | 100929_002 | CALM | CALM | 64.3 | 72.1 | 99.5 | 0 |
| 9/31/10 7:45 | 26.70 | 100930_001 | 41.50 | 100930_002 | CALM | CALM | 64.3 | 71.9 | 101.2 | 0 |
| 10/4/10 7:44 | 14.60 | 101003_001 | 35.15 | 101003_002 | CALM | CALM | 61.4 | 68.1 | 100.7 | 5 |
| 10/5/10 7:45 | 16.50 | 101004_002 | 33.60 | 101004_003 | CALM | CALM | 51.6 | 69.4 | 100.7 | 0 |
| 10/6/10 7:50 | 15.90 | 101005_001 | 32.30 | 101005_002 | CALM | CALM | 59.2 | 67.5 | 100.7 | 0 |
| 10/7/10 7:37 | 26.53 | 101006_001 | 45.91 | 101006_001 | CALM | CALM | 57.8 | 72.5 | 100.4 | 0 |
| 10/8/10 7:45 | 22.73 | 101007_001 | 32.14 | 101007_002 | CALM | CALM | 58.9 | 66.9 | 100.1 | 0 |
| 10/11/10 7:36 | 27.54 | 101010_001 | 45.25 | 101010_002 | CALM | CALM | 72.1 | 70.8 | 99.2 | 100 |

Table 3.6-1. GasFindIR Daily Demo (Continued)

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|---------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 10/12/10 7:30 | 18.28 | 101011_001 | 36.51 | 101011_002 | W | 1.9 | 62.5 | 77.5 | 99.6 | 4 |
| 10/13/10 7:40 | 23.50 | 101012_001 | 35.28 | 101012_002 | W | 1.2 | 64.7 | 69.7 | 100.3 | 0 |
| 10/14/10 7:45 | 18.00 | 101013_001 | 29.80 | 101013_002 | CALM | CALM | 57.8 | 54.1 | 100.8 | 0 |
| 10/15/10 7:50 | 22.10 | 101014_001 | 33.80 | 101014_002 | CALM | CALM | 60.1 | 69.1 | 100.1 | 0 |
| 10/18/10 7:40 | 17.50 | 101017_001 | 27.45 | 101017_002 | CALM | CALM | 69.5 | 78.4 | 99.5 | 0 |
| 10/19/10 7:40 | 22.16 | 101018_001 | 35.21 | 101018_002 | CALM | CALM | 70.5 | 71.3 | 99.4 | 0 |
| 10/20/10 7:35 | 21.78 | 101019_001 | 30.03 | 101019_002 | N | 2.5 | 67.3 | 65.5 | 99.8 | 60 |
| 10/21/10 7:53 | 16.89 | 101020_001 | 31.38 | 101020_002 | CALM | CALM | 68.5 | 82.7 | 99.7 | 67 |

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

**Table 3.6-2. IR Camera ID: GF-320 Daily Demo
September – October, 2010**

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|--------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 9/7/10 8:30 | 38.83 | 0025 | 70.85 | 0026 | CALM | CALM | 84.2 | 72.0 | 99.6 | 100 |
| 9/8/10 8:30 | 53.25 | 0034 | 71.57 | 0033 | CALM | CALM | 80.0 | 82.8 | 99.21 | 0 |
| 9/9/10 8:08 | 9.00 | 0041 | 22.00 | 0042 | S | 2.3 | 80.0 | 90.3 | 99.9 | 100 |
| 9/10/10 7:45 | 18.50 | 0054 | 27.00 | 0055 | SE | 1.1 | 82.9 | 84.7 | 99.01 | 85 |
| 9/13/10 8:45 | 48.69 | 0058 | 77.18 | 0059 | E | 1.9 | 80.5 | 82.7 | 99.85 | 80 |
| 9/14/10 7:20 | 18.93 | 0069 | 228.36 | 0020 | CALM | CALM | 81.1 | 77.8 | 99.63 | 0 |
| 9/15/10 7:17 | 20.17 | 0079 | 25.30 | 0080 | N | 1.5 | 76.5 | 76.8 | 99.5 | 0 |
| 9/16/10 7:10 | 19.00 | 0086 | 23.00 | 0087 | W | 1.8 | 81.2 | 75.4 | 99.4 | 4 |
| 9/17/10 0:00 | 9.40 | 0109 | 18.80 | 0110 | CALM | CALM | 80.2 | 61.5 | 99.5 | 10 |
| 9/20/10 7:45 | 8.60 | 0121 | 23.50 | 0122 | CALM | CALM | 80.3 | 67.2 | 99.7 | 1 |
| 9/21/10 7:30 | 13.60 | 0135 | 31.30 | 0136 | S | 2.8 | 78.8 | 81.2 | 99.3 | 15 |
| 9/22/10 7:24 | 7.80 | 0151 | 24.70 | 0152 | SE | 2.3 | 75.7 | 83.8 | 99.5 | 1 |
| 9/23/10 7:40 | 6.50 | 0175 | 28.30 | 0176 | E | 3.4 | 78.0 | 81.1 | 99.4 | 97 |
| 9/24/10 7:28 | 16.80 | 0199 | 34.90 | 0200 | SE | 1.8 | 79.9 | 81.0 | 99.8 | 80 |
| 9/27/10 7:35 | 13.10 | 0221 | 21.30 | 0222 | SW | 1.5 | 57.5 | 65.8 | 99.8 | 0 |
| 9/28/10 7:26 | 14.60 | 0234 | 26.00 | 0235 | SW | 1.4 | 59.3 | 78.7 | 99.5 | 0 |
| 9/29/10 7:15 | 16.40 | 0247 | 23.30 | 0248 | CALM | CALM | 63.8 | 71.0 | 99.1 | 0 |
| 9/30/10 7:45 | 10.30 | 0268 | 24.50 | 0269 | CALM | CALM | 64.3 | 72.1 | 99.5 | 0 |
| 9/31/10 7:35 | 14.86 | 0299 | 20.70 | 0300 | CALM | CALM | 64.3 | 71.9 | 100 | 0 |

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

Table 3.6-2. GF-320 Daily Demo (Continued)

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|---------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 10/4/10 7:35 | 17.57 | 0313 | 30.80 | 0314 | CALM | CALM | 61.4 | 68.1 | 100.7 | 5 |
| 10/5/10 7:35 | 13.42 | 0325 | 24.80 | 0326 | CALM | CALM | 51.6 | 69.4 | 100.7 | 0 |
| 10/6/10 7:58 | 12.44 | 0345 | 21.00 | 0346 | CALM | CALM | 59.2 | 67.5 | 100.7 | 0 |
| 10/7/10 7:32 | 29.78 | 0368 | 36.25 | 0372 | CALM | CALM | 57.8 | 72.5 | 100.8 | 0 |
| 10/12/10 7:36 | 18.20 | 0423 | 24.20 | 0424 | W | 1.9 | 62.5 | 77.5 | 99.6 | 4 |
| 10/13/10 7:40 | 23.00 | 0436 | 31.00 | 0437 | W | 1.2 | 64.7 | 69.7 | 100.3 | 0 |
| 10/14/10 7:50 | 18.10 | 0460 | 26.60 | 0461 | CALM | CALM | 57.4 | 54.0 | 100.8 | 0 |
| 10/15/10 7:50 | 17.00 | 0504 | 25.80 | 0505 | CALM | CALM | 60.4 | 69.0 | 100.1 | 0 |
| 10/18/10 7:50 | 7.80 | 0506 | 14.60 | 0507 | CALM | CALM | 69.5 | 78.4 | 99.5 | 0 |
| 10/18/10 7:55 | 12.02 | 0511 | 19.17 | 0512 | CALM | CALM | 70.5 | 94.0 | 99.4 | 0 |
| 10/20/10 7:49 | 12.30 | 0529 | 24.60 | 0530 | N | 2.5 | 67.3 | 65.5 | 99.8 | 60 |
| 10/21/10 7:55 | 13.7 | 0549 | 23.9 | 0550 | CALM | CALM | 68.5 | 82.7 | 99.7 | 67 |

**Table 3.6-3. IR Camera ID: Dexter Daily Demo
September – October, 2010**

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|--------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 9/15/10 7:45 | 3.00 | VID0016 | 4.00 | VID0015 | N | 1.5 | 76.5 | 76.8 | 99.5 | 0 |

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

**Table 3.6-4. IR Camera ID: GasFindIR Daily Demo
January – February, 2011**

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|--------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 1/4/11 7:50 | 34.1 | 110103_001 | 84.7 | 110103_002 | E | 1.4 | 64.2 | 58.5 | 99.9 | 0 |
| 1/5/11 7:21 | 23.94 | 110104_001 | 54.6 | 110104_002 | CALM | CALM | 46.2 | 64.9 | 99.5 | 0 |
| 1/6/11 7:28 | 30.81 | 110105_001 | 51.46 | 110105_002 | E | 1.8 | 51.3 | 36.7 | 99.38 | 5 |
| 1/7/11 7:35 | 32.81 | 110106_001 | 57.17 | 110106_002 | N | 1 | 51.1 | 42.9 | 99.1 | 10 |
| 1/8/11 7:32 | 21.66 | 110107_001 | 38.87 | 110107_002 | CALM | CALM | 48.5 | 45.4 | 99.5 | 0 |
| 1/10/11 7:36 | 10.178 | 110109_001 | 31.96 | 110109_002 | N | 2.1 | 38.4 | 59.3 | 99.8 | 100 |
| 1/13/11 7:26 | 21.86 | 110112_001 | 52.41 | 110112_002 | E | 1.4 | 34.7 | 65.3 | 101.6 | 100 |
| 1/14/11 7:23 | 14.45 | 110113_001 | 30.49 | 110113_002 | CALM | CALM | 41.2 | 35.2 | 100.5 | 100 |
| 1/15/11 8:05 | 17.51 | 110114_001 | 50.4 | 110114_002 | SE | 3.2 | 38.2 | 69.2 | 100.4 | 100 |
| 1/18/11 7:20 | 8.38 | 110117_001 | 17.36 | 110117_002 | 2.7 | W | 44.9 | 78.1 | 99.1 | 100 |
| 1/19/11 7:30 | 12.74 | 110118_001 | 24.86 | 110118_002 | CALM | CALM | 38.9 | 45.6 | 99.7 | 5 |
| 1/20/11 7:31 | 14.36 | 110119_001 | 22.79 | 110119_002 | N | 4.8 | 38.6 | 72.3 | 99.8 | 100 |
| 1/21/11 7:27 | 16.9 | 110120_001 | 30.78 | 110120_002 | CALM | CALM | 33 | 39.5 | 100.1 | 50 |
| 1/22/11 7:08 | 18.2 | 110121_001 | 31.8 | 110121_002 | CALM | CALM | 39.1 | 50.0 | 99.7 | 0 |
| 1/24/11 7:23 | 21 | 110123_001 | 29.6 | 110123_002 | CALM | CALM | 36.3 | 55.7 | 99.9 | 0 |
| 1/25/11 7:18 | 11.4 | 110124_001 | 11.4 | 110124_002 | NW | 3.8 | 42.1 | 46.3 | 100.5 | 100 |
| 1/26/11 7:15 | 13.7 | 110125_001 | 30.7 | 110125_002 | CALM | CALM | 38.8 | 46.6 | 100.1 | 0 |
| 1/27/11 7:15 | 12.6 | 110126_001 | 20.1 | 110126_002 | CALM | CALM | 33.6 | 75.3 | 100.2 | 0 |
| 1/28/11 6:50 | 24.6 | 110127_001 | 47.5 | 110127_002 | CALM | CALM | 37.3 | 73.6 | 99.8 | 0 |

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

Table 3.6-4. GasFindIR Daily Demo (Continued)

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|---------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 1/31/11 7:25 | 39.7 | 110130_002 | 62.4 | 110130_003 | NW | 2.4 | 44.5 | 62.9 | 99.6 | 100 |
| 2/3/11 10:35 | 20.9 | 110202_001 | 44.1 | 110202_002 | NW | 5.2 | 20.5 | 50.1 | 101.5 | 100 |
| 2/5/11 11:15 | 41.3 | 110204_001 | 78.4 | 110204_002 | W | 2.4 | 51.5 | 38.7 | 99.1 | 0 |
| 2/6/11 8:14 | 26.5 | 110105_001 | 79.4 | 110205_002 | CALM | CALM | 44.1 | 61.1 | 98.9 | 10 |
| 2/7/11 8:41 | 8 | 110206_001 | 21.3 | 110206_002 | W | 7.1 | 40.1 | 62.8 | 100.6 | 0 |
| 2/8/11 7:28 | 20.8 | 110207_001 | 35 | 110207_002 | E | 4.2 | 37.3 | 57.4 | 100.1 | 0 |
| 2/10/11 10:05 | 30.1 | 110209_001 | 52.7 | 110209_002 | N | 4.1 | 26.1 | 38.1 | 101 | 0 |
| 2/11/11 7:10 | 11.6 | 110210_001 | 20.6 | 110210_002 | CALM | CALM | 30.6 | 64.8 | 100.6 | 0 |
| 2/14/11 7:17 | 51.3 | 110213_001 | 79.4 | 110213_002 | CALM | CALM | 49.4 | 76.8 | 100 | 30 |
| 2/15/11 7:25 | 60 | 110214_001 | 130.9 | 110214_002 | SE | 2.3 | 59.8 | 86.0 | 99.86 | 90 |
| 2/16/11 7:28 | 41.1 | 110215_001 | 109.9 | 110215_002 | S | 6.8 | 64.3 | 77.9 | 99.53 | 95 |

**Table 3.6-5. IR Camera ID: GF-320 Daily Demo
January – February, 2011**

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|--------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 1/4/11 8:15 | 17.4 | 827 | 53.4 | 828 | E | 1.4 | 64.2 | 58.5 | 99.9 | 0 |
| 1/5/11 7:31 | 11.1 | 840 | 17.04 | 841 | W | 5 | 46.2 | 64.9 | 99.5 | 0 |
| 1/6/11 7:48 | 16.41 | 859 | 37.63 | 860 | E | 1.8 | 51.3 | 36.7 | 99.38 | 5 |
| 1/7/11 7:13 | 15.7 | 879 | 37.58 | 880 | N | 1 | 51.1 | 42.9 | 99.1 | 10 |
| 1/8/11 7:17 | 10.21 | 916 | 15.52 | 917 | N | 3.0 | 48.5 | 45.4 | 99.5 | 0 |
| 1/10/11 7:46 | 9.14 | 934 | 20.35 | 935 | N | 2.1 | 38.4 | 59.3 | 99.8 | 100 |
| 1/11/11 7:35 | 7.08 | 963 | 21.51 | 964 | NW | 3.2 | 24.7 | 38.8 | 101.6 | 0 |
| 1/12/11 7:26 | 11.25 | 986 | 38.72 | 987 | NW | 2.7 | 29.1 | 37.9 | 102.1 | 95 |
| 1/13/11 7:17 | 21.24 | 1004 | 41.82 | 1005 | E | 1.4 | 44.7 | 65.3 | 101.6 | 100 |
| 1/14/11 7:13 | 12.22 | 1020 | 18.48 | 1021 | CALM | CALM | 41.2 | 35.2 | 100.5 | 100 |
| 1/15/11 7:15 | 13 | 1046 | 18.81 | 1047 | SE | 3.2 | 38.2 | 69.2 | 100.4 | 100 |
| 1/18/11 7:20 | 4.50 | 1062 | 15.24 | 1063 | 2.7 | W | 44.9 | 78.1 | 99.1 | 100 |
| 1/19/11 7:15 | 10.37 | 1081 | 25.86 | 1082 | CALM | CALM | 48.9 | 45.6 | 99.7 | 5 |
| 1/20/11 7:14 | 6.87 | 1113 | 15.1 | 1114 | N | 4.8 | 38.6 | 72.3 | 99.8 | 100 |
| 1/21/11 6:58 | 15.88 | 1123 | 28.45 | 1124 | CALM | CALM | 33 | 39.5 | 100.1 | 50 |
| 1/22/11 6:45 | 8.6 | 1132 | 17.8 | 1133 | CALM | CALM | 39.1 | 50.0 | 99.7 | 0 |
| 1/24/11 7:06 | 11.8 | 1141 | 18.9 | 1142 | CALM | CALM | 36.3 | 55.7 | 99.9 | 0 |
| 1/25/11 7:00 | 6.9 | 1157 | 10.5 | 1158 | NW | 3.8 | 42.1 | 46.3 | 100.5 | 100 |
| 1/26/11 7:03 | 10.7 | 1191 | 26.5 | 1192 | CALM | CALM | 38.8 | 46.6 | 100.1 | 0 |

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

Table 3.6-5. GF-320 Daily Demo (Continued)

| Timestamp | Low Flow ^a | | Hi Flow ^b | | WD ^c (from) | WS ^d (mile/hr) | Temp ^e (°F) | RH ^f (%) | BP ^g (kPa) | Cloud (%) |
|--------------|--------------------------------|------------|--------------------------------|------------|---------------------------|------------------------------|---------------------------|------------------------|--------------------------|--------------|
| | Sighting Distance (feet) | Video File | Sighting Distance (feet) | Video File | | | | | | |
| 1/27/11 7:07 | 8.8 | 1209 | 16 | 1210 | CALM | CALM | 33.6 | 75.3 | 100.2 | 0 |
| 1/28/11 6:50 | 11.1 | 1223 | 22.4 | 1224 | W | 4.0 | 37.3 | 73.6 | 99.8 | 0 |
| 1/31/11 7:15 | 22.9 | 1247 | 53.6 | 1248 | NW | 2.4 | 44.5 | 62.9 | 99.6 | 100 |
| 2/3/11 10:17 | 14.4 | 1270 | 50.7 | 1271 | NW | 5.2 | 20.5 | 50.1 | 101.5 | 100 |
| 2/5/11 11:05 | 16.5 | 1283 | 35.9 | 1284 | W | 2.4 | 51.5 | 38.7 | 99.1 | 0 |
| 2/6/11 8:24 | 16.5 | 1287 | 32.4 | 1288 | CALM | CALM | 44.1 | 61.1 | 98.9 | 10 |
| 2/7/11 8:30 | 5 | 1300 | 16.6 | 1301 | W | 7.1 | 40.1 | 62.8 | 100.6 | 0 |
| 2/8/11 7:15 | 12 | 1316 | 17.6 | 1317 | E | 4.2 | 37.3 | 57.4 | 100.1 | 0 |
| 2/10/11 9:57 | 10.5 | 1333 | 39.5 | 1334 | N | 4.1 | 26.1 | 38.1 | 101 | 0 |
| 2/11/11 7:00 | 12.7 | 1354 | 18.1 | 1355 | CALM | CALM | 30.6 | 64.8 | 100.6 | 0 |
| 2/14/11 7:05 | 15.1 | 1370 | 51.2 | 1371 | CALM | CALM | 49.4 | 76.8 | 100 | 30 |
| 2/15/11 7:08 | 10 | 1398 | 19.2 | 1399 | SE | 2.3 | 59.8 | 86.0 | 99.86 | 90 |
| 2/16/11 7:15 | 10.4 | 1413 | 19.3 | 1414 | S | 6.8 | 64.3 | 77.9 | 99.53 | 95 |

**Table 3.6-6. Hi Flow ID: QS1002 Verification
September – October 2010**

| Timestamp | Input: 2.5% CH ₄ | | Input: 99% CH ₄ | |
|---------------|---|---------------------------------------|--------------------------------|--------------------------|
| | Background Sensor % Difference ^a | Leak Sensor % Difference ^b | Background Sensor % Difference | Leak Sensor % Difference |
| 9/8/10 8:46 | -0.8 | 0.4 | -5.5 | 0.3 |
| 9/9/10 18:13 | -1.2 | -2.8 | -- | -- |
| 9/10/10 7:43 | -0.8 | -0.8 | -- | -- |
| 9/13/10 7:12 | -1.2 | -0.8 | -2.8 | -0.9 |
| 9/14/10 7:12 | 0.0 | -0.8 | -- | -- |
| 9/15/10 7:15 | -1.2 | 0.8 | -- | -- |
| 9/16/10 7:21 | -1.2 | -1.2 | -- | -- |
| 9/18/10 6:48 | -2.0 | 0.4 | -- | -- |
| 9/20/10 7:34 | 5.6 | 0.8 | -- | -- |
| 9/21/10 7:28 | -3.2 | 0.0 | -- | -- |
| 9/22/10 7:08 | -2.8 | 0.4 | -- | -- |
| 9/23/10 7:17 | -3.2 | 0.4 | -- | -- |
| 9/24/10 7:27 | -0.8 | -0.4 | -- | -- |
| 9/27/10 9:40 | 1.6 | 0.0 | -0.1 | -0.1 |
| 9/28/10 7:13 | 0.4 | -0.4 | -- | -- |
| 9/29/10 7:12 | -1.2 | -0.8 | -- | -- |
| 9/30/10 7:55 | -1.6 | -0.4 | -- | -- |
| 10/1/10 7:33 | 0.0 | -1.6 | -- | -- |
| 10/4/10 7:53 | -0.4 | -0.8 | -- | -- |
| 10/5/10 7:23 | -0.8 | -1.2 | -- | -- |
| 10/6/10 7:15 | 0.8 | -3.2 | -- | -- |
| 10/7/10 7:14 | 0.4 | -2.0 | -- | -- |
| 10/8/10 7:25 | 0.0 | -3.2 | -- | -- |
| 10/11/10 7:15 | -0.4 | -4.8 | -- | -- |
| 10/12/10 7:22 | -0.8 | -4.4 | -- | -- |
| 10/13/10 7:26 | -0.4 | -3.6 | -- | -- |
| 10/14/10 7:21 | -1.2 | -3.2 | -- | -- |
| 10/15/10 7:26 | -0.8 | -2.4 | -- | -- |
| 10/18/10 7:23 | -2.4 | -3.6 | -- | -- |
| 10/19/10 7:19 | -2.8 | -3.6 | -- | -- |
| 10/20/10 7:25 | -15.2 | -4.8 | -- | -- |

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

**Table 3.6-7. Hi Flow ID: QS1005 Verification
September – October 2010**

| Timestamp | Input: 2.5% CH ₄ | | Input: 99% CH ₄ | |
|---------------|---|---------------------------------------|--------------------------------|--------------------------|
| | Background Sensor % Difference ^a | Leak Sensor % Difference ^b | Background Sensor % Difference | Leak Sensor % Difference |
| 9/8/10 8:27 | -0.4 | -0.8 | -1.01 | -3.84 |
| 9/9/10 6:51 | 1.2 | 0.4 | -- | -- |
| 9/10/10 7:31 | 8.0 | -1.2 | -- | -- |
| 9/13/10 8:26 | -7.6 | 0.4 | -- | -- |
| 9/14/10 7:45 | -0.4 | 0.4 | -- | -- |
| 9/15/10 7:35 | -4.8 | 1.2 | -- | -- |
| 9/16/10 7:15 | -2.0 | -2.0 | -- | -- |
| 9/17/10 6:32 | 0.0 | 1.2 | -- | -- |
| 9/20/10 7:40 | 1.2 | -0.8 | -- | -- |
| 9/21/10 7:20 | -2.0 | -0.4 | -1.11 | -1.72 |
| 9/22/10 7:31 | 4.8 | -1.2 | -- | -- |
| 9/23/10 7:14 | 1.6 | -1.2 | -- | -- |
| 9/24/10 7:27 | 6.0 | -0.4 | -- | -- |
| 10/4/10 8:12 | -4.4 | 0.0 | -- | -- |
| 10/5/10 7:55 | -2.0 | -1.6 | -1.92 | 1.11 |
| 10/6/10 7:10 | -3.2 | 0.0 | -- | -- |
| 10/7/10 7:16 | 0.8 | 7.6 | -- | -- |
| 10/8/10 7:22 | -0.4 | 10.4 | -- | -- |
| 10/11/10 7:13 | -2.8 | 13.2 | -- | -- |
| 10/12/10 7:15 | 1.2 | 0.4 | -- | -- |
| 10/13/10 7:20 | 1.6 | 0.0 | -- | -- |
| 10/14/10 7:17 | 2.8 | -1.6 | -- | -- |
| 10/15/10 7:30 | 2.4 | 3.2 | -- | -- |
| 10/18/10 7:40 | 1.2 | 3.2 | -- | -- |
| 10/19/10 7:23 | 2.8 | 4.8 | -- | -- |
| 10/20/10 7:30 | 3.2 | 4.0 | -- | -- |
| 10/21/10 7:34 | 2.8 | 5.2 | -- | -- |

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

**Table 3.6-8. Hi Flow ID: QS1002 Verification
January – February, 2011**

| Timestamp | Input: 2.5% CH ₄ | | Input: 100% CH ₄ | |
|--------------|---|---------------------------------------|--------------------------------|--------------------------|
| | Background Sensor % Difference ^a | Leak Sensor % Difference ^b | Background Sensor % Difference | Leak Sensor % Difference |
| 1/4/11 8:20 | -1.2 | 2.0 | -- | -- |
| 1/5/11 7:26 | -0.4 | 3.2 | -- | -- |
| 1/6/11 7:25 | -0.4 | 3.6 | -- | -- |
| 1/7/11 7:41 | -1.2 | 2.8 | -- | -- |
| 1/8/11 7:36 | -0.8 | 3.2 | -- | -- |
| 1/10/11 7:50 | -1.2 | 3.6 | -1.9 | 0.0 |
| 1/11/11 7:30 | 0.4 | 4.0 | -- | -- |
| 1/12/11 7:36 | 0.4 | 4.0 | -- | -- |
| 1/13/11 7:26 | -3.2 | 4.0 | -- | -- |
| 1/14/11 7:14 | 2.4 | 3.6 | -- | -- |
| 1/15/11 7:35 | 19.2 | 2.8 | -- | -- |
| 1/18/11 7:15 | -30 | 0.8 | -7.0 | 0.0 |
| 1/19/11 7:01 | 0 | 2.0 | -- | -- |
| 1/20/11 7:05 | 2.8 | 0.0 | -- | -- |
| 1/21/11 6:58 | 3.6 | 2.4 | -- | -- |
| 1/22/11 7:01 | 0.8 | 2.0 | -- | -- |
| 1/24/11 7:09 | 0 | 0.8 | -2.2 | 0.0 |
| 1/25/11 6:51 | 25.2 | 2.0 | -2.5 | 0.0 |
| 1/26/11 7:13 | 0 | -0.8 | 0.0 | 0.0 |
| 1/27/11 6:45 | -1.6 | -0.8 | -- | -- |
| 1/28/11 6:40 | -11.2 | -0.8 | -- | -- |
| 1/31/11 7:40 | 0 | 1.2 | 0.0 | -2.5 |
| 2/3/11 10:26 | -8 | -1.2 | -- | -- |
| 2/5/11 11:07 | 0 | -1.6 | -- | -- |
| 2/6/11 8:07 | 0 | -1.2 | -- | -- |
| 2/7/11 8:34 | 0 | -1.2 | -1.3 | -0.1 |
| 2/8/11 7:05 | 0 | -0.4 | -- | -- |
| 2/10/11 9:48 | -0.4 | 0.8 | -- | -- |
| 2/11/11 7:04 | -0.8 | -1.2 | -- | -- |
| 2/14/11 6:55 | 0 | -1.6 | -0.7 | -2.0 |
| 2/15/11 7:25 | 0 | -0.4 | -- | -- |
| 2/16/11 7:06 | 0 | -1.2 | -- | -- |

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

**Table 3.6-9. Hi Flow ID: QX1007 Verification
January – February, 2011**

| Date/Time | Input: 2.5% CH ₄ | | Input: 100% CH ₄ | |
|--------------|---|---------------------------------------|-----------------------------|--------------------------|
| | Background Sensor % Difference ^a | Leak Sensor % Difference ^b | Background Sensor % | Leak Sensor % Difference |
| 1/4/11 8:35 | 2.0 | 0.8 | -- | -- |
| 1/5/11 7:25 | 2.0 | 2.0 | -- | -- |
| 1/6/11 7:29 | 1.2 | 2.0 | -- | -- |
| 1/7/11 7:50 | 2.0 | 1.6 | -- | -- |
| 1/8/11 7:33 | 2.8 | 2.4 | -- | -- |
| 1/10/11 7:48 | 3.2 | 1.6 | -0.5 | -2.0 |
| 1/13/11 7:36 | 1.6 | 1.2 | -- | -- |
| 1/14/11 7:12 | 3.2 | 1.2 | -- | -- |
| 1/15/11 7:58 | 2.0 | 0.8 | -- | -- |
| 1/18/11 7:30 | 1.6 | 0.8 | -2.0 | 0.0 |
| 1/19/11 6:55 | 2.8 | 0.4 | -- | -- |
| 1/20/11 6:59 | 2.4 | 0.4 | -- | -- |
| 1/21/11 6:50 | 4.0 | 1.6 | -- | -- |
| 1/22/11 6:58 | 3.2 | 1.6 | -- | -- |
| 1/24/11 6:58 | 2.8 | 0.0 | 0.0 | 0.0 |
| 1/25/11 6:35 | 4.0 | 0.8 | -0.7 | -3.5 |
| 1/26/11 6:55 | 3.2 | 0.4 | -- | -- |
| 1/27/11 6:40 | 2.8 | 0.8 | -- | -- |
| 1/28/11 6:35 | 2.0 | 0.0 | -- | -- |
| 1/31/11 7:45 | 2.8 | -0.4 | -4.0 | -5.0 |
| 2/3/11 10:22 | 3.2 | 0.4 | -- | -- |
| 2/5/11 11:03 | 2.8 | 0.0 | -- | -- |
| 2/6/11 8:20 | -0.4 | -0.4 | -- | -- |
| 2/7/11 8:27 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2/8/11 7:08 | 0.0 | 0.0 | -- | -- |
| 2/10/11 9:45 | 0.4 | 0.0 | -- | -- |
| 2/11/11 6:58 | 0.4 | 0.0 | -- | -- |
| 2/14/11 7:15 | 0.0 | 0.4 | 0.0 | 0.0 |
| 2/15/11 7:00 | 1.2 | 1.2 | -- | -- |
| 2/16/11 6:56 | 2.0 | 0.8 | -- | -- |

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

3.6.3 TVA Calibration Procedures

Several TVAs were used during the point source field surveys. Each TVA was calibrated daily before testing with four certified gas standards:

- Zero Air (<0.1 total hydrocarbon content).
- Low Level Span (approximately 500 ppmv methane-in-air).
- Mid Level Span (approximately 2000 ppmv methane-in-air).
- High Level Span (approximately 10,000 ppmv methane-in-air).

Drift checks were performed during the test day using the Low Level calibration standard. Tables 3.6-10 through 3.6-15 summarize the calibration and drift check results for the project TVAs.

**Table 3.6-10. TVA Serial Number (S/N): 5362 Calibration and Drift Check Results
September – October 2010**

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|---------------|-------------|--|---------------------------------------|--|
| 8/30/10 10:00 | -0.5 | -1.22 | -3.57 | -9.83 |
| 9/1/10 8:05 | 0.4 | -0.20 | 0.26 | -0.23 |
| 9/1/10 14:50 | -- | -21.63 | -- | -- |
| 9/1/10 14:53 | 0.78 | 5.71 | 2.81 | -0.59 |
| 9/1/10 17:25 | -- | 25.10 | -- | -- |
| 9/2/10 9:03 | 0.61 | 4.90 | 2.24 | 4.06 |
| 9/2/10 17:33 | -- | 13.27 | -- | -- |
| 9/3/10 9:10 | 0.2 | 0.61 | 0.36 | -0.01 |
| 9/3/10 12:36 | -- | 20.41 | -- | -- |
| 9/7/10 8:10 | -0.98 | -1.84 | 0.46 | -0.46 |
| 9/8/10 8:02 | -0.7 | 1.02 | 0.92 | 0.56 |
| 9/9/10 8:25 | 0.18 | -3.88 | -5.05 | -7.20 |
| 9/9/10 16:28 | -- | 5.31 | -- | -- |
| 9/10/10 8:02 | -0.43 | -0.20 | -0.77 | 0.15 |
| 9/10/10 14:35 | -- | 0.20 | -- | -- |
| 9/13/10 8:14 | -0.37 | 0.20 | 0.10 | -1.61 |
| 9/13/10 13:30 | -- | -0.41 | -- | -- |
| 9/14/10 7:13 | -0.22 | 1.22 | 1.38 | 0.38 |
| 9/14/10 15:25 | -- | 5.10 | -- | -- |
| 9/15/10 7:25 | -0.17 | -4.08 | 1.02 | 1.32 |
| 9/16/10 7:13 | -0.27 | 0.41 | 0.66 | 0.03 |
| 9/17/10 7:35 | -0.35 | -3.06 | -0.46 | 1.01 |
| 9/17/10 13:15 | -- | 5.10 | -- | -- |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-10. TVA S/N: 5362 (Continued)

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|----------------|-------------|--|---------------------------------------|--|
| 9/20/10 7:43 | -0.75 | 0.61 | 0.56 | 0.20 |
| 9/20/10 16:04 | -- | 3.06 | -- | -- |
| 9/21/10 7:49 | -0.15 | 0.20 | 1.28 | 0.81 |
| 9/21/10 15:20 | -- | 2.04 | -- | -- |
| 9/22/10 7:41 | 0.24 | 2.04 | -2.81 | 3.45 |
| 9/22/10 16:15 | -- | 0.82 | -- | -- |
| 9/23/10 7:34 | -0.08 | 1.63 | 1.79 | 0.66 |
| 9/23/10 15:42 | -- | 4.49 | -- | -- |
| 9/24/10 7:45 | 0.53 | -2.24 | -1.53 | 0.11 |
| 9/24/10 13:45 | -- | -6.73 | -- | -- |
| 9/27/10 7:50 | 0.32 | 0.41 | 0.92 | 2.43 |
| 9/28/10 7:53 | 0.07 | 0.82 | 0.56 | 1.42 |
| 9/29/10 7:51 | 0.17 | 0.20 | 0.20 | -0.12 |
| 9/30/10 3:10 | -0.27 | 3.67 | 1.58 | 0.15 |
| 9/30/10 17:15 | -- | -1.63 | -- | -- |
| 10/4/10 7:38 | -0.15 | 1.63 | 0.77 | 0.95 |
| 10/4/10 15:57 | -- | -3.27 | -- | -- |
| 10/5/10 7:42 | 0.39 | -2.45 | 1.68 | 0.58 |
| 10/5/10 16:48 | -- | 8.57 | -- | -- |
| 10/6/10 7:35 | 1.62 | -4.08 | -1.53 | -1.52 |
| 10/6/10 16:20 | -- | 5.10 | -- | -- |
| 10/7/10 7:30 | 0.98 | -4.49 | 2.55 | -1.12 |
| 10/7/10 16:28 | -- | 9.80 | -- | -- |
| 10/8/10 7:30 | 1.31 | 2.04 | 0.66 | -0.10 |
| 10/8/10 12:42 | -- | 1.22 | -- | -- |
| 10/11/10 7:32 | 1.24 | -2.86 | -1.84 | -2.13 |
| 10/11/10 16:04 | -- | 4.49 | -- | -- |
| 10/12/10 7:23 | -0.39 | 3.47 | 3.62 | 0.16 |
| 10/12/10 16:41 | -- | 13.27 | -- | -- |
| 10/13/10 7:21 | 1.07 | 0.00 | -25.20 | -1.12 |
| 10/14/10 7:35 | -0.08 | 0.61 | 0.36 | 6.49 |
| 10/14/10 16:59 | -- | -2.45 | -- | -- |
| 10/15/10 7:36 | -0.73 | 1.02 | 0.92 | -0.19 |
| 10/15/10 12:24 | -- | -2.45 | -- | -- |
| 10/18/10 7:32 | 0.71 | 1.02 | 1.79 | 0.06 |
| 10/19/10 7:28 | -0.25 | 1.63 | 1.17 | 1.42 |
| 10/19/10 15:29 | -- | -2.45 | -- | -- |
| 10/20/10 7:34 | 1.51 | 4.49 | -3.06 | 5.48 |
| 10/20/10 17:00 | -- | 10.61 | -- | -- |

**Table 3.6-11. TVA S/N: K10419 Calibration and Drift Check Results
September – October 2010**

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|--------------|-------------|--|---------------------------------------|--|
| 9/1/10 8:10 | 0.85 | 0.0 | -0.3 | -0.9 |
| 9/2/10 8:59 | 1.8 | -0.6 | -1.3 | 2.4 |
| 9/3/10 9:10 | -0.46 | 1.8 | 1.1 | 1.4 |
| 9/3/10 12:36 | -- | -6.5 | -- | -- |
| 9/7/10 8:10 | -0.63 | -0.2 | 0.3 | 0.1 |
| 9/8/10 7:54 | -0.26 | 0.8 | -0.6 | -0.2 |
| 9/9/10 7:34 | 1.9 | 0.6 | 0.2 | 0.3 |
| 9/10/10 8:10 | 1.13 | 1.0 | 1.0 | 0.4 |
| 9/13/10 7:23 | 0.47 | -0.4 | 0.3 | -- |
| 9/13/10 7:23 | -1.33 | -0.6 | -0.3 | 1.0 |
| 9/14/10 7:25 | -0.19 | -1.0 | 1.2 | 0.2 |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-11. TVA S/N: K10419 (Continued)

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|----------------|-------------|--|---------------------------------------|--|
| 9/15/10 6:42 | 0.82 | 1.0 | -1.3 | 0.0 |
| 9/16/10 7:20 | 0.62 | 0.8 | 1.6 | 1.0 |
| 9/20/10 7:43 | 0.73 | -1.6 | -0.7 | -2.8 |
| 9/21/10 7:14 | 0.13 | -0.2 | 0.2 | 0.0 |
| 9/22/10 7:28 | 0.42 | -0.6 | -0.4 | 1.0 |
| 9/23/10 9:29 | 2.7 | 0.2 | -0.2 | 1.0 |
| 9/24/10 7:35 | 7.6 | 3.9 | 2.3 | 2.0 |
| 9/27/10 7:52 | 0.8 | 0.2 | 1.0 | 1.0 |
| 9/28/10 7:50 | 0.2 | 1.0 | 0.1 | 1.0 |
| 9/29/10 7:39 | 0.93 | -1.0 | -1.4 | -1.5 |
| 9/30/10 8:19 | 0.39 | -3.9 | -0.6 | 0.0 |
| 9/30/10 17:16 | -- | -0.6 | -- | -- |
| 10/1/10 8:07 | -0.35 | 2.4 | 0.6 | 1.0 |
| 10/4/10 8:00 | 1.29 | 1.2 | 2.5 | 1.0 |
| 10/4/10 0:00 | -- | 3.9 | -- | -- |
| 10/5/10 7:45 | 0.49 | 4.5 | 2.1 | 1.0 |
| 10/6/10 7:52 | 0.21 | 0.8 | 0.1 | 0.2 |
| 10/6/10 10:23 | -- | -8.8 | -- | -- |
| 10/7/10 7:26 | 0.01 | -2.0 | 0.9 | 1.0 |
| 10/7/10 15:26 | -- | 7.3 | -- | -- |
| 10/11/10 7:29 | 0.45 | -3.7 | -1.3 | -0.6 |
| 10/12/10 7:42 | 1.8 | 3.9 | 2.4 | 1.0 |
| 10/13/10 7:45 | -0.25 | 5.1 | 0.4 | 1.0 |
| 10/13/10 17:30 | -- | 1.2 | -- | -- |
| 10/14/10 7:40 | 1.12 | 0.0 | -0.4 | 0.4 |
| 10/14/10 17:05 | -- | 5.1 | -- | -- |
| 10/15/10 7:25 | 0.2 | 1.0 | 0.6 | 2.0 |
| 10/15/10 12:20 | -- | 0.4 | -- | -- |
| 10/18/10 7:30 | 0.35 | 6.1 | 3.6 | 1.0 |
| 10/18/10 17:30 | -- | -0.6 | -- | -- |
| 10/19/10 7:50 | 1.15 | -0.8 | -6.6 | -5.5 |
| 10/19/10 16:05 | -- | 9.4 | -- | -- |
| 10/20/10 7:40 | 1.35 | -2.0 | -0.6 | -1.4 |
| 10/20/10 16:40 | -- | -3.7 | -- | -- |
| 10/21/10 8:05 | 1.45 | 0.8 | 1.5 | -0.4 |
| 10/21/10 15:40 | -- | -0.6 | -- | -- |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

**Table 3.6-12. TVA S/N: 5362 Calibration and Drift Check Results
January – February 2011**

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|----------------|-------------|--|---------------------------------------|--|
| 1/5/11 7:48 | 2.21 | -1.6 | -0.1 | -1.2 |
| 1/6/11 7:07 | -0.97 | 1.8 | 1.2 | 0.6 |
| 1/6/11 16:38 | -- | -6.7 | -- | -- |
| 1/7/11 15:42 | -- | 4.1 | -- | -- |
| 1/8/11 7:09 | -0.42 | 1.8 | 0.7 | 0.5 |
| 1/8/11 14:41 | | -3.9 | -- | -- |
| 1/10/11 7:35 | -0.29 | -2.2 | 2.4 | 1.0 |
| 1/11/11 7:18 | 0.39 | 0.0 | 0.6 | -0.5 |
| 1/11/11 16:27 | | -3.1 | -- | -- |
| 1/12/11 7:45 | -1.07 | 0.0 | 0.2 | 0.1 |
| 1/12/11 13:36 | -- | -1.6 | -- | -- |
| 1/12/11 16:48 | -- | -1.2 | -- | -- |
| 1/13/11 7:30 | 0.19 | 0.6 | -0.1 | 0.0 |
| 1/13/11 14:50 | -- | 3.3 | -- | -- |
| 1/13/11 17:25 | -- | -6.5 | -- | -- |
| 1/14/11 7:07 | 0.22 | -1.6 | 0.8 | 0.0 |
| 1/14/11 17:47 | -- | 25.9 | -- | -- |
| 1/15/11 7:30 | 1.21 | 0.0 | -0.4 | 0.3 |
| 1/15/11 15:22 | -- | 6.5 | -- | -- |
| 1/18/11 7:07 | 0.19 | 0.4 | 0.5 | 0.5 |
| 1/18/11 17:41 | -- | -6.1 | -- | -- |
| 1/19/11 7:22 | 0.51 | 0.8 | -0.1 | 0.4 |
| 1/19/11 14:13 | -- | 5.1 | -- | -- |
| 1/19/11 17:22 | -- | 8.4 | -- | -- |
| 1/20/11 7:45 | 0.72 | -1.0 | 2.3 | 1.0 |
| 1/20/11 18:09 | -- | 5.9 | -- | -- |
| 1/21/11 7:12 | 1.07 | 0.2 | 0.1 | 0.7 |
| 1/21/11 16:11 | -- | 0.0 | -- | -- |
| 1/21/11 17:00 | -- | 2.9 | -- | -- |
| 1/22/11 7:19 | 1.2 | 0.4 | -1.0 | -0.4 |
| 1/22/11 13:45 | -- | -0.4 | -- | -- |
| 1/22/11 15:23 | -- | -1.0 | -- | -- |
| 1/24/11 7:30 | 0 | -0.6 | -0.2 | -0.4 |
| 1/24/11 17:27 | -- | 5.7 | -- | -- |
| 1/25/2011 6:40 | 0.61 | -2.4 | -1.6 | -1.2 |
| 1/26/2011 6:55 | 0.13 | -1.4 | -0.9 | -1.0 |
| 1/26/11 14:26 | 0.55 | -3.7 | -5.9 | -3.8 |
| 1/26/11 17:30 | -- | 0.4 | -- | -- |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-12. TVA S/N: 5362 (Continued)

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|---------------|-------------|--|---------------------------------------|--|
| 1/27/11 7:00 | 0.07 | 3.9 | 2.0 | 1.0 |
| 1/27/11 17:30 | -- | 21.4 | -- | -- |
| 1/28/11 6:50 | 0.01 | -0.4 | -1.0 | -0.3 |
| 1/28/11 18:10 | -- | -8.2 | -- | -- |
| 1/31/11 9:00 | 0.51 | 3.1 | 3.6 | 2.0 |
| 1/31/11 14:33 | -- | -3.1 | -- | -- |
| 1/31/11 17:22 | -- | 2.4 | -- | -- |
| 2/3/11 10:45 | 0 | 0.4 | 0.1 | 0.1 |
| 2/3/11 17:52 | -- | 3.7 | -- | -- |
| 2/5/11 11:33 | 0.56 | 1.2 | 1.0 | -0.5 |
| 2/5/11 16:17 | -- | -2.4 | -- | -- |
| 2/6/11 8:26 | 0.55 | 0.0 | -0.2 | 0.1 |
| 2/7/11 8:51 | 0 | -4.1 | 0.2 | 0.0 |
| 2/7/11 15:36 | -- | 1.2 | -- | -- |
| 2/7/11 17:05 | -- | -1.0 | -- | -- |
| 2/8/11 7:28 | 1.43 | -0.2 | 0.4 | 0.7 |
| 2/8/11 16:45 | -- | 3.3 | -- | -- |
| 2/10/11 11:12 | 0.59 | 0.4 | 2.0 | 0.0 |
| 2/10/11 16:45 | -- | 5.7 | -- | -- |
| 2/11/11 7:25 | 0 | 0.8 | 0.8 | -1.3 |
| 2/14/11 7:40 | -1.71 | -0.2 | 4.2 | 1.0 |
| 2/14/11 17:17 | -- | 6.1 | -- | -- |
| 2/15/11 7:40 | 0.49 | -0.6 | -0.5 | -1.1 |
| 2/15/11 16:55 | -- | -2.9 | -- | -- |
| 2/16/11 7:21 | 0.25 | 0.2 | -0.1 | 0.8 |

**Table 3.6-13. TVA S/N: 0528413543 Calibration and Drift Check Results
January – February 2011**

| Timestamp | Zero (ppmv) | Low Span^a % Difference^b | Mid Span^c % Difference | High Span^d % Difference |
|------------------|------------------------|--|--|---|
| 1/4/11 8:10 | 0.55 | -0.4 | 1.0 | 0.5 |
| 1/4/11 14:17 | -- | -2.7 | -- | -- |
| 1/5/11 7:36 | 1.15 | -0.4 | -0.3 | -0.1 |
| 1/5/11 13:33 | 0.8 | 1.0 | 0.2 | -12.5 |
| 1/5/11 14:42 | -- | -0.4 | -- | -- |
| 1/6/11 7:14 | 1.35 | 0.0 | 0.2 | -0.5 |
| 1/6/11 12:35 | -- | -4.1 | -- | -- |
| 1/6/11 13:06 | -- | -2.7 | -- | -- |
| 1/6/11 15:18 | -- | -4.3 | -- | -- |
| 1/6/11 16:32 | -- | -3.3 | -- | -- |
| 1/7/11 7:43 | N/A | -2.4 | 2.8 | 8.1 |
| 1/7/11 11:53 | -- | -1.8 | -- | -- |
| 1/7/11 15:04 | -- | -4.7 | -- | -- |
| 1/8/11 7:25 | -2.14 | -1.6 | -1.5 | -0.2 |
| 1/10/11 7:28 | -8.88 | -0.4 | -1.5 | -0.5 |
| 1/10/11 12:52 | -- | 4.5 | -- | -- |
| 1/10/11 15:30 | -- | 10.2 | -- | -- |
| 1/13/11 7:21 | 2.7 | 0.2 | -0.2 | 0.0 |
| 1/13/11 14:47 | -- | 7.3 | -- | -- |
| 1/13/11 16:32 | -- | -6.1 | -- | -- |
| 1/14/11 7:17 | -9 | 0.4 | 0.2 | -0.1 |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

**Table 3.6-14. TVA S/N: R6488 Calibration and Drift Check Results
January – February 2011**

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|---------------|-------------|--|---------------------------------------|--|
| 1/15/11 9:58 | 0 | 1.0 | -1.5 | 1.0 |
| 1/15/11 17:20 | -- | -2.0 | -- | -- |
| 1/18/11 7:00 | 0.23 | 0.2 | -1.5 | -0.3 |
| 1/18/11 13:43 | -- | 7.1 | -- | -- |
| 1/18/11 17:26 | -- | 6.9 | -- | -- |
| 1/19/11 7:18 | 0.98 | 1.6 | 0.5 | 0.5 |
| 1/19/11 13:30 | -- | 6.7 | -- | -- |
| 1/19/11 17:00 | -- | 2.7 | -- | -- |
| 1/20/11 7:32 | 0.65 | -3.3 | 0.3 | 0.5 |
| 1/20/11 13:50 | -- | 7.1 | -- | -- |
| 1/21/11 7:05 | 0.89 | -1.4 | 0.6 | 0.6 |
| 1/21/11 14:21 | -- | 3.5 | -- | -- |
| 1/21/11 16:52 | -- | -- | -- | -- |
| 1/22/11 7:12 | 0.79 | -2.2 | -1.5 | 1.0 |
| 1/22/11 14:20 | -- | 3.9 | -- | -- |
| 1/24/11 7:20 | 0 | -0.4 | -0.5 | 0.0 |
| 1/24/11 12:00 | -- | 1.4 | -- | -- |
| 1/24/11 16:45 | -- | -17.1 | -- | -- |
| 1/25/11 7:00 | 0.01 | -0.4 | -0.4 | -0.3 |
| 1/25/11 12:05 | -- | 2.4 | -- | -- |
| 1/25/11 17:40 | -- | 1.6 | -- | -- |
| 1/26/11 7:00 | 0.01 | 0.4 | 0.6 | -0.6 |
| 1/26/11 11:45 | -- | 1.2 | -- | -- |
| 1/26/11 14:55 | -- | 1.8 | -- | -- |
| 1/27/11 6:50 | 0.03 | 0.2 | -0.1 | 1.0 |
| 1/27/11 11:45 | -- | 2.4 | -- | -- |
| 1/27/11 17:05 | -- | 1.6 | -- | -- |
| 1/28/11 6:55 | 0.06 | -1.6 | -2.0 | -0.7 |
| 1/28/11 11:45 | -- | 2.4 | -- | -- |
| 1/28/11 16:20 | -- | 1.8 | -- | -- |
| 1/31/11 7:39 | 0.5 | -0.2 | -2.0 | -0.9 |
| 1/31/11 13:43 | -- | -5.3 | -8.7 | -7.5 |
| 1/31/11 17:55 | -- | -5.9 | -- | -- |
| 2/3/11 10:36 | 0 | 0.8 | -2.0 | 0.0 |
| 2/3/11 15:16 | -- | -6.5 | -- | -- |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-14. TVA S/N: R6488 (Continued)

| Timestamp | Zero (ppmv) | Low Span^a % Difference^b | Mid Span^c % Difference | High Span^d % Difference |
|------------------|------------------------|--|--|---|
| 2/5/11 11:25 | 1.03 | -1.6 | -1.1 | 0.3 |
| 2/5/11 14:56 | -- | -3.7 | -- | -- |
| 2/5/11 16:30 | -- | -6.5 | -- | -- |
| 2/6/11 8:20 | 0.12 | 2.4 | -1.1 | 0.3 |
| 2/6/11 11:45 | -- | -0.8 | -- | -- |
| 2/7/11 8:39 | 0 | 0.0 | 0.4 | 0.7 |

**Table 3.6-15. TVA S/N: R1376 Calibration and Drift Check Results
January – February 2011**

| Timestamp | Zero (ppmv) | Low Span ^a % Difference ^b | Mid Span ^c % Difference | High Span ^d % Difference |
|---------------|-------------|--|---------------------------------------|--|
| 2/8/11 10:18 | 0.61 | -0.8 | -0.2 | 0.2 |
| 2/8/11 13:51 | -- | -1.4 | -- | -- |
| 2/8/11 16:47 | -- | -2.7 | -- | -- |
| 2/10/11 10:59 | 0.23 | -0.6 | -0.7 | -0.1 |
| 2/10/11 14:05 | -- | -0.8 | -- | -- |
| 2/11/11 7:15 | 0 | 0.4 | 0.6 | 1.0 |
| 2/11/11 16:35 | -- | -3.9 | -- | -- |
| 2/11/11 16:35 | -- | 3.7 | -- | -- |
| 2/14/11 7:43 | 0.12 | 0.6 | 1.5 | 0.0 |
| 2/14/11 16:52 | -- | 3.1 | -- | -- |
| 2/15/11 7:32 | 0.93 | -0.6 | -0.8 | 0.1 |
| 2/15/11 15:07 | -- | 8.2 | -- | -- |
| 2/16/11 7:15 | 0.5 | -0.8 | -0.3 | 0.2 |
| 2/16/11 13:00 | -- | 1.0 | -- | -- |
| 2/16/11 17:03 | -- | -1.0 | -- | -- |

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

3.6.4 Field Data Review

Field data was reviewed each week in Phase I by the acting QAIQC Officer. In Phase II, this role was divided between the two field team leaders. Each team leader checked the other team's field data for completeness and accuracy on a daily basis. The team leaders also checked periodically for consistency in sampling procedures and data recording between the two teams.

3.6.5 Canister Sample Collection QC

A strict canister sampling protocol was followed to ensure quality sampling results:

1. All canisters were vacuum checked prior to sampling. Canisters with vacuums less than 25 inches Hg were rejected.
2. Residual vacuums of 2 to 10 inches Hg were left in canisters following sample collection.
3. Canister collection data was recorded on data forms as well as in canister logbooks (one per team).
4. Standard canister Chain-of-Custody procedures were observed.
5. Between use and prior to shipping, canisters were kept securely in the project field office.
6. Five percent of the canister samples were collected in duplicate to provide a measure of total sampling and analytical variability.

Eight duplicate canister samples were collected. Comparisons of the analytical results for each duplicate pair are provided in Table 3.6-16 as the relative percent differences (% RPD) between analytes. Since each canister sample was analyzed by EPA Method TO-15 for VOCs and by ASTM D1946 for methane, Table 3.6-16 includes the results for both analytical techniques. The average percent relative differences for the duplicate canisters range between 11 to 61 percent. This is considered an acceptable result for field samples.

Table 3.6-16. Duplicate Canister Results

| | |
|--------------------------|-----------------------|
| Site ID: | PS-134 |
| Site Address: | 5199 Village Creek Rd |
| Owner/Operator: | Quicksilver Resources |
| Date: | 10/5/2010 |
| Time: | 10:00-11:30 |
| Canister Numbers: | 103 and HL 0887 |

| Compounds | Sample #A020 | Sample #A021 | RPD ^a |
|------------------------|--------------|-----------------|------------------|
| Methane | 255000 | 480000 | 61.2 |
| Butane | 16.1 | 32.9 | 68.6 |
| Isopentane | 2.30 | 2.51 | 8.7 |
| Acetone | 0.034 | ND ^b | -- |
| n-Pentane | 1.53 | 1.08 | 34.5 |
| Methylene chloride | 0.0084 | 0.01120 | 28.6 |
| Hexane | 0.128 | 0.304 | 81.5 |
| Benzene | 1.87 | 3.01 | 46.7 |
| Cyclohexane | 1.10 | 1.32 | 18.2 |
| Heptane | ND | 0.0299 | -- |
| Toluene | 0.852 | 1.93 | 77.5 |
| n-Octane | ND | 0.00876 | -- |
| Ethylbenzene | 0.00531 | 0.0112 | 71.4 |
| m-Xylene & p-Xylene | 0.0466 | 0.0956 | 68.9 |
| o-Xylene | 0.0162 | 0.0316 | 64.4 |
| Isopropylbenzene | 0.00748 | 0.0134 | 56.7 |
| n-Propylbenzene | 0.0304 | 0.0574 | 61.5 |
| 4-Ethyltoluene | 0.105 | 0.143 | 30.7 |
| 1,3,5-Trimethylbenzene | 0.0599 | 0.12 | 66.8 |
| 1,2,4-Trimethylbenzene | 0.145 | 0.381 | 89.7 |
| n-Decane | ND | 0.00681 | -- |
| sec-Butylbenzene | ND | 0.00535 | -- |
| n-Undecane | ND | 0.0187 | -- |
| n-Dodecane | 0.128 | 1.49 | 168.4 |
| Average RPD: | | | 61.8 |
| Maximum RPD: | | | 168.4 |
| Minimum RPD: | | | 8.7 |

^a RPD = Relative Percent Difference = $100 * \text{Absolute Value}(X1-X2) / ((X1+X2)/2)$

^b ND = None Detected

Table 3.6-16. (Continued)

| | |
|--------------------------|------------------------------------|
| Site ID: | PS-171 |
| Site Address: | 3892 Lou Stevenson (Walls Coleman) |
| Owner/Operator: | Chesapeake Operating Inc. |
| Date: | 10/14/2010 |
| Time: | 13:38-16:15 |
| Canister Numbers: | 5440 and RA 2402 |

| Compounds | Sample #B034 | Sample #B035 | RPD |
|------------------------|---------------------|---------------------|------------|
| Methane | 357000 | 334000 | 6.7 |
| Chloromethane | 0.00837 | ND | -- |
| Butane | 8.18 | 7.86 | 4.0 |
| Isopentane | 0.486 | 0.494 | 1.6 |
| Acetone | 0.0196 | 0.0133 | 38.3 |
| n-Pentane | 0.490 | 0.539 | 9.5 |
| Methylene chloride | 0.01340 | 0.01450 | 7.9 |
| Hexane | 0.0165 | 0.0481 | 97.8 |
| Benzene | 0.188 | 0.370 | 65.2 |
| Cyclohexane | 0.183 | 0.249 | 30.6 |
| Toluene | ND | 0.0975 | -- |
| 1,2,4-Trichlorobenzene | 0.0199 | ND | -- |
| Naphthalene | 0.0230 | ND | -- |
| n-Dodecane | 0.0154 | ND | -- |
| 1,2,3-Trichlorobenzene | 0.0293 | ND | -- |
| Hexachlorobutadiene | 0.00863 | ND | -- |
| Average RPD: | | | 29.1 |
| Maximum RPD: | | | 97.8 |
| Minimum RPD: | | | 1.6 |

Table 3.6-16. (Continued)

| | |
|--------------------------|----------------------------|
| Site ID: | 176 |
| Site Address: | 11593 Saginaw Blvd |
| Owner/Operator: | Devon Energy Production Co |
| Date: | 1/7/2011 |
| Time: | 11:55-14:45 |
| Canister Numbers: | HL 0979 and 240 |

| Compounds | Sample #A036 | Sample #A037 | RPD |
|---------------------|---------------------|---------------------|------------|
| Methane | 65800 | 63800 | 3.1 |
| Butane | 1.20 | 1.14 | 5.1 |
| Isopentane | 0.0830 | 0.0833 | 0.4 |
| n-Pentane | 0.0525 | 0.0525 | 0.0 |
| Methylene chloride | 0.01260 | 0.01290 | 2.4 |
| Benzene | 0.117 | 0.115 | 1.7 |
| Cyclohexane | 0.0321 | 0.0255 | 22.9 |
| Toluene | 0.0906 | 0.0755 | 18.2 |
| m-Xylene & p-Xylene | 0.0289 | 0.0182 | 45.4 |
| Average RPD: | | | 11.0 |
| Maximum RPD: | | | 45.4 |
| Minimum RPD: | | | 0.0 |

Table 3.6-16. (Continued)

| | |
|--------------------------|----------------------------|
| Site ID: | 161 |
| Site Address: | 10999 Willow Springs Rd |
| Owner/Operator: | Devon Energy Production Co |
| Date: | 1/15/2011 |
| Time: | 11:00-13:15 |
| Canister Numbers: | RA 2247 and 221 |

| Compounds | Sample #A042 | Sample #A043 | RPD |
|------------------------|---------------------|---------------------|------------|
| Methane | 63800 | 35400 | 57.3 |
| Butane | 1.52 | 1.01 | 40.3 |
| Isopentane | 0.210 | 0.138 | 41.4 |
| n-Pentane | 0.103 | 0.0545 | 61.6 |
| Methylene chloride | 0.01080 | 0.0110 | 1.8 |
| Hexane | 0.0231 | 0.00570 | 120.8 |
| Benzene | 0.0803 | 0.0499 | 46.7 |
| Cyclohexane | 0.0250 | 0.0160 | 43.9 |
| Toluene | 0.0574 | 0.0299 | 63.0 |
| m-Xylene & p-Xylene | 0.0265 | ND | -- |
| 1,2,4-Trimethylbenzene | 0.00752 | ND | -- |
| Average RPD: | | | 52.9 |
| Maximum RPD: | | | 120.8 |
| Minimum RPD: | | | 1.8 |

Table 3.6-16. (Continued)

| | |
|--------------------------|----------------------------|
| Site ID: | 153 |
| Site Address: | 2492 Blue Mound Rd W |
| Owner/Operator: | Devon Energy Production Co |
| Date: | 1/19/2011 |
| Time: | 14:30-17:10 |
| Canister Numbers: | 203 and 5424 |

| Compounds | Sample #A047 | Sample #A048 | RPD |
|---------------------|---------------------|---------------------|------------|
| Methane | 118000 | 76200 | 43.1 |
| Butane | 2.28 | 1.57 | 36.9 |
| Isopentane | 0.139 | 0.0903 | 42.5 |
| n-Pentane | 0.0850 | 0.0533 | 45.8 |
| Methylene chloride | 0.010 | 0.01320 | 27.6 |
| Benzene | 0.189 | 0.144 | 27.0 |
| Cyclohexane | 0.0431 | 0.0295 | 37.5 |
| Toluene | 0.0475 | 0.0483 | 1.7 |
| Average RPD: | | | 32.8 |
| Maximum RPD: | | | 45.8 |
| Minimum RPD: | | | 1.7 |

Table 3.6-16. (Continued)

| | |
|--------------------------|------------------------|
| Site ID: | 240 |
| Site Address: | 1392 Conell Sampson Rd |
| Owner/Operator: | XTO Energy Inc |
| Date: | 1/27/2011 |
| Time: | 10:25-12:48 |
| Canister Numbers: | KA 2315 and HL 0930 |

| Compounds | Sample #A059 | Sample #A060 | RPD |
|---------------------|---------------------|---------------------|------------|
| Methane | 21300 | 39400 | 59.6 |
| Butane | 1.01 | 1.99 | 65.3 |
| Isopentane | 0.0823 | 0.164 | 66.3 |
| n-Pentane | 0.0377 | 0.0648 | 52.9 |
| Methylene chloride | 0.01390 | 0.02050 | 38.4 |
| Benzene | 0.0820 | 0.143 | 54.2 |
| Cyclohexane | 0.0213 | 0.0362 | 51.8 |
| Toluene | 0.0440 | 0.0855 | 64.1 |
| Average RPD: | | | 56.6 |
| Maximum RPD: | | | 66.3 |
| Minimum RPD: | | | 38.4 |

Table 3.6-16. (Continued)

| | |
|--------------------------|-------------------|
| Site ID: | 238 |
| Site Address: | 798 Industrial Rd |
| Owner/Operator: | XTO Energy Inc |
| Date: | 1/31/2011 |
| Time: | 10:55-16:25 |
| Canister Numbers: | 279 and 217 |

| Compounds | Sample #A065 | Sample #A066 | RPD |
|------------------------|--------------|--------------|------|
| Methane | 549000 | 528000 | 3.9 |
| Butane | 132 | 106 | 21.9 |
| Isopentane | 21.0 | 19.8 | 5.9 |
| Acetone | 0.0968 | 0.0898 | 7.5 |
| n-Pentane | 6.69 | 5.84 | 13.6 |
| Methylene chloride | 0.02310 | 0.01680 | 31.6 |
| Hexane | 2.90 | 2.65 | 9.0 |
| Benzene | 17.2 | 16.6 | 3.6 |
| Cyclohexane | 4.37 | 4.57 | 4.5 |
| Heptane | 0.269 | 0.259 | 3.8 |
| Toluene | 14.2 | 12.6 | 11.9 |
| n-Octane | 0.0285 | 0.0242 | 16.3 |
| Ethylbenzene | 0.139 | 0.126 | 9.8 |
| m-Xylene & p-Xylene | 3.67 | 3.04 | 18.8 |
| o-Xylene | 0.442 | 0.368 | 18.3 |
| n-Nonane | 0.0106 | ND | -- |
| Isopropylbenzene | 0.0162 | 0.0129 | 22.7 |
| n-Propylbenzene | 0.0209 | 0.0176 | 17.1 |
| 4-Ethyltoluene | 0.0312 | 0.0242 | 25.3 |
| 1,3,5-Trimethylbenzene | 0.214 | 0.144 | 39.1 |
| 1,2,4-Trimethylbenzene | 0.178 | 0.101 | 55.2 |
| n-Decane | 0.0126 | 0.00762 | 49.3 |
| Naphthalene | 0.0232 | ND | -- |
| 1,2,3-Trichlorobenzene | 0.0219 | ND | -- |
| Hexachlorobutadiene | 0.00995 | ND | -- |
| Average RPD: | | | 18.5 |
| Maximum RPD: | | | 55.2 |
| Minimum RPD: | | | 3.6 |

Table 3.6-16. (Continued)

| | |
|--------------------------|---------------------------|
| Site ID: | 426 |
| Site Address: | 692 Bridgewood Dr |
| Owner/Operator: | Chesapeake Operating Inc. |
| Date: | 2/11/2011 |
| Time: | 9:50-12:25 |
| Canister Numbers: | RA 2173 and RA 2150 |

| Compounds | Sample #B095 | Sample #B096 | RPD |
|---------------------|--------------|--------------|------|
| Methane | 76600 | 93800 | 20.2 |
| Butane | 1.98 | 2.46 | 21.6 |
| Isopentane | 0.135 | 0.162 | 18.2 |
| n-Pentane | 0.0664 | 0.0694 | 4.4 |
| Methylene chloride | 0.01180 | 0.01200 | 1.7 |
| Benzene | 0.135 | 0.173 | 24.7 |
| Cyclohexane | 0.0177 | 0.0101 | 54.7 |
| Toluene | 0.0383 | 0.0522 | 30.7 |
| Average RPD: | | | 22.1 |
| Maximum RPD: | | | 54.7 |
| Minimum RPD: | | | 1.7 |

3.6.6 Analytical QC Results

To ensure high quality analytical results, TestAmerica™ performed several quality control checks during the analysis of each batch of canister samples received by them from the point source team. The most significant of these were: Method Blanks, Surrogate Recoveries, Laboratory Control Samples and Control Sample Duplicates, and Continuing Calibration Verification checks.

Method Blanks

Analytical method blanks were analyzed by TestAmerica™ either daily or after a certain number samples (i.e. after each batch of 20 samples). The method blank is treated like any other sample except that a clean material, free from any of the sample targets, is used. The results of the method blank indicate if any contaminants are present in the analytical system. The only compound that routinely appeared in the analytical method blanks associated with this project's canister samples was small amounts of methylene chloride, a common laboratory solvent. In calculating the canister emission factors the amount of methylene chloride detected in the method blank was subtracted from the reported methylene chloride result. Method blank results are provided for each canister sample result in the TestAmerica™ analytical reports provided in Appendix 3-C.

Surrogate Recoveries

A surrogate standard is a non-target analyte having a chemical structure similar to the target analytes that is added to a sample prior to extraction. Six surrogate standards were added to each point source canister sample prior to extraction and their percent recoveries were evaluated following analysis of the canister's contents. The surrogates monitor the efficiency of the extraction, the cleanup, and evaporation of the solvent if any has been used on the sample. Surrogate percent recoveries for each canister result together with acceptable recovery limits are provided with each of TestAmerica's™ analytical reports contained in Appendix 3-C.

Laboratory Control Samples and Control Sample Duplicates

The Laboratory Control Sample (LCS) is a clean matrix that is fortified with the target analytes and analyzed in the same manner as a batch of samples is analyzed. Since in this case the concentration of each analyte is known, the resulting values provide a measure of the accuracy of the system for each analyte. As a further measure of quality control, the LCS is analyzed in duplicate and the relative percent difference between the two results is calculated and evaluated against the laboratory's acceptance criteria. Both LCS and LCS duplicate results are provided towards the conclusion of each TestAmerica™ report.

Continuing Calibration Verification

Continuing Calibration Verification (CCV) checks are performed over specific time periods during sample analysis to confirm the instrument's calibration and performance. A CCV check was performed by TestAmerica™ with each batch of sample analyses. The results are evaluated as the percent recoveries of the known analyte concentrations making up the CCV spike. The results of each CCV check are reported under the heading "Calibration Check" in the TestAmerica™ documentation located in Appendix 3-C.

3.7 Point Source Testing Conclusions

Point source testing was conducted to determine how much air pollution is being released by natural gas exploration in Fort Worth, and if natural gas extraction and processing sites comply with environmental regulations. The point source testing program occurred in two phases, with Phase I occurring from August through October of 2010, and Phase II occurring in January and February of 2011. Under the point source testing program, field personnel determined the amount of air pollution released at individual well pads, compressor stations, and other natural gas processing facilities by visiting 388 sites, includes two repeat visits, and testing the equipment at each site for emissions using infrared cameras, toxic vapor analyzers (TVAs), Hi Flow Samplers, and evacuated canisters to collect emission samples for laboratory analysis.

TOC, VOC, and HAP emissions were calculated on an annual basis for each site as the sum of 1) direct canister sample results; 2) adjusted canister results using correlation equations; 3) tank and non-tank surrogate emission profiles; 4) engine emission data; and 5) default zero emission factors. Emissions associated with tank unloading, tank flashing, well snubbing, glycol

reboilers, flares or any type of maintenance/repair activities were not included in the calculated site emissions profiles.

Key findings from the point source testing program are as follows:

- A total of 2,126 emission points were identified in the four month field study: 192 of the emission points were Valves, 644 were Connectors and 1,290 were classified as Other Equipment. 1,330 emission points were detected with the IR camera (i.e. high level emissions) and 796 emission points were detected by Method 21 screening (i.e. low level emissions).
- At 96 sites, no emissions were detected by the IR camera. At 46 sites, no emissions were detected by either the IR camera or the TVA. Of these 46 sites, 38 had less than three wells and subsequently lower auxiliary equipment counts such as tanks, separators, valves, and connectors.
- Emissions from lift compressors have a significant impact on well pad emissions. Most lift compressors are mobile and are moved from site to site as needed. The addition of a lift compressor to a well pad site has the effect of raising TOC emissions four-fold while emitting an average 16 tons/yr of criteria pollutants.
- The largest source of fugitive emissions detected with the IR camera was leaking tank thief hatches. Emissions were detected at 252 tank thief hatches resulting in a combined TOC emission rate of 4,483 tons/yr. Some of these emissions were due to the operators simply leaving the hatches unsecured as shown in Figure 3.7-1 below. Many others, however, appeared to be due to lack of proper maintenance.



Figure 3.7-1. Thief Hatch Left Open

- Pneumatic Valve Controllers were the most frequent emission sources encountered at well pads and compressor stations. These controllers use pressurized natural gas to

actuate separator unloading valves. Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually. The emissions from the 489 failed pneumatic valve controllers detected by the point source team result in a combined TOC emission rate of 3,003 tons per year.

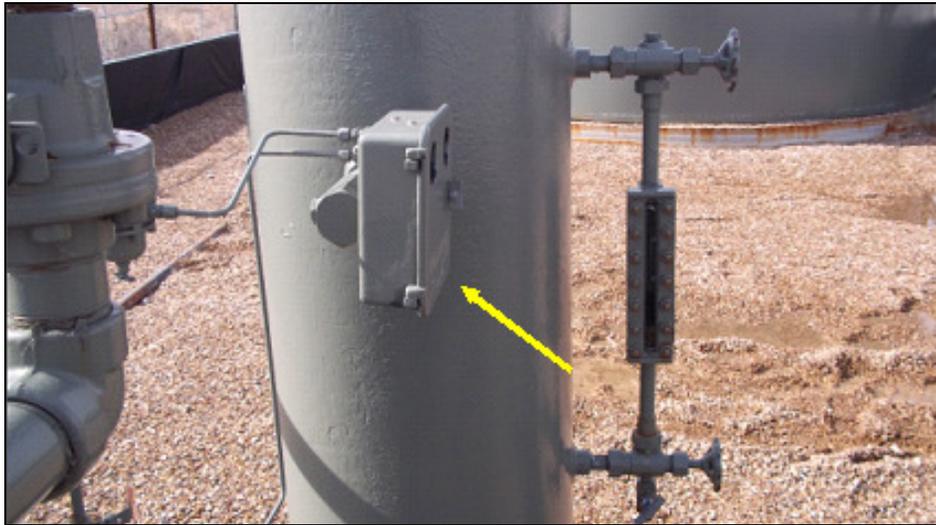


Figure 3.7-2. Pneumatic Valve Controller on Separator

- Emissions from 175 storage tank vents were detected by the IR camera accounting for a combined total of 2,076 tons of TOC per year. In numerous instances several tanks would be manifolded to one vent controlled by a pressure relief valve. In these cases, vent emissions detected with the IR camera indicated a failure of the pressure relief valve.



Figure 3.7-3. Storage Tank Vent

- Emissions from 257 leaking natural gas pressure regulators accounted for a combined TOC total of 614 tons/yr.

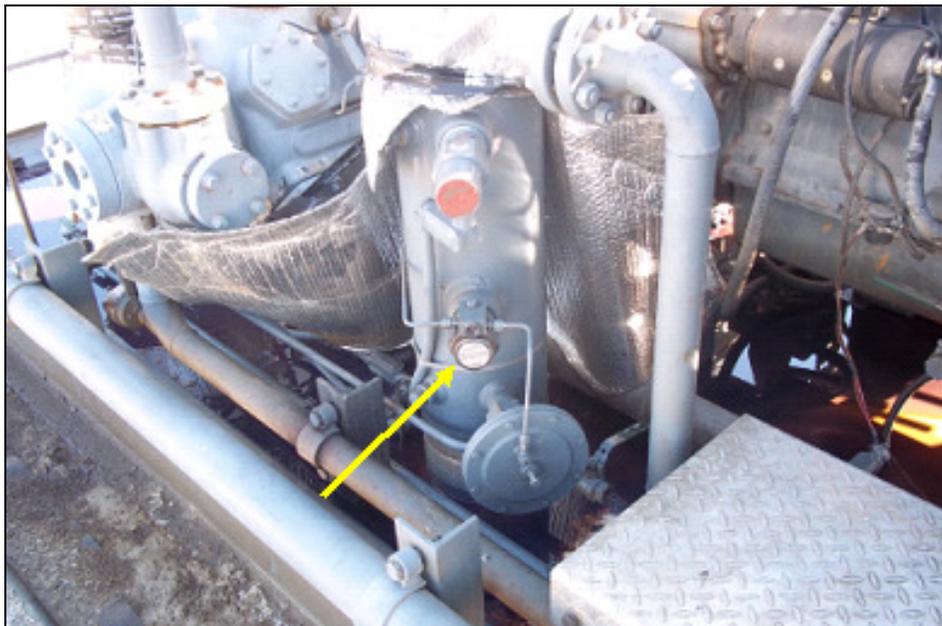


Figure 3.7-4. Natural Gas Pressure Regulator

- Fifty-five (55) instances of emissions from miscellaneous equipment were detected, accounting for a combined TOC emission rate of 731 tons/yr. Miscellaneous equipment includes pinholes, compressor shafts, sumps, knock-out pots, underground piping, glycol contactor controllers, pressure indicators, and quite frequently, holes or breaks in the tank roofs (Figure 3.7-5).



Figure 3.7-5. Hole in Tank Roof - Miscellaneous Emission Source

- No natural gas emissions associated with drilling and fracking activities were detected by the IR camera. Engine emissions associated with these activities were estimated based upon vendor data and published emission factors.
- Emissions were detected from a well completion activity with the IR camera. However, no measurements were taken using the TVA and Method 21 screening procedures and/or the highflow sampler due to safety considerations.
- Emissions were also detected at the Salt Water Treatment facility using the TVA. No emissions were detected using the IR camera. The emissions that were detected with the TVA resulted from minor fugitive emission components only. The Evaporative Unit was not able to be tested since it was out of service during the point source survey.
- Although there was little difference in average TOC emissions between dry and wet gas sites, average VOC and HAP emissions from wet gas sites proved to be considerably higher than dry gas sites as would be expected due to the additional storage and loading of condensate at wet gas sites.
- An Encana Oil & Gas Well Pad (Site ID PS-184) located at 10590 Chapin Road had the highest VOC emissions among well pads (22 tons/yr). This site had only a single well, with two tanks. However, it also had one large line compressor (Caterpillar G-399). Twelve (12) emission points were detected at this site with the IR camera: Four in the area of the separators, three on the tanks, and five at the compressor.

4.0 Air Dispersion Modeling

Existing well pads and compressor stations in the city of Fort Worth emit air pollutants that affect off-site air quality. Under Task 4, a modeling analysis was conducted to quantify downwind impacts from natural gas activities at facility property lines and beyond using the latest EPA-approved models and methodologies. Modeling was conducted for 91 pollutants for which emission rates were measured and/or estimated under the Point Source Testing task (Task 3). See Section 3 of this report for details on how the point source emission estimates were derived. The modeling did not include criteria pollutant emissions from natural gas combustion in the compressor engines, and only considered emissions data from the well pads. Emissions from other source types, such as onroad emissions, were not considered for this task.

The modeling results can also be used to assess the adequacy of existing setback distances; as well, they were also used in the public health evaluation performed under Task 7 of this project. The findings of the public health evaluation, including a detailed analysis of the modeling results and their implications relative to the city's required setback distances, can be found in Section 5 of this report.

This section has five sub-sections:

- 4.1 Modeling Scenarios and Source Parameters – A description of how the modeling scenarios were established is provided in this section.
- 4.2 Modeling Inputs and Options – This section provides the specific modeling inputs and options used to conduct the dispersion modeling.
- 4.3 Model Output – Summary tables showing the maximum 1-hour, 24-hour, and annual modeled impacts are provided in this section.
- 4.4 Electronic Modeling Files – This section provides electronic versions of the modeling input and output files.
- 4.5 Air Dispersion Modeling Conclusions – This section presents the conclusions of the air dispersion modeling task.

4.1 Modeling Scenarios and Source Parameters

There are over 500 individual well pads and compressor stations within the city of Fort Worth. While many of these sites are similar with respect to source types and emissions profiles, there is a wide variety of configurations of the emission sources at each site. For this analysis, as described in the Work Plan, four different scenarios were modeled that represent both average and potential worst-case estimates of modeled impacts based on actual emissions from source testing, source position relative to the property line, source alignments relative to one another, and associated downwash structure effects.

All emission sources observed during the point source testing were considered, and have been categorized and modeled as storage tanks, fugitive emission points, and compressor engines. A summary of these three source categories follows.

Storage tanks were modeled as pseudo-point sources, using an exit velocity of 0.001 meters per second and a stack diameter of 0.001 meters, along with ambient exhaust temperature. These stack parameters were chosen to produce conservative estimates of impacts from the tanks; such parameters effectively negate any airflow from the source, thereby eliminating the effect of vertical displacement on the plume. This approach is widely used in many states throughout the U.S., and is considered standard modeling practice for sources of this type. A hypothetical tank layout for each site, including tank diameters and heights, was used to determine the potential for downwash effects using AERMOD's included Plume Rise Model Enhancements (PRIME) algorithms. Based on ERG's understanding of the emission sources at each site, the tanks are the only sources that would significantly impede the free flow of air, so direction-specific source dimensions were only calculated for storage tanks. Figure 4.1-1 shows a battery of six storage tanks at a well pad (emissions associated with the horizontal separators shown on the right side of this image are accounted for with the fugitive emission points as discussed below).



Figure 4.1-1. Storage Tanks

All *fugitive emission points* were modeled as a single elevated area source. This source category includes estimated emissions from piping, valves, and connectors associated with emission sources such as wellheads, separators, or pneumatic liquid level controllers. A release height of 6 feet was assumed, representing the average height of all the piping and associated equipment. This source category included every emission type not modeled under the storage tank or compressor engine source category. Figure 4.1-2 shows a close-up view of equipment at a well pad or compressor station that may emit fugitive emissions.



Figure 4.1-2. Fugitive Emission Points

For *compressor engines*, emissions from the combustion of natural gas were modeled as standard point sources, using representative exhaust flow and temperature. Fugitive emissions of natural gas from piping associated with the gas compression process are included with the fugitive emission points discussed above. Figure 4.1-3 shows a compressor engine located at a compressor station.



Figure 4.1-3. Natural Gas Compression Engine

Table 4.1-1, below, summarizes the different types of source categories at well pads and compressor stations in Fort Worth, along with the modeling classification of each source.

Table 4.1-1. Source Types Modeled

| Source Category | Number of Modeled Sources per Well Pad or Compressor Station | Modeling Classification |
|--------------------------|--|-----------------------------------|
| Storage tanks | 5 to 10 | Pseudo-point source with downwash |
| Fugitive emission points | 1 | Elevated area source |
| Compressor engines | 0 to 6 | Point source |

The four modeling scenarios are described in more detail below.

4.1.1 Scenario 1 (Typical Well Pad)

This scenario represents a typical well pad without compression and includes storage tanks and fugitive emission points. Emission rates are based on point source testing conducted under Task 3. Typical well pad emission sources include storage tanks, wellheads, separators, and pneumatic devices. All identified emission sources at a well pad without compression have been included in this scenario. Specifically, this scenario includes the following:

- Five storage tanks, each 10 feet tall and 15 feet in diameter, modeled as pseudo-point sources.
- Storage tank emission rates based on the average, pollutant-specific storage tank emission rate observed at all well pad sites.
- Emission rates from fugitive emission points (wellheads, separators, pneumatic devices, piping, etc.) based on the average, pollutant-specific well pad emission rate observed during point source testing, modeled as a single elevated area source.
- Well pad measuring 200 feet by 200 feet.

Key Point: Scenario 1

Emission rates modeled under Scenario 1 represent the average emission rates from storage tanks and fugitive emission points from all well pads tested under this study.

Table 4.1-2 shows the emission rates used in the modeling demonstration for Scenario 1.

Table 4.1-2. Scenario 1 (Typical Well Pad) Model Input Emission Rates

| Pollutant | Storage Tanks (lb/hr) ^a | Fugitive Emission Points (lb/hr) |
|--|------------------------------------|----------------------------------|
| Acetone | 2.18E-05 | 5.67E-04 |
| Benzene | 1.16E-03 | 1.07E-04 |
| Bromomethane | NA | 1.14E-06 |
| Butadiene, 1,3- | NA | 4.85E-06 |
| Butane | 2.16E-02 | 8.96E-03 |
| Butanone, 2- (Methyl Ethyl Ketone) | 8.24E-06 | 3.36E-06 |
| Butylbenzene, <i>sec</i> - | 1.98E-05 | 6.63E-06 |
| Carbon disulfide | 2.77E-06 | NA |
| Carbon tetrachloride | NA | 1.12E-06 |
| Chlorodifluoromethane | NA | 4.41E-07 |
| Chloroethane | NA | 1.16E-06 |
| Chloromethane | 8.41E-07 | 6.07E-07 |
| Chlorotoluene, 2- | NA | 1.52E-06 |
| Cyclohexane | 1.38E-03 | 2.17E-04 |
| Decane, <i>n</i> - | 2.64E-04 | 4.83E-05 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | NA | 1.05E-06 |
| Dichlorodifluoromethane | NA | 8.77E-07 |
| Dodecane, <i>n</i> - | 2.11E-05 | 8.96E-06 |
| Ethylbenzene | 8.68E-05 | 1.65E-05 |
| Ethyltoluene, 4- | 8.11E-05 | 2.42E-05 |
| Heptane | 5.66E-03 | 4.32E-04 |
| Hexachlorobutadiene | 7.48E-06 | 6.61E-06 |
| Hexane | 5.22E-03 | 5.03E-04 |

Table 4.1-2. Scenario 1 (Typical Well Pad) Model Input Emission Rates (Continued)

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) |
|---|-----------------------|----------------------------------|
| Isopentane | 8.83E-03 | 2.53E-03 |
| Isopropylbenzene | 3.33E-05 | 6.29E-06 |
| Isopropyltoluene, 4- | 1.94E-05 | 1.77E-05 |
| Methane | 8.36E+00 | 3.60E+00 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 2.46E-06 | 1.17E-05 |
| Methylene chloride | 3.40E-06 | 4.43E-04 |
| Naphthalene | 1.02E-05 | 5.39E-06 |
| Nonane, <i>n</i> - | 4.78E-03 | 1.18E-04 |
| Octane, <i>n</i> - | 6.14E-03 | 2.17E-04 |
| Pentane, <i>n</i> - | 6.78E-03 | 1.67E-03 |
| Propylbenzene, <i>n</i> - | 4.11E-05 | 1.38E-05 |
| Propylene | 1.66E-06 | 2.51E-06 |
| Styrene | 2.68E-06 | NA |
| Tetrachloroethene | 7.04E-05 | NA |
| Toluene | 4.40E-03 | 2.80E-04 |
| Trichlorobenzene, 1,2,3- | 1.02E-05 | 1.14E-05 |
| Trichlorobenzene, 1,2,4- | 9.95E-06 | 7.46E-06 |
| Trichlorofluoromethane | NA | 1.29E-06 |
| Trimethylbenzene, 1,2,4- | 2.11E-04 | 3.73E-05 |
| Trimethylbenzene, 1,3,5- | 1.64E-04 | 4.36E-05 |
| Trimethylpentane, 2,2,4- | 1.31E-05 | 3.60E-06 |
| Undecane, <i>n</i> - | 4.23E-05 | 1.91E-05 |
| Vinyl acetate | 1.30E-05 | NA |
| Vinyl bromide | NA | 1.38E-06 |
| Vinyl chloride | NA | 6.67E-07 |
| Xylene, <i>o</i> - | 1.85E-04 | 4.06E-05 |
| Xylenes, <i>m</i> -, <i>p</i> - | 2.44E-03 | 2.14E-04 |

^a Emission estimates are shown in this table using scientific notation. In scientific notation, the format "2.18E-05" is used to display a value of "0.0000218" by shifting the decimal place 5 places to the left using "E-" prefix. Likewise, the format "2.18E+05" would be used to display a value of "218,000" by shifting the decimal place 5 places to the right using "E+" prefix.

NA = not applicable

Figure 4.1-4 shows the layout of the typical well pad modeled under Scenario 1.

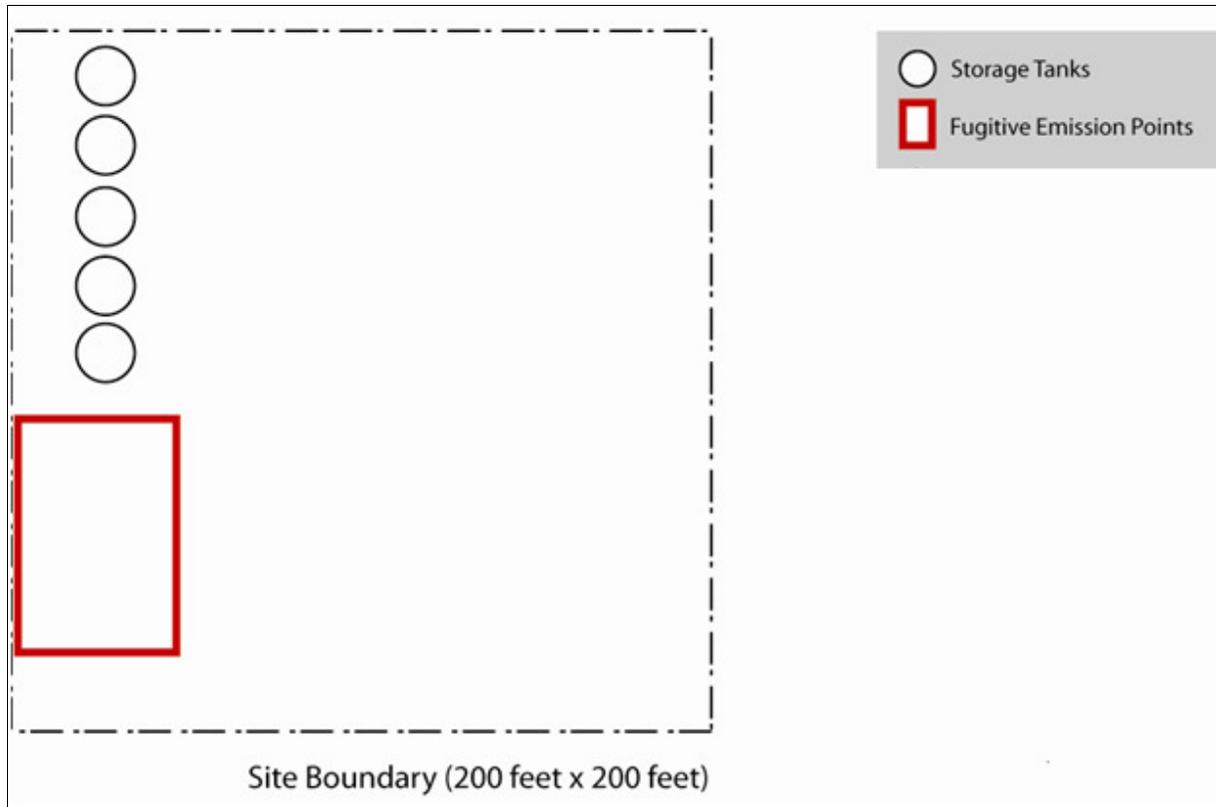


Figure 4.1-4. Scenario 1 Layout (Typical Well Pad)

4.1.2 Scenario 2 (Worst-Case Well Pad)

This scenario represents a worst-case well pad with storage tanks, fugitive emission points, and two compression engines (250 hp each). Emissions from combustion of natural gas in the compression engines are based on published emission factors, while emissions from storage tanks and fugitive emission points are based on point source testing. Specifically, this scenario includes the following:

Key Point: Scenario 2

Emission rates modeled under Scenario 2 represent the maximum emission rates from storage tanks and fugitive emission points from all well pads tested under this study.

- Ten storage tanks, each 10 feet tall and 15 feet in diameter, modeled as pseudo-point sources.
- Storage tank emission rates based on the maximum, pollutant-specific storage tank emission rate observed at all well pad sites.
- Two 250-hp compressor engines, uncontrolled, modeled as point sources.
- Emission rates from fugitive emission points (wellheads, separators, pneumatic devices, piping, etc.) based on the maximum, pollutant-specific well pad emission rate observed during point source testing, modeled as a single elevated area source.
- Well pad measuring 250 feet by 250 feet.

Table 4.1-3 shows the emission rates used in the modeling demonstration for Scenario 2.

Table 4.1-3. Scenario 2 (Worst-Case Well Pad) Model Input Emission Rates

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|--|-----------------------|----------------------------------|----------------------------|
| Acenaphthene | NA | NA | 5.17E-06 |
| Acenaphthylene | NA | NA | 2.15E-05 |
| Acetaldehyde | NA | NA | 3.25E-02 |
| Acetone | 8.98E-04 | 2.09E-01 | NA |
| Acrolein | NA | NA | 3.02E-02 |
| Anthracene | NA | NA | 2.79E-06 |
| Benzene | 5.26E-02 | 2.24E-02 | 7.54E-03 |
| Benzo (a) anthracene | NA | NA | 1.31E-06 |
| Benzo (a) pyrene | NA | NA | 2.21E-08 |
| Benzo (b) fluoranthene | NA | NA | 6.45E-07 |
| Benzo (e) pyrene | NA | NA | 1.61E-06 |
| Benzo (g,h,i) perylene | NA | NA | 1.61E-06 |
| Benzo (k) fluoranthene | NA | NA | 1.66E-08 |
| Biphenyl | NA | NA | 8.24E-04 |
| Bromomethane | NA | 3.82E-05 | NA |
| Butadiene, 1,3- | NA | 1.61E-04 | 3.19E-03 |
| Butane | 2.14E+00 | 2.16E+00 | NA |
| Butane, <i>n</i> - | NA | NA | 1.85E-02 |
| Butanone, 2- (Methyl Ethyl Ketone) | 1.88E-04 | 1.13E-04 | NA |
| Butylbenzene, <i>sec</i> - | 9.55E-04 | 2.22E-04 | NA |
| Carbon disulfide | 5.90E-05 | NA | NA |
| Carbon tetrachloride | NA | 3.74E-05 | 2.36E-04 |
| Chlorobenzene | NA | NA | 1.73E-04 |
| Chlorodifluoromethane | NA | 1.48E-05 | NA |
| Chloroethane | NA | 3.91E-05 | 7.27E-06 |
| Chloroform | NA | NA | 1.83E-04 |
| Chloromethane | 1.77E-05 | 1.99E-05 | NA |
| Chlorotoluene, 2- | NA | 5.10E-05 | NA |
| Chrysene | NA | NA | 2.69E-06 |
| Cyclohexane | 9.01E-02 | 6.52E-02 | 1.20E-03 |
| Cyclopentane | NA | NA | 8.82E-04 |
| Decane, <i>n</i> - | 2.17E-02 | 1.28E-02 | NA |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | NA | 3.50E-05 | NA |
| Dichlorodifluoromethane | NA | 2.94E-05 | NA |
| Dichloroethane, 1,1- | NA | NA | 1.52E-04 |
| Dichloropropene, 1,3- | NA | NA | 1.70E-04 |
| Dodecane, <i>n</i> - | 5.89E-04 | 1.45E-03 | NA |
| Ethane | NA | NA | 4.08E-01 |
| Ethylbenzene | 3.62E-03 | 4.20E-03 | 4.20E-04 |
| Ethylene dibromide | NA | NA | 2.85E-04 |
| Ethylene dichloride | NA | NA | 1.64E-04 |
| Ethyltoluene, 4- | 5.99E-03 | 1.72E-03 | NA |
| Fluoranthene | NA | NA | 4.32E-06 |

Table 4.1-3. Scenario 2 (Worst-Case Well Pad) Model Input Emission Rates (Continued)

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|---|-----------------------|----------------------------------|----------------------------|
| Fluorene | NA | NA | 2.20E-05 |
| Formaldehyde | NA | NA | 2.15E-01 |
| Heptane | 5.79E-01 | 1.32E-01 | NA |
| Hexachlorobutadiene | 1.68E-04 | 2.21E-04 | NA |
| Hexane | 6.00E-01 | 1.48E-01 | 4.32E-03 |
| Indeno (1,2,3-cd) pyrene | NA | NA | 3.86E-08 |
| Isobutane | NA | NA | 1.46E-02 |
| Isobutyraldehyde | NA | NA | 1.70E-03 |
| Isopentane | 7.25E-01 | 7.46E-01 | NA |
| Isopropylbenzene | 1.11E-03 | 7.92E-04 | NA |
| Isopropyltoluene, 4- | 4.94E-04 | 5.91E-04 | NA |
| Methane | 9.93E+01 | 7.27E+01 | NA |
| Methyl alcohol | NA | NA | 1.19E-02 |
| Methyl Naphthalene, 2- | NA | NA | 1.29E-04 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 5.59E-05 | 3.94E-04 | NA |
| Methylcyclohexane | NA | NA | 4.78E-03 |
| Methylene chloride | 7.08E-05 | 1.64E-01 | 5.71E-04 |
| Naphthalene | 2.00E-04 | 1.80E-04 | 3.77E-04 |
| Nonane, <i>n</i> - | 5.38E-01 | 3.45E-02 | 4.28E-04 |
| Octane, <i>n</i> - | 5.54E-01 | 7.13E-02 | 1.36E-03 |
| Pentane, <i>n</i> - | 6.05E-01 | 5.13E-01 | 1.01E-02 |
| Perylene | NA | NA | 1.93E-08 |
| Phenanthrene | NA | NA | 4.04E-05 |
| Phenol | NA | NA | 1.64E-04 |
| Polycyclic Aromatic Hydrocarbons (PAH) | NA | NA | 5.48E-04 |
| Propane | NA | NA | 1.63E-01 |
| Propylbenzene, <i>n</i> - | 2.00E-03 | 9.24E-04 | NA |
| Propylene | 3.46E-05 | 1.10E-04 | NA |
| Propylene dichloride | NA | NA | 1.73E-04 |
| Pyrene | NA | NA | 5.29E-06 |
| Styrene | 6.07E-05 | NA | 2.13E-04 |
| Tetrachloroethane, 1,1,2,2- | NA | NA | 2.58E-04 |
| Tetrachloroethene | 1.49E-03 | NA | NA |
| Toluene | 2.82E-01 | 8.39E-02 | 3.74E-03 |
| Trichlorobenzene, 1,2,3- | 2.28E-04 | 3.83E-04 | NA |
| Trichlorobenzene, 1,2,4- | 2.26E-04 | 2.49E-04 | NA |
| Trichloroethane, 1,1,2,2- | NA | NA | 2.05E-04 |
| Trichlorofluoromethane | NA | 4.32E-05 | NA |
| Trimethylbenzene, 1,2,3- | NA | NA | 1.38E-04 |
| Trimethylbenzene, 1,2,4- | 1.90E-02 | 7.75E-03 | 4.32E-04 |
| Trimethylbenzene, 1,3,5- | 7.87E-03 | 9.14E-03 | 1.31E-04 |
| Trimethylpentane, 2,2,4- | 4.18E-04 | 1.17E-04 | 3.29E-03 |
| Undecane, <i>n</i> - | 2.32E-03 | 5.32E-03 | NA |
| Vinyl acetate | 2.97E-04 | NA | NA |

Table 4.1-3. Scenario 2 (Worst-Case Well Pad) Model Input Emission Rates (Continued)

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|-----------------------|-----------------------|----------------------------------|----------------------------|
| Vinyl bromide | NA | 4.63E-05 | NA |
| Vinyl chloride | NA | 2.24E-05 | 9.60E-05 |
| Xylene, <i>o</i> - | 9.64E-03 | 1.17E-02 | 1.04E-03 |
| Xylenes, <i>m,p</i> - | 2.25E-01 | 7.10E-02 | 1.04E-03 |

NA = not applicable

Figure 4.1-5 shows the layout of the worst-case well pad modeled under Scenario 2.

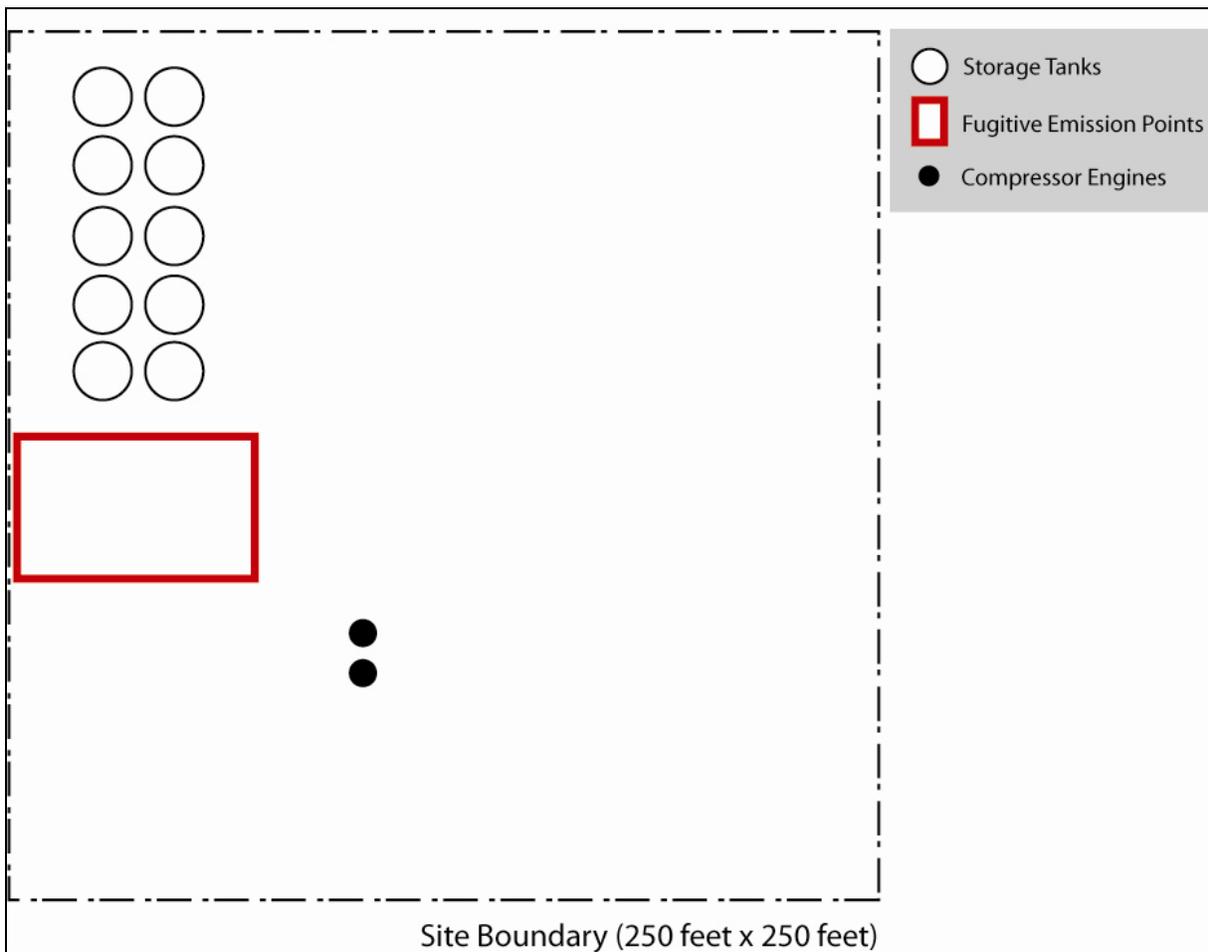


Figure 4.1-5. Scenario 2 Layout (Worst-Case Well Pad)

4.1.3 Scenario 3 (Worst-Case Compressor Station)

This scenario represents a worst-case compressor station with six compression engines (1,775 hp each). Emissions from combustion of natural gas in the compression engines are based on published emission factors, while emissions from storage tanks and fugitive emission points are based on point source testing. Specifically, this scenario includes the following:

Key Point: Scenario 3

Emission rates modeled under Scenario 3 represent the maximum emission rates from storage tanks and fugitive emission points from all compressor stations tested under this study.

- Storage tank emission rates based on the maximum, pollutant-specific storage tank emission rate observed at all compressor station sites.
- Eight tanks, each 10 feet tall and 15 feet in diameter, modeled as pseudo-point sources.
- Six 1,775-hp compressor engines, uncontrolled, modeled as point sources.
- Emission rates from all other sources (wellheads, separators, pneumatic devices, dehydrators, piping, etc.) based on the maximum, pollutant-specific compressor station emission rate observed during point source testing, modeled as a single elevated area source.
- Compressor station measuring 600 feet by 400 feet.

Table 4.1-4 shows the emission rates used in the modeling demonstration for Scenario 3.

Table 4.1-4. Scenario 3 (Worst-Case Compressor Station) Model Input Emission Rates

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|------------------------|-----------------------|----------------------------------|----------------------------|
| Acenaphthene | NA | NA | 9.40E-05 |
| Acenaphthylene | NA | NA | 3.91E-04 |
| Acetaldehyde | NA | NA | 5.91E-01 |
| Acetone | 5.27E-04 | 1.06E-03 | NA |
| Acrolein | NA | NA | 5.50E-01 |
| Anthracene | NA | NA | 5.07E-05 |
| Benzene | 1.53E-02 | 1.31E-03 | 1.37E-01 |
| Benzo (a) anthracene | NA | NA | 2.37E-05 |
| Benzo (a) pyrene | NA | NA | 4.01E-07 |
| Benzo (b) fluoranthene | NA | NA | 1.17E-05 |
| Benzo (e) pyrene | NA | NA | 2.93E-05 |
| Benzo (g,h,i) perylene | NA | NA | 2.93E-05 |
| Benzo (k) fluoranthene | NA | NA | 3.01E-07 |
| Biphenyl | NA | NA | 1.50E-02 |
| Bromomethane | NA | 1.38E-05 | NA |
| Butadiene, 1,3- | NA | 5.83E-05 | 5.79E-02 |
| Butane | 1.13E-01 | 1.45E-02 | NA |

Table 4.1-4. Scenario 3 (Worst-Case Compressor Station) Model Input Emission Rates (Continued)

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|---|-----------------------|----------------------------------|----------------------------|
| Butane, <i>n</i> - | NA | NA | 3.36E-01 |
| Butanone, 2- (Methyl Ethyl Ketone) | 1.79E-05 | 4.09E-05 | NA |
| Butylbenzene, <i>sec</i> - | 2.64E-05 | 5.58E-04 | NA |
| Carbon disulfide | 5.62E-06 | NA | NA |
| Carbon tetrachloride | NA | 1.36E-05 | 4.29E-03 |
| Chlorobenzene | NA | NA | 3.14E-03 |
| Chlorodifluoromethane | NA | 5.36E-06 | NA |
| Chloroethane | NA | 1.41E-05 | 1.32E-04 |
| Chloroform | NA | NA | 3.33E-03 |
| Chloromethane | 1.69E-06 | 7.19E-06 | NA |
| Chlorotoluene, 2- | NA | 1.85E-05 | NA |
| Chrysene | NA | NA | 4.90E-05 |
| Cyclohexane | 5.26E-03 | 4.36E-04 | 2.18E-02 |
| Cyclopentane | NA | NA | 1.60E-02 |
| Decane, <i>n</i> - | 3.86E-05 | 1.46E-04 | NA |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | NA | 1.27E-05 | NA |
| Dichlorodifluoromethane | NA | 1.07E-05 | NA |
| Dichloroethane, 1,1- | NA | NA | 2.76E-03 |
| Dichloropropene, 1,3- | NA | NA | 3.10E-03 |
| Dodecane, <i>n</i> - | 3.04E-05 | 4.80E-05 | NA |
| Ethane | NA | NA | 7.42E+00 |
| Ethylbenzene | 2.69E-04 | 5.21E-05 | 7.63E-03 |
| Ethylene dibromide | NA | NA | 5.19E-03 |
| Ethylene dichloride | NA | NA | 2.98E-03 |
| Ethyltoluene, 4- | 5.71E-05 | 1.35E-02 | NA |
| Fluoranthene | NA | NA | 7.84E-05 |
| Fluorene | NA | NA | 4.01E-04 |
| Formaldehyde | NA | NA | 3.90E+00 |
| Heptane | 3.66E-04 | 1.98E-04 | NA |
| Hexachlorobutadiene | 1.60E-05 | 8.00E-05 | NA |
| Hexane | 3.53E-03 | 4.68E-04 | 7.84E-02 |
| Indeno (1,2,3-cd) pyrene | NA | NA | 7.02E-07 |
| Isobutane | NA | NA | 2.65E-01 |
| Isobutyraldehyde | NA | NA | 3.09E-02 |
| Isopentane | 3.47E-02 | 5.52E-03 | NA |
| Isopropylbenzene | 3.95E-05 | 1.67E-04 | NA |
| Isopropyltoluene, 4- | 3.09E-05 | 2.90E-04 | NA |
| Methane | 2.17E+02 | 2.63E+01 | NA |
| Methyl alcohol | NA | NA | 2.16E-01 |
| Methyl naphthalene, 2- | NA | NA | 2.35E-03 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 5.32E-06 | 1.43E-04 | NA |

Table 4.1-4. Scenario 3 (Worst-Case Compressor Station) Model Input Emission Rates (Continued)

| Pollutant | Storage Tanks (lb/hr) | Fugitive Emission Points (lb/hr) | Compressor Engines (lb/hr) |
|--|-----------------------|----------------------------------|----------------------------|
| Methylcyclohexane | NA | NA | 8.69E-02 |
| Methylene chloride | 2.42E-05 | 1.82E-05 | 1.04E-02 |
| Naphthalene | 1.91E-05 | 6.53E-05 | 6.86E-03 |
| Nonane, <i>n</i> - | 8.99E-05 | 2.71E-04 | 7.77E-03 |
| Octane, <i>n</i> - | 9.89E-05 | 1.54E-04 | 2.48E-02 |
| <i>o</i> -Xylene, <i>o</i> - | 2.66E-04 | 1.87E-04 | 1.89E-02 |
| Pentane, <i>n</i> - | 1.33E-02 | 2.32E-03 | 1.84E-01 |
| Perylene | NA | NA | 3.51E-07 |
| Phenanthrene | NA | NA | 7.35E-04 |
| Phenol | NA | NA | 2.97E-03 |
| Polycyclic aromatic hydrocarbons (PAH) | NA | NA | 9.96E-03 |
| Propane | NA | NA | 2.96E+00 |
| Propylbenzene, <i>n</i> - | 4.42E-05 | 5.03E-03 | NA |
| Propylene | 3.29E-06 | 2.68E-05 | NA |
| Propylene dichloride | NA | NA | 3.15E-03 |
| Pyrene | NA | NA | 9.61E-05 |
| Styrene | 5.77E-06 | NA | 3.87E-03 |
| Tetrachloroethane, 1,1,2,2- | NA | NA | 4.68E-03 |
| Tetrachloroethene | 1.42E-04 | NA | NA |
| Toluene | 1.23E-02 | 6.97E-04 | 6.80E-02 |
| Trichlorobenzene, 1,2,3- | 2.17E-05 | 1.39E-04 | NA |
| Trichlorobenzene, 1,2,4- | 2.15E-05 | 9.03E-05 | NA |
| Trichloroethane, 1,1,2- | NA | NA | 3.72E-03 |
| Trichlorofluoromethane | NA | 1.57E-05 | NA |
| Trimethylbenzene, 1,2,3- | NA | NA | 2.50E-03 |
| Trimethylbenzene, 1,2,4- | 7.07E-05 | 5.98E-02 | 7.84E-03 |
| Trimethylbenzene, 1,3,5- | 7.79E-05 | 1.49E-02 | 2.39E-03 |
| Trimethylpentane, 2,2,4- | 1.84E-05 | 4.23E-05 | 5.98E-02 |
| Undecane, <i>n</i> - | 5.26E-05 | 5.68E-05 | NA |
| Vinyl acetate | 2.82E-05 | NA | NA |
| Vinyl bromide | NA | 1.68E-05 | NA |
| Vinyl chloride | NA | 8.11E-06 | 1.75E-03 |
| Xylenes, <i>m</i> -, <i>p</i> - | 1.67E-03 | 1.72E-04 | 1.89E-02 |

NA = not applicable

Figure 4.1-6 shows the layout of the worst-case compressor station modeled under Scenario 3.

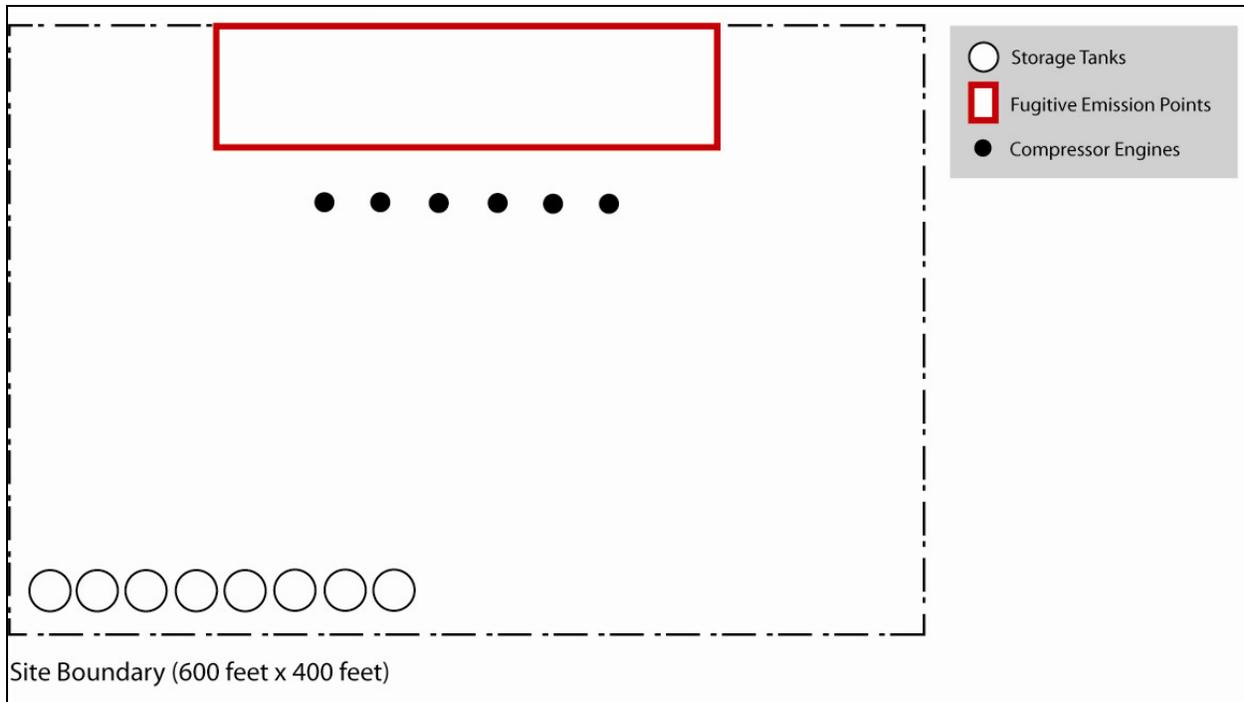


Figure 4.1-6. Scenario 3 Layout (Worst-Case Compressor Station)

4.1.4 Scenario 4 (Co-located Worst-Case Well Pad and Worst-Case Compressor Station)

This modeling scenario quantifies the combined impacts of the worst-case well pad in Scenario 2 and the worst-case compressor station in Scenario 3. This scenario assumes co-location of a well pad and a compressor station. The emission rates used in Scenario 4 are the same as used in Scenario 2 for the well pad and Scenario 3 for the compressor station.

Figure 4.1-7 shows the layout of the co-located well pad and compressor station modeled under Scenario 4.

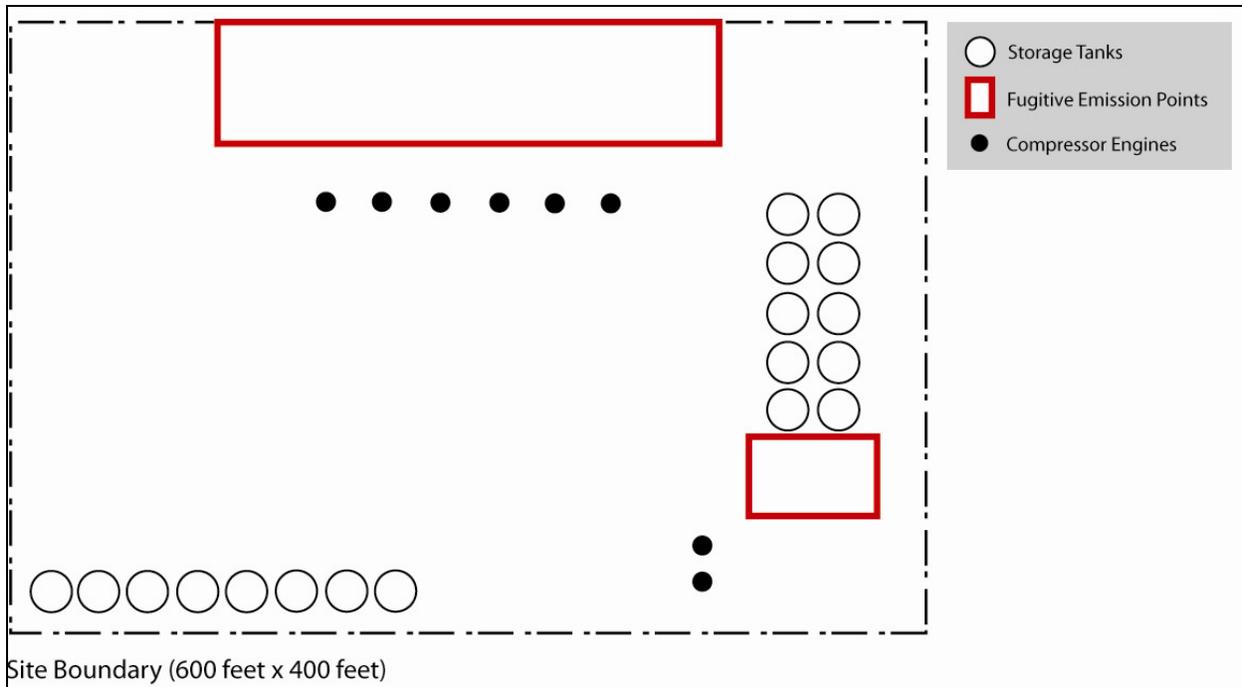


Figure 4.1-7. Scenario 4 Layout (Co-located Well Pad and Compressor Station)

4.2 Model Setup and Options

ERG used the latest version of the AMS/EPA Regulatory MODel (AERMOD), Version 11103, to estimate pollutant impacts for four different well pad and compressor station layouts. The modeling predicts, by scenario, 1-hour average, 24-hour average, and annual average concentrations for the pollutants listed in Section 4.1 above. Building downwash effects were simulated using the PRIME algorithm, which is included with AERMOD and is “designed to incorporate the two fundamental features associated with building downwash: enhanced plume dispersion coefficients due to the turbulent wake, and reduced plume rise caused by a combination of the descending streamlines in the lee of the building and the increased entrainment in the wake.”⁸ All model runs were constructed and executed using BEEST for Windows 9.90, a commercial dispersion modeling software package that combines AERMOD and its supporting programs into a single interface for use in model pre- and post-processing.

4.2.1 Receptor Grids

The modeling estimated air quality impacts at locations outside the property line of the well pads and compressor stations. Predictions were made from the property line out to a distance 2 kilometers away. Receptor grids of different resolutions were used to predict the maximum ambient concentrations around each site. ERG used 10-meter spacing along each site’s property fence line out to 40 meters; 25-meter spacing from 50 to 150 meters; 100-meter spacing from 200 meters to 1 kilometer; and 200-meter spacing between 1 and 2 kilometers. Because the terrain in the Fort Worth area is primarily flat, terrain heights of zero meters were assumed.

4.2.2 Meteorological Data and Surface Parameters

The meteorological data used in this analysis was obtained from TCEQ. It has been preprocessed to ensure data quality, and is approved for use in AERMOD for state and federal modeling analyses. It consists of a single year of surface data from Dallas–Fort Worth International Airport (about 10 miles east-northeast of the Fort Worth) and upper air observations from Stephenville, Texas (about 60 miles southwest of Fort Worth) for 1988. The associated albedo for this dataset is 0.150, while the Bowen ratio is 0.600; both of these were input to the model. A “medium” surface roughness of 0.5 meters, corresponding to rural/suburban areas, was selected; this choice is representative of a large portion of Tarrant County, where natural gas well pads are primarily situated.

4.3 Model Output

A summary of maximum impacts for each scenario, pollutant, and averaging period of interest are presented in Tables 4.3-1 through 4.3-4 below. In most cases, these outputs represent impacts at the fence line defined in each scenario. Figure 4.3-1 presents a graphical illustration of formaldehyde impacts for each of the four scenarios. Please see section 5 for a detailed analysis of the public health implication of the modeling findings, as well as additional modeling graphics.

Impacts for all receptors are contained within the modeling output files, which are described in further detail in Section 4.4. All modeled concentrations are presented in ppbv (with the exception of PAH as noted below).

Table 4.3-1. Modeled Impacts—Scenario 1 (Typical Well Pad)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|--|---------------------------|----------------------------|---------------------------|
| Acetone | 7.20E+00 | 1.44E+00 | 4.07E-01 |
| Benzene | 1.74E+00 | 4.72E-01 | 1.10E-01 |
| Bromomethane | 1.12E-03 | 2.21E-04 | 6.18E-05 |
| Butadiene, 1,3- | 8.33E-03 | 1.66E-03 | 4.70E-04 |
| Butane | 4.35E+01 | 1.22E+01 | 3.06E+00 |
| Butanone, 2- (Methyl Ethyl Ketone) | 1.23E-02 | 3.46E-03 | 8.67E-04 |
| Butylbenzene, <i>sec</i> - | 1.72E-02 | 4.76E-03 | 1.18E-03 |
| Carbon disulfide | 4.26E-03 | 1.16E-03 | 2.60E-04 |
| Carbon tetrachloride | 6.74E-04 | 1.34E-04 | 3.81E-05 |
| Chlorodifluoromethane | 4.75E-04 | 9.33E-05 | 2.54E-05 |
| Chloroethane | 1.68E-03 | 3.34E-04 | 9.48E-05 |
| Chloromethane | 2.11E-03 | 5.76E-04 | 1.60E-04 |
| Chlorotoluene, 2- | 1.11E-03 | 2.22E-04 | 6.18E-05 |
| Cyclohexane | 1.91E+00 | 5.20E-01 | 1.24E-01 |
| Decane, <i>n</i> - | 2.17E-01 | 5.92E-02 | 1.42E-02 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 5.69E-04 | 1.13E-04 | 3.15E-05 |
| Dichlorodifluoromethane | 6.73E-04 | 1.33E-04 | 3.84E-05 |
| Dodecane, <i>n</i> - | 1.46E-02 | 4.08E-03 | 1.03E-03 |

Table 4.3-1. Modeled Impacts—Scenario 1 (Typical Well Pad) (Continued)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|---|---------------------------|----------------------------|---------------------------|
| Ethylbenzene | 8.74E-02 | 2.38E-02 | 5.71E-03 |
| Ethyltoluene, 4- | 7.89E-02 | 2.17E-02 | 5.35E-03 |
| Heptane | 6.61E+00 | 1.80E+00 | 4.15E-01 |
| Hexachlorobutadiene | 3.78E-03 | 1.02E-03 | 2.98E-04 |
| Hexane, <i>n</i> - | 7.08E+00 | 1.93E+00 | 4.48E-01 |
| Isopentane | 1.43E+01 | 3.92E+00 | 9.67E-01 |
| Isopropylbenzene | 3.24E-02 | 8.82E-03 | 2.12E-03 |
| Isopropyltoluene, 4- | 1.92E-02 | 5.16E-03 | 1.52E-03 |
| Methane | 6.12E+04 | 1.71E+04 | 4.32E+03 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 1.09E-02 | 2.26E-03 | 7.52E-04 |
| Methylene chloride | 4.85E-01 | 9.69E-02 | 2.75E-02 |
| Naphthalene | 9.58E-03 | 2.66E-03 | 6.79E-04 |
| Nonane, <i>n</i> - | 4.36E+00 | 1.18E+00 | 2.68E-01 |
| Octane, <i>n</i> - | 6.29E+00 | 1.71E+00 | 3.89E-01 |
| Pentane, <i>n</i> - | 1.10E+01 | 2.99E+00 | 7.32E-01 |
| Propylbenzene, <i>n</i> - | 4.00E-02 | 1.11E-02 | 2.75E-03 |
| Propylene | 6.40E-03 | 1.55E-03 | 5.40E-04 |
| Styrene | 3.01E-03 | 8.17E-04 | 1.83E-04 |
| Tetrachloroethene | 4.97E-02 | 1.35E-02 | 3.03E-03 |
| Toluene | 5.59E+00 | 1.52E+00 | 3.49E-01 |
| Trichlorobenzene, 1,2,3- | 7.81E-03 | 2.07E-03 | 6.54E-04 |
| Trichlorobenzene, 1,2,4- | 7.00E-03 | 1.91E-03 | 5.32E-04 |
| Trichlorofluoromethane | 8.70E-04 | 1.74E-04 | 4.98E-05 |
| Trimethylbenzene, 1,2,4- | 2.06E-01 | 5.60E-02 | 1.34E-02 |
| Trimethylbenzene, 1,3,5- | 1.60E-01 | 4.35E-02 | 1.07E-02 |
| Trimethylpentane, 2,2,4- | 1.34E-02 | 3.66E-03 | 9.03E-04 |
| Undecane, <i>n</i> - | 3.20E-02 | 8.93E-03 | 2.26E-03 |
| Vinyl acetate | 1.77E-02 | 4.80E-03 | 1.08E-03 |
| Vinyl bromide | 1.20E-03 | 2.40E-04 | 6.86E-05 |
| Vinyl chloride | 9.90E-04 | 2.00E-04 | 5.48E-05 |
| Xylene, <i>o</i> - | 2.04E-01 | 5.56E-02 | 1.35E-02 |
| Xylenes, <i>m</i> -, <i>p</i> - | 2.69E+00 | 7.31E-01 | 1.69E-01 |

Table 4.3-2. Modeled Impacts—Scenario 2 (Worst-Case Scenario Well Pad)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|--|---------------------------|----------------------------|---------------------------|
| Acenaphthene | 1.08E-04 | 7.13E-05 | 1.43E-05 |
| Acenaphthylene | 4.53E-04 | 2.97E-04 | 6.27E-05 |
| Acetaldehyde | 2.37E+00 | 1.56E+00 | 3.27E-01 |
| Acetone | 2.71E+02 | 5.07E+01 | 1.55E+01 |
| Acrolein | 1.74E+00 | 1.14E+00 | 2.39E-01 |
| Anthracene | 5.08E-05 | 3.29E-05 | 6.86E-06 |
| Benzene | 5.95E+01 | 1.34E+01 | 3.99E+00 |
| Benzo (a) anthracene | 1.82E-05 | 1.18E-05 | 2.14E-06 |
| Benzo (a) pyrene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo (b) fluoranthene | 8.72E-06 | 5.81E-06 | 9.69E-07 |
| Benzo (e) pyrene | 2.04E-05 | 1.36E-05 | 2.91E-06 |
| Benzo (g,h,i) perylene | 1.86E-05 | 1.24E-05 | 2.65E-06 |
| Benzo (k) fluoranthene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Biphenyl | 1.72E-02 | 1.13E-02 | 2.38E-03 |
| Bromomethane | 3.02E-02 | 5.66E-03 | 1.73E-03 |
| Butadiene, 1,3- | 2.24E-01 | 1.29E-01 | 3.40E-02 |
| Butane | 4.00E+03 | 8.60E+02 | 2.38E+02 |
| Butane, <i>n</i> - | 1.02E+00 | 6.73E-01 | 1.41E-01 |
| Butanone , 2- (Methyl Ethyl Ketone) | 2.27E-01 | 5.03E-02 | 1.46E-02 |
| Butylbenzene, <i>sec</i> - | 5.80E-01 | 1.33E-01 | 4.07E-02 |
| Carbon disulfide | 5.70E-02 | 1.36E-02 | 4.27E-03 |
| Carbon tetrachloride | 1.83E-02 | 4.74E-03 | 1.60E-03 |
| Chlorobenzene | 4.94E-03 | 3.25E-03 | 6.82E-04 |
| Chlorodifluoromethane | 1.29E-02 | 2.41E-03 | 7.35E-04 |
| Chloroethane | 4.55E-02 | 8.55E-03 | 2.64E-03 |
| Chloroform | 4.95E-03 | 3.25E-03 | 6.82E-04 |
| Chloromethane | 3.95E-02 | 8.45E-03 | 2.44E-03 |
| Chlorotoluene, 2- | 3.03E-02 | 5.67E-03 | 1.73E-03 |
| Chrysene | 3.86E-05 | 2.46E-05 | 5.36E-06 |
| Cyclohexane | 1.06E+02 | 2.32E+01 | 6.60E+00 |
| Cyclopentane | 4.05E-02 | 2.66E-02 | 5.59E-03 |
| Decane, <i>n</i> - | 1.44E+01 | 3.18E+00 | 9.22E-01 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 1.54E-02 | 2.88E-03 | 8.81E-04 |
| Dichlorodifluoromethane | 1.83E-02 | 3.42E-03 | 1.05E-03 |
| Dichloroethane, 1,1- | 4.95E-03 | 3.25E-03 | 6.82E-04 |
| Dichloropropene, 1,3- | 4.94E-03 | 3.25E-03 | 6.81E-04 |
| Dodecane, <i>n</i> - | 7.04E-01 | 1.33E-01 | 4.40E-02 |
| Ethane | 4.37E+01 | 2.87E+01 | 6.03E+00 |
| Ethylbenzene | 3.55E+00 | 7.58E-01 | 2.23E-01 |
| Ethylene dibromide | 4.91E-03 | 3.23E-03 | 6.77E-04 |
| Ethylene dichloride | 5.34E-03 | 3.51E-03 | 7.36E-04 |
| Ethyltoluene, 4- | 4.16E+00 | 9.46E-01 | 2.87E-01 |
| Fluoranthene | 6.89E-05 | 4.47E-05 | 9.67E-06 |
| Fluorene | 4.27E-04 | 2.81E-04 | 5.88E-05 |

Table 4.3-2. Modeled Impacts—Scenario 2 (Worst-Case Scenario Well Pad) (Continued)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|---|---------------------------|----------------------------|---------------------------|
| Formaldehyde | 2.30E+01 | 1.51E+01 | 3.17E+00 |
| Heptane | 4.70E+02 | 1.08E+02 | 3.30E+01 |
| Hexachlorobutadiene | 7.92E-02 | 1.63E-02 | 5.01E-03 |
| Hexane, <i>n</i> - | 5.71E+02 | 1.31E+02 | 3.99E+01 |
| Indeno (1,2,3- <i>cd</i>) pyrene | 8.85E-07 | 0.00E+00 | 0.00E+00 |
| Isobutane | 8.09E-01 | 5.31E-01 | 1.12E-01 |
| Isobutyraldehyde | 7.59E-02 | 4.99E-02 | 1.05E-02 |
| Isopentane | 1.10E+03 | 2.36E+02 | 6.58E+01 |
| Isopropylbenzene | 9.10E-01 | 2.00E-01 | 5.69E-02 |
| Isopropyltoluene, 4- | 4.26E-01 | 9.02E-02 | 2.68E-02 |
| Methane | 6.13E+05 | 1.34E+05 | 3.82E+04 |
| Methyl alcohol | 1.20E+00 | 7.87E-01 | 1.65E-01 |
| Methyl Naphthalene, 2- | 2.92E-03 | 1.92E-03 | 4.04E-04 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 3.05E-01 | 5.64E-02 | 1.81E-02 |
| Methylcyclohexane | 1.57E-01 | 1.03E-01 | 2.16E-02 |
| Methylene chloride | 1.45E+02 | 2.71E+01 | 8.28E+00 |
| Naphthalene | 1.64E-01 | 3.64E-02 | 1.07E-02 |
| Nonane, <i>n</i> - | 3.18E+02 | 7.45E+01 | 2.33E+01 |
| Octane, <i>n</i> - | 3.78E+02 | 8.75E+01 | 2.73E+01 |
| Pentane, <i>n</i> - | 8.64E+02 | 1.88E+02 | 5.26E+01 |
| Perylene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Phenanthrene | 7.31E-04 | 4.80E-04 | 1.00E-04 |
| Phenol | 5.60E-03 | 3.68E-03 | 7.72E-04 |
| Polycyclic Aromatic Hydrocarbons (PAH) ^a | 7.23E-02 | 4.75E-02 | 9.96E-03 |
| Propane | 1.19E+01 | 7.82E+00 | 1.64E+00 |
| Propylbenzene, <i>n</i> - | 1.49E+00 | 3.33E-01 | 9.85E-02 |
| Propylene | 2.12E-01 | 3.96E-02 | 1.30E-02 |
| Propylene dichloride | 4.95E-03 | 3.25E-03 | 6.82E-04 |
| Pyrene | 8.46E-05 | 5.56E-05 | 1.21E-05 |
| Styrene | 4.28E-02 | 1.12E-02 | 3.75E-03 |
| Tetrachloroethane, 1,1,2,2- | 4.96E-03 | 3.26E-03 | 6.83E-04 |
| Tetrachloroethene | 6.59E-01 | 1.57E-01 | 4.94E-02 |
| Toluene | 2.57E+02 | 5.84E+01 | 1.77E+01 |
| Trichlorobenzene, 1,2,3- | 1.82E-01 | 3.48E-02 | 1.17E-02 |
| Trichlorobenzene, 1,2,4- | 1.39E-01 | 2.98E-02 | 8.56E-03 |
| Trichloroethane, 1,1,2- | 4.93E-03 | 3.24E-03 | 6.80E-04 |
| Trichlorofluoromethane | 2.37E-02 | 4.43E-03 | 1.35E-03 |
| Trimethylbenzene, 1,2,3- | 3.69E-03 | 2.42E-03 | 5.09E-04 |
| Trimethylbenzene, 1,2,4- | 1.39E+01 | 3.12E+00 | 9.31E-01 |
| Trimethylbenzene, 1,3,5- | 7.46E+00 | 1.59E+00 | 4.67E-01 |
| Trimethylpentane, 2,2,4- | 3.05E-01 | 8.17E-02 | 2.87E-02 |
| Undecane, <i>n</i> - | 2.83E+00 | 5.35E-01 | 1.78E-01 |
| Vinyl acetate | 2.53E-01 | 6.04E-02 | 1.90E-02 |
| Vinyl bromide | 3.25E-02 | 6.08E-03 | 1.86E-03 |

Table 4.3-2. Modeled Impacts—Scenario 2 (Worst-Case Scenario Well Pad) (Continued)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|-----------------------|---------------------------|----------------------------|---------------------------|
| Vinyl chloride | 2.69E-02 | 6.16E-03 | 2.09E-03 |
| Xylene, <i>o</i> - | 1.06E+01 | 2.24E+00 | 6.69E-01 |
| Xylenes, <i>m,p</i> - | 1.79E+02 | 4.07E+01 | 1.23E+01 |

^a Concentration in ($\mu\text{g}/\text{m}^3$).

Table 4.3-3. Modeled Impacts—Scenario 3 (Worst-Case Compressor Station)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|--|---------------------------|----------------------------|---------------------------|
| Acenaphthene | 1.62E-04 | 8.88E-05 | 2.06E-05 |
| Acenaphthylene | 6.80E-04 | 3.71E-04 | 8.68E-05 |
| Acetaldehyde | 3.55E+00 | 1.94E+00 | 4.52E-01 |
| Acetone | 7.95E-01 | 1.71E-01 | 4.20E-02 |
| Acrolein | 2.59E+00 | 1.42E+00 | 3.30E-01 |
| Anthracene | 7.55E-05 | 4.12E-05 | 9.60E-06 |
| Benzene | 1.50E+01 | 3.64E+00 | 9.05E-01 |
| Benzo (a) anthracene | 2.78E-05 | 1.50E-05 | 3.21E-06 |
| Benzo (a) pyrene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo (b) fluoranthene | 1.26E-05 | 6.78E-06 | 1.94E-06 |
| Benzo (e) pyrene | 3.10E-05 | 1.65E-05 | 3.88E-06 |
| Benzo (g,h,i) perylene | 2.83E-05 | 1.50E-05 | 3.54E-06 |
| Benzo (k) fluoranthene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Biphenyl | 2.57E-02 | 1.40E-02 | 3.28E-03 |
| Bromomethane | 2.68E-03 | 4.61E-04 | 1.47E-04 |
| Butadiene, 1,3- | 2.84E-01 | 1.55E-01 | 3.65E-02 |
| Butane | 1.49E+02 | 3.59E+01 | 8.80E+00 |
| Butane, <i>n</i> - | 1.53E+00 | 8.33E-01 | 1.94E-01 |
| Butanone, 2- (Methyl Ethyl Ketone) | 2.04E-02 | 4.34E-03 | 1.06E-03 |
| Butylbenzene, <i>sec</i> - | 7.67E-02 | 1.31E-02 | 4.17E-03 |
| Carbon disulfide | 5.59E-03 | 1.36E-03 | 3.34E-04 |
| Carbon tetrachloride | 7.41E-03 | 4.05E-03 | 9.68E-04 |
| Chlorobenzene | 7.38E-03 | 4.03E-03 | 9.41E-04 |
| Chlorodifluoromethane | 1.14E-03 | 1.95E-04 | 6.22E-05 |
| Chloroethane | 4.03E-03 | 7.31E-04 | 2.50E-04 |
| Chloroform | 7.38E-03 | 4.03E-03 | 9.40E-04 |
| Chloromethane | 3.38E-03 | 6.59E-04 | 1.60E-04 |
| Chlorotoluene, 2- | 2.68E-03 | 4.62E-04 | 1.47E-04 |
| Chrysene | 5.68E-05 | 3.11E-05 | 7.50E-06 |
| Cyclohexane | 4.77E+00 | 1.16E+00 | 2.85E-01 |
| Cyclopentane | 6.04E-02 | 3.30E-02 | 7.70E-03 |
| Decane, <i>n</i> - | 2.66E-02 | 5.29E-03 | 1.28E-03 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 1.36E-03 | 2.35E-04 | 7.44E-05 |
| Dichlorodifluoromethane | 1.62E-03 | 2.79E-04 | 8.90E-05 |
| Dichloroethane, 1,1- | 7.38E-03 | 4.03E-03 | 9.39E-04 |
| Dichloropropene, 1,3- | 7.38E-03 | 4.03E-03 | 9.41E-04 |
| Dodecane, <i>n</i> - | 1.52E-02 | 3.35E-03 | 8.22E-04 |
| Ethane | 6.55E+01 | 3.57E+01 | 8.34E+00 |
| Ethylbenzene | 1.78E-01 | 4.34E-02 | 1.11E-02 |
| Ethylene dibromide | 7.30E-03 | 3.99E-03 | 9.31E-04 |
| Ethylene dichloride | 7.97E-03 | 4.35E-03 | 1.02E-03 |
| Ethyltoluene, 4- | 2.07E+00 | 3.56E-01 | 1.13E-01 |
| Fluoranthene | 1.03E-04 | 5.56E-05 | 1.33E-05 |
| Fluorene | 6.38E-04 | 3.49E-04 | 8.09E-05 |

Table 4.3-3. Modeled Impacts—Scenario 3 (Worst-Case Compressor Station) (Continued)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|---|---------------------------|----------------------------|---------------------------|
| Formaldehyde | 3.44E+01 | 1.88E+01 | 4.38E+00 |
| Heptane | 2.88E-01 | 6.75E-02 | 1.66E-02 |
| Hexachlorobutadiene | 6.46E-03 | 1.22E-03 | 3.11E-04 |
| Hexane, <i>n</i> - | 3.14E+00 | 7.65E-01 | 1.95E-01 |
| Indeno (1,2,3-cd) pyrene | 8.85E-07 | 0.00E+00 | 0.00E+00 |
| Isobutane | 1.21E+00 | 6.59E-01 | 1.54E-01 |
| Isobutyraldehyde | 1.13E-01 | 6.19E-02 | 1.44E-02 |
| Isopentane | 3.69E+01 | 8.88E+00 | 2.18E+00 |
| Isopropylbenzene | 3.31E-02 | 6.47E-03 | 1.56E-03 |
| Isopropyltoluene, 4- | 4.01E-02 | 6.84E-03 | 2.18E-03 |
| Methane | 1.03E+06 | 2.49E+05 | 6.10E+04 |
| Methyl alcohol | 1.78E+00 | 9.74E-01 | 2.27E-01 |
| Methyl Naphthalene, 2- | 4.37E-03 | 2.38E-03 | 5.55E-04 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 2.62E-02 | 4.50E-03 | 1.43E-03 |
| Methylcyclohexane | 2.34E-01 | 1.28E-01 | 2.99E-02 |
| Methylene chloride | 3.24E-02 | 1.77E-02 | 4.20E-03 |
| Naphthalene | 1.43E-02 | 7.96E-03 | 1.97E-03 |
| Nonane, <i>n</i> - | 6.56E-02 | 1.42E-02 | 3.90E-03 |
| Octane, <i>n</i> - | 7.36E-02 | 3.44E-02 | 7.78E-03 |
| Pentane, <i>n</i> - | 1.41E+01 | 3.42E+00 | 8.59E-01 |
| Perylene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Phenanthrene | 1.09E-03 | 5.93E-04 | 1.39E-04 |
| Phenol | 8.37E-03 | 4.57E-03 | 1.07E-03 |
| Polycyclic Aromatic Hydrocarbons (PAH) ^a | 1.08E-01 | 5.88E-02 | 1.37E-02 |
| Propane | 1.78E+01 | 9.69E+00 | 2.26E+00 |
| Propylbenzene, <i>n</i> - | 7.69E-01 | 1.32E-01 | 4.19E-02 |
| Propylene | 1.19E-02 | 2.02E-03 | 6.45E-04 |
| Propylene dichloride | 7.38E-03 | 4.03E-03 | 9.39E-04 |
| Pyrene | 1.26E-04 | 6.89E-05 | 1.57E-05 |
| Styrene | 9.83E-03 | 5.37E-03 | 1.26E-03 |
| Tetrachloroethane, 1,1,2,2- | 7.39E-03 | 4.03E-03 | 9.41E-04 |
| Tetrachloroethene | 6.47E-02 | 1.57E-02 | 3.85E-03 |
| Toluene | 1.01E+01 | 2.46E+00 | 6.08E-01 |
| Trichlorobenzene, 1,2,3- | 1.43E-02 | 2.45E-03 | 7.73E-04 |
| Trichlorobenzene, 1,2,4- | 1.19E-02 | 2.33E-03 | 5.63E-04 |
| Trichloroethane, 1,1,2- | 7.39E-03 | 4.03E-03 | 9.42E-04 |
| Trichlorofluoromethane | 2.09E-03 | 3.60E-04 | 1.14E-04 |
| Trimethylbenzene, 1,2,3- | 5.51E-03 | 3.01E-03 | 7.02E-04 |
| Trimethylbenzene, 1,2,4- | 9.13E+00 | 1.57E+00 | 4.99E-01 |
| Trimethylbenzene, 1,3,5- | 2.28E+00 | 3.92E-01 | 1.25E-01 |
| Trimethylpentane, 2,2,4- | 1.39E-01 | 7.56E-02 | 1.78E-02 |
| Undecane, <i>n</i> - | 2.76E-02 | 6.25E-03 | 1.54E-03 |
| Vinyl acetate | 2.48E-02 | 6.04E-03 | 1.48E-03 |

Table 4.3-3. Modeled Impacts—Scenario 3 (Worst-Case Compressor Station) (Continued)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|---------------------------------|---------------------------------|----------------------------------|---------------------------------|
| Vinyl bromide | 2.88E-03 | 4.96E-04 | 1.58E-04 |
| Vinyl Chloride | 7.43E-03 | 4.08E-03 | 9.82E-04 |
| Xylene, <i>o</i> - | 2.00E-01 | 4.81E-02 | 1.32E-02 |
| Xylenes, <i>m</i> -, <i>p</i> - | 1.20E+00 | 2.92E-01 | 7.29E-02 |

^a Concentration in ($\mu\text{g}/\text{m}^3$).

Table 4.3-4. Modeled Impacts—Scenario 4 (Co-located Well Pad and Compressor Station)

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|--|---------------------------|----------------------------|---------------------------|
| Acenaphthene | 1.63E-04 | 8.88E-05 | 2.06E-05 |
| Acenaphthylene | 6.84E-04 | 3.74E-04 | 8.68E-05 |
| Acetaldehyde | 3.58E+00 | 1.96E+00 | 4.54E-01 |
| Acetone | 2.25E+02 | 4.18E+01 | 9.09E+00 |
| Acrolein | 2.62E+00 | 1.43E+00 | 3.32E-01 |
| Anthracene | 7.55E-05 | 4.12E-05 | 9.60E-06 |
| Benzene | 5.84E+01 | 6.36E+00 | 1.90E+00 |
| Benzo (a) anthracene | 2.78E-05 | 1.50E-05 | 3.21E-06 |
| Benzo (a) pyrene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo (b) fluoranthene | 1.26E-05 | 6.78E-06 | 1.94E-06 |
| Benzo (e) pyrene | 3.10E-05 | 1.65E-05 | 3.88E-06 |
| Benzo (g,h,i) perylene | 2.83E-05 | 1.50E-05 | 3.54E-06 |
| Benzo (k) fluoranthene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Biphenyl | 2.60E-02 | 1.42E-02 | 3.29E-03 |
| Bromomethane | 2.39E-02 | 4.44E-03 | 9.73E-04 |
| Butadiene, 1,3- | 2.87E-01 | 1.57E-01 | 3.68E-02 |
| Butane | 3.55E+03 | 5.67E+02 | 1.50E+02 |
| Butane, <i>n</i> - | 1.54E+00 | 8.41E-01 | 1.95E-01 |
| Butanone, 2- (Methyl Ethyl Ketone) | 1.88E-01 | 2.01E-02 | 4.47E-03 |
| Butylbenzene, <i>sec</i> - | 5.75E-01 | 6.31E-02 | 1.59E-02 |
| Carbon disulfide | 6.06E-02 | 6.46E-03 | 1.44E-03 |
| Carbon tetrachloride | 1.45E-02 | 4.98E-03 | 9.87E-04 |
| Chlorobenzene | 7.44E-03 | 4.06E-03 | 9.45E-04 |
| Chlorodifluoromethane | 1.02E-02 | 1.89E-03 | 4.13E-04 |
| Chloroethane | 3.60E-02 | 6.69E-03 | 1.48E-03 |
| Chloroform | 7.44E-03 | 4.07E-03 | 9.44E-04 |
| Chloromethane | 3.43E-02 | 5.70E-03 | 1.49E-03 |
| Chlorotoluene, 2- | 2.40E-02 | 4.45E-03 | 9.75E-04 |
| Chrysene | 5.68E-05 | 3.11E-05 | 7.50E-06 |
| Cyclohexane | 9.77E+01 | 1.30E+01 | 3.70E+00 |
| Cyclopentane | 6.10E-02 | 3.33E-02 | 7.74E-03 |
| Decane, <i>n</i> - | 1.35E+01 | 1.63E+00 | 4.82E-01 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 1.22E-02 | 2.26E-03 | 4.95E-04 |
| Dichlorodifluoromethane | 1.45E-02 | 2.69E-03 | 5.88E-04 |
| Dichloroethane, 1,1- | 7.44E-03 | 4.07E-03 | 9.44E-04 |
| Dichloropropene, 1,3- | 7.45E-03 | 4.07E-03 | 9.45E-04 |
| Dodecane, <i>n</i> - | 5.49E-01 | 1.11E-01 | 2.60E-02 |
| Ethane | 6.60E+01 | 3.61E+01 | 8.38E+00 |
| Ethylbenzene | 3.09E+00 | 5.34E-01 | 1.38E-01 |
| Ethylene dibromide | 7.37E-03 | 4.02E-03 | 9.34E-04 |
| Ethylene dichloride | 8.04E-03 | 4.39E-03 | 1.02E-03 |
| Ethyltoluene, 4- | 4.14E+00 | 4.81E-01 | 1.30E-01 |
| Fluoranthene | 1.04E-04 | 5.68E-05 | 1.33E-05 |
| Fluorene | 6.44E-04 | 3.52E-04 | 8.24E-05 |

**Table 4.3-4. Modeled Impacts—Scenario 4 (Co-located Well Pad and Compressor Station)
(Continued)**

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-hour Average (ppbv) | Max Annual Average (ppbv) |
|---|---------------------------------|----------------------------------|---------------------------------|
| Formaldehyde | 3.47E+01 | 1.89E+01 | 4.40E+00 |
| Heptane, <i>n</i> - | 4.74E+02 | 5.12E+01 | 1.36E+01 |
| Hexachlorobutadiene | 6.51E-02 | 1.18E-02 | 3.00E-03 |
| Hexane | 5.73E+02 | 6.20E+01 | 1.67E+01 |
| Indeno (1,2,3-cd) pyrene | 8.85E-07 | 0.00E+00 | 0.00E+00 |
| Isobutane | 1.22E+00 | 6.65E-01 | 1.55E-01 |
| Isobutyraldehyde | 1.14E-01 | 6.25E-02 | 1.45E-02 |
| Isopentane | 9.72E+02 | 1.57E+02 | 4.15E+01 |
| Isopropylbenzene | 8.42E-01 | 1.12E-01 | 3.18E-02 |
| Isopropyltoluene, 4- | 3.64E-01 | 6.30E-02 | 1.62E-02 |
| Methane | 1.03E+06 | 2.49E+05 | 6.14E+04 |
| Methyl alcohol | 1.80E+00 | 9.83E-01 | 2.28E-01 |
| Methyl Naphthalene, 2- | 4.40E-03 | 2.41E-03 | 5.59E-04 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 2.37E-01 | 4.54E-02 | 1.02E-02 |
| Methylcyclohexane | 2.37E-01 | 1.29E-01 | 3.00E-02 |
| Methylene chloride | 1.20E+02 | 2.23E+01 | 4.85E+00 |
| Naphthalene | 1.47E-01 | 2.18E-02 | 6.28E-03 |
| Nonane, <i>n</i> - | 3.31E+02 | 3.55E+01 | 8.35E+00 |
| Octane, <i>n</i> - | 3.89E+02 | 4.18E+01 | 1.04E+01 |
| Pentane, <i>n</i> - | 7.83E+02 | 1.14E+02 | 3.13E+01 |
| Perylene | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Phenanthrene | 1.10E-03 | 5.99E-04 | 1.39E-04 |
| Phenol | 8.44E-03 | 4.61E-03 | 1.07E-03 |
| Polycyclic Aromatic Hydrocarbons (PAH) ^a | 1.09E-01 | 5.94E-02 | 1.38E-02 |
| Propane | 1.79E+01 | 9.78E+00 | 2.27E+00 |
| Propylbenzene, <i>n</i> - | 1.44E+00 | 1.69E-01 | 5.01E-02 |
| Propylene | 1.70E-01 | 3.37E-02 | 7.78E-03 |
| Propylene dichloride | 7.44E-03 | 4.06E-03 | 9.43E-04 |
| Pyrene | 1.27E-04 | 6.89E-05 | 1.57E-05 |
| Styrene | 4.55E-02 | 7.43E-03 | 1.35E-03 |
| Tetrachloroethane, 1,1,2,2- | 7.45E-03 | 4.07E-03 | 9.45E-04 |
| Tetrachloroethene | 7.01E-01 | 7.48E-02 | 1.66E-02 |
| Toluene | 2.56E+02 | 2.77E+01 | 7.69E+00 |
| Trichlorobenzene, 1,2,3- | 1.37E-01 | 2.81E-02 | 6.83E-03 |
| Trichlorobenzene, 1,2,4- | 1.21E-01 | 2.00E-02 | 5.24E-03 |
| Trichloroethane, 1,1,2- | 7.46E-03 | 4.07E-03 | 9.46E-04 |

**Table 4.3-4. Modeled Impacts—Scenario 4 (Co-located Well Pad and Compressor Station)
(Continued)**

| Pollutant | Max 1-Hour Average (ppbv) | Max 24-Hour Average (ppbv) | Max Annual Average (ppbv) |
|---------------------------------|---------------------------------|----------------------------------|---------------------------------|
| Trichlorofluoromethane | 1.87E-02 | 3.48E-03 | 7.62E-04 |
| Trimethylbenzene, 1,2,3- | 5.56E-03 | 3.04E-03 | 7.06E-04 |
| Trimethylbenzene, 1,2,4- | 1.35E+01 | 1.64E+00 | 5.14E-01 |
| Trimethylbenzene, 1,3,5- | 6.49E+00 | 1.16E+00 | 2.97E-01 |
| Trimethylpentane, 2,2,4- | 3.03E-01 | 8.17E-02 | 1.82E-02 |
| Undecane, <i>n</i> - | 2.19E+00 | 4.47E-01 | 1.05E-01 |
| Vinyl acetate | 2.69E-01 | 2.87E-02 | 6.37E-03 |
| Vinyl bromide | 2.57E-02 | 4.78E-03 | 1.05E-03 |
| Vinyl chloride | 7.46E-03 | 4.07E-03 | 9.47E-04 |
| Xylene, <i>o</i> - | 9.08E+00 | 1.61E+00 | 4.13E-01 |
| Xylenes, <i>m</i> -, <i>p</i> - | 1.78E+02 | 1.93E+01 | 5.41E+00 |

^a Concentration in ($\mu\text{g}/\text{m}^3$).

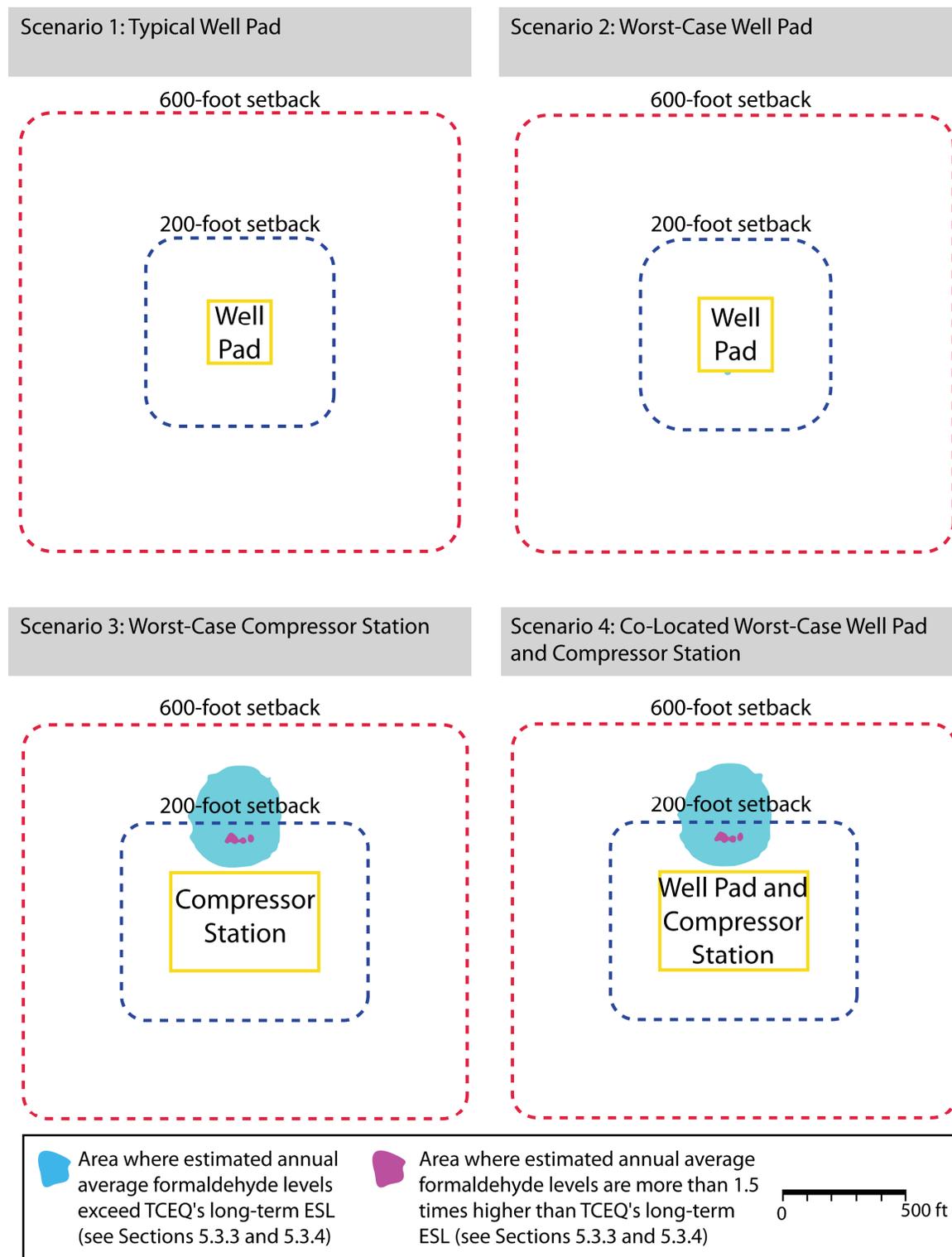


Figure 4.3-1. Formaldehyde Modeling Results for Scenarios 1 - 4

4.4 Electronic Modeling Files

Modeling input and output files are provided electronically in Appendix 4-A. This includes files associated with AERMOD as well as its downwash processing program, BPIP-PRIME, along with meteorological files. AERMOD inputs and outputs follow a specific naming convention: “ScenXX_1988_Pollutant.ext,” where XX is the scenario of interest (01 through 04), *Pollutant* is an abbreviation for the compound modeled, and *ext* is the extension denoting the file type. BPIP-PRIME files follow a similar convention, “ScenXX-Prime.ext.” The various types of files included in Appendix 4-A are described below. Table 4.4-1 contains a crosswalk table which associates the compound abbreviations used in the BEEST modeling package with their proper chemical names.

Model Input Extensions

- **DTA**—AERMOD runstream files
- **PIP**—BPIP-PRIME inputs files
- **SFC**—Surface meteorological data
- **PFL**—Upper Air meteorological data

Model Output Extensions

- **GRF**—AERMOD detailed plot files
- **LST**—AERMOD detailed list files
- **SUM**—AERMOD summary files
- **TAB**—BPIP-PRIME detailed results
- **SO**—BPIP-PRIME block outputs for use in the model runstream

Table 4.4-1. BEEST Pollutant Abbreviation Crosswalk

| Pollutant Abbreviation | Pollutant Name |
|------------------------|---|
| 1122TCE | Tetrachloroethane, 1,1,2,2- |
| 112TCE | Trichloroethane, 1,1,2- |
| 11DCE | Dichloroethane, 1,1- |
| 123TCB | Trichlorobenzene, 1,2,3- |
| 123TMB | Trimethylbenzene, 1,2,3- |
| 124TCB | Trichlorobenzene, 1,2,4- |
| 124TMB | Trimethylbenzene, 1,2,4- |
| 12D1122T | Dichloro-1,1,2,2-tetrafluoroethane, 1,2- |
| 135TMB | Trimethylbenzene, 1,3,5- |
| 13BUTAD | Butadiene, 1,3- |
| 13DICHL | Dichloropropene, 1,3- |
| 224TMP | Trimethylpentane, 2,2,4- |
| 2BN | Butanone, 2- (Methyl Ethyl Ketone) |
| 2CT | Chlorotoluene, 2- |
| 2MN | Methyl Naphthalene, 2- |
| 3CLFMETH | Trichlorofluoromethane |
| 4ET | Ethyltoluene, 4- |
| 4IPT | Isopropyltoluene, 4- |
| 4M2P | Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) |
| ACENAP1 | Acenaphthene |
| ACENAP2 | Acenaphthylene |
| ACETALDE | Acetaldehyde |
| ACETONE | Acetone |
| ACROLEIN | Acrolein |
| ANTHRACE | Anthracene |
| BAA | Benzo (a) anthracene |
| BAP | Benzo (a) pyrene |
| BBFA | Benzo (b) fluoranthene |
| BENZENE | Benzene |
| BEP | Benzo (e) pyrene |
| BGHIP | Benzo (g,h,i) perylene |
| BIPHENYL | Biphenyl |
| BKF | Benzo(k)fluoranthene |
| BRMETH | Bromomethane |
| BUTANE | Butane |
| CCL4 | Carbon tetrachloride |
| CHRYSENE | Chrysene |

Table 4.4-1. BEEST Pollutant Abbreviation Crosswalk (Continued)

| Pollutant Abbreviation | Pollutant Name |
|------------------------|---------------------------------|
| CL2F2MET | Dichlorodifluoromethane |
| CL4ETHEN | Tetrachloroethene |
| CL6BUTA | Hexachlorobutadiene |
| CLBENZ | Chlorobenzene |
| CLDFM | Chlorodifluoromethane |
| CLETH | Chloroethane |
| CLFORM | Chloroform |
| CLMETH | Chloromethane |
| CS2 | Carbon disulfide |
| CYCLOHEX | Cyclohexane |
| CYCLOPEN | Cyclopentane |
| ETHANE | Ethane |
| ETHYLBEN | Ethylbenzene |
| ETHYLBR2 | Ethylene dibromide |
| ETHYLCL | Ethyl chloride |
| FLANTH | Fluoranthene |
| FLUORENE | Fluorene |
| FORMALDE | Formaldehyde |
| HEPTANE | Heptane |
| HEXANE | Hexane, <i>n</i> - |
| IND123PY | Indeno (1,2,3-cd) pyrene |
| ISOBUTAN | Isobutane |
| ISOBUTYR | Isobutyraldehyde |
| ISOPENT | Isopentane |
| ISOPRBEN | Isopropylbenzene |
| METHALC | Methyl alcohol |
| METHANE | Methane |
| METHCL | Methylene chloride |
| METHCYHX | Methylcyclohexane |
| MPXYL | Xylenes, <i>m</i> -, <i>p</i> - |
| NAPTH | Naphthalene |
| NBUT | Butane, <i>n</i> - |
| NDEC | Decane, <i>n</i> - |
| NDODEC | Dodecane, <i>n</i> - |
| NNON | Nonane, <i>n</i> - |
| NOCT | Octane, <i>n</i> - |
| NPENT | Pentane, <i>n</i> - |
| NPROP BEN | Propylbenzene, <i>n</i> - |

Table 4.4-1. BEEST Pollutant Abbreviation Crosswalk (Continued)

| Pollutant Abbreviation | Pollutant Name |
|-------------------------------|--|
| NUNDEC | Undecane, <i>n</i> - |
| OXYL | Xylene, <i>o</i> - |
| PAH | Polycyclic Aromatic Hydrocarbons (PAH) |
| PERYLENE | Perylene |
| PHENAN | Phenanthrene |
| PHENOL | Phenol |
| PROPANE | Propane |
| PROPYCL2 | Propylene dichloride |
| PROPYL | Propylene |
| PYRENE | Pyrene |
| SECBUTYL | Butylbenzene, <i>sec</i> - |
| STYRENE | Styrene |
| TOLUENE | Toluene |
| VINLYBRO | Vinyl bromide |
| VINYLAACE | Vinyl acetate |
| VINYLCCL | Vinyl chloride |

4.5 Air Dispersion Modeling Conclusions

Air dispersion modeling was conducted using the emission estimates developed under Task 3 (Point Source Testing) to estimate how releases from natural gas sites affect off-site air pollution levels. The estimated off-site air pollution impacts are fully analyzed in Section 5 of this report to determine if the city's required setbacks (as published in City Ordinance No. 18449-02-2009) for natural gas exploration and production sites are adequate to protect public health.

5.0 Public Health Evaluation

This section evaluates the ambient air monitoring data and the dispersion modeling results from a public health perspective. The evaluation compares measured and modeled air pollution levels to TCEQ's health-based screening levels. Additional context and more detailed evaluations are presented for the pollutants with estimated or measured air concentrations greater than these screening levels. The monitoring and modeling results are also used to assess the adequacy of the city of Fort Worth's setback distances for sites with natural gas exploration and production activity. Text boxes throughout this section highlight important findings for specific topics. This section has five sub-sections:

- 5.1 Methodology – Describes the approach used to evaluate the air data.
- 5.2 Interpretation of Ambient Air Monitoring Data – Includes a health screening analysis for the measured air pollution levels.
- 5.3 Interpretation of Dispersion Modeling Data – Includes a health screening analysis for the modeled air pollution levels.
- 5.4 Additional Context for Selected Pollutants – Provides further perspective for pollutants selected for further evaluation.
- 5.5 Public Health Evaluation Conclusions – Concisely summarizes the public health evaluation.

5.1 Methodology

The point source testing identified numerous pollutants that natural gas exploration and production activities in Fort Worth release to the air. Once emitted, these pollutants move through the air to downwind locations where residents can be exposed. Air pollution levels at a given time and location in Fort Worth are ultimately influenced by emissions from a wide range of sources, not just releases from natural gas exploration and production activity. Examples of other sources that affect Fort Worth's outdoor air quality include industrial facilities, motor vehicles, and gasoline stations.

Key Point: Screening Methodology

This study presents measured and modeled air pollution levels for more than 150 different pollutants. Health-based screening levels are used to identify which pollutants are most important from a health perspective.

Several factors must be considered when evaluating the public health implications of outdoor air pollution levels. Which pollutants are found in the air and at what concentrations? Over what duration are people exposed? Are the exposed populations uniquely susceptible to the effects of air pollution? Environmental and health agencies use different approaches when evaluating the public health implications of exposure to outdoor air pollution. In cases with thousands of measurements and estimates of outdoor air quality for numerous pollutants, a commonly applied methodology is to use health-based screening levels to determine which subsets of pollutants are of potential health concern.

Health-based screening levels are developed from scientific studies that have examined links between air pollution and health effects. To ensure that screening levels are protective of public health, the agencies that derive these values set them at levels considerably lower than

concentrations found to have been associated with adverse health effects. This means that residents are generally not expected to experience health effects when exposed to air pollution levels that are lower than health-based screening levels—but also that the levels are not thresholds for toxicity. Measured or modeled air pollution levels above a health-based screening level are not necessarily harmful, but they do require a more detailed evaluation to assess public health implications. Broadly speaking, this document uses the health-based screening levels to identify the subset of pollutants that require more thorough health evaluations.

This report primarily relies on screening levels published by TCEQ for evaluating the implications of inhalation exposure to outdoor air pollution, considering both measured and estimated air pollution levels. TCEQ has published two sets of screening levels for use in evaluating outdoor air quality issues:

- *Effects Screening Levels (ESLs)*. For many years, TCEQ has published and updated its ESLs. These values are primarily used in the permitting process, particularly when reviewing dispersion modeling data. TCEQ has developed separate ESLs for short-term and long-term exposure durations, where short-term values are typically used for assessing 1-hour average concentrations and long-term values are typically used for assessing annual average concentrations. Most of TCEQ's ESLs were developed based on health effects, but some were developed to protect vegetation or based on odor detection. The ESLs are not regulatory standards, but are used to interpret potential exposures to air pollution, primarily pollution levels predicted by models.

TCEQ advises that estimated air quality impacts and ESLs should be interpreted as follows: “If predicted airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If predicted ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a review in more depth.” The complete set of ESLs is available at <http://www.tceq.texas.gov/toxicology/esl>.

- *Air Monitoring Comparison Values (AMCVs)*. In addition to ESLs, TCEQ has more recently developed AMCVs, which are pollutant-specific ambient air concentrations that the agency has established to protect human health and welfare. In contrast to ESLs, which are primarily used when evaluating air pollution levels predicted by models, AMCVs are used when conducting health screening evaluations of air monitoring data. The complete set of AMCVs is also available online at <http://www.tceq.texas.gov/toxicology/AirToxics.html#amcv>.

In this section, the modeled and measured air pollution levels are presented alongside the corresponding health-based ESLs and AMCVs. For pollutants with air concentrations above the TCEQ screening levels, additional context is provided in Section 5.4 by presenting screening levels published by ATSDR and EPA. All screening values used in this report were accessed from agency publications in March 2011.

5.2 Interpretation of Ambient Air Monitoring Data

This section presents a health screening analysis for this program's ambient air monitoring data—the air pollution levels that were measured at eight locations in Fort Worth in September and October, 2010. Ambient air monitoring data are particularly useful for health evaluations, because they represent direct measurements of the air pollution levels that residents actually breathe, without introducing the uncertainty of models. These measurements reflect contributions from many different local emission sources. While many pollutants found in the air samples are emitted from natural gas exploration and production activity, not every pollutant is associated with this source. The dispersion modeling analysis (Section 5.3) comments further on incremental air quality impacts attributable specifically to the well pads and compressor stations.

The section first evaluates the sensitivity of the monitoring methods (Section 5.2.1) and then compares the measured concentrations for nearly 150 pollutants to health-based screening levels, for both short-term (Section 5.2.2) and long-term (Section 5.2.3) exposure durations. The purpose of the health screening analysis is to identify the subset of pollutants requiring further evaluation. The section concludes by acknowledging limitations and uncertainties inherent in the screening of the ambient air monitoring data (Section 5.2.4).

5.2.1 Sensitivity of Monitoring Methods

An important consideration when evaluating ambient air monitoring data is whether the measurement methods are capable of detecting air pollution at levels of interest. As Section 2 of this report describes, all ambient air monitoring for this study was conducted with methods developed by EPA and widely used in air toxics monitoring programs nationwide. To assess whether the methods were adequately sensitive to support a health evaluation, this section compares the detection limits achieved in this monitoring program to the pollutants' lowest health-based screening levels published by TCEQ, considering both short-term and long-term values.

Key Point: Measurement Sensitivity

The ambient air monitoring program used highly sensitive measurement methods. For all but two pollutants, the methods were capable of detecting air concentrations at levels below TCEQ's most protective health-based screening values. Therefore, the air pollution measurements were sensitive enough to support health evaluations.

Table 5.2-1 compares the ranges of pollutant detection limits for the two laboratories that analyzed samples to the lowest health-based screening levels published by TCEQ, whether for short-term or long-term exposure durations. The ERG laboratory analyzed all samples collected from Sites S-1 through S-5, and the TestAmerica™ laboratory analyzed all samples collected from Sites S-6 and S-7. When planning this program, ERG's goal was to achieve detection limits lower than health-based screening values for as many pollutants as possible, but particularly for pollutants that had previously been identified as potential concerns for these operations (e.g., benzene, formaldehyde). Shading is used in the table to identify pollutants whose ranges of detection limits were not lower than TCEQ screening levels.

As Table 5.2-1 shows, the ERG laboratory's detection limits were below the TCEQ health-based screening values for every pollutant considered, including for benzene and

formaldehyde. With just two exceptions, TestAmerica's™ detection limits were also below the screening values. For just two pollutants (1,2-dibromoethane and hexachloro-1,3-butadiene), TestAmerica's™ detection limits were higher than the most protective health-based TCEQ screening values, but only by small margins. This is not a significant limitation for the study, because both pollutants are primarily synthetic chemicals that are not typically associated with natural gas reserves. The modeling results presented in Section 5.3 confirm that these pollutants are not found at levels of health concern near natural gas sites in Fort Worth. Overall, the comparisons in Table 5.2-1 demonstrate that the measurement methods used in the ambient air monitoring program achieved adequate sensitivity for comparing measured concentrations to TCEQ's health-based screening levels.

Table 5.2-1. Ranges of Detection Limits, by Laboratory

| Pollutant | Lowest TCEQ Short- or Long-Term Health-Based Screening Level (ppbv) | | Range of Detection Limits (ppbv) ^{a,b} | |
|----------------------------------|---|----------|---|--------------|
| | Value | Type | ERG Laboratory | TestAmerica™ |
| Acetaldehyde | 25 | AMCV/ESL | 0.006–0.009 | NM |
| Acetone | 250 | AMCV/ESL | 0.007–0.011 | 0.05–0.07 |
| Acetylene | 2,500 | AMCV/ESL | 0.025–0.025 | NM |
| Acrylonitrile | 2 | ESL | 0.027–0.027 | NM |
| Allyl chloride | 1 | ESL | NM | 0.06–0.16 |
| Amyl methyl ether, <i>tert</i> - | 65 | ESL | 0.013–0.013 | NM |
| Benzaldehyde | 2 | ESL | 0.002–0.003 | NM |
| Benzene | 1.4 | AMCV/ESL | 0.019–0.019 | 0.05–0.08 |
| Bromochloromethane | 200 | ESL | 0.018–0.018 | NM |
| Bromodichloromethane | 10 | ESL | 0.021–0.021 | 0.06–0.08 |
| Bromoform | 0.5 | ESL | 0.011–0.011 | 0.06–0.13 |
| Bromomethane | 3 | AMCV/ESL | 0.013–0.013 | 0.06–0.11 |
| Butadiene, 1,3- | 4.5 | ESL | 0.01–0.01 | 0.04–0.07 |
| Butane, <i>n</i> - | 800 | AMCV | 0.043–0.043 | 0.05–0.07 |
| Butanol, <i>n</i> - | 20 | ESL | NM | 0.11–0.18 |
| Butene, <i>cis</i> -2- | 15,000 | AMCV | 0.045–0.045 | 0.06–0.11 |
| Butene, <i>trans</i> -2- | 15,000 | AMCV | 0.035–0.035 | 0.06–0.12 |
| Butyraldehyde/isobutyraldehyde | 25 | ESL | 0.002–0.003 | NM |
| Carbon disulfide | 1 | ESL | 0.011–0.011 | NM |
| Carbon tetrachloride | 2 | AMCV/ESL | 0.024–0.024 | 0.06–0.08 |
| Chlorobenzene | 10 | AMCV/ESL | 0.014–0.014 | 0.06–0.08 |
| Chloroethane | 19 | ESL | 0.012–0.012 | 0.04–0.14 |
| Chloroform | 2 | AMCV/ESL | 0.017–0.017 | 0.06–0.14 |
| Chloromethane | 50 | AMCV/ESL | 0.016–0.016 | 0.05–0.12 |
| Chloromethylbenzene | 1 | ESL | 0.017–0.017 | NM |

Table 5.2-1. Ranges of Detection Limits, by Laboratory (Continued)

| Pollutant | Lowest TCEQ Short- or Long-Term Health-Based Screening Level (ppbv) | | Range of Detection Limits (ppbv) ^{a,b} | |
|---------------------------------------|---|----------|---|------------------|
| | Value | Type | ERG Laboratory | TestAmerica™ |
| Chloroprene | 1 | ESL | 0.014–0.014 | NM |
| Crotonaldehyde | 0.3 | AMCV/ESL | 0.002–0.004 | NM |
| Cyclohexane | 100 | AMCV/ESL | 0.032–0.032 | 0.05–0.08 |
| Cyclopentane | 120 | AMCV/ESL | 0.024–0.024 | NM |
| Cyclopentene | 290 | AMCV/ESL | 0.048–0.048 | NM |
| Decane, <i>n</i> - | 175 | AMCV/ESL | 0.023–0.023 | 0.06–0.10 |
| Decene, 1- | 20 | ESL | 0.024–0.024 | NM |
| Dibromochloromethane | 0.2 | ESL | 0.011–0.011 | 0.06–0.08 |
| Dibromoethane, 1,2- | 0.05 | AMCV/ESL | 0.012–0.012 | 0.06–0.12 |
| Dichlorobenzene, <i>m</i> - | 5.4 | ESL | 0.01–0.01 | 0.06–0.08 |
| Dichlorobenzene, <i>o</i> - | 5.4 | ESL | 0.012–0.012 | 0.06–0.12 |
| Dichlorobenzene, <i>p</i> - | 5.4 | ESL | 0.01–0.01 | 0.06–0.13 |
| Dichlorodifluoromethane | 1,000 | AMCV/ESL | 0.012–0.012 | 0.06–0.08 |
| Dichloroethane, 1,1- | 100 | AMCV/ESL | 0.017–0.017 | 0.06–0.13 |
| Dichloroethane, 1,2- | 1 | AMCV/ESL | 0.015–0.015 | 0.06–0.11 |
| Dichloroethylene, 1,1- | 26 | ESL | 0.013–0.013 | 0.07–0.10 |
| Dichloroethylene, <i>cis</i> -1,2- | 200 | ESL | 0.036–0.036 | 0.06–0.08 |
| Dichloroethylene, <i>trans</i> -1,2- | 200 | ESL | 0.014–0.014 | 0.12–0.15 |
| Dichloropropane, 1,2- | 10 | AMCV/ESL | 0.025–0.025 | 0.05–0.08 |
| Dichloropropylene, <i>cis</i> -1,3- | 1 | AMCV/ESL | 0.016–0.016 | 0.05–0.08 |
| Dichloropropylene, <i>trans</i> -1,3- | 1 | AMCV/ESL | 0.015–0.015 | 0.04–0.08 |
| Dichlorotetrafluoroethane | 1,000 | ESL | 0.012–0.012 | 0.06–0.10 |
| Diethylbenzene, <i>m</i> - | 46 | AMCV/ESL | 0.024–0.024 | NM |
| Diethylbenzene, <i>p</i> - | 46 | AMCV/ESL | 0.014–0.014 | NM |
| Dimethylbenzaldehyde, 2,5- | 2 | ESL | 0.001–0.002 | NM |
| Dimethylbutane, 2,2- | 100 | AMCV/ESL | 0.033–0.033 | NM |
| Dimethylbutane, 2,3- | 99 | AMCV | 0.033–0.033 | NM |
| Dimethylpentane, 2,3- | 85 | AMCV/ESL | 0.053–0.053 | NM |
| Dimethylpentane, 2,4- | 85 | AMCV/ESL | 0.033–0.033 | NM |
| Dioxane, 1,4- | 25 | ESL | NM | 0.09–0.19 |
| Dodecane, <i>n</i> - | 50 | ESL | 0.024–0.024 | NM |
| Dodecene, 1- | 10 | ESL | 0.029–0.029 | NM |
| Ethane | 1,000,000 ^c | AMCV/ESL | 0.06–0.06 | 0.06–0.84 |
| Ethyl acrylate | 4 | ESL | 0.011–0.011 | NM |
| Ethyl <i>tert</i> -butyl ether | 5 | ESL | 0.009–0.009 | NM |

Table 5.2-1. Ranges of Detection Limits, by Laboratory (Continued)

| Pollutant | Lowest TCEQ Short- or Long-Term Health-Based Screening Level (ppbv) | | Range of Detection Limits (ppbv) ^{a,b} | |
|---------------------------------|---|----------|---|------------------|
| | Value | Type | ERG Laboratory | TestAmerica™ |
| Ethyl-1-butene, 2- | No screening level | | 0.06–0.06 | NM |
| Ethylbenzene | 135 | ESL | 0.012–0.012 | 0.06–0.12 |
| Ethylene | 30 | ESL | 0.19–0.19 | 0.08–0.16 |
| Ethyltoluene, <i>m</i> - | 25 | AMCV/ESL | 0.017–0.017 | NM |
| Ethyltoluene, <i>o</i> - | 25 | AMCV/ESL | 0.02–0.02 | NM |
| Ethyltoluene, <i>p</i> - | 25 | AMCV/ESL | 0.027–0.027 | 0.05–0.08 |
| Formaldehyde | 2.7 | ESL | 0.004–0.006 | NM |
| Heptane, <i>n</i> - | 85 | AMCV/ESL | 0.026–0.026 | 0.04–0.08 |
| Heptene, 1- | 350 | ESL | 0.053–0.053 | NM |
| Hexachloro-1,3-butadiene | 0.02 | ESL | 0.012–0.012 | 0.06–0.37 |
| Hexanaldehyde | 200 | AMCV/ESL | 0.001–0.002 | NM |
| Hexane, <i>n</i> - | 57 | ESL | 0.04–0.04 | 0.06–0.13 |
| Hexene, 1- | 50 | AMCV/ESL | 0.06–0.06 | NM |
| Hexene, <i>cis</i> -2- | 50 | AMCV/ESL | 0.06–0.06 | NM |
| Hexene, <i>trans</i> -2- | 50 | AMCV/ESL | 0.06–0.06 | NM |
| Isobutane | 800 | AMCV/ESL | 0.0325–0.0325 | 0.06–0.12 |
| Isobutene/1-butene | 800 | ESL | 0.0375–0.0375 | 0.04–0.08 |
| Isopentane | 120 | AMCV/ESL | 0.038–0.038 | NM |
| Isoprene | 2 | AMCV/ESL | 0.048–0.048 | NM |
| Isopropylbenzene | 50 | AMCV/ESL | 0.023–0.023 | 0.11–0.15 |
| Isovaleraldehyde | 50 | AMCV/ESL | 0.002–0.003 | NM |
| Methane | No screening level | | NM | 280–399 |
| Methanol | 200 | ESL | NM | 0.22–0.28 |
| Methyl ethyl ketone | 200 | AMCV | 0.026–0.026 | 0.08–0.15 |
| Methyl isobutyl ketone | 20 | ESL | 0.01–0.01 | 0.05–0.15 |
| Methyl methacrylate | 120 | ESL | 0.02–0.02 | NM |
| Methyl <i>tert</i> -butyl ether | 50 | AMCV/ESL | 0.009–0.009 | 0.11–0.14 |
| Methyl-1-butene, 2- | No screening level | | 0.048–0.048 | NM |
| Methyl-1-butene, 3- | 800 | AMCV/ESL | 0.048–0.048 | NM |
| Methyl-1-pentene, 2- | 30 | ESL | 0.06–0.06 | NM |
| Methyl-1-pentene, 4- | 30 | ESL | 0.06–0.06 | NM |
| Methyl-2-butene, 2- | 50 | AMCV | 0.048–0.048 | NM |
| Methylcyclohexane | 400 | AMCV/ESL | 0.027–0.027 | NM |
| Methylcyclopentane | 75 | AMCV | 0.016–0.016 | NM |
| Methylene chloride | 7.5 | ESL | 0.023–0.023 | 0.06–0.08 |

Table 5.2-1. Ranges of Detection Limits, by Laboratory (Continued)

| Pollutant | Lowest TCEQ Short- or Long-Term Health-Based Screening Level (ppbv) | | Range of Detection Limits (ppbv) ^{a,b} | |
|-----------------------------|---|----------|---|--------------|
| | Value | Type | ERG Laboratory | TestAmerica™ |
| Methylheptane, 2- | 75 | AMCV/ESL | 0.021–0.021 | NM |
| Methylheptane, 3- | 75 | AMCV/ESL | 0.014–0.014 | NM |
| Methylhexane, 2- | 75 | AMCV/ESL | 0.016–0.016 | NM |
| Methylhexane, 3- | 75 | AMCV/ESL | 0.021–0.021 | NM |
| Methylpentane, 2- | 100 | AMCV/ESL | 0.023–0.023 | NM |
| Methylpentane, 3- | 100 | AMCV/ESL | 0.033–0.033 | NM |
| Nonane, <i>n</i> - | 200 | AMCV/ESL | 0.02–0.02 | 0.06–0.11 |
| Nonene, 1- | 100 | ESL | 0.027–0.027 | NM |
| Octane, <i>n</i> - | 75 | AMCV/ESL | 0.012–0.012 | 0.06–0.10 |
| Octene, 1- | 75 | ESL | 0.035–0.035 | NM |
| Pentane, <i>n</i> - | 120 | AMCV/ESL | 0.018–0.018 | 0.06–0.12 |
| Pentene, 1- | 2,600 | AMCV | 0.024–0.024 | NM |
| Pentene, <i>cis</i> -2- | 2,600 | AMCV/ESL | 0.038–0.038 | NM |
| Pentene, <i>trans</i> -2- | 2,600 | AMCV/ESL | 0.028–0.028 | NM |
| Pinene, <i>alpha</i> - | 1 | ESL | 0.024–0.024 | NM |
| Pinene, <i>beta</i> - | 1 | ESL | 0.024–0.024 | NM |
| Propane | 1,000,000 ^c | AMCV/ESL | 0.067–0.067 | 0.06–0.11 |
| Propionaldehyde | 20 | AMCV/ESL | 0.002–0.004 | NM |
| Propylbenzene, <i>n</i> - | 25 | AMCV/ESL | 0.022–0.022 | 0.06–0.16 |
| Propylene | 1,000,000 ^c | AMCV/ESL | 0.028–0.028 | 0.05–0.08 |
| Propyne | 1,000 | ESL | 0.067–0.067 | NM |
| Styrene | 33 | ESL | 0.01–0.01 | 0.06–0.15 |
| Tetrachloroethane, 1,1,2,2- | 1 | AMCV/ESL | 0.011–0.011 | 0.06–0.11 |
| Tetrachloroethylene | 3.8 | AMCV/ESL | 0.011–0.011 | 0.04–0.08 |
| Tolualdehydes | 2 | ESL | 0.003–0.004 | NM |
| Toluene | 330 | ESL | 0.013–0.013 | 0.06–0.08 |
| Trichlorobenzene, 1,2,4- | 5 | ESL | 0.018–0.018 | 0.06–0.46 |
| Trichloroethane, 1,1,1- | 200 | ESL | 0.02–0.02 | 0.06–0.13 |
| Trichloroethane, 1,1,2- | 10 | AMCV/ESL | 0.018–0.018 | 0.06–0.08 |
| Trichloroethylene | 10 | AMCV/ESL | 0.017–0.017 | 0.05–0.08 |
| Trichlorofluoromethane | 500 | ESL | 0.012–0.012 | 0.06–0.08 |
| Trichlorotrifluoroethane | 500 | ESL | 0.014–0.014 | 0.06–0.09 |
| Tridecane, <i>n</i> - | 50 | ESL | 0.022–0.022 | NM |
| Tridecene, 1- | 10 | ESL | 0.022–0.022 | NM |
| Trimethylbenzene, 1,2,3- | 25 | AMCV/ESL | 0.02–0.02 | NM |

Table 5.2-1. Ranges of Detection Limits, by Laboratory (Continued)

| Pollutant | Lowest TCEQ Short- or Long-Term Health-Based Screening Level (ppbv) | | Range of Detection Limits (ppbv) ^{a,b} | |
|--------------------------------|---|----------|---|---------------------------|
| | Value | Type | ERG Laboratory | TestAmerica TM |
| Trimethylbenzene, 1,2,4- | 25 | AMCV/ESL | 0.011–0.027 | 0.05–0.08 |
| Trimethylbenzene, 1,3,5- | 25 | AMCV/ESL | 0.01–0.019 | 0.06–0.18 |
| Trimethylpentane, 2,2,3- | No screening level | | 0.035–0.035 | NM |
| Trimethylpentane, 2,2,4- | 75 | AMCV/ESL | 0.021–0.021 | 0.06–0.08 |
| Trimethylpentane, 2,3,4- | 75 | AMCV | 0.018–0.018 | NM |
| Undecane, <i>n</i> - | 50 | ESL | 0.02–0.02 | NM |
| Undecene, 1- | 20 | ESL | 0.02–0.02 | NM |
| Valeraldehyde | 50 | AMCV/ESL | 0.003–0.004 | NM |
| Vinyl acetate | 4 | ESL | NM | 0.10–0.33 |
| Vinyl chloride | 0.45 | AMCV/ESL | 0.013–0.013 | 0.06–0.12 |
| Xylene, <i>m</i> -, <i>p</i> - | 42 | ESL | 0.014–0.014 | 0.13–0.22 |
| Xylene, <i>o</i> - | 42 | ESL | 0.01–0.01 | 0.06–0.10 |

NM = not monitored.

No screening level = For these pollutants, TCEQ has not published an ESL or an AMCV.

^a The two laboratories that analyzed ambient air samples—ERG and TestAmericaTM—measured different pollutants.

The ERG laboratory measured a greater number of pollutants, primarily because ERG had sole responsibility for measuring the carbonyl and SNMOC samples. For VOCs, TestAmerica'sTM measurements considered the following pollutants that were not measured by ERG: allyl chloride, *n*-butanol, 1,4-dioxane, methanol, and vinyl acetate.

^b In the final two columns, bold font is used to indicate pollutants for which the range of detection limits was not lower than the lowest health-based screening value. Refer to Appendix 5-A for further information on how health-based screening values were selected for this program.

^c For ethane, propane, and propylene, TCEQ has not published specific values for AMCVs or ESLs, but has instead labeled these pollutants as “simple asphyxiants.” The principal concern for asphyxiants at sufficiently high concentrations is that they displace oxygen in the air. A concentration of 0.1% (by volume) is used in this table as a very conservative estimated screening level for these pollutants.

5.2.2 Health Evaluation for Measured 24-Hour Average Concentrations

As described previously, ambient air monitoring occurred for two months at eight locations throughout the city of Fort Worth, and concentrations were measured for nearly 150 pollutants. All measurements were based on 24-hour average samples, and more than 15,000 observations were recorded over the course of the program.

When evaluating the monitoring data, ERG first considered whether the highest measured 24-hour average concentrations exceeded TCEQ's *short-term* health-based screening levels. Throughout the monitoring program in 2010, ERG made these comparisons in order to promptly identify any indications of imminent health hazards, but none occurred. Comparing 24-hour average measurements to *long-term* health-based screening values is scientifically inappropriate and is not done in this report. For every pollutant considered in the ambient monitoring program, Table 5.2-2 lists the highest 24-hour average concentration detected during the program, the location where this value was detected, and the lowest short-term, health-based screening level published by TCEQ. For this evaluation, the hierarchy for selecting screening levels follows: First, if a pollutant has a short-term *health-based* AMCV, that value was used in Table 5.2-1, even if a different ESL is available. The preference for AMCVs over ESLs was applied here because this is an evaluation of ambient air monitoring data, not modeling data. Next, if a pollutant does not have a *health-based* AMCV, the table displays the pollutant's short-term *health-based* ESL. If neither value is available for the pollutant, short-term *odor-based* ESLs are used, if available. The table also indicates which pollutants have no TCEQ screening values. Shading is used in the table to identify pollutants that had at least one measured 24-hour average concentration higher than the TCEQ short-term screening level.

Key Point: Short-Term Air Pollution Measurements

The ambient air monitoring data provide no evidence of 24-hour average concentrations reaching levels of health concern. Out of more than 15,000 air pollution measurements, only one exceeded a TCEQ health-based screening level for short-term exposures; but that one measurement was of questionable quality and was for a pollutant not typically associated with natural gas activity.

Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels

| Pollutant | Highest Measured 24-Hour Average Concentration ^a | | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|----------------------------------|---|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Acetaldehyde | 9.06 | S-4 | 250 | AMCV |
| Acetone | 8.20 | S-7 | 2,500 | AMCV |
| Acetylene | 3.57 | S-4 | 25,000 | AMCV |
| Acrylonitrile | Never detected | | 20 | ESL |
| Allyl chloride | Never detected | | 10 | ESL |
| Amyl methyl ether, <i>tert</i> - | 0.065 | S-2 | 130 ^c | ESL |
| Benzaldehyde | 0.11 | S-4 | 21 | AMCV |
| Benzene | 1.83 | S-4 | 180 | AMCV |
| Bromochloromethane | Never detected | | 2,000 | ESL |
| Bromodichloromethane | 0.075 | S-5 | 100 | ESL |
| Bromoform | Never detected | | 5 | ESL |
| Bromomethane | 0.03 | S-4 | 30 | AMCV |
| Butadiene, 1,3- | 0.30 | S-4 | 1,700 | AMCV |
| Butane, <i>n</i> - | 35.75 | S-4 | 8,000 | AMCV |
| Butanol, <i>n</i> - | Never detected | | 200 | ESL |
| Butene, <i>cis</i> -2- | 3.43 | S-3B | 15,000 | AMCV |
| Butene, <i>trans</i> -2- | 1.24 | S-4 | 15,000 | AMCV |
| Butyraldehyde | 0.66 | S-4 | 2,700 | AMCV |
| Carbon disulfide | 1.64 | S-5 | 10 | ESL |
| Carbon tetrachloride | 0.14 | S-4 | 20 | AMCV |
| Chlorobenzene | 0.026 | S-5 | 100 | AMCV |
| Chloroethane | 0.24 | S-7 | 190 | ESL |
| Chloroform | 0.11 | S-1 | 20 | AMCV |
| Chloromethane | 0.95 | S-4 | 500 | AMCV |
| Chloromethylbenzene | 0.30 | S-5 | 10 | ESL |
| Chloroprene | Never detected | | 10 | ESL |
| Crotonaldehyde | 0.19 | S-4 | 3 | AMCV |
| Cyclohexane | 0.71 | S-4 | 1,000 | AMCV |
| Cyclopentane | 1.20 | S-4 | 1,200 | AMCV |
| Cyclopentene | 0.049 | S-4 | 2,900 | AMCV |
| Decane, <i>n</i> - | 1.44 | S-2 | 1,750 | AMCV |
| Decene, 1- | 0.031 | S-1 | 20 ^c | ESL |
| Dibromochloromethane | 0.017 | S-1 | 2 | ESL |

**Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels
(Continued)**

| Pollutant | Highest Measured 24-Hour Average Concentration ^a | | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|---------------------------------------|---|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Dibromoethane, 1,2- | 0.28 | S-5 | 0.5 | AMCV |
| Dichlorobenzene, <i>m</i> - | 0.55 | S-5 | 120 | ESL |
| Dichlorobenzene, <i>o</i> - | 0.48 | S-5 | 120 | ESL |
| Dichlorobenzene, <i>p</i> - | 0.71 | S-5 | 120 | ESL |
| Dichlorodifluoromethane | 0.67 | S-2 | 10,000 | AMCV |
| Dichloroethane, 1,1- | 0.009 | S-5 | 1,000 | AMCV |
| Dichloroethane, 1,2- | Never detected | | 40 | AMCV |
| Dichloroethylene, 1,1- | 0.007 | S-5 | 180 | AMCV |
| Dichloroethylene, <i>cis</i> -1,2- | Never detected | | 2,000 | ESL |
| Dichloroethylene, <i>trans</i> -1,2- | Never detected | | 2,000 | ESL |
| Dichloropropane, 1,2- | Never detected | | 100 | AMCV |
| Dichloropropylene, <i>cis</i> -1,3- | 0.045 | S-5 | 10 | AMCV |
| Dichloropropylene, <i>trans</i> -1,3- | 0.046 | S-5 | 10 | AMCV |
| Dichlorotetrafluoroethane | 0.026 | S-5 | 10,000 | ESL |
| Diethylbenzene, <i>m</i> - | 0.082 | S-4 | 460 | AMCV |
| Diethylbenzene, <i>p</i> - | 0.10 | S-4 | 460 | AMCV |
| Dimethylbenzaldehyde, 2,5- | Never detected | | 21 | AMCV |
| Dimethylbutane, 2,2- | 0.81 | S-4 | 1,000 | AMCV |
| Dimethylbutane, 2,3- | 2.52 | S-4 | 990 | AMCV |
| Dimethylpentane, 2,3- | 0.73 | S-4 | 850 | AMCV |
| Dimethylpentane, 2,4- | 0.82 | S-4 | 850 | AMCV |
| Dioxane, 1,4- | Never detected | | 250 | ESL |
| Dodecane, <i>n</i> - | 0.33 | S-5 | 500 | ESL |
| Dodecene, 1- | 0.225 | S-4 | 10 ^c | ESL |
| Ethane | 93.2 | S-7 | 1,000,000 ^d | AMCV |
| Ethyl acrylate | Never detected | | 1.3 ^c | ESL |
| Ethyl <i>tert</i> -butyl ether | 0.006 | S-5 | 50 | ESL |
| Ethyl-1-butene, 2- | 0.87 | S-2 | No screening level | |
| Ethylbenzene | 0.94 | S-2 | 20,000 | AMCV |
| Ethylene | 5.40 | S-4 | 500,000 | AMCV |
| Ethyltoluene, <i>m</i> - | 0.30 | S-2 | 250 | AMCV |
| Ethyltoluene, <i>o</i> - | 0.39 | S-2 | 250 | AMCV |
| Ethyltoluene, <i>p</i> - | 0.34 | S-2 | 250 | AMCV |

**Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels
(Continued)**

| Pollutant | Highest Measured 24-Hour Average Concentration ^a | | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|---------------------------------------|---|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Formaldehyde | 4.45 | S-4 | 41 | AMCV |
| Heptane, <i>n</i> - | 0.86 | S-4 | 850 | AMCV |
| Heptene, 1- | 0.77 | S-2 | 4 ^c | ESL |
| Hexachloro-1,3-butadiene ^e | 0.37 | S-6 | 0.2 | ESL |
| Hexanaldehyde | 0.55 | S-4 | 2,000 | AMCV |
| Hexane, <i>n</i> - | 3.48 | S-4 | 1,800 | AMCV |
| Hexene, 1- | 0.15 | S-4 | 500 | AMCV |
| Hexene, <i>cis</i> -2- | 0.26 | S-4 | 500 | AMCV |
| Hexene, <i>trans</i> -2- | 0.35 | S-4 | 500 | AMCV |
| Isobutane | 9.48 | S-4 | 8,000 | AMCV |
| Isobutene/1-butene | 2.29 | S-4 | 50,000 | AMCV |
| Isopentane | 36.4 | S-4 | 1,200 | AMCV |
| Isoprene | 0.50 | S-1 | 20 | AMCV |
| Isopropylbenzene | 0.05 | S-4 | 500 | AMCV |
| Isovaleraldehyde | Never detected | | 500 | AMCV |
| Methane | 9,890 | S-7 | No screening level | |
| Methanol | 19.4 | S-6 | 2,000 | ESL |
| Methyl ethyl ketone | 8.85 | S-4 | 2,000 | AMCV |
| Methyl isobutyl ketone | 0.60 | S-2 | 500 | AMCV |
| Methyl methacrylate | 0.45 | S-1 | 80 ^c | ESL |
| Methyl <i>tert</i> -butyl ether | Never detected | | 500 | AMCV |
| Methyl-1-butene, 2- | 1.66 | S-4 | No screening level | |
| Methyl-1-butene, 3- | 0.046 | S-4 | 8,000 | AMCV |
| Methyl-1-pentene, 2- | 0.26 | S-4 | 500 | AMCV |
| Methyl-1-pentene, 4- | 0.13 | S-4 | 500 | AMCV |
| Methyl-2-butene, 2- | 2.82 | S-4 | 500 | AMCV |
| Methylcyclohexane | 0.82 | S-4 | 4,000 | AMCV |
| Methylcyclopentane | 1.39 | S-4 | 750 | AMCV |
| Methylene chloride | 2.21 | S-2 | 3,500 | AMCV |
| Methylheptane, 2- | 0.30 | S-4 | 750 | AMCV |
| Methylheptane, 3- | 0.24 | S-4 | 750 | AMCV |
| Methylhexane, 2- | 1.79 | S-4 | 750 | AMCV |
| Methylhexane, 3- | 1.24 | S-4 | 750 | AMCV |

Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels (Continued)

| Pollutant | Highest Measured 24-Hour Average Concentration ^a | | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|-----------------------------|---|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Methylpentane, 2- | 6.45 | S-4 | 1,000 | AMCV |
| Methylpentane, 3- | 3.77 | S-4 | 1,000 | AMCV |
| Nonane, <i>n</i> - | 1.28 | S-2 | 2,000 | AMCV |
| Nonene, 1- | 0.25 | S-2 | 6 ^c | ESL |
| Octane, <i>n</i> - | 0.84 | S-2 | 750 | AMCV |
| Octene, 1- | 0.055 | S-5 | 4.4 ^c | ESL |
| Pentane, <i>n</i> - | 15.68 | S-4 | 1,200 | AMCV |
| Pentene, 1- | 0.88 | S-4 | 2,600 | AMCV |
| Pentene, <i>cis</i> -2- | 1.07 | S-4 | 2,600 | AMCV |
| Pentene, <i>trans</i> -2- | 2.10 | S-4 | 2,600 | AMCV |
| Pinene, <i>alpha</i> - | 0.42 | S-3A | 628 | AMCV |
| Pinene, <i>beta</i> - | 0.21 | S-2 | 200 | AMCV |
| Propane | 34.67 | S-4 | 1,000,000 ^d | AMCV |
| Propionaldehyde | 0.38 | S-4 | 200 | AMCV |
| Propylbenzene, <i>n</i> - | 0.22 | S-2 | 250 | AMCV |
| Propylene | 2.38 | S-4 | 1,000,000 ^d | AMCV |
| Propyne | 0.025 | S-2 | 10,000 | ESL |
| Styrene | 0.76 | S-1 | 5,100 | AMCV |
| Tetrachloroethane, 1,1,2,2- | Never detected | | 10 | AMCV |
| Tetrachloroethylene | 0.22 | S-2 | 1,000 | AMCV |
| Tolualdehydes | 0.053 | S-4 | 21 | AMCV |
| Toluene | 12.6 | S-2 | 4,000 | AMCV |
| Trichlorobenzene, 1,2,4- | 0.84 | S-5 | 50 | ESL |
| Trichloroethane, 1,1,1- | 0.46 | S-2 | 1,700 | AMCV |
| Trichloroethane, 1,1,2- | 0.12 | S-5 | 100 | AMCV |
| Trichloroethylene | 0.093 | S-5 | 100 | AMCV |
| Trichlorofluoromethane | 0.33 | S-1 | 10,000 | AMCV |
| Trichlorotrifluoroethane | 0.11 | S-5 | 5,000 | ESL |
| Tridecane, <i>n</i> - | 0.056 | S-4 | 500 | ESL |
| Tridecene, 1- | 0.068 | S-4 | 100 | ESL |
| Trimethylbenzene, 1,2,3- | 0.28 | S-2 | 250 | AMCV |
| Trimethylbenzene, 1,2,4- | 0.73 | S-2 | 250 | AMCV |
| Trimethylbenzene, 1,3,5- | 0.58 | S-2 | 250 | AMCV |

**Table 5.2-2. Highest Measured Concentrations and TCEQ Short-Term Screening Levels
(Continued)**

| Pollutant | Highest Measured 24-Hour Average Concentration ^a | | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|--------------------------------|---|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Trimethylpentane, 2,2,3- | 0.56 | S-4 | No screening level | |
| Trimethylpentane, 2,2,4- | 3.10 | S-4 | 750 | AMCV |
| Trimethylpentane, 2,3,4- | 0.79 | S-4 | 750 | AMCV |
| Undecane, <i>n</i> - | 0.69 | S-5 | 550 | AMCV |
| Undecene, 1- | 0.25 | S-4 | 20 ^c | ESL |
| Valeraldehyde | 0.14 | S-4 | 500 | AMCV |
| Vinyl acetate | 0.36 | S-7 | 40 | ESL |
| Vinyl chloride | 0.052 | S-5 | 26,000 | AMCV |
| Xylene, <i>m</i> -, <i>p</i> - | 3.12 | S-2 | 1,700 | AMCV |
| Xylene, <i>o</i> - | 0.94 | S-2 | 1,700 | AMCV |

^a In the column for highest concentrations, pollutant concentrations less than 1 ppb are rounded to two significant figures, and “never detected” indicates that the pollutant was not detected in any of the samples collected during the ambient air monitoring program.

^b Refer to Section 5.2.2 for a description of the hierarchy used in this table for selecting short-term health-based screening values.

^c For these pollutants, TCEQ has not published short-term *health-based* screening values; the values shown in the table are short-term *odor-based* screening values.

^d For ethane, propane, and propylene, TCEQ has not published specific values for AMCVs or ESLs, but has instead labeled these pollutants as “simple asphyxiants.” The principal concern for asphyxiants at sufficiently high concentrations is that they displace oxygen in the air. A concentration of 0.1% (by volume) is used in this table as a very conservative estimated screening level for these pollutants.

^e Hexachloro-1,3-butadiene is shaded because its highest concentration was higher than TCEQ’s short-term ESL. However, as Section 5.2.2 describes, this particular measurement is of questionable quality.

With one exception, every measurement made during the program was lower than TCEQ's short-term health-based screening levels, suggesting that the pollution levels would not cause adverse health effects among exposed populations. As the exception, a single detection of hexachloro-1,3-butadiene exceeded TCEQ's short-term health-based ESL. For the air sample collected at Site S-6 on October 7, 2010, TestAmerica™ reported a hexachloro-1,3-butadiene concentration of 0.369 ppbv, and TCEQ's ESL is 0.2 ppbv. For further context on this issue, ERG plotted the results of all 129 ambient air monitoring measurements for this pollutant (Figure 5.2-1). The following important observations are made about these measurements:

- The highest detected concentration (0.369 ppbv) exceeded the short-term ESL (0.2 ppbv) by a relatively small margin. This was the only sample with a measured concentration higher than the ESL.
- The highest measurement is of questionable quality. When originally reporting this sample result, TestAmerica™ noted two data quality issues. First, the analytical report indicates that the measured concentration (0.369 ppb) is higher than the method detection limit, but lower than the laboratory's reporting limit. The report further indicated that "...the user of this data should be aware that this data is of limited reliability." Second, the testing laboratory reported that the sample was analyzed after the recommended holding time for this particular monitoring method had passed, which introduces additional uncertainty into the result.
- The 128 other measurements (see Figure 5.2-1), including every measurement at the two monitoring stations near the highest natural gas production activity, were all lower than the ESL; and 125 of these measurements were non-detects.
- For further context, ERG also considered the outputs from the dispersion modeling analysis, including those based on well pads found to have the highest emission rates throughout Fort Worth. The comparison (see Section 5.3.1) showed that the highest outputs predicted by the model were considerably lower than the average concentrations of hexachloro-1,3-butadiene observed during the ambient air monitoring data.

The most logical and consistent explanation for the above observations is that the single hexachloro-1,3-butadiene concentration above TCEQ's ESL is not a reliable measurement.

In summary, for every pollutant considered in this program, ERG concludes that the ambient air monitoring data provide no evidence of 24-hour average concentrations reaching levels of health concern for acute exposures. Few pollutants shown in Table 5.2-2 do not have published short-term health-based screening levels. However, with the exception of methane, these pollutants were detected at relatively low quantities. The measured methane concentrations ranked the highest of all pollutants considered, which was not a surprising result considering that measurements occurred in close proximity to active well pads. Though elevated, these methane concentrations did not approach values that would present a physical hazard (such as the lower explosive limit of 5%, or 50,000,000 ppbv) or an asphyxiation hazard, which are the two safety and health endpoints most frequently evaluated for this pollutant. A recent literature review

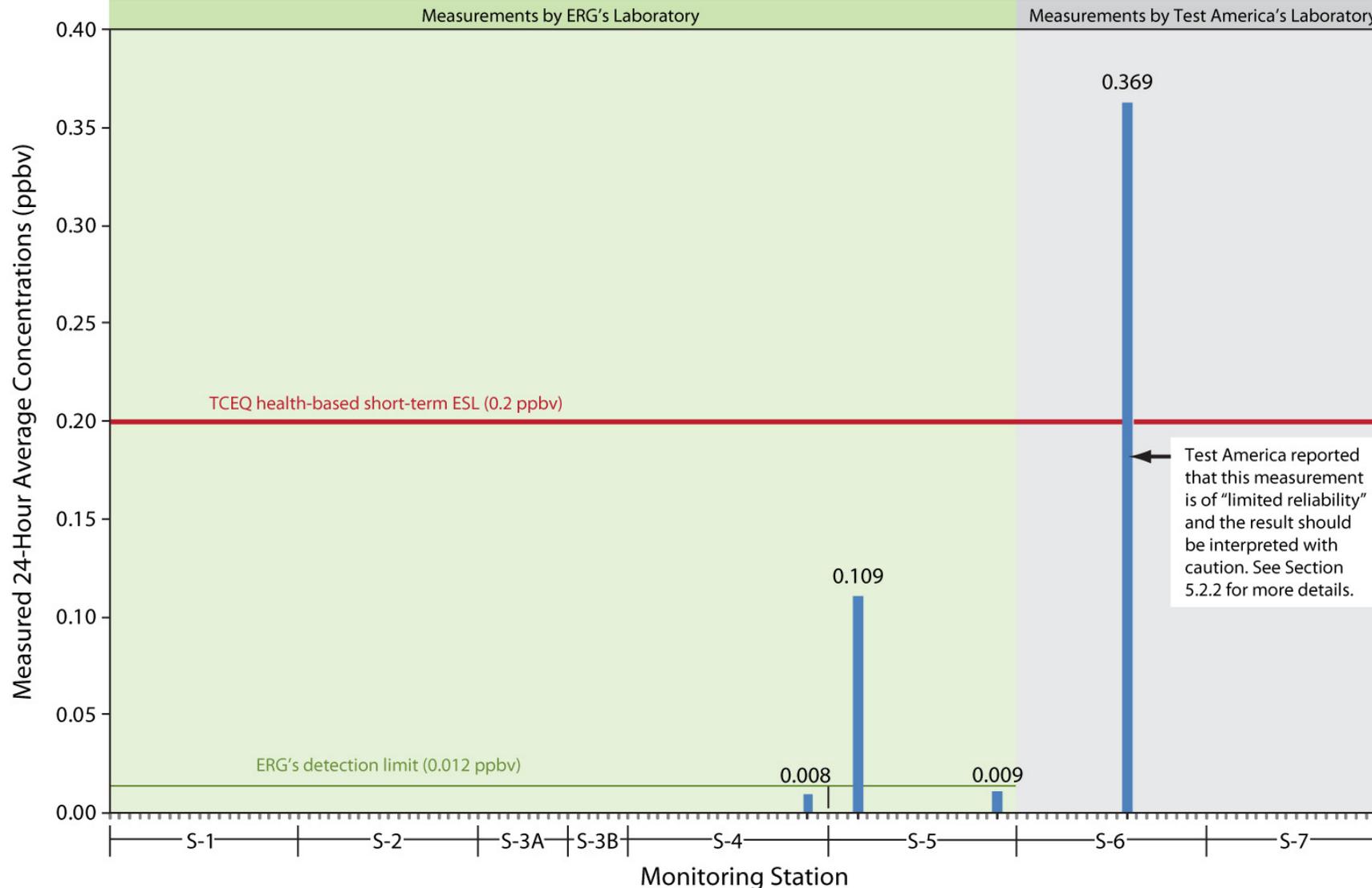


Figure 5.2-1. All Measurements of Hexachloro-1,3-Butadiene during the Ambient Air Monitoring Program

A tick mark is placed along the x-axis for every air sample that was analyzed for hexachloro-1,3-butadiene. The vertical columns display the measurement results for the four samples in which the pollutant was detected; the remaining 125 samples were non-detects. Detection limits are not displayed for the samples analyzed by TestAmerica™, because these values varied from one sample to the next.

documented in conference proceedings concluded that methane exhibits “no systemic toxicity” and supported the approach of assessing methane exposures by focusing on asphyxiation hazards.⁹ Similarly, the Canadian Centre for Occupational Health and Safety has concluded that “harmful effects are not expected following long-term exposure” to methane, though this same finding acknowledges a lack of information about underlying human studies.¹⁰ ERG conducted a supplemental literature search, but found no studies documenting adverse health effects in humans following long-term inhalation exposures to airborne methane.

5.2.3 Health Evaluation for Program-Average Concentrations

During this study, ambient air samples were collected every three days for two months. To assess the implications of longer-term exposures to the measured air pollution levels, ERG calculated average (i.e., arithmetic mean) concentrations for the individual pollutants at the eight different sites. These average concentrations represent two months of potential exposures, and were compared to longer-term health-based screening levels. The following paragraphs discuss this analysis.

When calculating average concentrations from individual sampling results, a decision must be made about how to handle non-detect observations, which are valid observations suggesting that a pollutant’s actual concentration in a sample had a value between zero and the detection limit. An approach commonly used when conducting health screening evaluations is to replace non-detects with a surrogate concentration of one-half the detection limit, and that approach is applied here. In cases where pollutants were detected in a large fraction of a site’s valid air samples, the approach used for replacing non-detects has little bearing on the magnitude of the calculated average concentrations, and the program-averages for the frequently detected pollutants are known to a high degree of confidence. On the other hand, for pollutants rarely detected in the air samples, there is considerable uncertainty associated with calculating the actual average concentrations—an observation revisited later in this section. Nonetheless, for sake of completeness, this analysis presents average concentrations for all pollutants detected in at least one sample.

Key Point: Program-Average Air Pollution Measurements

At the eight monitoring stations considered in this study, program-average concentrations for all but one pollutant were below levels of health concern. As the one exception, the program-average concentration of hexachloro-1,3-butadiene was higher than the TCEQ long-term effects screening level. However, this result is driven by a single unreliable measurement and is therefore of limited significance.

For every pollutant detected in the ambient air monitoring program, ERG compared the highest program-average concentrations to TCEQ’s corresponding long-term health-based screening levels. Table 5.2-3 lists the highest program-average concentration for each pollutant, the location where this value was observed, and the TCEQ screening level. For this evaluation, the hierarchy for selecting screening levels follows: If a pollutant has a long-term health-based AMCV, that value is used in Table 5.2-3 even if a different ESL is available; this preference again reflects the fact that TCEQ specifically derived AMCVs for evaluating ambient air monitoring data. Next, for pollutants that do not have AMCVs, the table displays the long-term health-based ESLs; and when no AMCV or ESL has been published for the pollutant, then “no screening level” appears in the table. Shading is used in the table to identify pollutants that had program-average concentrations higher than the TCEQ long-term screening level.

With one exception, every program-average concentration calculated for the pollutants listed in Table 5.2-3 is lower than the TCEQ long-term health-based screening values. This suggests that longer term exposure to the calculated program-average concentrations would not be expected to cause adverse health effects among exposed populations. The exception is again for hexachloro-1,3-butadiene. The calculated annual average concentration at monitoring site S-6 was 0.13 ppbv, which is higher than TCEQ's long-term ESL (0.02 ppbv). However, this calculated annual average concentration is highly uncertain, because it is driven entirely by a single measurement of questionable quality (see Section 5.2.2 and Figure 5.2-1) with the rest of the measurements at site S-6 being non-detects. ERG does not advise further evaluation of hexachloro-1,3-butadiene, given the extremely limited evidence of it being found in Fort Worth's air. ERG has no expectation of the chemical being found in underground shale formations, given that hexachloro-1,3-butadiene is a synthetic chemical that does not naturally occur in the environment.¹¹

Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels

| Pollutant | Highest Program-Average Concentration ^a | | Lowest TCEQ Long-Term Health-Based Screening Level ^b | |
|----------------------------------|--|--|---|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Acetaldehyde | 3.80 | S-4 | 25 | AMCV |
| Acetone | 4.30 | S-7 | 250 | AMCV |
| Acetylene | 1.02 | S-4 | 2,500 | AMCV |
| Acrylonitrile | Never detected | | 2 | ESL |
| Allyl chloride | Never detected | | 1 | ESL |
| Amyl methyl ether, <i>tert</i> - | 0.0098 ^c | S-2 | 65 | ESL |
| Benzaldehyde | 0.025 | S-4 | 2.1 | AMCV |
| Benzene | 0.69 | S-4 | 1.4 | AMCV |
| Bromochloromethane | Never detected | | 200 | ESL |
| Bromodichloromethane | 0.037 ^c | S-6 | 10 | ESL |
| Bromoform | Never detected | | 0.5 | ESL |
| Bromomethane | 0.045 ^c | S-6 | 3 | AMCV |
| Butadiene, 1,3- | 0.092 | S-4 | 9.1 | AMCV |
| Butane, <i>n</i> - | 11.0 | S-4 | 800 | AMCV |
| Butanol, <i>n</i> - | Never detected | | 20 | ESL |
| Butene, <i>cis</i> -2- | 0.60 | S-3B | No screening level | |
| Butene, <i>trans</i> -2- | 0.38 | S-4 | No screening level | |
| Butyraldehyde | 0.17 | S-4 | 270 | AMCV |
| Carbon disulfide | 0.94 | S-5 | 1 | ESL |
| Carbon tetrachloride | 0.12 | S-1 | 2 | AMCV |
| Chlorobenzene | 0.036 ^c | S-6 | 10 | AMCV |
| Chloroethane | 0.056 | S-7 | 19 | ESL |

**Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels
(Continued)**

| Pollutant | Highest Program-Average Concentration ^a | | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|---------------------------------------|--|--|--|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Chloroform | 0.041 | S-1 | 2 | AMCV |
| Chloromethane | 0.69 | S-4 | 50 | AMCV |
| Chloromethylbenzene | 0.024 ^c | S-5 | 1 | ESL |
| Chloroprene | Never detected | | 1 | ESL |
| Crotonaldehyde | 0.072 | S-4 | 0.3 | AMCV |
| Cyclohexane | 0.29 | S-4 | 100 | AMCV |
| Cyclopentane | 0.45 | S-4 | 120 | AMCV |
| Cyclopentene | 0.056 ^c | S-2 | 290 | AMCV |
| Decane, <i>n</i> - | 0.26 | S-2 | 175 | AMCV |
| Decene, 1- | 0.079 ^c | S-2 | 20 | ESL |
| Dibromochloromethane | 0.0062 ^c | S-5 | 0.2 | ESL |
| Dibromoethane, 1,2- | 0.046 ^c | S-6 | 0.05 | AMCV |
| Dichlorobenzene, <i>m</i> - | 0.037 | S-6 | 5.4 | ESL |
| Dichlorobenzene, <i>o</i> - | 0.045 ^c | S-6 | 5.4 | ESL |
| Dichlorobenzene, <i>p</i> - | 0.061 | S-4 | 5.4 | ESL |
| Dichlorodifluoromethane | 0.60 | S-3B | 1,000 | AMCV |
| Dichloroethane, 1,1- | 0.050 ^c | S-6 | 100 | AMCV |
| Dichloroethane, 1,2- | Never detected | | 1 | AMCV |
| Dichloroethylene, 1,1- | 0.045 ^c | S-6 | 86 | AMCV |
| Dichloroethylene, <i>cis</i> -1,2- | Never detected | | 200 | ESL |
| Dichloroethylene, <i>trans</i> -1,2- | Never detected | | 200 | ESL |
| Dichloropropane, 1,2- | Never detected | | 10 | AMCV |
| Dichloropropylene, <i>cis</i> -1,3- | 0.030 ^c | S-7 | 1 | AMCV |
| Dichloropropylene, <i>trans</i> -1,3- | 0.033 ^c | S-7 | 1 | AMCV |
| Dichlorotetrafluoroethane | 0.041 ^c | S-6 | 1,000 | ESL |
| Diethylbenzene, <i>m</i> - | 0.080 ^c | S-2 | 46 | AMCV |
| Diethylbenzene, <i>p</i> - | 0.061 | S-2 | 46 | AMCV |
| Dimethylbenzaldehyde, 2,5- | Never detected | | 2.1 | AMCV |
| Dimethylbutane, 2,2- | 0.30 | S-4 | 100 | AMCV |
| Dimethylbutane, 2,3- | 0.95 | S-4 | 99 | AMCV |
| Dimethylpentane, 2,3- | 0.34 | S-4 | 85 | AMCV |
| Dimethylpentane, 2,4- | 0.33 | S-4 | 85 | AMCV |
| Dioxane, 1,4- | Never detected | | 25 | ESL |
| Dodecane, <i>n</i> - | 0.048 | S-4 | 50 | ESL |

**Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels
(Continued)**

| Pollutant | Highest Program-Average Concentration ^a | | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|---------------------------------|--|--|--|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Dodecene, 1- | 0.030 | S-4 | 10 | ESL |
| Ethane | 24.0 | S-7 | No screening level | |
| Ethyl acrylate | Never detected | | 4 | ESL |
| Ethyl <i>tert</i> -butyl ether | 0.0046 ^c | S-5 | 5 | ESL |
| Ethyl-1-butene, 2- | 0.14 ^c | S-2 | No screening level | |
| Ethylbenzene | 0.24 | S-2 | 450 | AMCV |
| Ethylene | 1.77 | S-4 | 5,300 | AMCV |
| Ethyltoluene, <i>m</i> - | 0.085 | S-4 | 25 | AMCV |
| Ethyltoluene, <i>o</i> - | 0.083 | S-2 | 25 | AMCV |
| Ethyltoluene, <i>p</i> - | 0.069 | S-2 | 25 | AMCV |
| Formaldehyde | 1.14 | S-4 | 8.9 | AMCV |
| Heptane, <i>n</i> - | 0.30 | S-4 | 85 | AMCV |
| Heptene, 1- | 0.14 ^c | S-2 | 350 | ESL |
| Hexachloro-1,3-butadiene | 0.13 ^{c,d} | S-6 | 0.02 | ESL |
| Hexanaldehyde | 0.11 | S-4 | 200 | AMCV |
| Hexane, <i>n</i> - | 1.31 | S-4 | 190 | AMCV |
| Hexene, 1- | 0.073 | S-4 | 50 | AMCV |
| Hexene, <i>cis</i> -2- | 0.089 ^c | S-2 | 50 | AMCV |
| Hexene, <i>trans</i> -2- | 0.13 | S-4 | 50 | AMCV |
| Isobutane | 2.87 | S-4 | 800 | AMCV |
| Isobutene/1-butene | 0.67 | S-4 | 800 | ESL |
| Isopentane | 13.0 | S-4 | 120 | AMCV |
| Isoprene | 0.27 | S-1 | 2 | AMCV |
| Isopropylbenzene | 0.067 | S-2 | 50 | AMCV |
| Isovaleraldehyde | Never detected | | 50 | AMCV |
| Methane | 5,687 | S-7 | No screening level | |
| Methanol | 6.740 | S-7 | 200 | ESL |
| Methyl ethyl ketone | 1.55 | S-4 | 200 | AMCV |
| Methyl isobutyl ketone | 0.12 | S-2 | 50 | AMCV |
| Methyl methacrylate | 0.046 ^c | S-1 | 120 | ESL |
| Methyl <i>tert</i> -butyl ether | Never detected | | 50 | AMCV |
| Methyl-1-butene, 2- | 0.51 | S-4 | No screening level | |
| Methyl-1-butene, 3- | 0.056 ^c | S-2 | 800 | AMCV |
| Methyl-1-pentene, 2- | 0.090 | S-4 | 50 | AMCV |

**Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels
(Continued)**

| Pollutant | Highest Program-Average Concentration ^a | | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|-----------------------------|--|--|--|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Methyl-1-pentene, 4- | 0.055 | S-4 | 50 | AMCV |
| Methyl-2-butene, 2- | 1.00 | S-4 | 50 | AMCV |
| Methylcyclohexane | 0.31 | S-4 | 400 | AMCV |
| Methylcyclopentane | 0.57 | S-4 | 75 | AMCV |
| Methylene chloride | 0.37 | S-2 | 100 | AMCV |
| Methylheptane, 2- | 0.11 | S-4 | 75 | AMCV |
| Methylheptane, 3- | 0.088 | S-4 | 75 | AMCV |
| Methylhexane, 2- | 0.50 | S-4 | 75 | AMCV |
| Methylhexane, 3- | 0.55 | S-4 | 75 | AMCV |
| Methylpentane, 2- | 2.55 | S-4 | 100 | AMCV |
| Methylpentane, 3- | 1.43 | S-4 | 100 | AMCV |
| Nonane, <i>n</i> - | 0.21 | S-2 | 200 | AMCV |
| Nonene, 1- | 0.045 | S-2 | 100 | ESL |
| Octane, <i>n</i> - | 0.19 | S-2 | 75 | AMCV |
| Octene, 1- | 0.076 ^c | S-1 | 75 | ESL |
| Pentane, <i>n</i> - | 5.50 | S-4 | 120 | AMCV |
| Pentene, 1- | 0.33 | S-4 | No screening level | |
| Pentene, <i>cis</i> -2- | 0.39 | S-4 | No screening level | |
| Pentene, <i>trans</i> -2- | 0.77 | S-4 | No screening level | |
| Pinene, <i>alpha</i> - | 0.11 | S-3A | 63 | AMCV |
| Pinene, <i>beta</i> - | 0.097 ^c | S-2 | 20 | AMCV |
| Propane | 10.7 | S-4 | No screening level | |
| Propionaldehyde | 0.13 | S-4 | 20 | AMCV |
| Propylbenzene, <i>n</i> - | 0.056 ^c | S-6 | 25 | AMCV |
| Propylene | 0.81 | S-4 | No screening level | |
| Propyne | 0.048 ^c | S-2 | 1,000 | ESL |
| Styrene | 0.17 | S-1 | 110 | AMCV |
| Tetrachloroethane, 1,1,2,2- | Never detected | | 1 | AMCV |
| Tetrachloroethylene | 0.061 | S-3B | 3.8 | AMCV |
| Tolualdehydes | 0.0078 ^c | S-4 | 2.1 | AMCV |
| Toluene | 2.31 | S-2 | 1,100 | AMCV |
| Trichlorobenzene, 1,2,4- | 0.14 | S-6 | 5 | ESL |
| Trichloroethane, 1,1,1- | 0.052 | S-2 | 940 | AMCV |
| Trichloroethane, 1,1,2- | 0.035 ^c | S-6 | 10 | AMCV |

**Table 5.2-3. Program-Average Concentrations and TCEQ Long-Term Screening Levels
(Continued)**

| Pollutant | Highest Program-Average Concentration ^a | | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|--------------------------------|--|--|--|-------------------------|
| | Value (ppbv) | Monitoring Site Where Highest Value Occurred | Value (ppbv) | Type of Screening Level |
| Trichloroethylene | 0.033 ^c | S-7 | 10 | AMCV |
| Trichlorofluoromethane | 0.28 | S-1 | 1,000 | AMCV |
| Trichlorotrifluoroethane | 0.053 | S-7 | 500 | ESL |
| Tridecane, <i>n</i> - | 0.12 ^c | S-2 | 50 | ESL |
| Tridecene, 1- | 0.12 ^c | S-2 | 10 | ESL |
| Trimethylbenzene, 1,2,3- | 0.052 | S-4 | 25 | AMCV |
| Trimethylbenzene, 1,2,4- | 0.15 | S-2 | 25 | AMCV |
| Trimethylbenzene, 1,3,5- | 0.11 | S-2 | 25 | AMCV |
| Trimethylpentane, 2,2,3- | 0.18 | S-4 | No screening level | |
| Trimethylpentane, 2,2,4- | 1.14 | S-4 | 75 | AMCV |
| Trimethylpentane, 2,3,4- | 0.28 | S-4 | 75 | AMCV |
| Undecane, <i>n</i> - | 0.12 | S-2 | 55 | AMCV |
| Undecene, 1- | 0.080 ^c | S-2 | 20 | ESL |
| Valeraldehyde | 0.039 | S-4 | 50 | AMCV |
| Vinyl acetate | Never detected | | 4 | ESL |
| Vinyl chloride | 0.046 ^c | S-6 | 0.45 | AMCV |
| Xylene, <i>m</i> -, <i>p</i> - | 0.76 | S-4 | 140 | AMCV |
| Xylene, <i>o</i> - | 0.25 | S-4 | 140 | AMCV |

^a In the column for highest program-average concentrations, pollutant concentrations less than 1 ppb are rounded to two significant figures, and “never detected” indicates that the pollutant was not detected in any of the samples collected during the ambient air monitoring program.

^b Refer to Section 5.2.3 for a description of the hierarchy used in this table for selecting long-term health-based screening values. Several pollutants do not have any long-term screening values.

^c These program-average concentrations are highly uncertain, because the pollutant was detected in fewer than half of the samples at the site with the highest average. The values shown are heavily influenced by the use of surrogate values (one-half the detection limit) for the non-detects.

^d Hexachloro-1,3-butadiene is shaded because its highest concentration was higher than TCEQ’s short-term ESL. However, as Section 5.2.2 describes, this particular measurement is of questionable quality.

5.2.4 Measured Concentrations: Main Findings, Limitations, and Uncertainties

The ambient air monitoring program was designed to provide insights into the nature and magnitude of air pollution levels at eight locations in Fort Worth. The more than 15,000 individual measurements of outdoor air pollution levels allowed for a health evaluation that considered both peak and average air pollution levels. The program found no evidence of air pollution reaching levels of health concern at these eight monitoring locations. However, the ambient air monitoring program has some inherent limitations that should be acknowledged:

Key Point: Air Monitoring Data

Overall, the short-term and long-term air pollution levels measured during the monitoring program did not reach levels of public health concern. However, this finding pertains only to the pollutants considered in this study and the locations where measurements were made.

- The analyses throughout Section 5.2 are based strictly on the air samples that ERG collected at eight locations in Fort Worth over a two-month time frame. The data should not be used to make inferences about air quality during times when, and at locations where, samples were not collected. This does not mean that this study failed to meet its stated goals, because a dispersion modeling analysis was conducted to help characterize potential air pollution levels at locations that were not sampled. Thus, the interpretations of the modeling data (see Section 5.3) help address this inherent limitation of the monitoring program.
- The ambient air monitoring program considered nearly 150 air pollutants, including dozens that were also detected during point source testing. The coverage of the monitoring data is therefore very extensive, but not necessarily comprehensive. This program did not consider the complete range of air pollutants that might be emitted from natural gas sites. For example, the monitoring program did not measure acrolein, which the modeling (see Section 5.3) identified as a pollutant of potential concern for certain sites. Therefore, this study's findings apply only to the pollutants considered in the ambient air monitoring program and point source testing program, and should not be assumed to apply to a broader range of pollutants.

5.3 Interpretation of Dispersion Modeling Data

The dispersion modeling analysis conducted by ERG is an important complement to the ambient air monitoring data presented in Section 5.2. While the ambient air monitoring data has the advantage of directly measuring air pollution levels that residents might breathe, those data do not quantify how much different emission sources contribute to the measured concentrations. Further, the monitoring data do not characterize air quality for the entire range of well pad configurations. Dispersion modeling analysis was used to help fill these gaps. These models have the advantage of quantifying the incremental air quality impacts that can be attributed to natural gas exploration and production activity, based on the measured emission rates from the point source testing program. Section 4 of this report describes in detail the scope of the dispersion

modeling analysis, and the inputs and assumptions used; this section comments on the health implications of the modeling results.

5.3.1 Comparison of Modeled and Measured Air Pollution Levels

Before evaluating health implications, ERG first compared the air concentrations predicted by the model to the air concentrations measured during the monitoring program. This comparison was performed for a subset of pollutants that were considered for both the ambient air monitoring and point source testing programs. Table 5.3-1 presents these results.

Table 5.3-1. Monitor-to-Model Comparisons for Selected Pollutants

| Pollutant | Highest Program-Average Concentration Observed During the Monitoring Program (ppbv) | Highest Offsite Annual Average Concentration Predicted by the Dispersion Model (ppbv)^b |
|--------------------------|--|--|
| Acetaldehyde | 3.80 | 0.45 |
| Benzene | 0.69 | 3.99 |
| Butadiene, 1,3- | 0.092 | 0.037 |
| Carbon tetrachloride | 0.12 | 0.0016 |
| Chloroform | 0.050 | 0.00094 |
| Dibromoethane, 1,2- | 0.026 ^a | 0.00093 |
| Ethylbenzene | 0.24 | 0.22 |
| Formaldehyde | 1.14 | 4.40 |
| Hexachloro-1,3-butadiene | 0.13 ^a | 0.0050 |
| Tetrachloroethylene | 0.061 | 0.049 |
| Trichloroethane, 1,1,2- | 0.035 ^a | 0.00095 |
| Vinyl chloride | 0.046 ^a | 0.0021 |

^a These program-average concentrations are highly uncertain, because the pollutants were detected in fewer than half of the samples at the sites with the highest average concentrations. The values shown are heavily influenced by the surrogate values (one-half the detection limit) used for the non-detects.

^b For purposes of this table, “offsite” refers to any location at or beyond the facility fence lines for the modeling scenarios described in Section 4.

For many pollutants in the table, the highest program-average concentration observed during the monitoring program was considerably higher than the highest offsite annual average concentration predicted by the dispersion model—a trend that was particularly evident for the halogenated hydrocarbons. For purposes of this analysis, “offsite” refers to any location at or beyond the facility fence lines. Considering that the specific modeling results shown in Table 5.3-1 were based on the highest emission rates measured during the point source testing program, the substantially lower modeling results suggest that well pad and compressor stations emissions are not major contributors to the measured concentrations found during the ambient air monitoring program. In other words, even the highest emissions from well pads and compressor stations would not be expected to account for the levels measured in the ambient air for this subset of pollutants. ERG also considered the possibility that the modeling results might be biased low and therefore underestimating air quality impacts; however, this explanation does not appear to be likely, considering the fact that the modeling is based on the highest emission rates observed across all well pads that were tested. For the reasons stated above, ERG concludes that trace levels of halogenated hydrocarbons detected during the ambient air monitoring program cannot be attributed primarily to emissions from the natural gas exploration and production activity.

Conversely, for other pollutants listed in Table 5.3-1, the highest annual average concentration predicted by the modeling analysis was considerably higher than the highest program-average concentration calculated from the air sampling results. For benzene, the modeled concentration was nearly 6 times greater than the highest measured value; for formaldehyde, the measured and modeled values differed by nearly a factor of 4. For these two pollutants, the differences between the measured and modeled results most likely reflect the different scenarios portrayed by these data points. Specifically, the modeled values are estimates of the highest offsite annual average concentrations at the well pad or compressor station with the highest emissions—or the highest concentrations at or beyond the facility fence lines. On the other hand, the measured concentrations were intended to reflect some of the highest site-related air quality impacts; however, the monitoring generally did not occur at fence line locations, and the point source testing revealed that the ambient air monitoring stations were not close to some of the highest-emitting well pads. This discrepancy most likely explains why, for these two pollutants, the modeled concentrations were considerably higher than the measured ones.

5.3.2 Health Evaluation for Modeled 1-Hour Average Concentrations

As Section 4 describes, the dispersion modeling analysis was conducted for four different hypothetical scenarios, including some anticipated to represent the worst-case conditions for offsite air quality impacts. As noted previously, “offsite” in this section refers to any receptor location at or beyond the facility fence lines for the four modeling scenarios. Modeling was conducted for nearly 90 pollutants, depending on the scenario. Potential short-term air quality impacts are assessed here using the highest 1-hour average

Key Point: Short-Term Modeling

A model estimated how emissions from certain well pad and compressor station configurations affect local air quality. Of all pollutants considered, only acrolein, benzene, and formaldehyde had estimated 1-hour average concentrations greater than TCEQ’s short-term ESLs. The model output suggested that estimated methylene chloride concentrations might also exceed health-based screening levels, but this was based on a suspect measurement and is not a robust finding.

concentrations output by the dispersion model for any location at or beyond the fence lines of the modeled well pads and compressor stations. Fence line concentrations were considered for the short-term evaluation, because access restrictions do not prevent residents from walking alongside the production operations at these sites. The modeling estimates are based on the highest emission rates observed during the point source testing, combined with the meteorological conditions anticipated to lead to the least dispersion.

For every pollutant considered in the modeling analysis, Table 5.3-2 compares the highest estimated 1-hour average concentrations to TCEQ's health-based short-term screening levels. For this evaluation, the hierarchy for selecting screening levels follows: First, if a pollutant has a short-term *health-based* ESL, that value was used in Table 5.2-1, even if a different AMCV is available. The preference for ESLs over AMCVs was applied here because this is an evaluation of dispersion modeling data, not ambient air monitoring data. Next, if a pollutant does not have a *health-based* ESL, the table displays the pollutant's short-term *health-based* AMCV. If neither value is available for the pollutant, short-term *odor-based* ESLs are used, if available. The table also indicates which pollutants have no TCEQ screening values. Shading is used in the table to identify pollutants that had at least one estimated 24-hour average concentration higher than the TCEQ short-term screening level.

Table 5.3-2. Modeled 1-Hour Average Concentrations and TCEQ Short-Term Screening Levels

| Pollutant ^a | Highest Estimated 1-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|----------------------------|---|---|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Acenaphthene | 0.00016 | 0.2 | ESL |
| Acenaphthylene | 0.00068 | 0.2 | ESL |
| Acetaldehyde | 3.58 | 250 | AMCV |
| Acetone | 271 | 2,500 | ESL |
| Acrolein | 2.62 | 1.6 | ESL |
| Anthracene | 0.000075 | 0.07 | ESL |
| Benzene | 59.5 | 54 | ESL |
| Benzo (a) anthracene | 0.000028 | 0.05 | ESL |
| Benzo (b) fluoranthene | 0.000013 | 0.05 | ESL |
| Benzo (e) pyrene | 0.000031 | 0.05 | ESL |
| Benzo (g,h,i) perylene | 0.000028 | 0.04 | ESL |
| Biphenyl | 0.026 | 0.4 ^c | ESL |
| Bromomethane | 0.030 | 30 | ESL |
| Butadiene, 1,3- | 0.29 | 1,700 | AMCV |
| Butane, <i>n</i> - | 3,990 | 10,000 | ESL |
| Butylbenzene, <i>sec</i> - | 0.58 | 500 | ESL |
| Carbon disulfide | 0.061 | 10 | ESL |

Table 5.3-2. Modeled 1-Hour Average Concentrations and TCEQ Short-Term Screening Levels (Continued)

| Pollutant ^a | Highest Estimated 1-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|---------------------------|---|---|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Carbon tetrachloride | 0.018 | 20 | ESL |
| Chlorobenzene | 0.0074 | 100 | ESL |
| Chlorodifluoromethane | 0.013 | 5,000 | ESL |
| Chloroethane | 0.045 | 190 | ESL |
| Chloroform | 0.0074 | 20 | ESL |
| Chloromethane | 0.040 | 500 | ESL |
| Chlorotoluene, 2- | 0.030 | 45 ^c | ESL |
| Chrysene | 0.000057 | 0.05 | ESL |
| Cyclohexane | 106 | 1,000 | ESL |
| Cyclopentane | 0.061 | 1,200 | ESL |
| Decane, <i>n</i> - | 14.4 | 1,750 | ESL |
| Dibromoethane, 1,2- | 0.0074 | 0.5 | ESL |
| Dichlorodifluoromethane | 0.018 | 10,000 | ESL |
| Dichloroethane, 1,1- | 0.0074 | 1,000 | ESL |
| Dichloroethane, 1,2- | 0.0080 | 40 | ESL |
| Dichloropropane, 1,2- | 0.0074 | 100 | ESL |
| Dichloropropylene, 1,3- | 0.0074 | 10 | ESL |
| Dichlorotetrafluoroethane | 0.015 | 10,000 | ESL |
| Dodecane, <i>n</i> - | 0.70 | 500 | ESL |
| Ethane | 66.0 | 1,000,000 ^d | ESL |
| Ethylbenzene | 3.55 | 20,000 | AMCV |
| Ethyltoluene, 4- | 4.16 | 250 | ESL |
| Fluoranthene | 0.00010 | 0.06 | ESL |
| Fluorene | 0.00064 | 1 | ESL |
| Formaldehyde | 34.7 | 12 | ESL |
| Heptane, <i>n</i> - | 474 | 850 | ESL |
| Hexachloro-1,3-butadiene | 0.079 | 0.2 | ESL |
| Hexane, <i>n</i> - | 573 | 1,500 | ESL |
| Indeno(1,2,3-cd)pyrene | 0.00000088 | 0.04 | ESL |
| Isobutane | 1.22 | 8,000 | AMCV |
| Isobutyraldehyde | 0.11 | 2,700 | AMCV |
| Isopentane | 1,099 | 1,200 | ESL |
| Isopropylbenzene | 0.91 | 500 | AMCV |
| Isopropyltoluene, 4- | 0.43 | 500 | ESL |

Table 5.3-2. Modeled 1-Hour Average Concentrations and TCEQ Short-Term Screening Levels (Continued)

| Pollutant ^a | Highest Estimated 1-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Lowest TCEQ <i>Short-Term</i> Health-Based Screening Level ^b | |
|-----------------------------|---|---|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Methane | 1,033,000 | No screening level | |
| Methanol | 1.80 | 2,000 | ESL |
| Methyl ethyl ketone | 0.23 | 2,000 | AMCV |
| Methyl naphthalene, 2- | 0.0044 | 5 | ESL |
| Methyl-2-pentanone, 4- | 0.31 | 200 | ESL |
| Methylcyclohexane | 0.24 | 4,000 | AMCV |
| Methylene chloride | 145 | 75 | ESL |
| Naphthalene | 0.16 | 500,000 | AMCV |
| Nonane, <i>n</i> - | 331 | 2,000 | ESL |
| Octane, <i>n</i> - | 389 | 750 | ESL |
| Pentane, <i>n</i> - | 864 | 1,200 | ESL |
| Phenanthrene | 0.0011 | 0.07 | ESL |
| Phenol | 0.0084 | 40 ^c | ESL |
| Propane | 17.9 | 1,000,000 ^d | ESL |
| Propylbenzene, <i>n</i> - | 1.49 | 250 | ESL |
| Propylene | 0.21 | 1,000,000 ^d | ESL |
| Pyrene | 0.00013 | 0.06 | ESL |
| Styrene | 0.046 | 5,100 | AMCV |
| Tetrachloroethane, 1,1,2,2- | 0.0075 | 10 | ESL |
| Tetrachloroethylene | 0.70 | 300 | ESL |
| Toluene | 257 | 4,000 | AMCV |
| Trichlorobenzene, 1,2,3- | 0.18 | 50 | ESL |
| Trichlorobenzene, 1,2,4- | 0.14 | 50 | ESL |
| Trichloroethane, 1,1,2- | 0.0075 | 100 | ESL |
| Trichlorofluoromethane | 0.024 | 5,000 | ESL |
| Trimethylbenzene, 1,2,3- | 0.0056 | 250 | ESL |
| Trimethylbenzene, 1,2,4- | 13.9 | 250 | ESL |
| Trimethylbenzene, 1,3,5- | 7.46 | 250 | ESL |
| Trimethylpentane, 2,2,4- | 0.30 | 750 | ESL |
| Undecane, <i>n</i> - | 2.83 | 500 | ESL |
| Vinyl acetate | 0.27 | 40 | ESL |
| Vinyl bromide | 0.033 | 50 | ESL |

Table 5.3-2. Modeled 1-Hour Average Concentrations and TCEQ Short-Term Screening Levels (Continued)

| Pollutant ^a | Highest Estimated 1-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Lowest TCEQ <i>Short-Term Health-Based Screening Level</i> ^b | |
|------------------------|---|---|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Vinyl chloride | 0.027 | 7,800 | ESL |
| Xylene, <i>m,p</i> - | 179 | 1,700 | AMCV |
| Xylene, <i>o</i> - | 10.6 | 1,700 | AMCV |

^a Acrolein, benzene, formaldehyde, and methylene chloride are shaded because their highest estimated 1-hour average concentrations were higher than TCEQ's short-term ESL. Refer to Section 5.3.2 for further information on these pollutants. Data are presented for all individual pollutants considered in the modeling analysis. As the exception, estimated concentrations are not presented for benzo(a)pyrene, benzo(k)fluoranthene, and perylene. For these pollutants, the estimated concentrations were so low that the model rounded the values to zero.

^b Refer to Section 5.3.2 for a description of the hierarchy used in this table for selecting short-term health-based screening values. AMCVs are used for those pollutants that do not have health-based ESLs.

^c For these pollutants, TCEQ has not published short-term *health-based* screening values; the values shown in the table are short-term *odor-based* screening values.

^d For ethane, propane, and propylene, TCEQ has not published specific values for AMCVs or ESLs, but has instead labeled these pollutants as "simple asphyxiants." The principal concern for asphyxiants at sufficiently high concentrations is that they displace oxygen in the air. A concentration of 0.1% (by volume) is used in this table as a very conservative estimated screening level for these pollutants.

The highest offsite air quality impacts were found for Scenarios 2, 3, and 4 in the modeling analysis. For pollutants emitted primarily by tanks, modeling Scenario 2 yielded the highest offsite 1-hour average concentration, primarily because this scenario had tanks placed along the northern fence line and southerly winds (i.e., winds blowing from south to north) prevail in Fort Worth. On the other hand, for pollutants released largely by engines, Scenarios 3 and 4 predicted the highest offsite air quality impacts, because these scenarios considered the largest engines.

As Table 5.3-2 shows, four pollutants considered in the modeling analysis had at least one estimated 1-hour average concentrations greater than lowest short-term health-based TCEQ screening levels. When reviewing these results, it is important to remember that the model estimates are based on the least favorable meteorological conditions for dispersion and for the highest-emitting well pads and compressor stations. Modeling Scenario 1, which was based on typical well pad emissions, had considerably lower estimated air quality impacts—and no 1-hour average concentrations greater than short-term screening levels.

ERG further examined the underlying modeling outputs and screening levels, and notes the following important observations:

- *Benzene.* ERG modeled air quality impacts of benzene at hundreds of offsite locations, commonly referred to as receptors. In Scenarios 1 and 3, every estimated 1-hour average concentration at every receptor was below TCEQ's short-term ESL. In Scenarios 2 and 4, only a single receptor—out of the hundreds modeled—had at least one estimated 1-hour average concentration greater than the ESL, and this occurred at just one receptor located at the fence line within a few feet of the tanks themselves. Receptors just 30 feet downwind showed no concentrations above the ESL. Further, at this one receptor, estimated 1-hour average benzene concentrations above the ESL occurred no more than 6 hours per year, and these values (54–59.5 ppbv) were only marginally above the health-protective ESL (54 ppbv). Recalling that these estimates are based on the highest emission rates measured in the point source testing program, the available modeling data suggest that only the single well pad found to have the highest benzene emissions would likely lead to offsite concentrations above the short-term ESL, and this would occur infrequently and only within a few feet of the highest-emitting tanks. ERG's main recommendation for benzene (see Section 5.5) is that city officials periodically review TCEQ's "auto-GC" sampling data for sites throughout the Barnett Shale formation, and evaluate whether any benzene concentrations ever exceed short-term screening levels. Should this occur, city officials should confer with TCEQ about proper interpretation of the monitoring data and the health implications for the particular monitoring site and for unmonitored locations.
- *Acrolein and formaldehyde.* These two pollutants are combustion by-products emitted by engines at the well pads and compressor stations. The magnitude of emissions—and offsite air quality impacts—depends on the type of engines used. Modeling Scenario 2 considered the smaller "lift engines," which typically fall between 150 and

250 hp. For this scenario, highest 1-hour average concentrations of acrolein and formaldehyde exceeded TCEQ's short-term ESL, but this only occurred at fence line locations for acrolein and at receptors within 100 feet of fence lines for formaldehyde. On the other hand, Scenarios 3 and 4 considered the larger "line engines," which operate at roughly 1,500 hp. For these scenarios, 1-hour average concentrations of acrolein greater than TCEQ's short-term ESL extended approximately 400 feet from the fence lines, and 1-hour average concentrations of formaldehyde greater than TCEQ's ESL were estimated to occur up to 750 feet beyond the fence lines. In the case of formaldehyde, the highest offsite 1-hour average concentration was estimated to be nearly 3 times higher than TCEQ's short-term ESL. Section 5.4 presents further information on the health implications of the estimated concentrations for these pollutants.

- *Methylene chloride.* As Table 5.3-2 shows, the highest estimated 1-hour average concentration of methylene chloride (145 ppbv) is higher than TCEQ's short-term ESL (75 ppbv). However, the modeling output for methylene chloride is based on an emissions measurement of suspect quality. Specifically, the emission rate used in the modeling analysis is based on a sample (#B015) collected on September 20, 2010, at a well pad (Site #PS-075). However, the analytical report for this sample includes two qualifiers. First, the laboratory reported a "B" qualifier, which indicates that methylene chloride was also detected in the method blank, raising questions about contamination of the sampling equipment. Second, the laboratory reported a "J" qualifier, which means the measured concentration was higher than the MDL but lower than the laboratory's reporting limit; the analytical report further states that "...the user of [J-qualified] data should be aware that this data is of limited reliability." For these reasons, ERG concludes that the highest estimated methylene chloride concentration shown in Table 5.3-2 is of questionable quality. If this one sample were omitted from the emissions estimation analysis, the next highest 1-hour average concentrations of methylene chloride predicted by the model would be substantially lower than TCEQ's short-term ESL. Accordingly, ERG does not recommend further evaluation of this pollutant.

Overall, the highest estimated 1-hour average concentrations predicted by the dispersion model are below TCEQ's health-based short-term screening levels for nearly every pollutant considered. For reasons stated above, ERG concludes that further evaluation is warranted for the air quality impacts of acrolein and formaldehyde, which had 1-hour concentrations above screening levels beyond the fence line of any site with operating lift engines or line engines. Section 5.4 provides further insights on these two pollutants.

5.3.3 Health Evaluation for Modeled Annual Average Concentrations

ERG assessed potential long-term exposures to site-related pollutants by evaluating the highest annual average concentrations output by the dispersion model. This comparison considered all locations more than 200 feet from fence lines of well pads and compressor stations. This downwind distance was selected because, although most gas well must be at least 600 feet from residences, city variances allow setback distances as low as 200 feet. The comparisons presented here represent a worst-case scenario: a full-time resident living just 200 feet from the highest-emitting well pads and compressor stations.

Key Point: Long-Term Modeling

A model was used to estimate annual average air quality impacts caused by emissions from well pads and compressor stations. Of all pollutants considered, only acrolein and formaldehyde had estimated annual average concentrations at locations at least 200 feet from fence lines greater than TCEQ screening levels. These air quality impacts are greatest for well pads and compressor stations with large line engines.

For every pollutant considered in the modeling analysis, Table 5.3-3 compares the highest estimated annual average concentrations to TCEQ's health-based, long-term screening levels. For this evaluation, the hierarchy for selecting screening levels follows: If a pollutant has a long-term health-based ESL, that value is used in Table 5.3-3, even if a different AMCV is available for the pollutant. This preference again reflects the fact that TCEQ specifically derived ESLs for evaluating dispersion modeling data, whereas AMCVs are the screening levels of choice when assessing ambient air monitoring data. The few pollutants that do not have long-term ESLs do not have any TCEQ health-based screening values, as indicated in the table. Shading is used in the table to identify pollutants that had at least one estimated annual average concentration at distances more than 200 feet from the fence lines higher than the TCEQ long-term screening level.

As Table 5.3-3 shows, only two pollutants considered in the modeling analysis—acrolein and formaldehyde—had estimated annual average concentrations greater than TCEQ's health-based, long-term ESLs. Across all pollutants, the highest annual average concentrations reported in the table were all observed for modeling Scenarios 2, 3, or 4. In contrast, Scenario 1, which was based on typical well pad emissions, had considerably lower estimated air quality impacts—and no annual average concentrations greater than long-term screening levels at any locations beyond the fence lines. Further information follows for the two pollutants with estimated annual average concentrations greater than screening levels:

- *Acrolein*. The highest annual average concentration of acrolein at locations at least 200 feet from fence lines predicted by the model (0.33 ppbv) was higher than TCEQ's health-based, long-term ESL (0.066 ppbv). However, considering receptors at least 200 feet from fence lines, only Scenarios 3 and 4 had at least one estimated annual average concentration of acrolein greater than TCEQ's ESL. This suggests that emissions from the larger line engines account for the only instances where estimated acrolein levels exceeded TCEQ's long-term ESL.

Table 5.3-3. Modeled Annual Average Concentrations and TCEQ Long-Term Screening Levels

| Pollutant ^a | Highest Estimated Annual Average Concentration at Locations 200 Feet Beyond Fence Lines (ppbv) | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|-------------------------|--|--|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Acenaphthene | 0.000021 | 0.02 | ESL |
| Acenaphthylene | 0.000085 | 0.02 | ESL |
| Acetaldehyde | 0.45 | 25 | ESL |
| Acetone | 0.75 | 250 | ESL |
| Acrolein | 0.33 | 0.066 | ESL |
| Anthracene | 0.0000096 | 0.007 | ESL |
| Benzene | 0.24 | 1.4 | ESL |
| Benzo (a) anthracene | 0.0000032 | 0.005 | ESL |
| Benzo (b) fluoranthene | 0.0000019 | 0.005 | ESL |
| Benzo (e) pyrene | 0.0000039 | 0.005 | ESL |
| Benzo (g,h,i) perylene | 0.0000035 | 0.004 | ESL |
| Biphenyl | 0.0033 | 0.2 | ESL |
| Bromomethane | 0.000082 | 3 | ESL |
| Butadiene, 1,3- | 0.036 | 4.5 | ESL |
| Butane, <i>n</i> - | 16.2 | 1,000 | ESL |
| Butylbenzene, sec- | 0.0022 | 50 | ESL |
| Carbon disulfide | 0.00021 | 1 | ESL |
| Carbon tetrachloride | 0.00096 | 2 | ESL |
| Chlorobenzene | 0.00093 | 10 | ESL |
| Chlorodifluoromethane | 0.000037 | 500 | ESL |
| Chloroethane | 0.00014 | 19 | ESL |
| Chloroform | 0.00093 | 2 | ESL |
| Chloromethane | 0.00016 | 50 | ESL |
| Chlorotoluene, 2- | 0.000083 | 60 | ESL |
| Chrysene | 0.0000075 | 0.005 | ESL |
| Cyclohexane | 0.42 | 100 | ESL |
| Cyclopentane | 0.0076 | 120 | ESL |
| Decane, <i>n</i> - | 0.057 | 175 | ESL |
| Dibromoethane, 1,2- | 0.00092 | 0.05 | ESL |
| Dichlorodifluoromethane | 0.000051 | 1,000 | ESL |
| Dichloroethane, 1,1- | 0.00093 | 100 | ESL |
| Dichloroethane, 1,2- | 0.0010 | 1 | ESL |
| Dichloropropane, 1,2- | 0.00093 | 10 | ESL |

Table 5.3-3. Modeled Annual Average Concentrations and TCEQ Long-Term Screening Levels (Continued)

| Pollutant ^a | Highest Estimated Annual Average Concentration at Locations 200 Feet Beyond Fence Lines (ppbv) | Lowest TCEQ Long-Term Health-Based Screening Level ^b | |
|---------------------------|--|---|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Dichloropropylene, 1,3- | 0.00093 | 1 | ESL |
| Dichlorotetrafluoroethane | 0.000043 | 1,000 | ESL |
| Dodecane, <i>n</i> - | 0.0025 | 50 | ESL |
| Ethane | 8.28 | No screening level | |
| Ethylbenzene | 0.015 | 135 | ESL |
| Ethyltoluene, 4- | 0.027 | 25 | ESL |
| Fluoranthene | 0.000013 | 0.006 | ESL |
| Fluorene | 0.000081 | 0.1 | ESL |
| Formaldehyde | 4.34 | 2.7 | ESL |
| Heptane, <i>n</i> - | 1.79 | 85 | ESL |
| Hexachloro-1,3-butadiene | 0.00032 | 0.02 | ESL |
| Hexane, <i>n</i> - | 2.19 | 57 | ESL |
| Isobutane | 0.15 | 800 | ESL |
| Isobutyraldehyde | 0.014 | 25 | ESL |
| Isopentane | 4.47 | 120 | ESL |
| Isopropylbenzene | 0.0036 | 50 | ESL |
| Isopropyltoluene, 4- | 0.0017 | 50 | ESL |
| Methane | 3,660 | No screening level | |
| Methanol | 0.23 | 200 | ESL |
| Methyl ethyl ketone | 0.00090 | 900 | ESL |
| Methyl naphthalene, 2- | 0.00055 | 0.5 | ESL |
| Methyl-2-pentanone, 4- | 0.00094 | 20 | ESL |
| Methylcyclohexane | 0.030 | 400 | ESL |
| Methylene chloride | 0.40 | 7.5 | ESL |
| Naphthalene | 0.0021 | 10 | ESL |
| Nonane, <i>n</i> - | 1.19 | 200 | ESL |
| Octane, <i>n</i> - | 1.43 | 75 | ESL |
| Pentane, <i>n</i> - | 3.48 | 120 | ESL |
| Phenanthrene | 0.00014 | 0.007 | ESL |
| Phenol | 0.0011 | 5 | ESL |
| Propane | 2.24 | No screening level | |
| Propylbenzene, <i>n</i> - | 0.0099 | 25 | ESL |
| Propylene | 0.00073 | No screening level | |
| Pyrene | 0.000016 | 0.006 | ESL |

Table 5.3-3. Modeled Annual Average Concentrations and TCEQ Long-Term Screening Levels (Continued)

| Pollutant ^a | Highest Estimated Annual Average Concentration at Locations 200 Feet Beyond Fence Lines (ppbv) | Lowest TCEQ <i>Long-Term</i> Health-Based Screening Level ^b | |
|-----------------------------|--|--|-------------------------|
| | | Value (ppbv) | Type of Screening Level |
| Styrene | 0.0013 | 33 | ESL |
| Tetrachloroethane, 1,1,2,2- | 0.00093 | 1 | ESL |
| Tetrachloroethylene | 0.0024 | 3.8 | ESL |
| Toluene | 0.99 | 330 | ESL |
| Trichlorobenzene, 1,2,3- | 0.00072 | 5 | ESL |
| Trichlorobenzene, 1,2,4- | 0.00057 | 5 | ESL |
| Trichloroethane, 1,1,2- | 0.00093 | 10 | ESL |
| Trichlorofluoromethane | 0.000066 | 500 | ESL |
| Trimethylbenzene, 1,2,3- | 0.00070 | 25 | ESL |
| Trimethylbenzene, 1,2,4- | 0.12 | 25 | ESL |
| Trimethylbenzene, 1,3,5- | 0.034 | 25 | ESL |
| Trimethylpentane, 2,2,4- | 0.018 | 75 | ESL |
| Undecane, <i>n</i> - | 0.010 | 50 | ESL |
| Vinyl acetate | 0.00094 | 4 | ESL |
| Vinyl bromide | 0.000089 | 5 | ESL |
| Vinyl chloride | 0.00095 | 0.45 | ESL |
| Xylene, <i>m,p</i> - | 0.69 | 42 | ESL |
| Xylene, <i>o</i> - | 0.044 | 42 | ESL |

^a Acrolein and formaldehyde are shaded because their highest estimated annual average concentrations were higher than TCEQ's long-term ESL. Refer to Sections 5.2.3 and 5.2.4 for further information on these pollutants. Data are presented for all individual pollutants considered in the modeling analysis. As the exception, estimated concentrations are not presented for benzo(a)pyrene, benzo(k)fluoranthene, and perylene. For these pollutants, the estimated concentrations were so low that the model rounded the values to zero.

^b Refer to Section 5.2.3 for a description of the hierarchy used in this table for selecting long-term health-based screening values. Several pollutants do not have any long-term screening values.

- *Formaldehyde.* The highest annual average concentration of formaldehyde predicted by the modeling analysis beyond 200 feet from a fence line was 4.34 ppbv—higher than TCEQ’s health-based, long-term ESL (2.7 ppbv). Estimated annual average concentrations greater than the long-term ESL were observed for Scenarios 3 and 4, but not at distances more than 600 feet from the fence lines.

In summary, for receptors at least 200 feet from fence lines, the highest estimated annual average concentrations predicted by the dispersion model are below TCEQ’s health-based long-term ESL for every pollutant and modeling scenario considered, except for acrolein and formaldehyde in Scenarios 3 and 4. This indicated that air emissions from line engines account for the highest estimated air quality impacts. Because this study relied upon estimated emission rates for these engines, consideration should be given to gathering additional information (e.g., measured emission rates from compressor engines, ambient air monitoring data downwind from the highest-emitting sites) to gain greater confidence in the conclusions for these pollutants. Sections 5.4 and 5.5 provide further insights on this issue.

5.3.4 Adequacy of Setback Limits

Taken together, monitoring and modeling data provide a basis for assessing the adequacy of the city of Fort Worth’s setback distances. The minimum setback distance required is 600 feet, though variances can lead to setbacks as low as 200 feet. The critical issue in evaluating setback distances is the extent to which air quality impacts decrease with distance from the facilities.

For some emission sources at well pads, particularly the tanks and fugitive emissions, estimated offsite air quality impacts peak at the fence line and decrease considerably with downwind distance. For instance, in Scenario 2, the highest annual average concentration of benzene at the fence line was 3.99 ppbv; the highest value at distances 200 feet from the fence line was 0.24 ppbv, falling to 0.04 ppbv at the 600-foot setback distance. Therefore, for this scenario, the annual average concentration decreased by 99% from the fence line to the setback distance. For pollutants emitted primarily or entirely by line engines and lift engines, the concentration gradient was notably less pronounced. In the case of acrolein for Scenario 4, for example, the maximum annual average concentration at the 600-foot setback distance was only 55% lower than the maximum offsite value.

Key Point: Setback Distances

For nearly every pollutant considered, the 600-foot setback distance appears to be adequately protective of public health, even for the highest-emitting sites. However, for sites with large line engines: (1) estimated annual average concentrations of acrolein are higher than TCEQ’s long-term ESLs at distances more than 600 feet from the fence line, and (2) for formaldehyde, estimated 1-hour average concentrations are higher than TCEQ’s short-term ESLs at some locations beyond the setback distance. Section 5.4 provides further context on these two pollutants.

To assess the setback distances, ERG focused on estimated air quality impacts at receptors 600 feet from fence lines, and additional insight is provided on distances as short as 200 feet, given the variances that can apply. A given well pad or compressor station’s air quality impacts depend on the nature and extent of the site’s emissions sources—the number and placement of tanks; the number, type, and size of engines; and so on. ERG’s assessment of the

setback distances is framed around the modeling results for the four scenarios defined in Section 4. For every scenario considered, Figures 5.3-1 through 5.3-3 illustrate how estimated annual average concentrations varied with location for acrolein, benzene, and formaldehyde. These pollutants were selected for the displays because they are the only site-related pollutants that had at least one offsite modeling result greater than a screening value.

ERG's assessment of the adequacy of the setback distances follows:

- *Well pads with tanks and fugitive emissions, but no engines.* The modeling results indicate that the setback distances are adequate for well pads equipped with tanks and fugitive emission sources, but no engines. Even in modeling analyses framed around the highest-emitting tanks and fugitive emissions, the setback distances were adequate for all pollutants considered (e.g., see Figure 5.3-1). Every estimated 1-hour average concentration at all offsite receptors was less than TCEQ's short-term ESLs, and every estimated annual average concentration at locations more than 200 feet from fence lines was less than TCEQ's long-term ESLs.
- *Well pads with tanks and lift engines.* Scenario 2 in the modeling analysis considered a well pad with two 250-hp lift engines. It also considered the highest measured emission rates for tanks and fugitive emissions. For this configuration, estimated annual average concentrations of all pollutants were lower than TCEQ's long-term ESL for receptor locations at least 200 feet from site fence lines. Further, estimated 1-hour average concentrations of all pollutants were lower than TCEQ's short-term ESL for receptor locations at least 600 feet from sites. While not an issue for the setback distances, some estimated 1-hour average concentrations of acrolein and formaldehyde exceeded TCEQ's short-term ESL, but this was limited to distances within 100 feet of the fence lines.
- *Well pads and compressor stations with line engines.* The primary issues for sites with line engines are emissions of acrolein and formaldehyde. For acrolein, estimated annual average concentrations exceed TCEQ's long-term ESL for several hundred feet beyond the 600-foot setback (see Figure 5.3-2). For formaldehyde, estimated annual average concentrations were below TCEQ's long-term ESL at all locations beyond the setback (see Figure 5.3-3), but some estimated 1-hour average concentrations were higher than the short-term ESL at a small number of receptors beyond the setback. While the estimated concentrations for these pollutants were higher than health-protective screening values, the modeled air quality impacts are lower than levels that have been actually associated with adverse health effects (see Section 5.4).

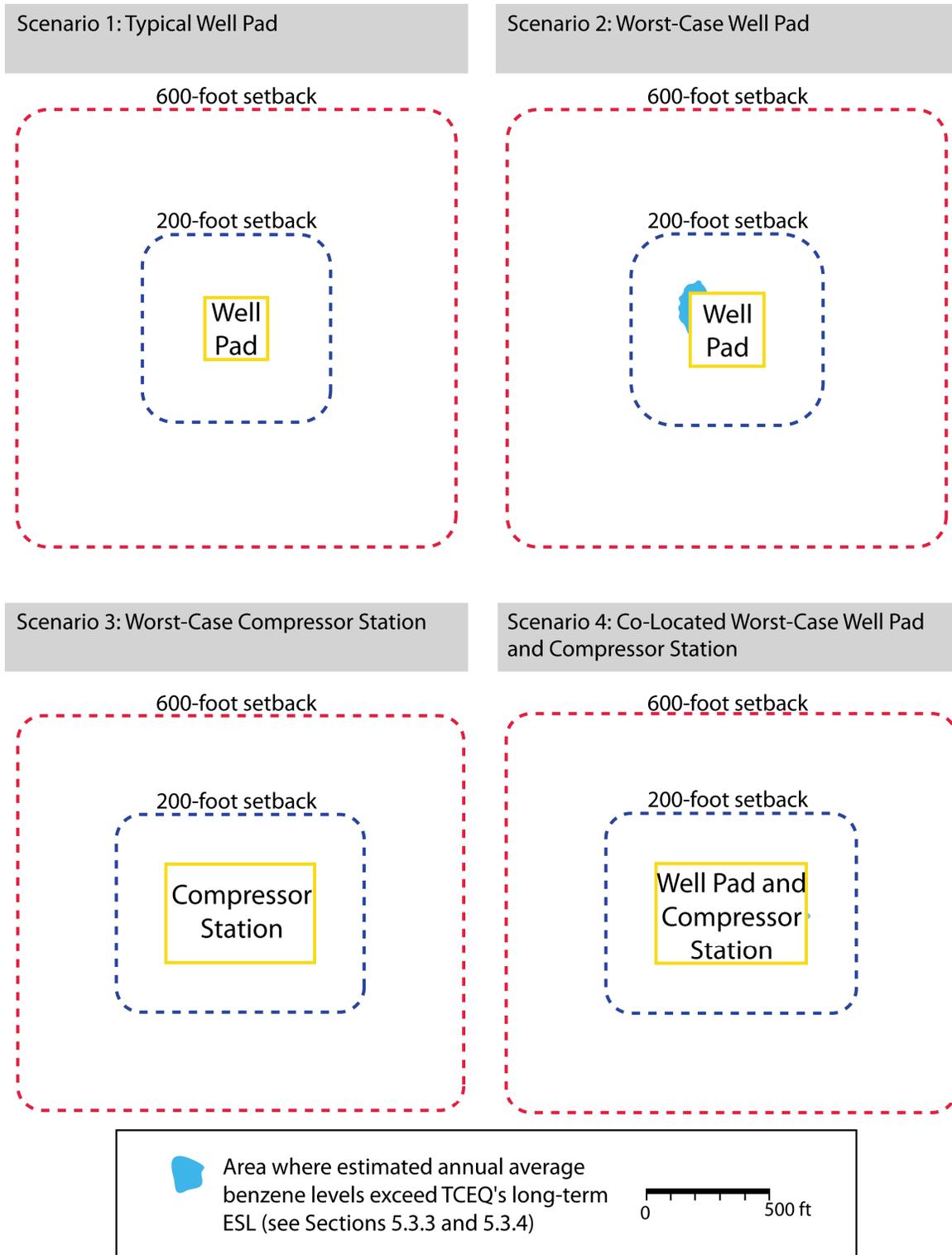


Figure 5.3-1. Locations of Estimated Annual Average Benzene Concentrations Greater Than TCEQ's Long-Term ESL, by Modeling Scenario

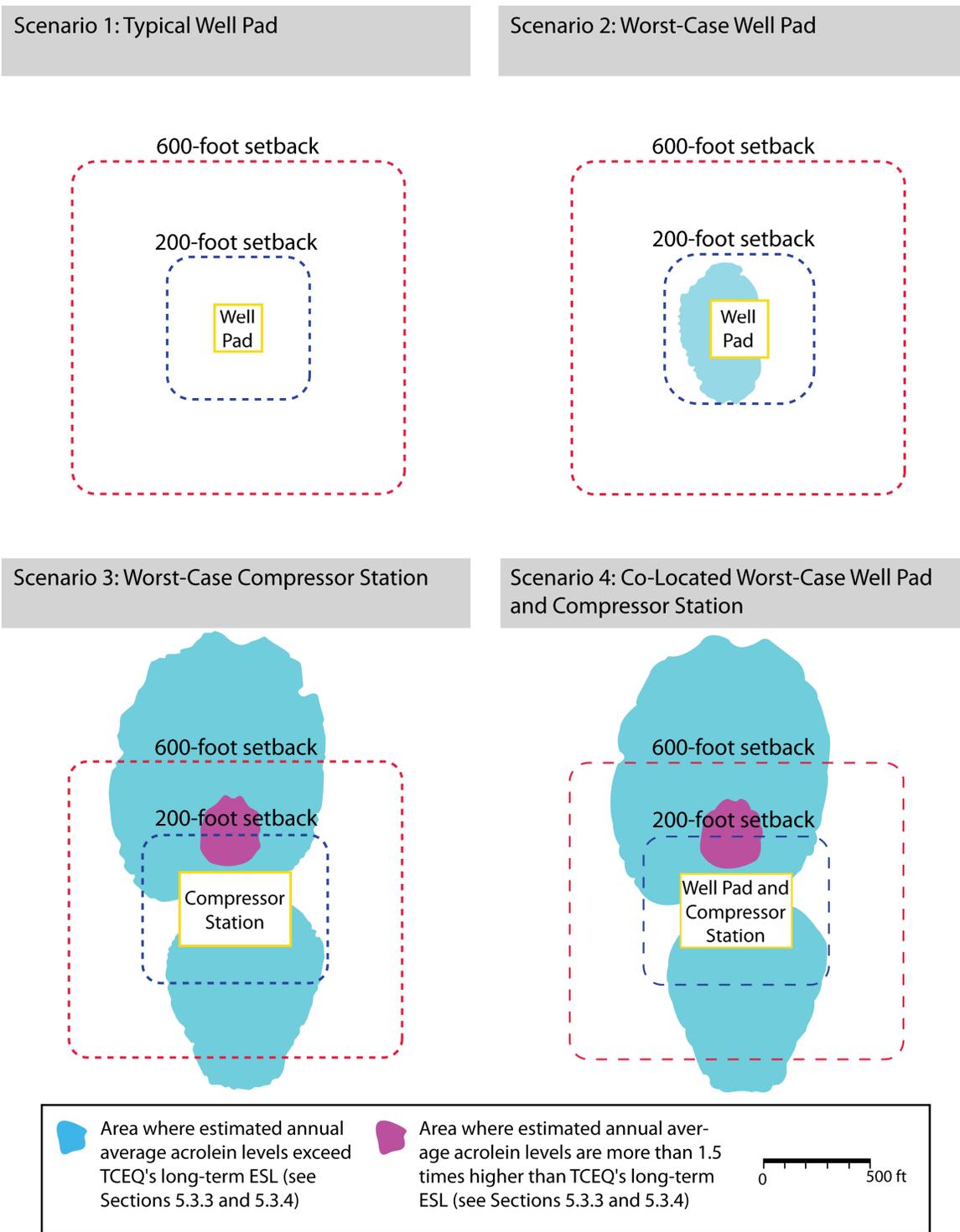


Figure 5.3-2. Locations of Estimated Annual Average Acrolein Concentrations Greater Than TCEQ’s Long-Term ESL, by Modeling Scenario

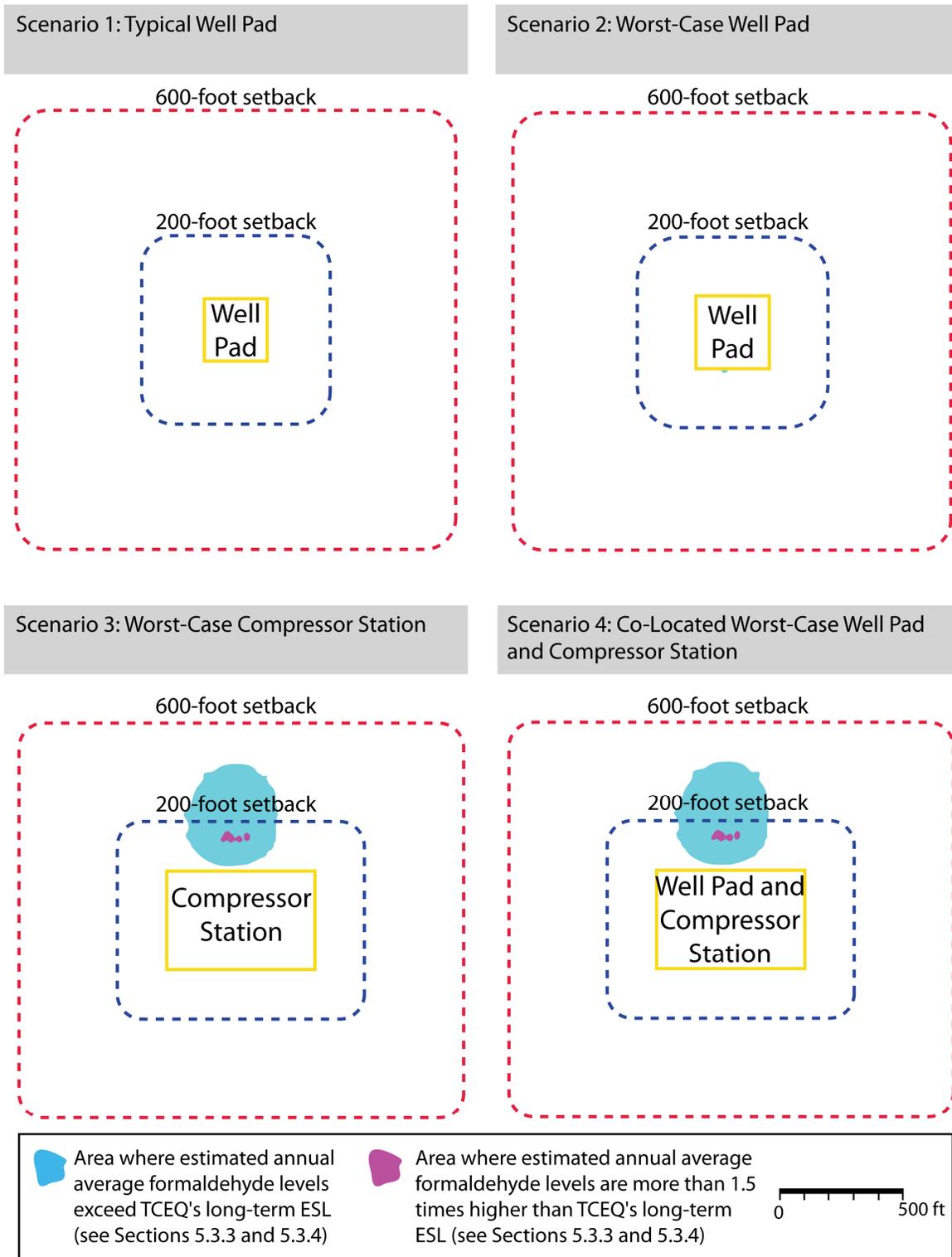


Figure 5.3-3. Locations of Estimated Annual Average Formaldehyde Concentrations Greater Than TCEQ's Long-Term ESL, by Modeling Scenario

In summary, for the overwhelming majority of sites considered in this study, the modeling analysis indicates that Fort Worth's 600-foot setback distance is adequate. For the relatively few sites with multiple, large line engines, the modeling analysis found some areas beyond the setbacks to have estimated acrolein and formaldehyde concentrations greater than TCEQ's ESLs. For both pollutants, ERG's modeling is based entirely on estimated emission rates, and not measured values. This underscores the value of obtaining more detailed acrolein and formaldehyde emissions data for line engines and focused ambient air monitoring to validate these findings. Such studies would provide greater confidence in the adequacy and protectiveness of the city's setbacks.

5.3.5 Modeled Concentrations: Main Findings, Limitations, and Uncertainties

The information presented throughout Section 5.3 is based entirely on the dispersion modeling analysis. Unlike ambient air monitoring data, which are direct measurements of air pollution levels, models provide estimates of ambient air concentrations. The accuracy of the modeling outputs depends on many factors, but especially on the representativeness of the emissions data input to the model. Emission rates for this study were based on measured and estimated data: emissions from tanks and fugitive sources were directly measured during the point source testing program, and emissions from lift engines and line engines were estimated using standard computational algorithms and EPA-published emission factors. For some pollutants, most notably acrolein and formaldehyde, the estimated offsite ambient air concentrations from the model are based entirely on the estimated emissions from lift engines and line engines. While these estimates were generated using the best information available to ERG, the methodologies may not adequately represent the types of engines typically used at well pads and compressor stations in Fort Worth. Because acrolein and formaldehyde are two pollutants of concern for this study, consideration should be given to reducing uncertainties associated with the estimated concentrations. This could be achieved by either additional point source testing at sites with line engines or air monitoring for these compounds downwind from a line engine site known to burn the largest quantities of natural gas.

Additionally, the modeling conducted for this study only evaluated dispersion, or the movement of the pollutants through the air from their sources to offsite receptors. Many of the pollutants emitted at the well pads and compressor stations are known to react in the air and form other pollutants, and this was not considered in the modeling analysis. Supplemental analyses using photochemical models might be warranted to more fully investigate the full range of air quality impacts on local air quality (e.g., consideration of contributions to ozone formation and other processes).

5.4 Additional Context for Selected Pollutants

The earlier analyses in this section identified acrolein and formaldehyde as the pollutants that are most likely to have site-related air quality impacts greater than TCEQ health-based screening levels at locations beyond the 600-foot setbacks. Additionally, estimated ambient air concentrations of benzene were found to exceed short-term screening levels in the immediate vicinity of the highest-emitting tanks. This section presents additional context for these pollutants, which includes comparisons to air pollution levels measured elsewhere in Texas and

further insights into toxicity. Finally, this section presents information on two pollutants that had estimated 1-hour average concentrations greater than *odor-based* short-term screening levels.

- *Benzene*. For additional perspective on benzene, ERG compared program-average concentrations calculated for all eight monitoring stations to 2010 annual average levels measured by TCEQ at 45 other locations statewide (see Figure 5.4-1). For the other statewide monitoring stations, 2010 statistical data summaries were downloaded from TCEQ's Texas Air Monitoring Information System.¹² ERG only considered sites that employed 24-hour average canister sampling technology—the same sampling approach used in the ambient air monitoring program. Further, ERG excluded any sites that had fewer than 40 valid 24-hour air samples over the calendar year, due to the large number of missing or invalid measurements for these sites. In the few cases where more than one monitor was placed at a given site, data from the monitor with the higher number of valid samples were used in this analysis.

Figure 5.4-1 shows how program-average concentrations of benzene from this study compared to annual average concentrations measured elsewhere in Texas. The figure lists the names of the cities where the other monitoring occurred. While some comparison stations are located near large petrochemical refineries and industrial complexes, several other comparison stations were located in residential and commercial settings away from such larger sources.

For seven out of eight monitoring stations in this study, the program-average benzene concentrations ranked relatively low when compared to 2010 annual averages for other monitors in Texas. However, program-average benzene levels at site S-4 ranked 11th out of the 53 sites shown in the figure. The relatively high ranking for this site likely reflects contributions from a nearby compressor station and well pad, and mobile source activity near the monitor. Overall, Figure 5.4-1 provides no evidence that benzene levels measured during this study were unusually elevated when compared to other monitoring stations in Texas. More importantly, the program-average concentrations for the Fort Worth monitoring stations are all lower than TCEQ's long-term health-based AMCV.

- *Acrolein*. As noted previously, acrolein was not a target analyte for the ambient air monitoring program. Even though many parties have previously measured airborne levels of acrolein at other locations in Texas and nationwide, recent studies have identified important data quality concerns associated with the ambient air monitoring methods that had been widely used for this pollutant. In December 2010, EPA summarized these concerns and began flagging past air measurements of acrolein as “unverified” if certain canister cleaning practices, calibration standards, and timely analysis were not applied.¹³

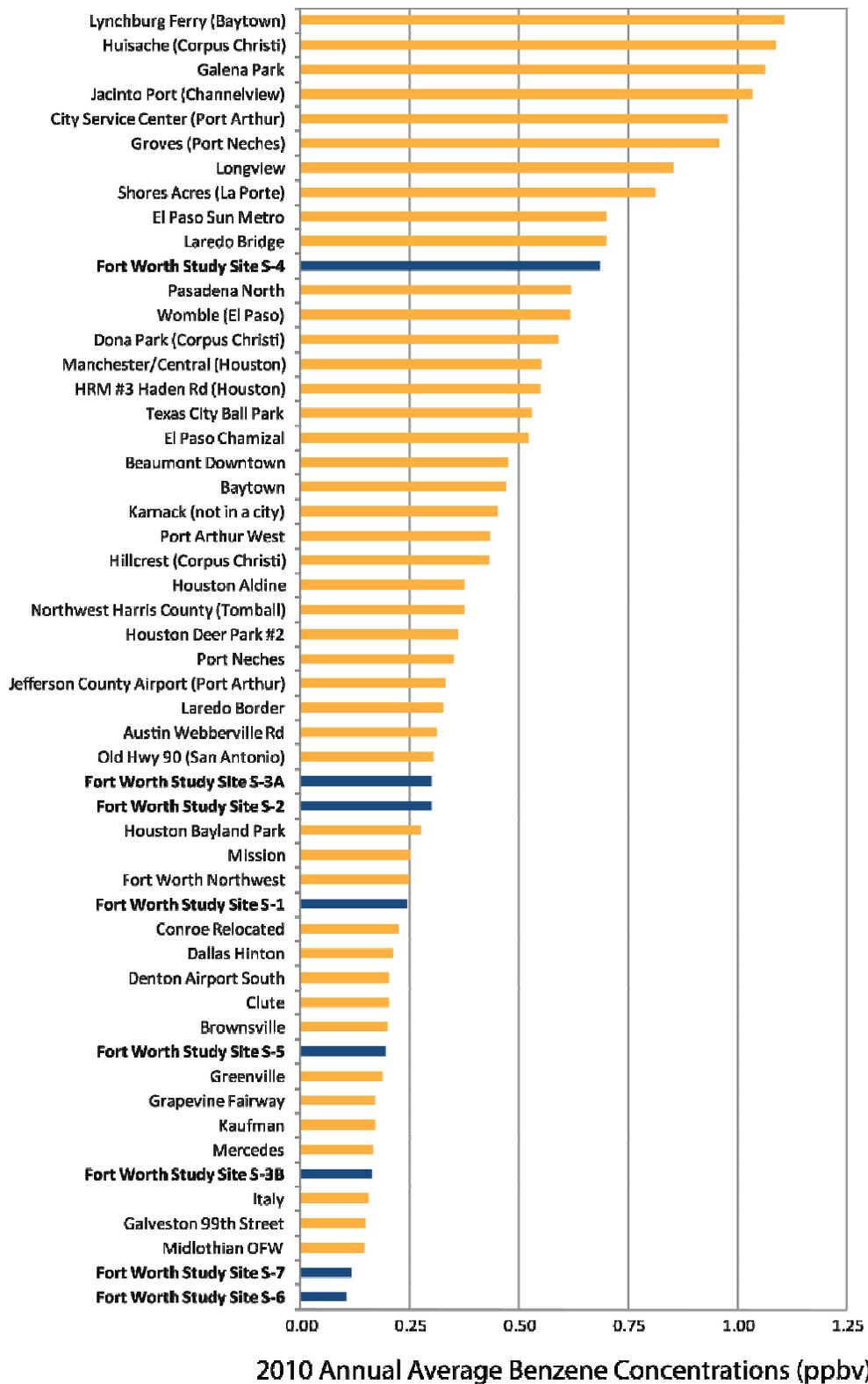


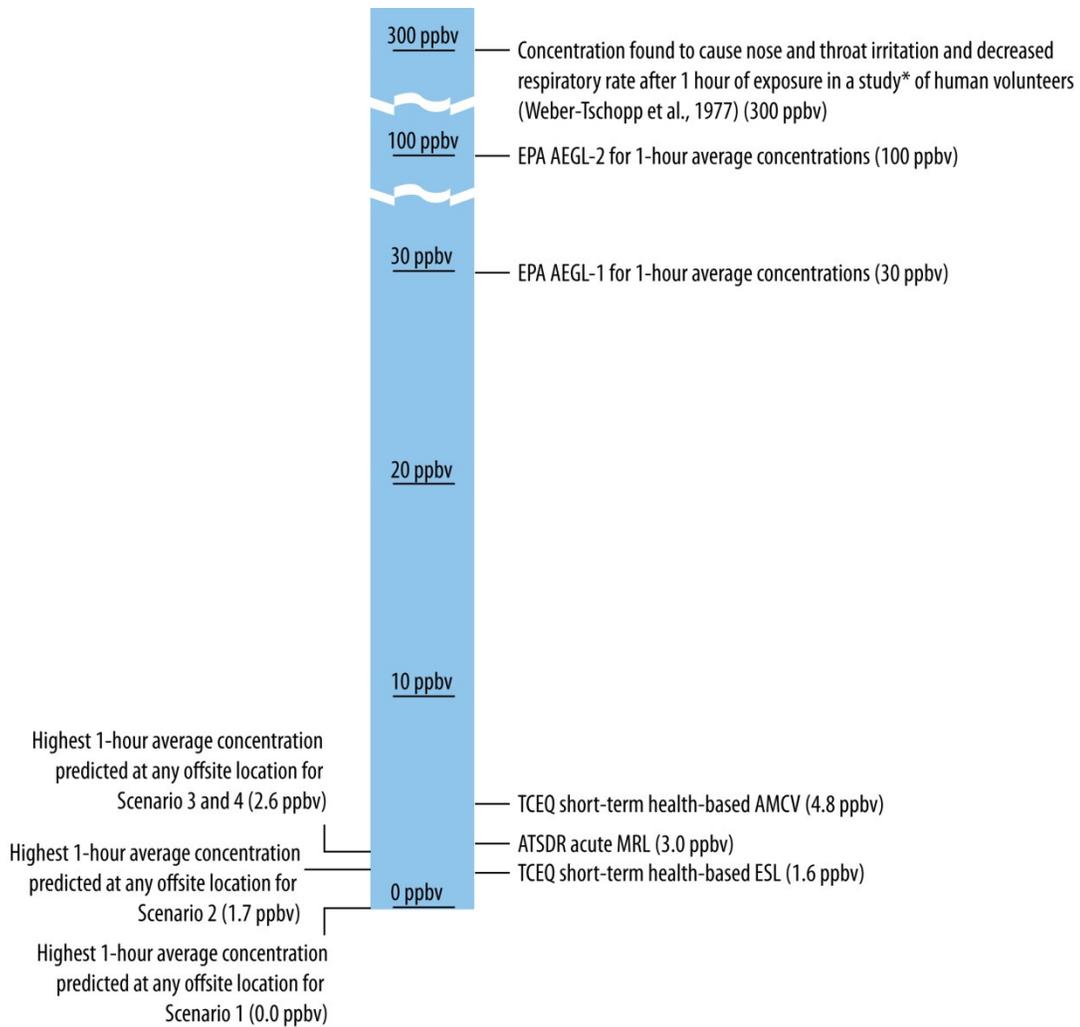
Figure 5.4-1. Comparison of Program-Average Benzene Concentrations in Fort Worth to 2010 Annual Average Benzene Concentrations Statewide (see Section 5.4)

Due to these and other data quality concerns that have been expressed for past measurements, the focus of this section is on acrolein toxicity. Extensive information is available on various non-cancer respiratory effects that have resulted from inhalation exposures to acrolein^{14,15}, and the following paragraphs assess whether the estimated acrolein air quality impacts are expected to result in adverse health effects, both for acute and chronic exposure durations. According to ATSDR, only limited, weak evidence is available suggesting that acrolein is carcinogenic¹², and no agencies have developed quantitative approaches for evaluating cancer risks for this pollutant. Potential cancer effects associated with acrolein exposures are therefore not evaluated here.

The assessment of acute, non-cancer effects is based on an earlier finding in this section indicating that lift engines and line engines are expected to contribute up to 2.6 ppbv to the highest offsite 1-hour average concentrations of acrolein. Figure 5.4-2¹⁶ compares this estimated air quality impact to screening levels published by multiple agencies. Most notably, the estimated 1-hour average air quality impact of 2.6 ppbv is lower than ATSDR's acute Minimal Risk Level (3.0 ppbv), which is defined as an exposure concentration that is likely to be without appreciable risk of non-cancer health effects. Further, the highest modeling result is more than 100 times below the lowest exposure concentration that has been documented to cause health effects in humans. It is therefore unlikely that even the highest 1-hour average concentration would be expected to cause adverse health effects among the general population.

Figure 5.4-3¹⁷ presents similar information on acrolein toxicity, but considering longer-term (e.g., annual) exposure scenarios. The highest annual average concentration estimated by the dispersion model varied considerably across model scenarios. For well pads with tanks and small lift engines, the highest annual average concentration predicted for receptors beyond the 600-foot setback distance was 0.012 ppbv—lower than health-based screening values published both by ATSDR and TCEQ. For sites having multiple, large line engines, which are represented by Scenarios 3 and 4, the highest annual average acrolein concentration beyond the 600-foot setback distance was 0.15 ppbv. While greater than certain screening values published by ATSDR, EPA, and TCEQ, this annual average concentration is still considerably lower than the lowest exposure concentration found to cause adverse health effects in laboratory studies.

Of all pollutants considered, acrolein was one of only two found to have estimated air quality impacts greater than highly protective screening levels at locations beyond the setback distances. The many layers of health-protective assumptions suggest that the estimated air concentrations would not lead to adverse health effects among residents who live beyond the setbacks. However, additional air sampling of acrolein is recommended to confirm these findings.



Definitions:

ATSDR Minimal Risk Level (MRL): "An estimate of daily human exposure to a hazardous substance that is likely to be without an appreciable risk of adverse non-cancer health effects."

EPA Acute Exposure Guideline Level (AEGL)-1: "The airborne concentration . . . of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure."

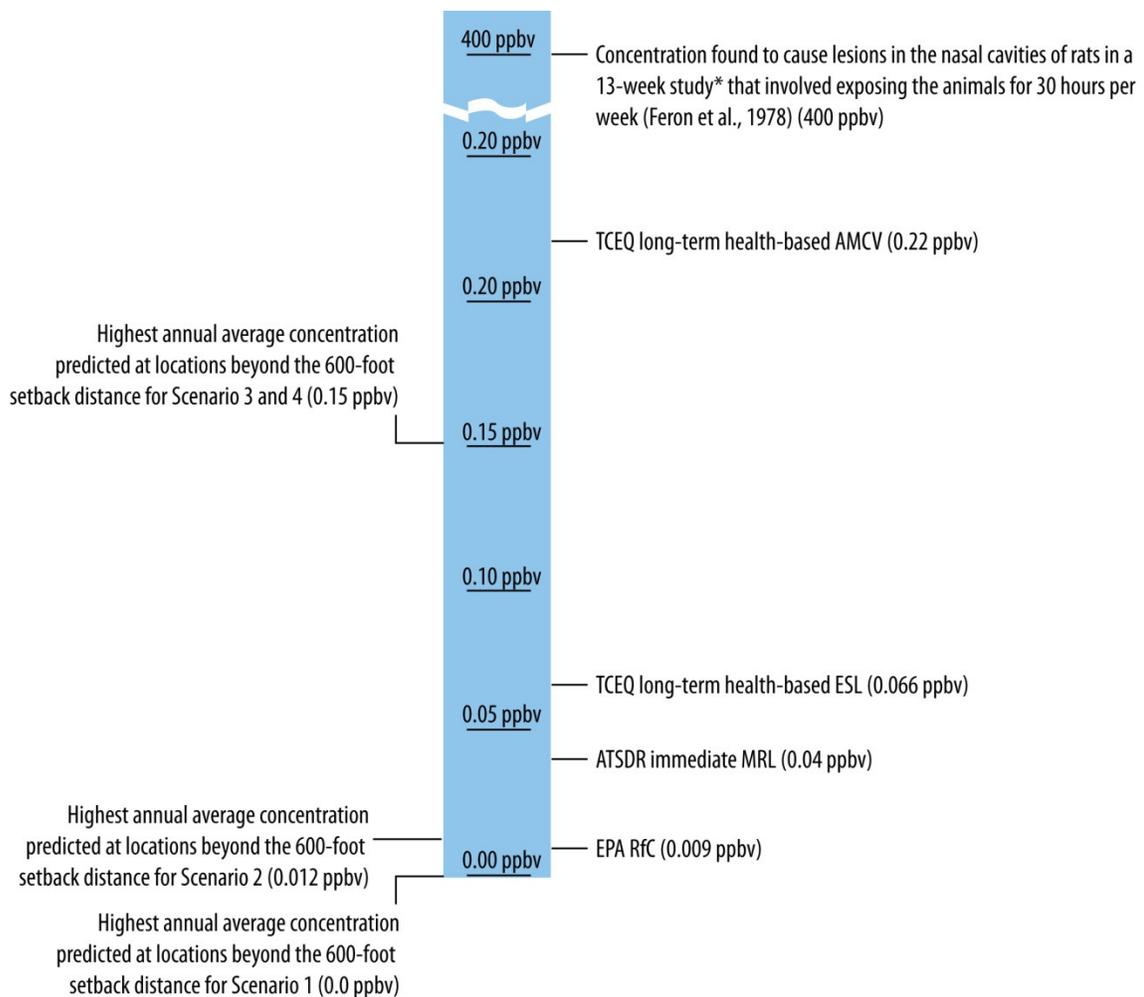
EPA Acute Exposure Guideline Level (AEGL)-2: "The airborne concentration . . . of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects."

TCEQ ESL: "Used in TCEQ's air permitting process to evaluate air dispersion modeling's predicted impacts. . . If predicted airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If predicted ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a review in more depth."

TCEQ AMCV: "Chemical-specific air concentrations set to protect human health and welfare. Exposure to an air concentration at or below the AMCVs is not likely to cause adverse health effects in the general public, including sensitive subgroups such as children, the elderly, pregnant women, and people with pre-existing health conditions."

* The study described at the top of this figure was used to derive some of the screening levels shown.

Figure 5.4-2. Toxicity of Acrolein: Short-Term Exposures



Definitions:

ATSDR Minimal Risk Level (MRL): "An estimate of daily human exposure to a hazardous substance that is likely to be without an appreciable risk of adverse non-cancer health effects."

EPA Reference Concentration (RfC): "An estimate . . . of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."

TCEQ ESL: "Used in TCEQ's air permitting process to evaluate air dispersion modeling's predicted impacts. . . If predicted airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If predicted ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a review in more depth."

TCEQ AMCV: "Chemical-specific air concentrations set to protect human health and welfare. Exposure to an air concentration at or below the AMCVs is not likely to cause adverse health effects in the general public, including sensitive subgroups such as children, the elderly, pregnant women, and people with pre-existing health conditions."

* The study described at the top of this figure was used to derive some of the screening levels shown.

Figure 5.4-3. Toxicity of Acrolein: Long-Term Exposures

- *Formaldehyde.* For additional context on measured and estimated formaldehyde levels, ERG compared program-average concentrations calculated for the two monitoring stations with available sampling data to 2010 annual average levels measured by TCEQ at six other locations statewide (see Figure 5.4-4). Data for the other monitoring stations were accessed from TCEQ's Texas Air Monitoring Information System¹² and processed following the same methodology that is documented for the benzene analysis. As Figure 5.4-4 shows, formaldehyde is routinely monitored at far fewer stations in comparison to benzene. However, at every other TCEQ station that met the site selection criteria, annual average concentrations of formaldehyde in 2010 were higher than the program-average concentrations calculated for monitoring sites S-4 and S-5. This suggests that the formaldehyde levels measured during the Fort Worth Natural Gas Air Quality Study were not elevated in comparison to other monitoring locations in Texas.

ERG also considered the health implications of the measured and modeled air quality impacts. This was done for both non-cancer health effects (for acute and chronic exposure durations) and for potential cancer effects (chronic exposures only). Figure 5.4-5¹⁸ provides additional context on the health implications of short-term inhalation exposures to formaldehyde. All measured 24-hour average concentrations during the ambient air monitoring program were considerably lower than the most health-protective screening levels. Further, the highest 1-hour average concentration predicted by the model for the highest-emitting site (34 ppbv) was not only lower than ATSDR's Minimal Risk Level, but substantially below the lowest concentration that has been shown to cause adverse acute health effects in humans. Accordingly, the peak formaldehyde air quality impacts identified in this study are not expected to cause acute health effects among city residents.

For chronic exposure durations, the highest program-average formaldehyde concentration calculated from the monitoring data and the highest annual average formaldehyde concentration estimated by the dispersion model were both lower than every applicable non-cancer screening level published by ATSDR and TCEQ. Therefore, even when considering the highest-emitting sites, the long-term air quality impacts of formaldehyde are not expected to cause adverse non-cancer effects. Figure 5.4-6¹⁹ provided additional context on the health implications of long term inhalation exposures to formaldehyde. ERG also considered cancer endpoints, given that formaldehyde has been classified as a human carcinogen. According to risk levels currently published on EPA's Integrated Risk Information System (IRIS),¹ formaldehyde concentrations between 0.06 ppbv and 6 ppbv are expected to have theoretical lifetime cancer risks between 1 in 1,000,000 and 1 in 10,000. This risk range is common for urban settings, and the theoretical cancer risks for Fort Worth are lower than those for every other monitoring site shown in Figure 5.4-4.

¹ New scientific information is continually becoming available on the links between certain air pollutants and adverse health effects. This is particularly true for formaldehyde, for which EPA, the National Academy of Sciences, and other entities have very recently published updates and reviews of the chemical's toxicity and carcinogenicity. However, EPA's final formaldehyde inhalation assessment was not available at the time this report was completed.

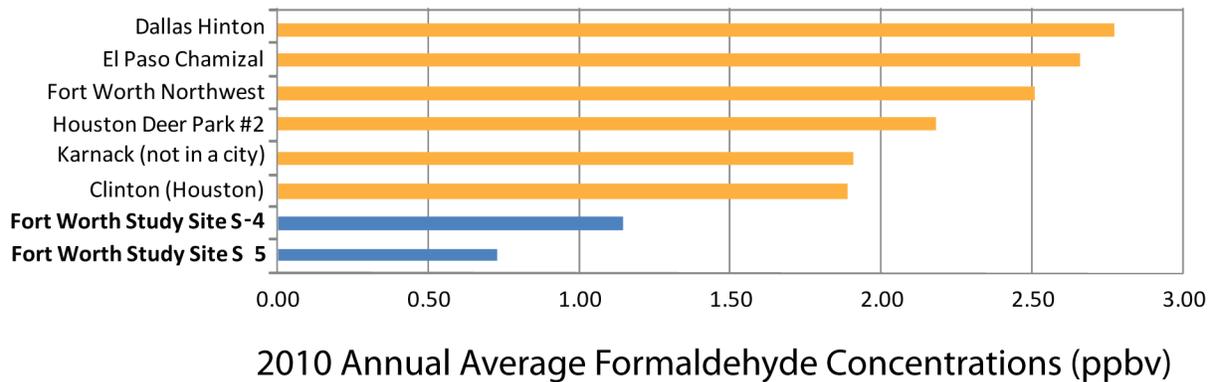
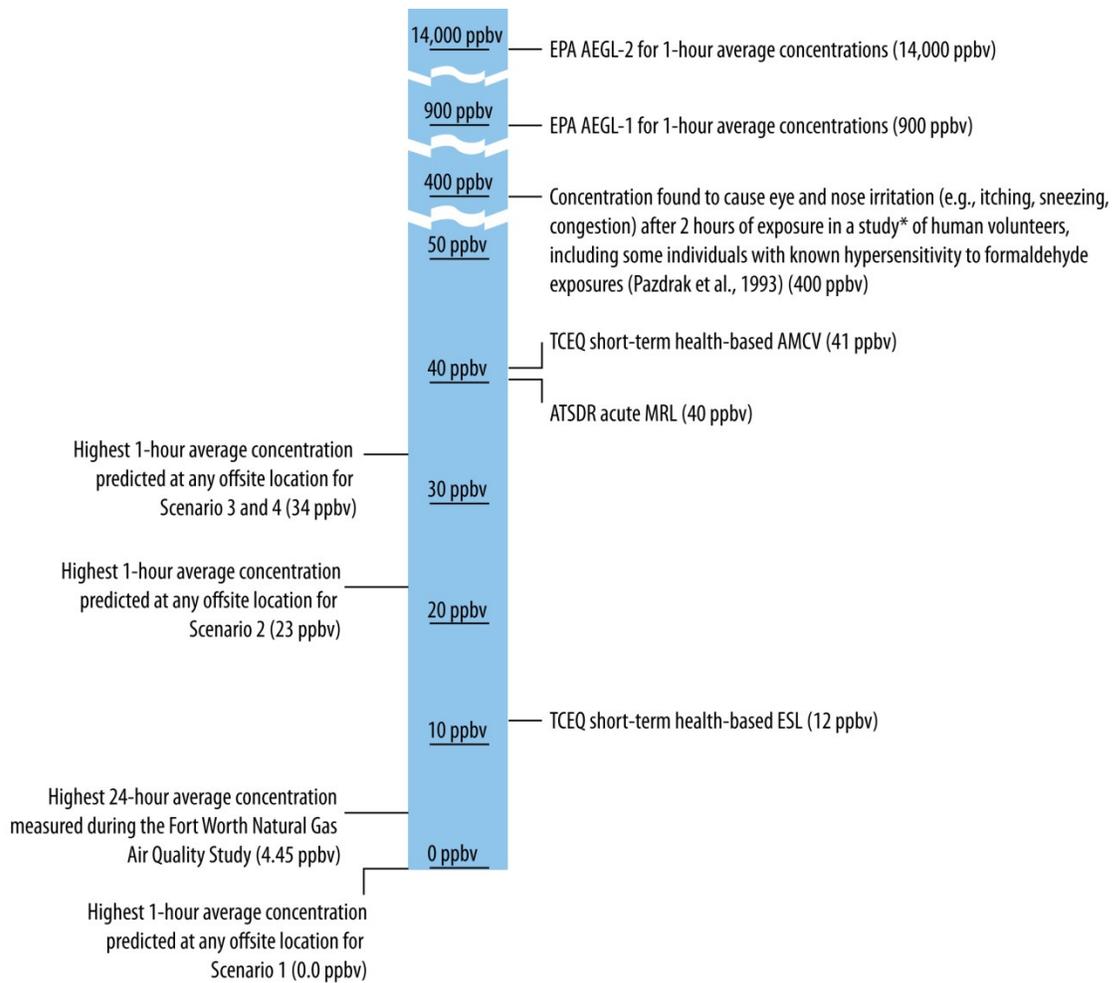


Figure 5.4-4. Comparison of Program-Average Formaldehyde Concentrations in Fort Worth to 2010 Annual Average Formaldehyde Concentrations Statewide (see Section 5.4)

- *Pollutants above odor-based screening levels.* Throughout this section, health-based screening levels were used to interpret the ambient air monitoring data and dispersion modeling results, but many pollutants emitted from well pads and compressor stations also have odor-based screening levels. Though not documented in the previous summary tables, ERG compared every measured and modeled ambient air concentration to pollutant-specific odor-based screening levels, where available. Every 24-hour average concentration measured during the monitoring program was lower than TCEQ's short-term odor-based ESLs. However, two pollutants—toluene and *m,p*-xylene—had estimated 1-hour average concentrations in certain modeling scenarios that exceeded the odor-based ESLs. This effect was highly localized to tanks at the highest-emitting sites and was predicted to occur just a few hours per year. While the peak levels of toluene and *m,p*-xylene would be expected to result in odorous conditions, neither pollutant had estimated short-term concentrations above health-based screening levels.



Definitions:

ATSDR Minimal Risk Level (MRL): "An estimate of daily human exposure to a hazardous substance that is likely to be without an appreciable risk of adverse non-cancer health effects."

EPA Acute Exposure Guideline Level (AEGL)-1: "The airborne concentration . . . of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure."

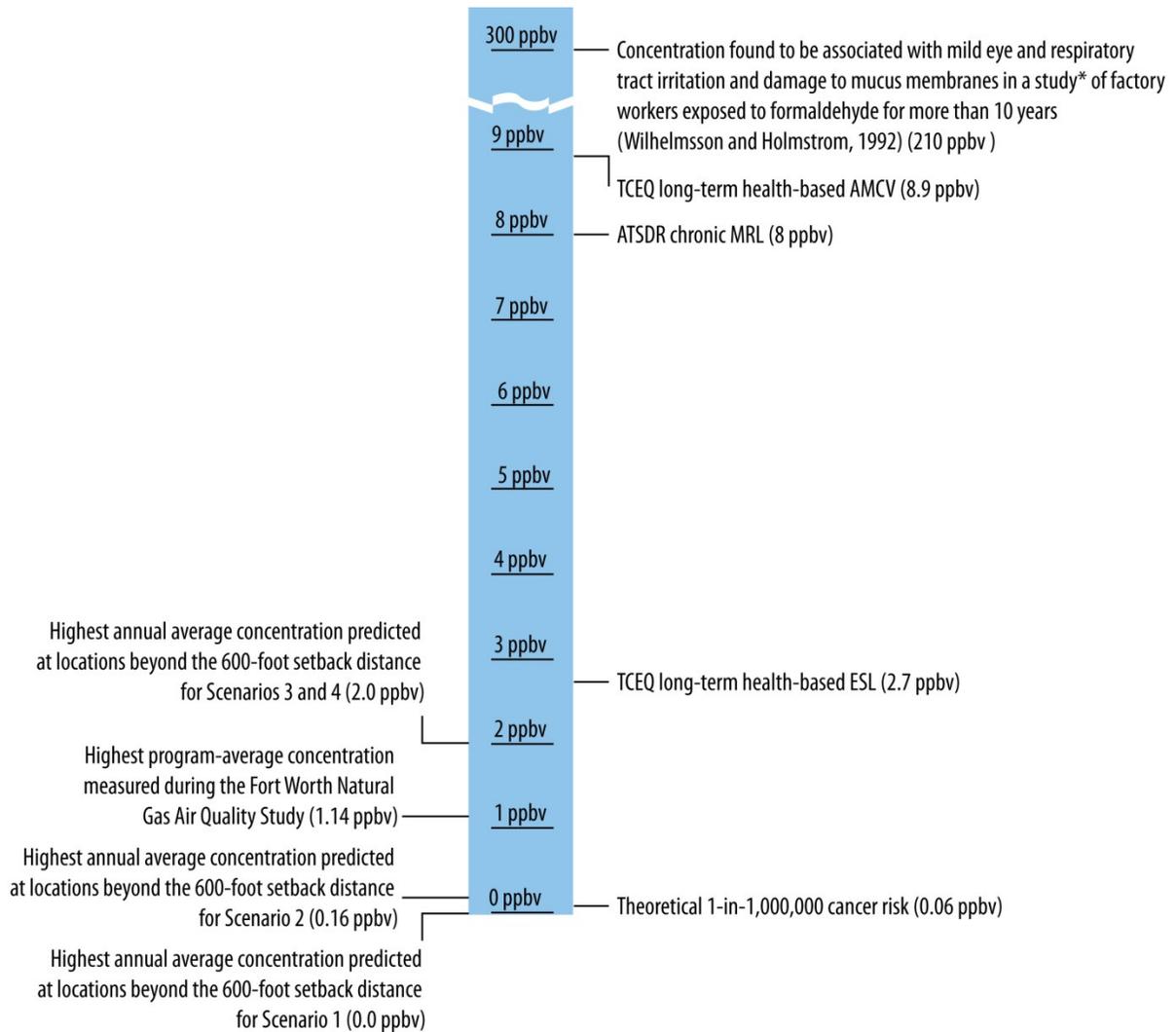
EPA Acute Exposure Guideline Level (AEGL)-2: "The airborne concentration . . . of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects."

TCEQ ESL: "Used in TCEQ's air permitting process to evaluate air dispersion modeling's predicted impacts . . . If predicted airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If predicted ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a review in more depth."

TCEQ AMCV: "Chemical-specific air concentrations set to protect human health and welfare. Exposure to an air concentration at or below the AMCVs is not likely to cause adverse health effects in the general public, including sensitive subgroups such as children, the elderly, pregnant women, and people with pre-existing health conditions."

* The study with the 400 ppbv observed effects level was used to derive some of the screening levels shown.

Figure 5.4-5. Toxicity of Formaldehyde: Short-Term Exposures



Definitions:

ATSDR Minimal Risk Level (MRL): "An estimate of daily human exposure to a hazardous substance that is likely to be without an appreciable risk of adverse non-cancer health effects."

TCEQ ESL: "Used in TCEQ's air permitting process to evaluate air dispersion modeling's predicted impacts. . . If predicted airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If predicted ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a review in more depth."

TCEQ AMCV: "Chemical-specific air concentrations set to protect human health and welfare. Exposure to an air concentration at or below the AMCVs is not likely to cause adverse health effects in the general public, including sensitive subgroups such as children, the elderly, pregnant women, and people with pre-existing health conditions."

* The study described at the top of this figure was used to derive some of the screening levels shown.

Figure 5.4-6. Toxicity of Formaldehyde: Long-Term Exposures

5.5 Public Health Evaluation Conclusions

The ambient air monitoring conducted in Fort Worth found dozens of air pollutants above detection limits. However, this is not uncommon for urban air quality, due to the complex mixture of emissions sources found in our country's metropolitan areas. The presence of a pollutant in Fort Worth's air likely reflects contributions from many different sources. Quantifying the extent to which natural gas exploration and production activity contributes to air quality is a complicated task, due to the confounding effect of other emission sources, such as motor vehicles, gasoline stations, and industrial sources. It is for this reason that the Fort Worth Natural Gas Air Quality Study considered two different approaches to evaluate air quality impacts from natural gas exploration and production activity.

First, ERG considered findings from the ambient air monitoring program, which directly measured air pollution levels at eight locations throughout Fort Worth. The ambient air monitoring data did not reveal any evidence of pollutants associated with natural gas exploration and production activity reaching concentrations above applicable screening levels: The highest 24-hour average concentrations of all site-related pollutants were lower than TCEQ's health-based short-term screening levels, and the program-average concentrations of all site-related pollutants were lower than TCEQ's health-based long-term screening levels. Even though the ambient air monitoring data provided useful insights into local air quality, review of modeling data was needed to consider potential air quality impacts at locations where and times when monitoring did not occur.

Next, ERG conducted a dispersion modeling analysis, which estimated air quality impacts that can be attributed specifically to emissions from well pads and compressor stations. These estimates were derived from measured emissions for tanks and fugitive sources and estimated emissions from compressor engines. The model was run for four different equipment configurations at well pads and compressor stations, and some modeling scenarios were based on the highest emission rates measured during the point source testing program. Most notably, the worst-case scenario assumed that the highest measured emission rates of all pollutants occurred at a single hypothetical site. The modeling analysis confirmed that benzene emissions from tanks could lead to air pollution levels slightly higher than TCEQ's short-term ESL, but this occurred infrequently and only in very close proximity to the highest-emitting tanks. The modeling also indicated that sites containing multiple, large line engines can emit acrolein and formaldehyde at levels that would cause offsite ambient air concentrations to exceed TCEQ's short-term and long-term screening levels over various distances. For all remaining pollutants considered, the modeling found no evidence of short-term or long-term air quality impacts at levels of health concern.

ERG considered both the modeling and monitoring results when assessing the adequacy of Fort Worth's setback limits. The details of this analysis depend on multiple factors, including the pollutant, exposure duration, and well pad equipment configuration. Table 5.5-1 documents ERG's main findings for different combinations of these factors. Overall, ERG concluded that the 600-foot setback distances are adequately protective of public health. Greater confidence in this finding can be gained through further study of acrolein and formaldehyde air quality impacts

near sites with multiple, large line engines, especially when variances to the 600-foot setbacks are being considered for these higher-emitting facilities. TCEQ has recently completed an ambient air monitoring study that considered acrolein and formaldehyde levels in Fort Worth.²⁰ The week-long monitoring effort found no evidence of acrolein and formaldehyde exceeding short-term health-based screening levels, but that study was limited in scope and duration. Routine monitoring over a longer duration near a site with multiple, large lift engines is encouraged.

Table 5.5-1. Key Findings for Health Evaluation

| Pollutant | Exposure Duration ^a | Key Findings from Screening Evaluation, by Equipment Configuration | Additional Context | Recommendations |
|-----------|--------------------------------|---|--|---|
| Benzene | Short-term | <p><i>For sites with the highest-emitting tanks:</i> Receptors less than 30 feet from the highest emitting tanks had maximum 1-hour concentrations marginally above the short-term ESL.</p> <p><i>For all remaining sites:</i> Estimated offsite 1-hour average benzene levels were lower than TCEQ’s short-term ESL for the overwhelming majority of well pad and compressor station configurations.</p> | These results are generally consistent with the findings of the ambient air monitoring program. Additionally, long-term average benzene levels in Fort Worth ranked relatively low when compared to those measured at other locations statewide. | Compare any future sampling results (e.g., from TCEQ’s “auto-GC” monitors) to screening levels. |
| | Long-term | <p><i>For every equipment configuration:</i> For all receptors at least 200 feet from fence lines, annual average concentrations were found to be lower than TCEQ’s screening values, even for the highest-emitting sites (see Figure 5.3-1).</p> | | |
| Acrolein | Short-term | <p><i>For sites with no engines:</i> Acrolein emissions were not measured, but are not expected due to the lack of combustion.</p> | The modeling results are based on the best available information, but no long-term ambient air monitoring data are available to verify or validate the modeling results. TCEQ conducted a week-long carbonyl monitoring program in December 2010, which found no acrolein levels above ESLs, but that program was limited in scope and duration. | Acrolein is one of only two pollutants that had estimated air quality impacts above ESLs beyond the setback distances. This occurred only for sites with multiple, large line engines. Routine monitoring downwind from one of the larger facilities would provide greater confidence in the adequacy of the city’s setback limits. |
| | | <p><i>For sites with lift or line engines:</i> All modeling simulations involving engines found some offsite 1-hour average concentrations greater than TCEQ’s short-term ESL. The spatial extent and frequency of these elevated concentrations increased with the number and size of engines at a given site. For sites with multiple, large line engines, estimated 1-hour average concentrations above the ESL occurred up to 400 feet beyond the fence lines.</p> | | |
| | Long-term | <p><i>For sites with multiple, large line engines:</i> Estimated annual average concentrations exceeded the long-term ESL at locations several hundred feet beyond the 600-foot setback. Though greater than highly protective screening levels, the estimated air quality impacts did not reach concentrations that have been shown to cause adverse health effects.</p> <p><i>For all other sites:</i> For all receptors at least 200 feet from fence lines, annual average concentrations were found to be lower than TCEQ’s screening values, even for the highest-emitting sites (see Figure 5.3-2).</p> | | |

Table 5.5-1. Key Findings for Health Evaluation (Continued)

| Pollutant | Exposure Duration ^a | Key Findings from Screening Evaluation, by Equipment Configuration | Additional Context | Recommendations |
|---|--------------------------------|---|---|---|
| Formaldehyde | Short-term | <i>For sites with no engines:</i> Formaldehyde emissions were not measured, but are not expected due to the lack of combustion. | The findings for long-term exposures are consistent with the program-average formaldehyde levels from the monitoring program. Further, when compared to other active monitoring sites in Texas, the program-average concentrations measured in this study ranked the lowest. TCEQ conducted a week-long carbonyl monitoring program in December 2010, which found formaldehyde levels below ESLs, but that program was limited in scope and duration. | Formaldehyde is one of only two pollutants that had estimated air quality impacts above ESLs beyond the setback distances. This occurred only for sites with multiple, large line engines. Routine monitoring downwind from one of the larger facilities would provide greater confidence in the adequacy of the city's setback limits. |
| | | <i>For sites with lift or line engines:</i> All modeling simulations involving engines found some offsite 1-hour average concentrations greater than TCEQ's short-term ESL. The spatial extent and frequency of these elevated concentrations increased with the number and size of engines. For sites with multiple, large line engines, estimated 1-hour average concentrations above the ESL occurred up to 750 feet beyond the fence lines, and the peak values were nearly 3 times higher than TCEQ's short-term ESL. However, even the highest estimated air quality impacts did not reach concentrations that have been shown to cause adverse health effects. | | |
| | Long-term | <i>For every equipment configuration:</i> For all receptors at least 600 feet from fence lines, annual average concentrations were found to be lower than TCEQ's screening values, even for the highest-emitting sites (see Figure 5.3-3). | | |
| All other pollutants considered in this study | Short- and long-term | <i>For every equipment configuration considered:</i> Estimated 1-hour average and annual average concentrations were lower than TCEQ's health-protective screening values at every offsite location, even for the highest-emitting sites. | This result is supported by the ambient air monitoring data, which found no site-related pollutants above screening levels. | Compare any future sampling results (e.g., from TCEQ's "auto-GC" monitors) to screening levels. |

^a For purposes of this table, "short-term" exposures are evaluated based on the highest estimated 1-hour average concentrations; and "long-term" exposures are evaluated based on program-average concentrations calculated from the monitoring data and annual average concentrations estimated by the dispersion model.

6.0 Regulatory Assessment

Under this task, facility-level emission estimates developed under Task 3 (point source testing) for well pads, compressor stations, and natural gas processing and treatment plants were evaluated against various federal and state air quality regulatory thresholds and standards applicable to these types of facilities. Regulatory standards considered include EPA's operating and construction permit rules, National Emissions Standard for Hazardous Air Pollutants (NESHAPs), and New Source Performance Standards (NSPS); TCEQ's permit-by-rule, standard permit, and other regulations applicable to upstream oil and gas facilities; and the city of Fort Worth's Gas Well Drilling Ordinance.

This section has four sub-sections:

- 6.1 Federal Air Quality Rules – A description of potentially applicable U.S. EPA air quality rules are provided here.
- 6.2 Texas Commission on Environmental Quality Air Quality Rules – This section provides a discussion of potentially applicable TCEQ air quality rules.
- 6.3 City of Fort Worth Air Quality Rules – The city of Fort Worth's Gas Well Drilling Ordinance (Ordinance No. 18449-02-2009) is discussed in this section.
- 6.4 Regulatory Assessment Conclusions – Provides a summary of the results of the regulatory assessment.

6.1 Federal Air Quality Rules

EPA regulates air emissions from stationary sources such as well pads and compressor stations through a variety of regulatory mechanisms. In brief, these are:

- Operating permit rules
- Construction permit rules
- NSPS
- NESHAPs
- The Greenhouse Gas Reporting Program

These air quality regulations are discussed individually in Sections 6.1.1 through 6.1.5.

6.1.1 Operating Permits

Operating permits are legally enforceable documents that permitting authorities issue to air pollution sources *after* the sources begin to operate. Depending on the magnitude of emissions from a facility, there are different types of operating permits available, with the largest sources (typically those emitting over 100 tons per year (tpy) of a regulated pollutant such as VOCs) required to obtain a Title V Operating permit. In Texas, these permits are issued by TCEQ as discussed below in Section 6.2.

6.1.2 Construction Permits

Construction permits are legally enforceable documents that permitting authorities issue to air pollution sources *before* construction. EPA regulations applicable to all new sources are included under the New Source Review (NSR) provisions, which are broken down into regulations for attainment areas and regulations for nonattainment areas. Tarrant County is considered a nonattainment area for ozone, which requires more stringent control of VOC and NO_x emissions.

The state of Texas implements the federal NSR rules through its construction permit program. Under Title 30 of the Texas Administrative Code (TAC), Chapter 116, Subchapter B, oil and gas exploration and production facilities may be authorized to construct through TCEQ's Permit-by-Rule (PBR), Standard Permit, or NSR permitting process. These types of permits are discussed in more detail below in Section 6.2.

6.1.3 New Source Performance Standards

NSPS regulations apply to new, modified, or reconstructed emission sources categorized by source type. For the oil and gas industry, the potentially applicable NSPS include the following:

- Subpart A—General Requirements (including flares)
- Subparts K and Ka—Storage Vessels for Petroleum Liquids
- Subpart Kb—Volatile Organic Liquid Storage Vessels (including Liquid Storage)
- Subpart GG—Stationary Gas Turbines
- Subpart KKK—Equipment Leaks of VOC from Onshore Natural Gas Processing Plants
- Subpart LLL—Onshore Natural Gas Processing: SO₂ Emissions
- Subpart IIII—Stationary Compression Ignition Internal Combustion Engines
- Subpart JJJJ—Stationary Spark Ignition Internal Combustion Engines
- Subpart KKKK—Stationary Combustion Engines

A brief discussion of each of these regulations follows. Where possible, a preliminary determination of compliance and applicability status with respect to the sites visited under the point source task has been made. However, a formal and comprehensive compliance and applicability assessment is not possible for each facility without a complete record of construction, monitoring, and recordkeeping activities.

Subparts K and Ka—Storage Vessels for Petroleum Liquids. These regulations apply to storage vessels for volatile organic liquids (including petroleum) built or modified after June 11, 1973 (Subpart K), or after May 18, 1978 (Subpart Ka). These rules apply to storage tanks with a design capacity greater than 40,000 gallons. None of the tanks visited under Task 3 have

capacities greater than 40,000 gallons, so it appears that none of the visited tanks are subject to these rules.

Subpart Kb—Volatile Organic Liquid Storage Vessels (Including Liquid Storage). This regulation applies to storage vessels for volatile organic liquids (including petroleum) built or modified after July 23, 1984 (Subpart Kb) and with a capacity greater than 19,800 gallons. Six tanks that were visited under Task 3 appear to have capacities greater than 19,800 gallons. However, the rule does not apply to “Vessels with a design capacity less than or equal to 1,589.874 m³ (~420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer.” Therefore, this rule does not appear to apply to any storage tanks visited under Task 3.

Subpart GG—Stationary Gas Turbines. This regulation applies to stationary gas turbines with a heat input at peak load greater than 10 million British thermal units (Btu) per hour. This rule limits NO_x and SO₂ emissions from subject facilities. ERG did not identify any gas turbines under Task 3.

Subpart KKK—Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This regulation applies to onshore natural gas processing plants as defined as “any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.” This rule requires VOC leak detection and repair at facilities that remove natural gas liquids from field gas. Site PS-159 (the Crosstex Amine Treatment Center) could be subject to this rule. However, status of compliance with the monitoring requirements under this rule cannot be determined using the data obtained at the time of the survey.

Subpart LLL—Onshore Natural Gas Processing: SO₂ Emissions. This regulation applies to sweetening units (process devices that remove hydrogen sulfide (H₂S) and CO₂ contents from sour natural gas) and sulfur recovery units at facilities that process natural gas. Sour natural gas is natural gas with an H₂S concentration greater than 0.25 grains per 100 standard cubic feet. The natural gas in the Barnett Shale is not considered to be sour natural gas, so this rule does not appear to apply to any facilities in Fort Worth.

Subpart IIII—Stationary Compression Ignition Internal Combustion Engines. This regulation applies to compression ignition internal combustion engines of various sizes, dependent upon date of construction. Much of this regulation is applicable to engine manufacturers themselves, not the engine users. This rule limits combustion emissions (hydrocarbons, NO_x, CO, and PM) from subject engines, which were not tested as part of this project. While this rule may apply to engines used at natural gas well pads and compressor stations in Fort Worth, no applicability or compliance determination can be made at this time.

Subpart JJJJ—Stationary Spark Ignition Internal Combustion Engines. This regulation, similar to Subpart IIII, applies to stationary spark ignition internal combustion engines of various sizes, dependent upon date of construction. Much of this regulation is applicable to engine manufacturers themselves, not the engine users. This rule limits combustion emissions (VOC, NO_x, and CO) from subject engines, which were not tested as part of this project. While this rule

may apply to engines used at natural gas well pads and compressor stations in Fort Worth, no applicability or compliance determination can be made at this time.

Subpart KKKK—Stationary Combustion Turbines. This regulation applies to stationary combustion turbines constructed, modified, or reconstructed after February 18, 2005. This rule limits NO_x and SO₂ emissions from subject facilities. ERG did not identify any gas turbines under Task 3.

6.1.4 National Emission Standards for Hazardous Air Pollutants

NESHAPs regulate HAPs from new and existing stationary sources. For the oil and gas industry, the potentially applicable NESHAPs include the following:

- Subpart H—Organic Hazardous Air Pollutants for Equipment Leaks
- Subpart V—Equipment Leaks (Fugitive Emission Sources)
- Subpart HH—Oil and Natural Gas Production Facilities
- Subpart VV—Oil-Water Separators and Organic-Water Separators
- Subpart HHH—Natural Gas Transmission and Storage Facilities
- Subpart YYYY—Stationary Combustion Turbines
- Subpart ZZZZ—Stationary Reciprocating Internal Combustion Engines

A brief discussion of each of these rules follows. Where possible, a preliminary determination of compliance and applicability status with respect to the sites visited under the point source task has been made. However, a formal and comprehensive compliance and applicability assessment is not possible for each facility without a complete record of construction, monitoring, and recordkeeping activities.

Many of the NESHAP regulations apply only to major HAP sources, those defined as emitting greater than 10 tpy of any single HAP, or 25 tpy of all HAPs combined. As a result of the point source testing task, three potential major HAP sources were identified, including two compressor stations (Site IDs PS-118 and PS-119) and the gas processing plant (Site ID PS-159). All of these facilities were determined to be major HAP sources due to formaldehyde emissions from their compressor engines. Due to the conservative nature of the emissions estimation approach used for these engines (24-hour-per-day, 365-day-per-year operation of all the engines at the facility without controls), a full compliance evaluation would need to be made to definitively conclude whether or not these facilities are major sources of HAP.

Subpart H—Organic Hazardous Air Pollutants for Equipment Leaks. This regulation applies to sources subject to other NESHAP rules under 40 CFR Part 63 that specifically point back to this rule. As such, any applicability under Subpart H would be referenced in the rules discussed below.

Subpart V—Equipment Leaks (Fugitive Emission Sources). This regulation applies to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or

lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems that are intended to operate in volatile HAP service. However, this rule is only triggered when the fluid or gas flowing through the equipment contains at least 10% by weight of a volatile HAP. No sources visited under Task 3 have volatile HAP concentrations of 10% or greater.

Subpart HH—Oil and Natural Gas Production Facilities. This regulation applies to oil and gas production facilities. There are different requirements for major and minor HAP sources, based on the magnitude of emissions. Requirements for major HAP sources include controlling HAP from tanks with flash emissions, controlling equipment leaks, and controlling glycol dehydrators. As discussed above, there are three potential major HAP sources that were visited that may be subject to the major source provisions of this regulation.

For minor HAP sources, there are limited requirements under this rule for triethylene glycol dehydration units, and those requirements are dependent upon the throughput or benzene emissions. For sources with benzene emissions less than 1 tpy, the only requirement is to maintain records verifying the benzene emission rate. There was one source visited under Task 3 that was estimated to emit over one tpy of benzene, the gas processing plant (PS-159). The remainder of the sites emitted less than one tpy of benzene. The only requirement applicable to these sources would be to keep records (as defined under the rule) of benzene emissions.

Subpart VV—Oil-Water Separators and Organic-Water Separators. This regulation applies to facilities that control air emissions from oil-water and organic-water separators. However, it only applies when another NESHAP subpart references it. No such facilities have been identified under this project.

Subpart HHH—Natural Gas Transmission and Storage Facilities. This regulation applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas before it enters the pipeline to a local distribution company or a final end user, and that are major sources of HAPs. A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. If applicable, this rule would require control of emissions from any glycol dehydration unit that emits more than 1 tpy of benzene. As mentioned above, the gas processing plant (PS-159) was the only facility estimated to emit over one tpy of benzene, with estimated benzene emissions at 1.2 tpy.

Subpart YYYY—Stationary Combustion Turbines. This regulation applies to stationary combustion turbines located at major sources of HAPs. ERG did not identify any stationary combustion turbines under Task 3.

Subpart ZZZZ—Stationary Reciprocating Internal Combustion Engines. This regulation applies to stationary reciprocating internal combustion engines located at major and area sources of HAPs. The applicability of this rule depends on both the construction date and the size of the engine. For many of the engines subject to this rule in Fort Worth, the only requirements are to comply with 40 CFR part 60 subpart IIII for compression ignition engines, or 40 CFR part 60 subpart JJJJ for spark ignition engines, as discussed in Section 6.1.3. Certain engines may also be required to specifically control formaldehyde emissions.

6.1.5 Greenhouse Gas Reporting Program

On November 8, 2010, EPA signed a rule that finalizes reporting requirements for the petroleum and natural gas industry under 40 CFR Part 98, the regulatory framework for the Greenhouse Gas Reporting Program. In short, Subpart W of Part 98 requires petroleum and natural gas facilities that emit 25,000 metric tons or more of CO₂ equivalent per year to report annual methane and CO₂ emissions from equipment leaks and venting, and emissions of CO₂, methane, and nitrous oxide from gas flaring and from onshore petroleum and natural gas production stationary and portable combustion emissions and combustion emissions from stationary equipment involved in natural gas distribution. However, this rule does not require facilities to report their emissions until March 31, 2012, at which time emissions for the 2011 calendar year will need to be reported for subject facilities.

Based on the results of the point source testing, there are several facilities with methane emissions from equipment leaks and venting that emit over 8,000 metric tons of CO₂ equivalents per year. In addition, emissions from compressor engine exhausts are likely to account for a significant amount of CO₂ (a single 2,000 hp engine may emit over 7,000 metric tons of CO₂ equivalents per year), which would result in many of the larger compressor stations exceeding the annual threshold of 25,000 metric tons of CO₂ equivalent emissions. As such, it appears that several facilities in the city of Fort Worth will be required to report their greenhouse gas emissions to EPA under this rule beginning in 2012.

However, it should be noted that there is some uncertainty as to the applicability of this rule, and EPA is currently actively providing guidance and rule interpretation to the oil and gas industry as they prepare to begin reporting emissions next year.

6.2 Texas Commission on Environmental Quality Air Quality Rules

Like EPA, TCEQ regulates air emissions from stationary sources related to upstream oil and gas facilities through a variety of regulatory mechanisms:

- PBRs
- Standard permits
- NSR permits
- Control of Air Pollution from Visible Emissions and Particulate Matter
- Control of Air Pollution from Sulfur Compounds
- Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants
- Control of Air Pollution from Volatile Organic Compounds
- Control of Air Pollution from Nitrogen Compounds
- Federal operating permits

These air quality regulations are discussed individually in Sections 6.2.1 through 6.2.9. Where possible, a preliminary determination of compliance and applicability status with respect

to the sites visited under the point source task has been made. However, a formal and comprehensive compliance and applicability assessment is not possible for each facility without a complete record of construction, monitoring, and recordkeeping activities.

6.2.1 Permit-by-Rules

PBRs are an abbreviated permitting mechanism provided by TCEQ to authorize emissions from new construction or modifications to existing facilities. PBR requirements are grouped by source types (e.g., stationary turbines and engines) and codified under Title 30 of the Texas Administrative Code (TAC), Chapter 106 (30 TAC 106). The most common PBR used to authorize new construction or modifications involving oil and gas exploration and production facilities is found under 30 TAC 106, Subchapter O, Section 106.352, "Oil and Gas Handling and Production Facilities." TCEQ updated this PBR in February 2011, significantly expanding the requirements for oil and gas handling and production facilities located in the Barnett Shale, including Tarrant County. Per the rule, these new requirements took effect in April 2011 and apply only to new or modified emissions sources.

Key Point: Permit-By Rule

TCEQ's PBR for Oil and Gas Handling and Production Facilities is the primary regulatory mechanism applicable to natural gas well pads and compressor stations in Fort Worth.

The new requirements include more stringent control requirements and emission limits. In addition to more stringent site-wide emission limits, the revised PBR requires a health effects demonstration using calculated emission limits based on ESLs for certain toxins and source specific characteristics. The maximum emission rates allowed by the new PBR for Level 2 Requirements are summarized in Table 6.2-1.

Table 6.2-1. New PBR Emission Rates

| Pollutant | Steady-state lb/hr | < 30 psig periodic lb/hr up to 300 hr/yr | ≥ 30 psig periodic lb/hr up to 300 hr/yr | Total tpy |
|--------------------------------------|-----------------------|---|---|-----------|
| Total VOC | | | | 25 |
| Total crude oil or condensate VOC | 100 | 145 | 318 | |
| Total natural gas VOC | 356 | 750 | 1,500 | |
| Benzene | 3.35 | 7 | 15.4 | 4.8 |
| Hydrogen sulfide | 6 | 6 | 9.8 | 25 |
| Sulfur dioxide | 63 | 93.2 | | 25 |
| Nitrogen oxides | 54.4 | | | 250 |
| Carbon monoxide | 57 | | | 250 |
| PM _{2.5} | 12.7 | | | 10 |
| PM ₁₀ | 12.7 | | | 15 |

The ESL based emission limits are site and source specific based on the source characteristics and the distance of the source relative to the nearest off-site receptor.

Based on the emission estimates developed under Task 3, most of the facilities surveyed would likely meet the new site-wide emissions limits if they were applicable, except for two compressor stations (Site IDs PS-118 and PS-127) and the gas processing facility (Site ID PS-159). The emissions estimates for CO from these three sites are above the CO lb/hr emission limits. A complete comparison to the new ESL based emission limits cannot be determined using the data collected during the point source testing.

As the new PBR rule was not in effect at the time of the point source testing, it is likely that most of the emissions sources located at the sites tested in Task 3 were previously authorized and were operating under the old PBR requirements outlined in 30 TAC Section 106.352(l). Under the old PBR requirements, total emissions could not exceed 25 tpy each of SO₂, all other sulfur compounds combined, or all VOCs combined or 250 tpy each of NO_x and CO. Total emissions of sulfur compounds, excluding sulfur oxides, from all vents could not exceed 4.0 pounds per hour. Through the point source testing task, three potential sources were identified, including two compressor stations (Site IDs PS-118 and PS-119) and the gas processing plant (Site ID PS-159), with site-wide emissions exceeding the 25 tpy VOC limit. Additionally, estimated CO emissions from two compressor stations (Site IDs PS-118 and PS-127) and the gas processing plant (Site ID PS-159) exceed the 250 tpy threshold. For each of these facilities, it appears that emissions from the natural gas compressor engines cause them to exceed PBR thresholds.

30 TAC Section 106.352(l) also requires compressors and flares to meet the requirements of §106.492 and §106.512 of 30 TAC (relating to flares and stationary engines and turbines, respectively). 30 TAC §106.512 limits NO_x emissions, depending on engine type (rich-burn or lean-burn), fuel type (gas-fired, dual fuel-fired, liquid fuel-fired) and manufacturing date.

Compliance with the emission specification requirements under the PBR rules cannot be determined using the data obtained at the time of the survey. Records of manufacturing dates and the dates in which existing sources were last modified would be required to complete a full compliance assessment for any individual facility.

6.2.2 Standard Permit

Similar to PBRs, standard permits are an abbreviated permitting mechanism provided by TCEQ to authorize emissions from new construction or modifications. However, standard permits generally require more stringent emission controls meeting what is considered the best available control technology (BACT). New construction or modifications involving oil and gas exploration and production facilities permitted by standard permit must meet the requirements provided under 30 TAC Chapter 116, Subchapter F, Section 116.620, "Installation and/or Modification of Oil and Gas Facilities." The standard permit issued by TCEQ often includes site-specific requirements including, but not limited to, site-wide and/or source-specific emission limits. While some of the facilities visited in Task 3 may have been authorized under a standard permit, no information on these was available during this review.

6.2.3 New Source Review Permits

New construction or projects involving modifications to existing facilities that cannot meet the requirements of an applicable PBR or standard permit must be authorized prior to start of construction under 30 TAC Chapter 116, Subchapter B, "New Source Review Permits." This permitting mechanism requires installation of either BACT or lowest achievable emission reductions, depending on whether the source is located in an attainment or a non-attainment area. Tarrant County is located in a non-attainment area for ozone, so the latter would be required for project sources emitting VOCs and NO_x; BACT would be required for all other project-related criteria pollutants. NSR permits also require two public notice periods and a health impacts review to evaluate to potential health impacts from certain toxins associated with the project-related emissions. The NSR permit issued by TCEQ often includes site-specific requirements including, but not limited to, site-wide and/or source-specific emission limits. NSR permits issued for the sites visited under Task 3 were considered outside the scope of this study, and were therefore not reviewed.

6.2.4 Control of Air Pollution from Visible Emissions and Particulate Matter

This rule regulates the amount of visible emissions and particulate matter that are permissible from any source operated in Texas. Visible emissions from stationary vents are not allowed to exceed opacities greater than 30% averaged over a six-minute period, 20% averaged over a six-minute period for any source on which construction was begun after January 31, 1972, or 15% averaged over a six-minute period for any source having a total flowrate greater than or equal to 100,000 actual cubic feet per minute, unless an optical instrument capable of measuring the opacity of emissions is installed in the vent. No visible emissions were observed from stationary vents located at the sites visited under Task 3. Visible emissions from a process gas flare used in routine or scheduled facility operations are not allowed for more than five minutes in any two-hour period. Two sites visited during Task 3 operated flares; however, compliance status with the requirements under this rule cannot be determined using the data obtained at the time of the survey. Compliance status with this requirement cannot be determined for the vents visited using the data obtained at the time of the survey. However, considering the nature of material (i.e., natural gas) being managed at the sites studied, the particulate matter emission rate limits specified are not expected to be exceeded.

6.2.5 Control of Air Pollution from Sulfur Compounds

This rule regulates the amount of sulfur compound emissions, particularly SO₂, H₂S, sulfuric acid, and total reduced sulfur, that are permissible from certain sources operated in Texas. Those sulfur compounds applicable to the operation of oil and gas facilities are SO₂ and H₂S. SO₂ emissions from a source or sources operated on a property or multiple sources operated on contiguous properties cannot cause an exceedance of a net ground level concentration of 0.4 parts per million by volume (ppmv) averaged over any 30-minute period. H₂S from a source or sources operated on a property or multiple sources operated on contiguous properties are also limited; the specific limit depends on the affected downwind sources.

Compliance with the ground-level concentration requirements under this rule cannot be determined using the data obtained at the time of the survey. As mentioned previously, the natural gas in the Barnett Shale is not considered to be sour natural gas, so this rule does not appear to apply to any facilities in Fort Worth.

6.2.6 Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants

This rule simply incorporates, by reference, all of the federal NESHAPs that regulate HAPs from new and existing stationary sources. Section 6.1.4 lists and briefly describes the potentially applicable NESHAPs for the oil and gas industry.

6.2.7 Control of Air Pollution from Volatile Organic Compounds

This rule regulates the amount of VOCs that are permissible from sources operated in Texas. The rule requirements are organized by source type under 30 TAC Chapter 115 and only apply to sources located in non-attainment areas specified in the rule. Those parts of the rule that are potentially subject to upstream oil and gas facilities are Subchapter B, Division 1, "Storage of VOCs"; Subchapter C, Division 1, "Loading and Unloading of VOCs"; and Subchapter D, Division 3, "Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Non-attainment Areas." Storage tanks containing VOCs including, but not limited to, crude or condensate must control emissions using control technologies specified in the rule. Control options vary depending on the size of the tank and its configuration. Loading of certain VOC materials must be controlled by a vapor control system that maintains a control efficiency of at least 90%, a vapor balance system, or pressurized loading. This rule also requires VOC leak detection and repair at natural gas/gasoline processing operations. Site PS-159 (the Crosstex Amine Treatment Center) could be subject to this rule.

Compliance status with the control and monitoring requirements under this rule cannot be determined using the data obtained at the time of the survey.

6.2.8 Control of Air Pollution from Nitrogen Compounds

This rule regulates the amount of nitrogen compounds that are permissible from sources operated in Texas. Similar to 30 TAC Chapter 115, the rule requirements for this chapter are organized by source type under 30 TAC Chapter 117 and only apply to sources located in non-attainment areas specified in the rule. Those parts of the rule that are most commonly subject to upstream oil and gas facilities are found under Subchapter D, "Combustion Control at Minor Sources in Ozone Non-attainment Areas." For the Dallas-Fort Worth area, including Tarrant County, NO_x emissions from stationary internal combustion engines at any minor stationary source of NO_x (a source that emits less than 250 tpy) are limited, depending on engine type and construction date. Most engines at sites visited under Task 3 would be subject to a limit of 0.50 grams of NO_x per hp per hour.

Compliance with the emission specification requirements under this rule cannot be determined using the data obtained at the time of the survey. Records of manufacturing dates and

the dates in which existing sources were last modified would be required to complete a full compliance assessment for any individual engine.

6.2.9 Federal Operating Permits

The Title V Federal Operating Permit Program is regulated under 30 TAC Chapter 122. Title V operating permits are required for any site that is a major source. A major source is a site which that emits, or has the potential to emit, 100 tpy or more of any air pollutant. A site is also considered a major source if it emits or has the potential to emit, in the aggregate, 10 tpy or more of any single hazardous air pollutant listed under the federal Clean Air Act or 25 tpy or more of any combination of hazardous air pollutants listed under the Act. One of the primary objectives of the Title V operating program is to assimilate in one document all of the requirements to which a facility is subject. The Title V permit serves as the key verification and documentation of a facility's compliance with all applicable requirements of the Texas and federal Clean Air Acts. Permit holders must annually certify compliance with the permit terms and conditions and submit semi-annual deviation reports in which they self-disclose known non-compliance activities during the reporting period.

Five potential major sources were identified, including three compressor stations (Site IDs PS-118, PS-119, PS-127), the gas processing plant (Site ID PS-159), and one well pad (Site ID 238). All of these facilities were determined to be major sources due to formaldehyde and/or CO emissions from their compressor engines. However, due to the conservative nature of the emissions estimation approach used for these engines (24-hour-per-day, 365-day-per-year operation of all the engines at the facility without controls), a full compliance evaluation would need to be made to definitively conclude whether or not these facilities are major sources and subject to the Title V Federal Operating Program.

6.3 City of Fort Worth Air Quality Rules

The city of Fort Worth's Gas Well Drilling Ordinance (Ordinance No. 18449-02-2009) has one provision that requires air emissions control. Under Section 15-42 of this ordinance, tank batteries with a rolling annual aggregate emissions rate of 25 tpy or more of VOC must use vapor recovery equipment with a 95% recovery efficiency. Based on the results of the point source testing under Task 3, two compressor stations (Site IDs PS-118 and PS-119) and the gas processing plant (Site ID PS-159) have facility-wide VOC emissions greater than 25 tpy. However, the majority of the VOC emissions at these sites come from non-tank emission points and the natural-gas-fired compression engines, and none of these facilities have VOC emissions from their storage tank batteries exceeding 25 tpy. Therefore, based on the results of Task 3, this rule does not appear to apply to any of the tested facilities.

6.4 Regulatory Assessment Conclusions

A regulatory assessment was conducted based on the results of the point source testing to determine if any facilities exceeded regulatory thresholds. For many of the rules potentially applicable to oil and gas sources in Fort Worth, we were unable to make a definitive determination on whether the source was subject to the rule, and/or whether the source was in

compliance with the rule. A full compliance evaluation for any individual site is an involved process that requires research into historical construction, operating, and production records and was beyond the scope of this study. However, based on the emission estimates developed under Task 3, the sources listed in Table 6.4-1 may exceed the regulatory thresholds discussed above.

Table 6.4-1. Sources Above Regulatory Thresholds

| Site ID | Site Type | VOC (tons/yr) | CO (tons/yr) | Total HAP (tons/yr) | Formaldehyde (tons/yr) |
|---------|---------------------|------------------|-----------------------|------------------------|---------------------------|
| PS-159 | Processing Facility | 80 ^a | 1,039 ^{b, c} | 47 ^d | 32 ^e |
| PS-118 | Compressor Station | 43 ^a | 270 ^{b, c} | 25 ^d | 17 ^e |
| PS-119 | Compressor Station | 38 ^a | 240 ^c | 22 | 15 ^e |
| PS-127 | Compressor Station | 24 | 545 ^{b, c} | 14 | 9 |
| 238 | Well Pad | 14 | 219 ^c | 8 | 6 |

^a This site potentially exceeds the 25 tpy VOC threshold under 30 TAC 106, Subchapter O, Section 106.352.

^b This site potentially exceeds the 250 tpy CO threshold under 30 TAC 106, Subchapter O, Section 106.352.

^c This site potentially exceeds the 100 tpy CO threshold under the federal Title V Operating Permit Program.

^d This site potentially exceeds the 25 tpy total HAP threshold under the federal Title V Operating Permit Program.

^e This site potentially exceeds the 10 tpy single HAP threshold under the federal Title V Operating Permit Program.

7.0 Full Build-Out Estimates

Over the last five years, there has been a dramatic increase in natural gas production in the Barnett Shale, and in the city of Fort Worth itself. The expansion of the natural gas industry within the city is expected to continue into the future, and emissions from these activities are also expected to increase. ERG has developed estimates of total emissions from natural gas production from 2010 to 2018, based on the results of the point source testing task. As described below, ERG projects that emissions from natural gas production will peak in 2012 and 2013, and will slowly decline over time as the known natural gas reserves in the Barnett Shale are depleted. In this context, “full build-out” means the point at which natural production will result in the maximum annual emissions. For purposes of this evaluation, total emissions from natural gas production activity are assumed to correlate to total natural gas production levels.

Key Point: Full Build-Out Estimates
ERG projects that emissions from natural gas production operations in Fort Worth will peak in 2012 and 2013 before beginning to decline.

This evaluation includes emissions from production activities (all emission sources found at producing well pads, compressor stations, and the gas processing plant), but does not include emissions from pre-production activities such as site construction, exploration (drilling), stimulation (fracking), or well completion.

One drilling operation, one fracking operation, and one well completion operation were visited under the point source testing task, and emissions estimates were developed for each of these operations. However, this information was insufficient to extrapolate to all drilling, fracking, and completion operations occurring in 2010 due to the variability in how these operations are conducted from well to well, and from operator to operator. Additionally, the single saltwater treatment facility located in Fort Worth was also visited. However, emissions at the time of the visit were determined to be very small (less than half a pound of VOC per year).

This section has five sub-sections:

- 7.1 Factors Affecting Natural Gas Production – This section describes the various factors that must be considered when predicting future natural gas production.
- 7.2 Methodology for Forecasting Natural Gas Production – A description of the methodology used to estimate future natural gas production is provided in this section.
- 7.3 2010 Base Year Emissions Inventory – Describes how the current (2010) emissions inventory was compiled.
- 7.4 2010 through 2018 Projected Emissions Inventories – This section describes how the emissions estimates for 2011 – 2018 were calculated.
- 7.5 Full Build-Out Estimates Conclusions – This section presents the conclusions of the full build-out component of this study.

7.1 Factors Affecting Natural Gas Production

Estimating the future production of natural gas depends upon several factors. The primary factors include the amount of recoverable natural gas in the Barnett Shale formation, the ability of operators to access the gas with available drilling and fracturing methods (amounts technically recoverable), and the economics of the extraction process (amounts economically recoverable). Other operational factors include the number of existing producing wells, the depletion rate of existing wells, the number of new wells drilled, and the initial production from new wells, all of which contribute to the amounts of gas technically recoverable. These operational factors depend on the wellhead price of natural gas (price received by producers) and the costs of extracting the gas.

Key Point: Drilling and Permit Activity

By 2010, the number of active drill rigs and the number of well pad permits issued by the City of Fort Worth were down nearly 60% from their 2008 highs.

While the amount of recoverable gas in the Barnett Shale is finite, there will still be technically recoverable natural gas decades from now. However, the rate at which this gas is extracted will depend on the price received and the costs of drilling wells, installing production infrastructure such as pipelines and compressor stations, and the costs of operating these facilities.

The amount of recoverable gas in the Barnett Shale area is unknown. Current estimates of gas reserves in the Barnett Shale vary from 25 to 30 trillion cubic feet. This is not an absolute figure, as estimates of proven reserves and recoverable reserves change year by year. Reserve estimates increase as new data is obtained from exploration and drilling activities, while gas reserves are depleted as gas is extracted from existing wells. The Barnett Shale is unique in that it is the first domestic shale gas play to be extensively drilled and developed. Therefore, there is a wealth of information available about the size of the resource. In 2007, the Perryman Group estimated economically recoverable reserves of gas in the Barnett Shale at 2 trillion cubic feet and technically recoverable reserves at 30 trillion cubic feet.²¹ The U.S. Energy Information Administration's most recent estimate of shale gas reserves for the three Texas Districts (Districts 5, 7B, and 9) that include Barnett Shale acreage is 26.47 trillion cubic feet.²²

Figure 7.1-1 shows natural gas production in the entire Barnett Shale and in Tarrant County since 1993.²³ Notice that, over time, production of shale gas in Tarrant County has mirrored the larger trend in the entire Barnett Shale region. Due to the availability of county-level data from the Railroad Commission of Texas, this analysis uses current and projected production data for Tarrant County as a surrogate to reflect current and projected production data for the city of Fort Worth.

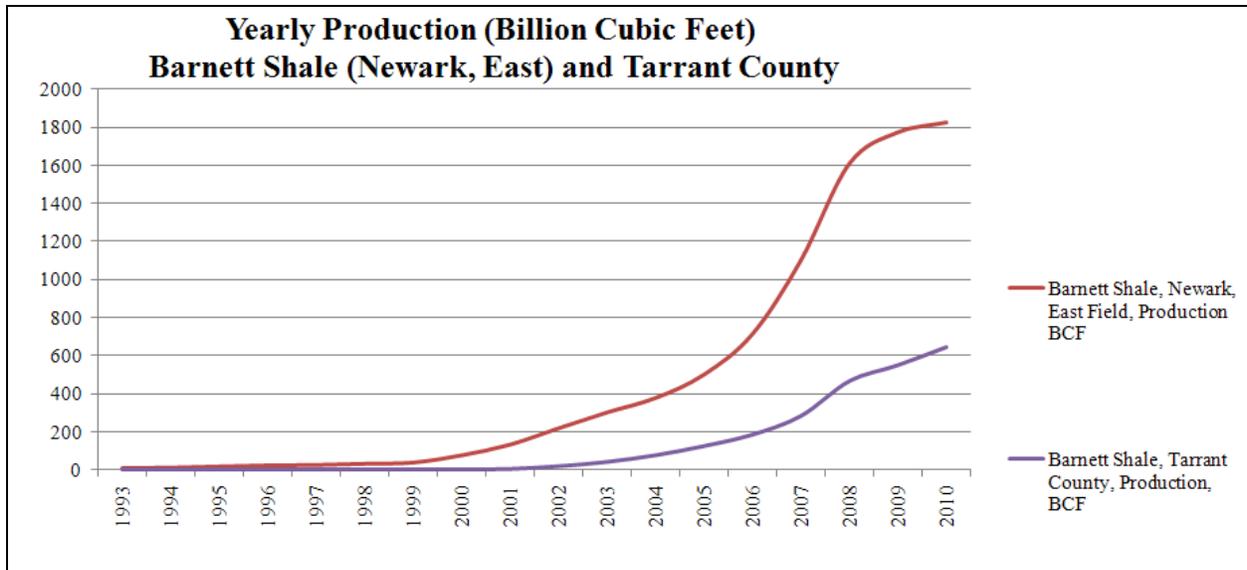


Figure 7.1-1. Natural Gas Production in the Barnett Shale and Tarrant County (1993–2010)

The price received for natural gas (the wellhead price) has a significant effect on the extent of exploration and the amount of gas produced. Higher wellhead prices stimulate increased exploration, drilling, and production. Figure 7.1-2 shows the monthly wellhead price of natural gas during the previous decade in which the shale gas underneath Tarrant and neighboring counties began to be extracted in significant amounts.²⁴ As can be seen in the figure, wellhead prices have fluctuated significantly over this time and peaked in 2008 before falling by more than 50% to current levels.

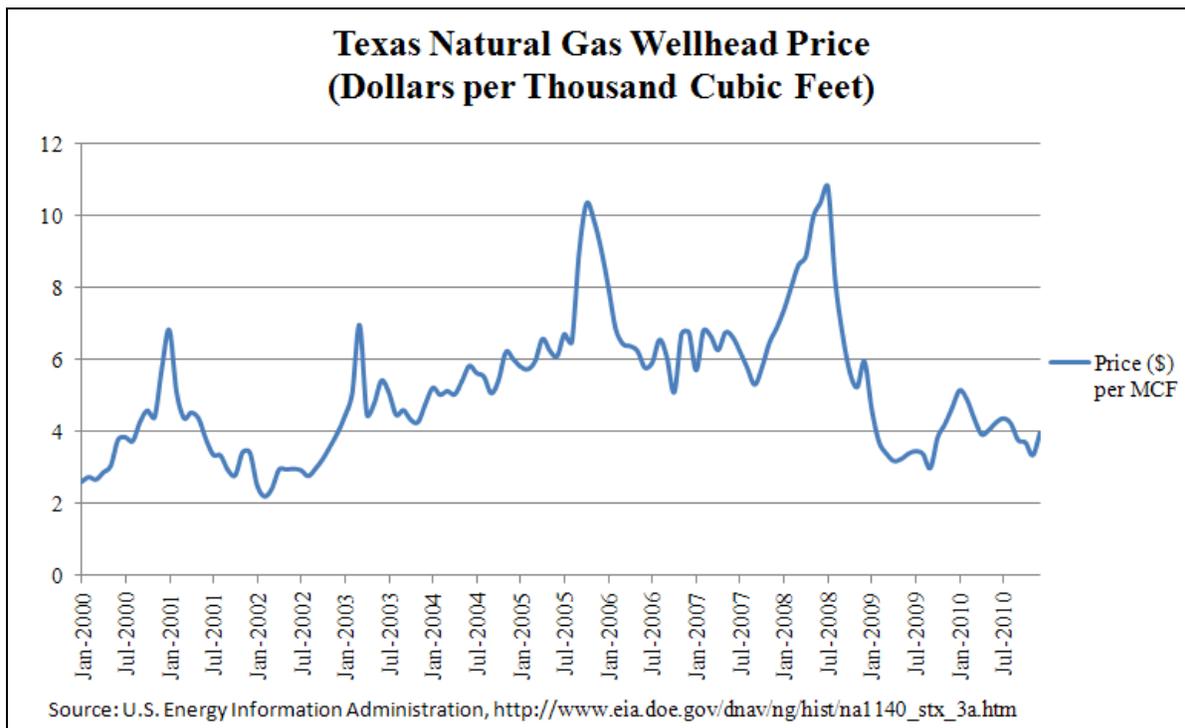


Figure 7.1-2. Texas Natural Gas Wellhead Price (2000–2010)

The U.S. Energy Information Administration, in its *Annual Energy Outlook Overview 2011*,²⁵ has forecast natural gas prices for the next 25 years. The Administration predicts that the average wellhead price for natural gas will increase by an average of 2.1% per year, to \$5.00 per million Btu in 2024 and to \$6.26 per million Btu in 2035 (2009 dollars). It should be noted that these estimates fall below the average wellhead natural gas prices between 2005 and 2008, indicating a less desirable economic climate for producers to invest in new drilling and production compared to the prices during the peak in these activities as discussed below.

Due to the depletion of existing wells, new wells must be drilled on a continuing basis to ensure a constant supply of natural gas. However, with current gas prices remaining relatively low, it may not make economic sense for producers to continue to invest in new production. Figure 7.1-3 shows the relationship between wellhead prices and drilling and permit activity over the last 10 years.

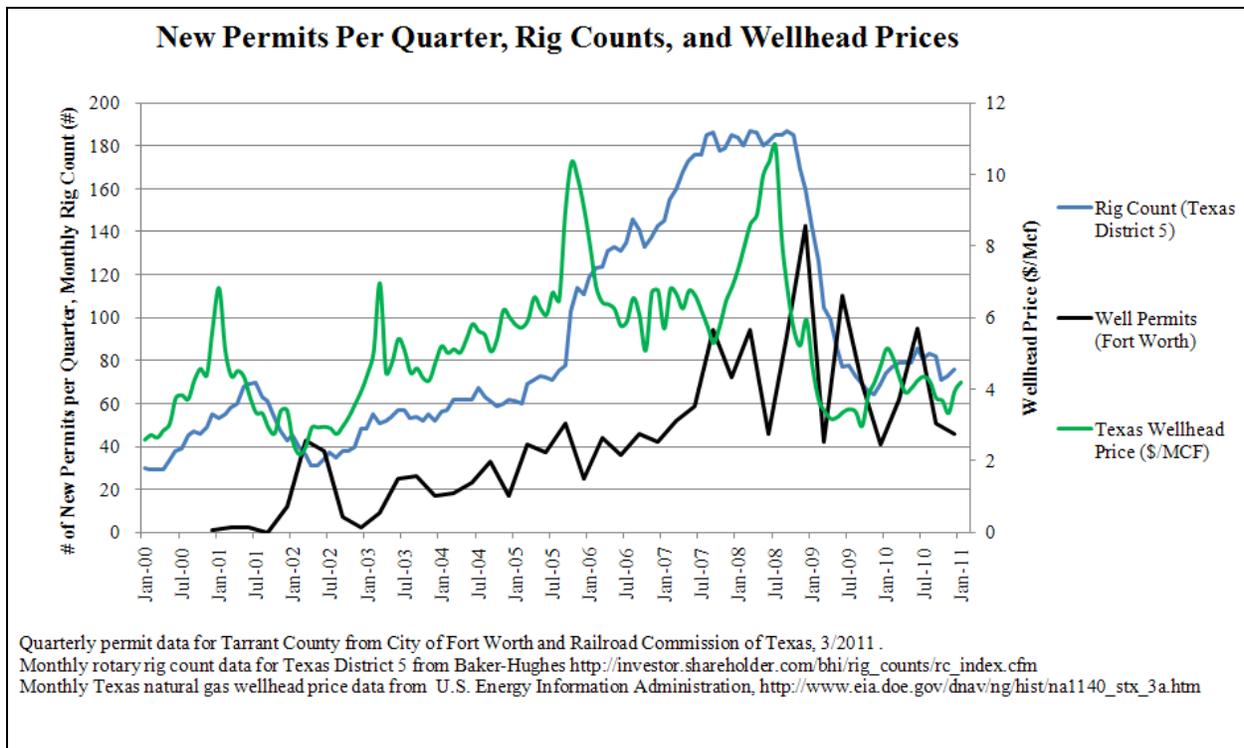


Figure 7.1-3. Permits, Rig Counts, and Wellhead Gas Prices in Tarrant County (2000–2010)

As shown in the figure, the number of active drilling rigs in District 5 (which includes Tarrant County) decreased dramatically in response to the drop in natural gas wellhead price beginning in August 2008.²⁶ Likewise, the number of well pad permits processed by the city of Fort Worth peaked shortly after the peak in natural gas wellhead price in 2008 and have trended downward since then. Prices dropped below \$7 per thousand cubic feet in September 2008, below \$6 per thousand cubic feet in October 2008. By 2010, both District 5 rig counts and the number of well pad permits issued by the city of Fort Worth were down nearly 60% from their highs in 2008.

7.2 Methodology for Forecasting Natural Gas Production

To estimate future emissions, an estimate of future natural gas production for the target years of 2010 through 2018 must be developed. In 2008, Tristone Capital estimated future production of shale gas in nine shale gas basins in the U.S. and Canada, including the Barnett Shale, for a 10-year period from 2008 to 2018.²⁷ Figure 7.2-1 shows Tristone’s estimates of future production for these eight shale gas plays.

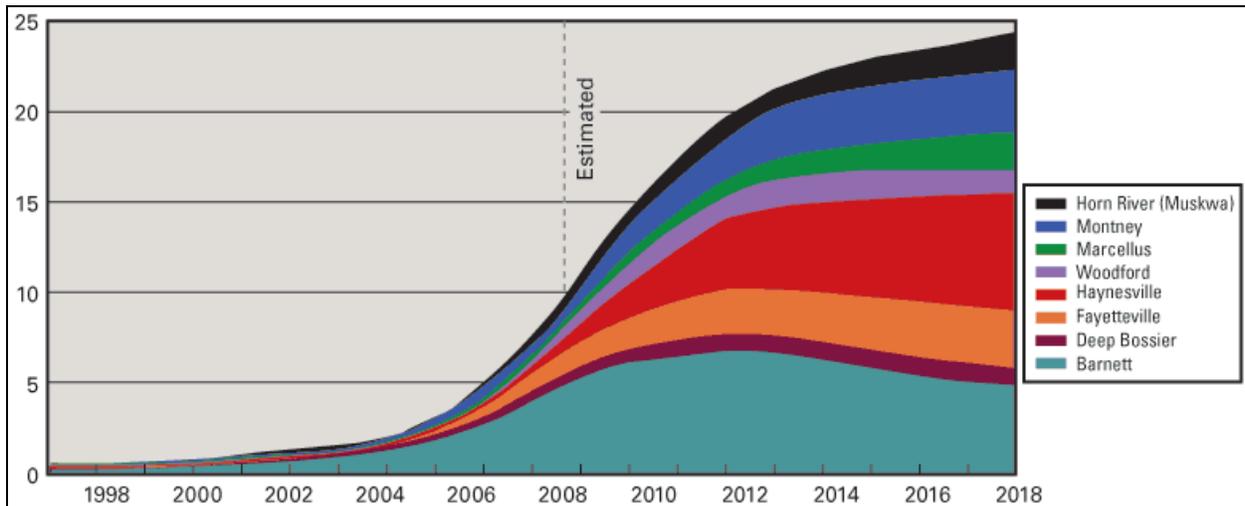


Figure 7.2-1. Projected Production in Eight Shale Plays (BCF) (1998–2018)

Tristone’s estimate of future production from the Barnett Shale is reproduced in Figure 7.2-2 as the purple dashed line in the graph. This data is compared with actual production data for the Barnett Shale as taken from the Railroad Commission of Texas (the solid red line). Actual production data for Tarrant County is also presented in the graph (the solid green line), as is projected production data for Tarrant County (the dashed turquoise line). To develop the projected production data for Tarrant County, it was assumed that the percentage growth in production in Tarrant County would increase (or decrease) at the same rate as the Barnett Shale as a whole.

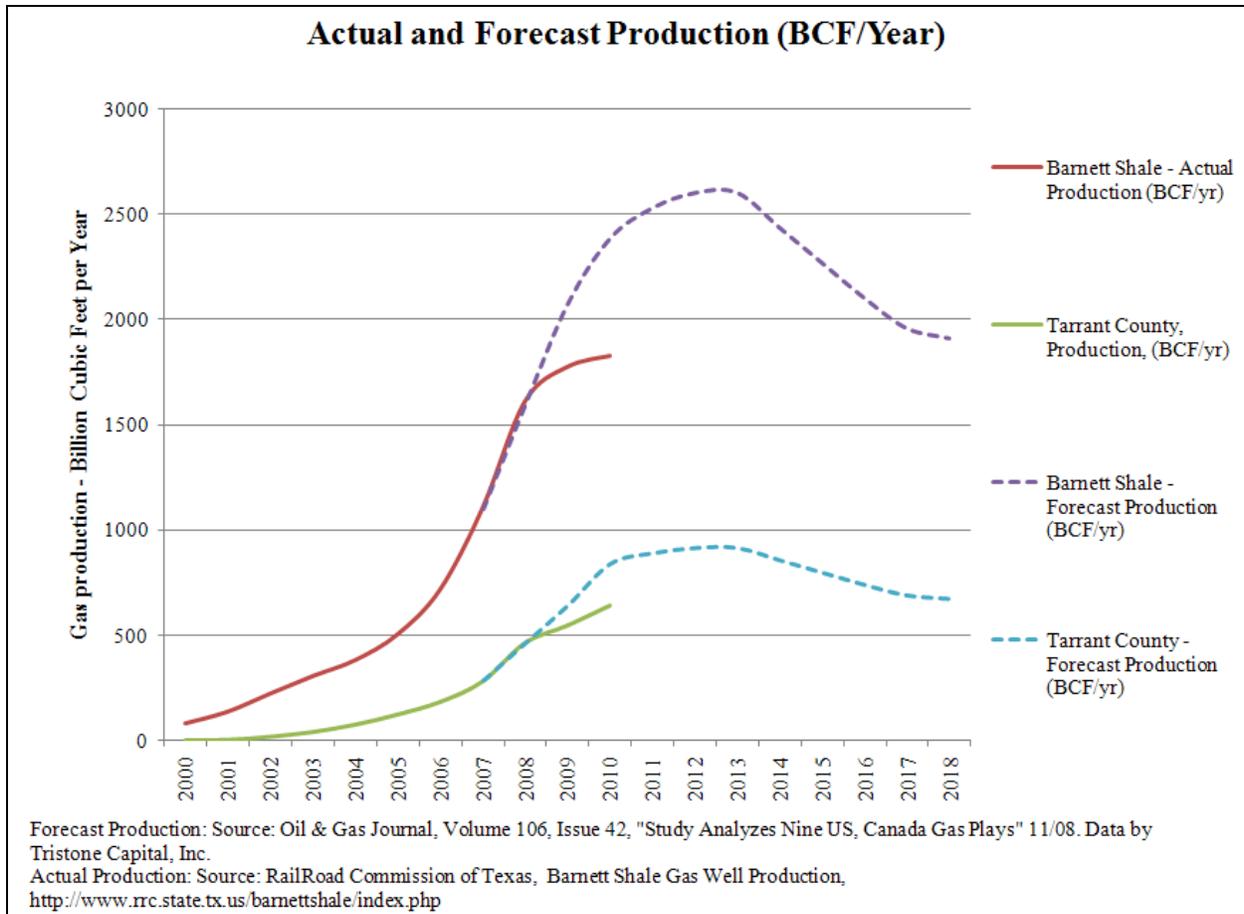


Figure 7.2-2. Barnett Shale and Tarrant County Actual and Projected Natural Gas Production (2000–2018)

As can be seen in the graph, Tristone’s estimates closely align with actual production through 2009, then appear to overestimate production. This may be attributed to the dramatic decrease in natural gas prices between 2008 and 2009, resulting in a decrease in drilling activity. Note that this decrease occurred after Tristone had published its projected trends in natural gas production activity. Therefore, ERG believes Tristone’s projections provide a conservative estimate of the peak natural gas production in the city of Fort Worth and has based the full build-out emissions inventory on this data, as described below.

7.3 2010 Base Year Emissions Inventory

Under Task 2 of the Fort Worth Natural Gas Air Quality Study, point source testing was conducted at 388 sites, including 375 well pads, eight compressor stations, and the gas processing plant. These data were used to calculate average emission rates for well pads and compressor stations. ERG used these average emission rates to develop a complete 2010 base year emissions inventory from natural gas production in the city of Fort Worth by multiplying the average emissions per well pad (and compressor station) by the total number of well pads (and compressor stations) operating in 2010. As documented in the Final Point Source Test Plan (October 4, 2010) there were 489 active well pads in the city of Fort Worth at the

commencement of this study. While data from the city of Fort Worth indicated there were 13 active compressor stations in Fort Worth at the start of this study, there were a total of 30 compressor stations either permitted, under construction, or already in service in 2010. Therefore, for purposes of developing the 2010 base year emissions inventory, it was assumed that there were 30 active compressor stations in Fort Worth in 2010.

Table 7.3-1 shows the average emissions for an individual well pad as determined from the point source testing, as well as the projected total 2010 base year emissions across all 489 well pads in the city of Fort Worth.

Table 7.3-1. 2010 Base Year Well Pad Emissions Inventory

| Pollutant | 2010 Base Year Average Well Pad Emissions (tons/yr) | 2010 Base Year Total Well Pad Emissions (tons/yr) |
|------------------------|--|--|
| TOC | 33.34 | 16,302.29 |
| VOCs | 0.68 | 332.71 |
| Total HAPs | 0.31 | 152.36 |
| Methane | 32.30 | 15,795.98 |
| PM | 0.03 | 13.57 |
| NO _x | 0.55 | 266.76 |
| CO | 4.77 | 2,330.62 |
| SO ₂ | 0.002 | 0.97 |
| Acenaphthene | 4.50E-06 | 2.20E-03 |
| Acenaphthylene | 1.87E-05 | 9.14E-03 |
| Acetaldehyde | 2.83E-02 | 1.38E+01 |
| Acetone | 2.52E-03 | 1.23E+00 |
| Acrolein | 2.63E-02 | 1.29E+01 |
| Anthracene | 2.43E-06 | 1.19E-03 |
| Benzene | 9.45E-03 | 4.62E+00 |
| Benzo (a) anthracene | 1.14E-06 | 5.56E-04 |
| Benzo (a) pyrene | 1.92E-08 | 9.39E-06 |
| Benzo (b) fluoranthene | 5.61E-07 | 2.74E-04 |
| Benzo (e) pyrene | 1.40E-06 | 6.86E-04 |
| Benzo (g,h,i) perylene | 1.40E-06 | 6.84E-04 |
| Benzo (k) fluoranthene | 1.44E-08 | 7.04E-06 |
| Biphenyl | 7.17E-04 | 3.51E-01 |
| Bromomethane | 4.98E-06 | 2.43E-03 |
| Butadiene, 1,3- | 2.79E-03 | 1.37E+00 |
| Butane | 8.33E-02 | 4.07E+01 |
| Butane, n- | 1.61E-02 | 7.85E+00 |

Table 7.3-1. 2010 Base Year Well Pad Emissions Inventory (Continued)

| Pollutant | 2010 Base Year Average Well Pad Emissions (tons/yr) | 2010 Base Year Total Well Pad Emissions (tons/yr) |
|--|---|---|
| Butanone (MEK), 2- | 3.08E-05 | 1.51E-02 |
| Carbon disulfide | 5.36E-06 | 2.62E-03 |
| Carbon tetrachloride | 2.10E-04 | 1.03E-01 |
| Chlorobenzene | 1.50E-04 | 7.34E-02 |
| Chlorodifluoromethane | 1.93E-06 | 9.43E-04 |
| Chloroethane | 1.14E-05 | 5.58E-03 |
| Chloroform | 1.59E-04 | 7.79E-02 |
| Chloromethane | 4.29E-06 | 2.10E-03 |
| Chlorotoluene, 2- | 6.64E-06 | 3.25E-03 |
| Chrysene | 2.34E-06 | 1.15E-03 |
| Cyclohexane | 4.81E-03 | 2.35E+00 |
| Cyclopentane | 7.67E-04 | 3.75E-01 |
| Decane, n- | 7.50E-04 | 3.67E-01 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 4.57E-06 | 2.24E-03 |
| Dichlorodifluoromethane | 3.83E-06 | 1.87E-03 |
| Dichloroethane, 1,1- | 1.32E-04 | 6.46E-02 |
| Dichloropropene, 1,3- | 1.48E-04 | 7.24E-02 |
| Dodecane, n- | 8.18E-05 | 4.00E-02 |
| Ethane | 3.55E-01 | 1.74E+02 |
| Ethylbenzene | 6.14E-04 | 3.00E-01 |
| Ethylene dibromide | 2.48E-04 | 1.21E-01 |
| Ethylene dichloride | 1.43E-04 | 6.98E-02 |
| Ethyltoluene, 4- | 2.69E-04 | 1.31E-01 |
| Fluoranthene | 3.75E-06 | 1.84E-03 |
| Fluorene | 1.92E-05 | 9.37E-03 |
| Formaldehyde | 1.87E-01 | 9.13E+01 |
| Heptane | 1.35E-02 | 6.58E+00 |
| Hexachlorobutadiene | 4.33E-05 | 2.12E-02 |
| Hexane | 1.66E-02 | 8.12E+00 |
| Indeno(1,2,3-cd) pyrene | 3.36E-08 | 1.64E-05 |
| Isobutane | 1.27E-02 | 6.20E+00 |
| Isobutyraldehyde | 1.48E-03 | 7.23E-01 |
| Isopentane | 2.91E-02 | 1.42E+01 |
| Isopropylbenzene | 9.36E-05 | 4.58E-02 |
| Isopropyltoluene, 4- | 1.15E-04 | 5.63E-02 |
| Methyl alcohol | 1.03E-02 | 5.06E+00 |
| Methyl Naphthalene, 2- | 1.12E-04 | 5.49E-02 |
| Methyl-2-pentanone, 4- (MIBK) | 5.59E-05 | 2.73E-02 |
| Methylcyclohexane | 4.16E-03 | 2.03E+00 |
| Methylene chloride | 2.44E-03 | 1.19E+00 |
| Naphthalene | 3.72E-04 | 1.82E-01 |
| Nonane, n- | 1.07E-02 | 5.21E+00 |

Table 7.3-1. 2010 Base Year Well Pad Emissions Inventory (Continued)

| Pollutant | 2010 Base Year Average Well Pad Emissions (tons/yr) | 2010 Base Year Total Well Pad Emissions (tons/yr) |
|--|---|---|
| Octane, n- | 1.47E-02 | 7.18E+00 |
| Pentane, n- | 2.99E-02 | 1.46E+01 |
| Perylene | 1.68E-08 | 8.22E-06 |
| Phenanthrene | 3.52E-05 | 1.72E-02 |
| Phenol | 1.42E-04 | 6.96E-02 |
| Polycyclic Aromatic Hydrocarbons (PAH) | 4.77E-04 | 2.33E-01 |
| Propane | 1.42E-01 | 6.93E+01 |
| Propylbenzene, n- | 1.42E-04 | 6.94E-02 |
| Propylene | 1.42E-05 | 6.94E-03 |
| Propylene dichloride | 1.51E-04 | 7.37E-02 |
| Pyrene | 4.60E-06 | 2.25E-03 |
| sec-Butylbenzene | 6.80E-05 | 3.32E-02 |
| Styrene | 1.90E-04 | 9.31E-02 |
| Tetrachloroethane, 1,1,2,2- | 2.24E-04 | 1.10E-01 |
| Tetrachloroethene | 1.37E-04 | 6.69E-02 |
| Toluene | 1.35E-02 | 6.62E+00 |
| Trichlorobenzene, 1,2,3- | 6.96E-05 | 3.41E-02 |
| Trichlorobenzene, 1,2,4- | 5.18E-05 | 2.53E-02 |
| Trichloroethane, 1,1,2- | 1.78E-04 | 8.71E-02 |
| Trichlorofluoromethane | 5.63E-06 | 2.75E-03 |
| Trimethylbenzene, 1,2,3- | 1.20E-04 | 5.85E-02 |
| Trimethylbenzene, 1,2,4- | 9.67E-04 | 4.73E-01 |
| Trimethylbenzene, 1,3,5- | 6.37E-04 | 3.12E-01 |
| Trimethylpentane, 2,2,4- | 2.90E-03 | 1.42E+00 |
| Undecane, n- | 1.68E-04 | 8.20E-02 |
| Vinyl acetate | 2.51E-05 | 1.23E-02 |
| Vinyl bromide | 6.03E-06 | 2.95E-03 |
| Vinyl chloride | 8.64E-05 | 4.23E-02 |
| Xylene, o | 5.58E-04 | 2.73E-01 |
| Xylenes (isomers) | 9.06E-04 | 4.43E-01 |
| Xylenes, m-, p- | 5.92E-03 | 2.90E+00 |

Table 7.3-2 shows the average emissions for an individual compressor station as determined from the point source testing, as well as the projected total 2010 base year emissions across all 30 compressor stations in the city of Fort Worth.

Table 7.3-2. 2010 Base Year Compressor Station Emissions Inventory

| Pollutant | 2010 Base Year Average Compressor Station Emissions (tons/yr) | 2010 Base Year Total Compressor Station Emissions (tons/yr) |
|--|---|---|
| TOC | 99.61 | 2,988.29 |
| VOCs | 17.20 | 515.86 |
| Total HAPs | 10.17 | 304.95 |
| Methane | 69.37 | 2,080.99 |
| PM | 0.36 | 10.94 |
| NO _x | 19.63 | 588.88 |
| CO | 151.47 | 4,544.19 |
| SO ₂ | 0.07 | 2.17 |
| Acenaphthene | 1.65E-04 | 4.96E-03 |
| Acenaphthylene | 6.87E-04 | 2.06E-02 |
| Acetaldehyde | 1.04E+00 | 3.12E+01 |
| Acetone | 6.63E-04 | 1.99E-02 |
| Acrolein | 9.67E-01 | 2.90E+01 |
| Anthracene | 8.92E-05 | 2.68E-03 |
| Benzene | 2.44E-01 | 7.31E+00 |
| Benzo (a) anthracene | 4.18E-05 | 1.25E-03 |
| Benzo (a) pyrene | 7.06E-07 | 2.12E-05 |
| Benzo (b) fluoranthene | 2.06E-05 | 6.19E-04 |
| Benzo (e) pyrene | 5.16E-05 | 1.55E-03 |
| Benzo (g,h,i) perylene | 5.14E-05 | 1.54E-03 |
| Benzo (k) fluoranthene | 5.29E-07 | 1.59E-05 |
| Biphenyl | 2.63E-02 | 7.90E-01 |
| Bromomethane | 7.78E-06 | 2.33E-04 |
| Butadiene, 1,3- | 1.02E-01 | 3.06E+00 |
| Butane | 2.65E-02 | 7.94E-01 |
| Butane, n- | 5.90E-01 | 1.77E+01 |
| Butanone (MEK), 2- | 2.76E-05 | 8.28E-04 |
| Carbon disulfide | 1.44E-06 | 4.32E-05 |
| Carbon tetrachloride | 7.55E-03 | 2.27E-01 |
| Chlorobenzene | 5.52E-03 | 1.66E-01 |
| Chlorodifluoromethane | 3.02E-06 | 9.05E-05 |
| Chloroethane | 2.40E-04 | 7.21E-03 |
| Chloroform | 5.85E-03 | 1.76E-01 |
| Chloromethane | 4.48E-06 | 1.34E-04 |
| Chlorotoluene, 2- | 1.04E-05 | 3.12E-04 |
| Chrysene | 8.61E-05 | 2.58E-03 |
| Cyclohexane | 3.94E-02 | 1.18E+00 |
| Cyclopentane | 2.82E-02 | 8.46E-01 |
| Decane, n- | 9.74E-05 | 2.92E-03 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 7.14E-06 | 2.14E-04 |
| Dichlorodifluoromethane | 5.99E-06 | 1.80E-04 |
| Dichloroethane, 1,1- | 4.86E-03 | 1.46E-01 |
| Dichloropropene, 1,3- | 5.44E-03 | 1.63E-01 |

Table 7.3-2. 2010 Base Year Compressor Station Emissions Inventory (Continued)

| Pollutant | 2010 Base Year Average Compressor Station Emissions (tons/yr) | 2010 Base Year Total Compressor Station Emissions (tons/yr) |
|--|---|---|
| Dodecane, n- | 4.57E-05 | 1.37E-03 |
| Ethane | 1.30E+01 | 3.91E+02 |
| Ethylbenzene | 1.35E-02 | 4.05E-01 |
| Ethylene dibromide | 9.12E-03 | 2.74E-01 |
| Ethylene dichloride | 5.24E-03 | 1.57E-01 |
| Ethyltoluene, 4- | 7.55E-03 | 2.27E-01 |
| Fluoranthene | 1.38E-04 | 4.14E-03 |
| Fluorene | 7.05E-04 | 2.11E-02 |
| Formaldehyde | 6.86E+00 | 2.06E+02 |
| Heptane | 2.76E-04 | 8.27E-03 |
| Hexachlorobutadiene | 4.91E-05 | 1.47E-03 |
| Hexane | 1.39E-01 | 4.16E+00 |
| Indeno(1,2,3-cd) pyrene | 1.23E-06 | 3.70E-05 |
| Isobutane | 4.66E-01 | 1.40E+01 |
| Isobutyraldehyde | 5.43E-02 | 1.63E+00 |
| Isopentane | 6.77E-03 | 2.03E-01 |
| Isopropylbenzene | 1.29E-04 | 3.86E-03 |
| Isopropyltoluene, 4- | 2.86E-04 | 8.59E-03 |
| Methyl alcohol | 3.80E-01 | 1.14E+01 |
| Methyl Naphthalene, 2- | 4.13E-03 | 1.24E-01 |
| Methyl-2-pentanone, 4- (MIBK) | 1.33E-04 | 3.98E-03 |
| Methylcyclohexane | 1.53E-01 | 4.59E+00 |
| Methylene chloride | 1.83E-02 | 5.49E-01 |
| Naphthalene | 1.21E-02 | 3.64E-01 |
| Nonane, n- | 1.38E-02 | 4.15E-01 |
| Octane, n- | 4.37E-02 | 1.31E+00 |
| Pentane, n- | 3.26E-01 | 9.78E+00 |
| Perylene | 6.18E-07 | 1.85E-05 |
| Phenanthrene | 1.29E-03 | 3.88E-02 |
| Phenol | 5.23E-03 | 1.57E-01 |
| Polycyclic Aromatic Hydrocarbons (PAH) | 1.75E-02 | 5.26E-01 |
| Propane | 5.21E+00 | 1.56E+02 |
| Propylbenzene, n- | 2.84E-03 | 8.51E-02 |
| Propylene | 1.59E-05 | 4.78E-04 |
| Propylene dichloride | 5.54E-03 | 1.66E-01 |
| Pyrene | 1.69E-04 | 5.07E-03 |
| sec-Butylbenzene | 3.57E-04 | 1.07E-02 |
| Styrene | 6.81E-03 | 2.04E-01 |
| Tetrachloroethane, 1,1,2,2- | 8.24E-03 | 2.47E-01 |
| Tetrachloroethene | 3.62E-05 | 1.09E-03 |
| Toluene | 1.21E-01 | 3.64E+00 |
| Trichlorobenzene, 1,2,3- | 8.35E-05 | 2.51E-03 |

Table 7.3-2. 2010 Base Year Compressor Station Emissions Inventory (Continued)

| Pollutant | 2010 Base Year Average Compressor Station Emissions (tons/yr) | 2010 Base Year Total Compressor Station Emissions (tons/yr) |
|--------------------------|---|---|
| Trichlorobenzene, 1,2,4- | 5.63E-05 | 1.69E-03 |
| Trichloroethane, 1,1,2- | 6.55E-03 | 1.96E-01 |
| Trichlorofluoromethane | 8.81E-06 | 2.64E-04 |
| Trimethylbenzene, 1,2,3- | 4.40E-03 | 1.32E-01 |
| Trimethylbenzene, 1,2,4- | 4.66E-02 | 1.40E+00 |
| Trimethylbenzene, 1,3,5- | 1.25E-02 | 3.75E-01 |
| Trimethylpentane, 2,2,4- | 1.05E-01 | 3.15E+00 |
| Undecane, n- | 4.54E-05 | 1.36E-03 |
| Vinyl acetate | 7.23E-06 | 2.17E-04 |
| Vinyl bromide | 9.43E-06 | 2.83E-04 |
| Vinyl chloride | 3.07E-03 | 9.22E-02 |
| Xylene, o | 1.89E-04 | 5.68E-03 |
| Xylenes (isomers) | 3.33E-02 | 9.99E-01 |
| Xylenes, m-, p- | 3.30E-04 | 9.89E-03 |

Table 7.3-3 shows the cumulative 2010 base year emissions from all compressor stations, well pads, and the gas processing plant in the city of Fort Worth, combined.

Table 7.3-3. 2010 Base Year Cumulative Emissions Inventory

| Pollutant | 2010 Compressor Station Emissions (tons/yr) | 2010 Well Pad Emissions (tons/yr) | 2010 Processing Plant Emissions (tons/yr) | 2010 Total Emissions (tons/yr) |
|------------------------|---|-----------------------------------|---|--------------------------------|
| TOC | 2,988.29 | 16,302.29 | 1,293.26 | 20,583.84 |
| VOCs | 515.86 | 332.71 | 79.93 | 928.51 |
| Total HAPs | 304.95 | 152.36 | 47.32 | 504.63 |
| Methane | 2,080.99 | 15,795.98 | 1,152.60 | 19,029.56 |
| PM | 10.94 | 13.57 | 1.00 | 25.51 |
| NO _x | 588.88 | 266.76 | 87.74 | 943.38 |
| CO | 4,544.19 | 2,330.62 | 1,038.90 | 7,913.71 |
| SO ₂ | 2.17 | 0.97 | 0.34 | 3.48 |
| Acenaphthene | 4.96E-03 | 2.20E-03 | 7.69E-04 | 7.93E-03 |
| Acenaphthylene | 2.06E-02 | 9.14E-03 | 3.20E-03 | 3.30E-02 |
| Acetaldehyde | 3.12E+01 | 1.38E+01 | 4.84E+00 | 4.98E+01 |
| Acetone | 1.99E-02 | 1.23E+00 | 2.35E-04 | 1.25E+00 |
| Acrolein | 2.90E+01 | 1.29E+01 | 4.50E+00 | 4.64E+01 |
| Anthracene | 2.68E-03 | 1.19E-03 | 4.15E-04 | 4.28E-03 |
| Benzene | 7.31E+00 | 4.62E+00 | 1.14E+00 | 1.31E+01 |
| Benzo (a) anthracene | 1.25E-03 | 5.56E-04 | 1.94E-04 | 2.00E-03 |
| Benzo (a) pyrene | 2.12E-05 | 9.39E-06 | 3.29E-06 | 3.39E-05 |
| Benzo (b) fluoranthene | 6.19E-04 | 2.74E-04 | 9.60E-05 | 9.89E-04 |
| Benzo (e) pyrene | 1.55E-03 | 6.86E-04 | 2.40E-04 | 2.47E-03 |
| Benzo (g,h,i) perylene | 1.54E-03 | 6.84E-04 | 2.39E-04 | 2.47E-03 |
| Benzo (k) fluoranthene | 1.59E-05 | 7.04E-06 | 2.46E-06 | 2.54E-05 |
| Biphenyl | 7.90E-01 | 3.51E-01 | 1.23E-01 | 1.26E+00 |
| Bromomethane | 2.33E-04 | 2.43E-03 | 9.34E-07 | 2.67E-03 |
| Butadiene, 1,3- | 3.06E+00 | 1.37E+00 | 4.74E-01 | 4.90E+00 |
| Butane | 7.94E-01 | 4.07E+01 | 2.15E-01 | 4.17E+01 |
| Butane, n- | 1.77E+01 | 7.85E+00 | 2.75E+00 | 2.83E+01 |
| Butanone (MEK), 2- | 8.28E-04 | 1.51E-02 | 2.58E-05 | 1.59E-02 |
| Carbon disulfide | 4.32E-05 | 2.62E-03 | 7.25E-06 | 2.67E-03 |
| Carbon tetrachloride | 2.27E-01 | 1.03E-01 | 3.51E-02 | 3.64E-01 |
| Chlorobenzene | 1.66E-01 | 7.34E-02 | 2.57E-02 | 2.65E-01 |
| Chlorodifluoromethane | 9.05E-05 | 9.43E-04 | 3.62E-07 | 1.03E-03 |
| Chloroethane | 7.21E-03 | 5.58E-03 | 1.08E-03 | 1.39E-02 |
| Chloroform | 1.76E-01 | 7.79E-02 | 2.72E-02 | 2.81E-01 |
| Chloromethane | 1.34E-04 | 2.10E-03 | 1.07E-04 | 2.34E-03 |

Table 7.3-3. 2010 Base Year Cumulative Emissions Inventory (Continued)

| Pollutant | 2010 Compressor Station Emissions (tons/yr) | 2010 Well Pad Emissions (tons/yr) | 2010 Processing Plant Emissions (tons/yr) | 2010 Total Emissions (tons/yr) |
|--|---|-----------------------------------|---|--------------------------------|
| Chlorotoluene, 2- | 3.12E-04 | 3.25E-03 | 1.25E-06 | 3.56E-03 |
| Chrysene | 2.58E-03 | 1.15E-03 | 4.01E-04 | 4.13E-03 |
| Cyclohexane | 1.18E+00 | 2.35E+00 | 1.91E-01 | 3.72E+00 |
| Cyclopentane | 8.46E-01 | 3.75E-01 | 1.31E-01 | 1.35E+00 |
| Decane, n- | 2.92E-03 | 3.67E-01 | 5.97E-05 | 3.70E-01 |
| Dichloro-1,1,2,2-tetrafluoroethane, 1,2- | 2.14E-04 | 2.24E-03 | 8.57E-07 | 2.45E-03 |
| Dichlorodifluoromethane | 1.80E-04 | 1.87E-03 | 7.19E-07 | 2.05E-03 |
| Dichloroethane, 1,1- | 1.46E-01 | 6.46E-02 | 2.26E-02 | 2.33E-01 |
| Dichloropropene, 1,3- | 1.63E-01 | 7.24E-02 | 2.53E-02 | 2.61E-01 |
| Dodecane, n- | 1.37E-03 | 4.00E-02 | 4.25E-05 | 4.14E-02 |
| Ethane | 3.91E+02 | 1.74E+02 | 6.07E+01 | 6.26E+02 |
| Ethylbenzene | 4.05E-01 | 3.00E-01 | 6.27E-02 | 7.68E-01 |
| Ethylene dibromide | 2.74E-01 | 1.21E-01 | 4.25E-02 | 4.37E-01 |
| Ethylene dichloride | 1.57E-01 | 6.98E-02 | 2.44E-02 | 2.51E-01 |
| Ethyltoluene, 4- | 2.27E-01 | 1.31E-01 | 8.90E-05 | 3.58E-01 |
| Fluoranthene | 4.14E-03 | 1.84E-03 | 6.42E-04 | 6.62E-03 |
| Fluorene | 2.11E-02 | 9.37E-03 | 3.28E-03 | 3.38E-02 |
| Formaldehyde | 2.06E+02 | 9.13E+01 | 3.19E+01 | 3.29E+02 |
| Heptane | 8.27E-03 | 6.58E+00 | 2.75E-03 | 6.59E+00 |
| Hexachlorobutadiene | 1.47E-03 | 2.12E-02 | 2.60E-05 | 2.27E-02 |
| Hexane | 4.16E+00 | 8.12E+00 | 6.52E-01 | 1.29E+01 |
| Indeno(1,2,3-cd) pyrene | 3.70E-05 | 1.64E-05 | 5.74E-06 | 5.92E-05 |
| Isobutane | 1.40E+01 | 6.20E+00 | 2.17E+00 | 2.23E+01 |
| Isobutyraldehyde | 1.63E+00 | 7.23E-01 | 2.53E-01 | 2.60E+00 |
| Isopentane | 2.03E-01 | 1.42E+01 | 4.54E-02 | 1.45E+01 |
| Isopropylbenzene | 3.86E-03 | 4.58E-02 | 5.43E-05 | 4.97E-02 |
| Isopropyltoluene, 4- | 8.59E-03 | 5.63E-02 | 5.43E-05 | 6.50E-02 |
| Methyl alcohol | 1.14E+01 | 5.06E+00 | 1.77E+00 | 1.82E+01 |
| Methyl Naphthalene, 2- | 1.24E-01 | 5.49E-02 | 1.92E-02 | 1.98E-01 |
| Methyl-2-pentanone, 4- (MIBK) | 3.98E-03 | 2.73E-02 | 1.65E-05 | 3.13E-02 |
| Methylcyclohexane | 4.59E+00 | 2.03E+00 | 7.11E-01 | 7.33E+00 |
| Methylene chloride | 5.49E-01 | 1.19E+00 | 8.53E-02 | 1.83E+00 |
| Naphthalene | 3.64E-01 | 1.82E-01 | 5.62E-02 | 6.02E-01 |
| Nonane, n- | 4.15E-01 | 5.21E+00 | 6.41E-02 | 5.69E+00 |
| Octane, n- | 1.31E+00 | 7.18E+00 | 2.04E-01 | 8.69E+00 |
| Pentane, n- | 9.78E+00 | 1.46E+01 | 1.54E+00 | 2.60E+01 |
| Perylene | 1.85E-05 | 8.22E-06 | 2.87E-06 | 2.96E-05 |
| Phenanthrene | 3.88E-02 | 1.72E-02 | 6.01E-03 | 6.20E-02 |
| Phenol | 1.57E-01 | 6.96E-02 | 2.43E-02 | 2.51E-01 |

Table 7.3-3. 2010 Base Year Cumulative Emissions Inventory (Continued)

| Pollutant | 2010 Compressor Station Emissions (tons/yr) | 2010 Well Pad Emissions (tons/yr) | 2010 Processing Plant Emissions (tons/yr) | 2010 Total Emissions (tons/yr) |
|--|---|-----------------------------------|---|--------------------------------|
| Polycyclic Aromatic Hydrocarbons (PAH) | 5.26E-01 | 2.33E-01 | 8.15E-02 | 8.40E-01 |
| Propane | 1.56E+02 | 6.93E+01 | 2.42E+01 | 2.50E+02 |
| Propylbenzene, n- | 8.51E-02 | 6.94E-02 | 6.59E-05 | 1.55E-01 |
| Propylene | 4.78E-04 | 6.94E-03 | 6.06E-06 | 7.43E-03 |
| Propylene dichloride | 1.66E-01 | 7.37E-02 | 2.58E-02 | 2.66E-01 |
| Pyrene | 5.07E-03 | 2.25E-03 | 7.87E-04 | 8.11E-03 |
| sec-Butylbenzene | 1.07E-02 | 3.32E-02 | 3.95E-05 | 4.40E-02 |
| Styrene | 2.04E-01 | 9.31E-02 | 3.17E-02 | 3.29E-01 |
| Tetrachloroethane, 1,1,2,2- | 2.47E-01 | 1.10E-01 | 3.83E-02 | 3.95E-01 |
| Tetrachloroethene | 1.09E-03 | 6.69E-02 | 1.83E-04 | 6.81E-02 |
| Toluene | 3.64E+00 | 6.62E+00 | 5.63E-01 | 1.08E+01 |
| Trichlorobenzene, 1,2,3- | 2.51E-03 | 3.41E-02 | 3.74E-05 | 3.66E-02 |
| Trichlorobenzene, 1,2,4- | 1.69E-03 | 2.53E-02 | 3.39E-05 | 2.70E-02 |
| Trichloroethane, 1,1,2- | 1.96E-01 | 8.71E-02 | 3.05E-02 | 3.14E-01 |
| Trichlorofluoromethane | 2.64E-04 | 2.75E-03 | 1.06E-06 | 3.02E-03 |
| Trimethylbenzene, 1,2,3- | 1.32E-01 | 5.85E-02 | 2.05E-02 | 2.11E-01 |
| Trimethylbenzene, 1,2,4- | 1.40E+00 | 4.73E-01 | 6.43E-02 | 1.94E+00 |
| Trimethylbenzene, 1,3,5- | 3.75E-01 | 3.12E-01 | 1.97E-02 | 7.07E-01 |
| Trimethylpentane, 2,2,4- | 3.15E+00 | 1.42E+00 | 4.89E-01 | 5.06E+00 |
| Undecane, n- | 1.36E-03 | 8.20E-02 | 7.17E-05 | 8.34E-02 |
| Vinyl acetate | 2.17E-04 | 1.23E-02 | 3.64E-05 | 1.25E-02 |
| Vinyl bromide | 2.83E-04 | 2.95E-03 | 1.13E-06 | 3.23E-03 |
| Vinyl chloride | 9.22E-02 | 4.23E-02 | 1.43E-02 | 1.49E-01 |
| Xylene, o | 5.68E-03 | 2.73E-01 | 2.87E-04 | 2.79E-01 |
| Xylenes (isomers) | 9.99E-01 | 4.43E-01 | 1.55E-01 | 1.60E+00 |
| Xylenes, m-, p- | 9.89E-03 | 2.90E+00 | 1.01E-03 | 2.91E+00 |

7.4 2010 through 2018 Projected Emissions Inventories

Using the projected production data shown in Figure 7.2-2, growth factors (relative to the 2010 base year) were developed for years 2010 through 2018. Table 7.4-1 shows these factors, and indicates that projected peak production will occur in 2012 and 2013.

Table 7.4-1. Growth Factors for Years 2010–2018

| Year | Growth Factor |
|------|---------------|
| 2010 | 1.00 |
| 2011 | 1.06 |
| 2012 | 1.09 |
| 2013 | 1.09 |
| 2014 | 1.02 |
| 2015 | 0.95 |
| 2016 | 0.88 |
| 2017 | 0.82 |
| 2018 | 0.80 |

The growth factors shown in Table 7.4-1 were then used to project the 2010 base year emissions inventory to the years 2011 through 2018. Table 7.4-2 shows the resultant emissions inventory for each pollutant for each year.

Table 7.4-2. Projected Emissions for Years 2010–2018

| Pollutant | 2010 (tons/yr) | 2011 (tons/yr) | 2012 (tons/yr) | 2013 (tons/yr) | 2014 (tons/yr) | 2015 (tons/yr) | 2016 (tons/yr) | 2017 (tons/yr) | 2018 (tons/yr) |
|------------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| TOC | 20,583.84 | 21,818.87 | 22,436.38 | 22,436.38 | 20,995.51 | 19,554.65 | 18,113.78 | 16,878.75 | 16,467.07 |
| VOCs | 928.51 | 984.22 | 1,012.07 | 1,012.07 | 947.08 | 882.08 | 817.09 | 761.38 | 742.80 |
| Total HAPs | 504.63 | 534.91 | 550.04 | 550.04 | 514.72 | 479.40 | 444.07 | 413.79 | 403.70 |
| Methane | 19,029.56 | 20,171.33 | 20,742.22 | 20,742.22 | 19,410.15 | 18,078.08 | 16,746.01 | 15,604.24 | 15,223.65 |
| PM | 25.51 | 27.04 | 27.81 | 27.81 | 26.02 | 24.24 | 22.45 | 20.92 | 20.41 |
| NO _x | 943.38 | 999.99 | 1,028.29 | 1,028.29 | 962.25 | 896.21 | 830.18 | 773.57 | 754.71 |
| CO | 7,913.71 | 8,388.53 | 8,625.94 | 8,625.94 | 8,071.98 | 7,518.02 | 6,964.06 | 6,489.24 | 6,330.97 |
| SO ₂ | 3.48 | 3.68 | 3.79 | 3.79 | 3.55 | 3.30 | 3.06 | 2.85 | 2.78 |
| Acenaphthene | 7.93E-03 | 8.40E-03 | 8.64E-03 | 8.64E-03 | 8.08E-03 | 7.53E-03 | 6.98E-03 | 6.50E-03 | 6.34E-03 |
| Acenaphthylene | 3.30E-02 | 3.49E-02 | 3.59E-02 | 3.59E-02 | 3.36E-02 | 3.13E-02 | 2.90E-02 | 2.70E-02 | 2.64E-02 |
| Acetaldehyde | 4.98E+01 | 5.28E+01 | 5.43E+01 | 5.43E+01 | 5.08E+01 | 4.73E+01 | 4.38E+01 | 4.09E+01 | 3.99E+01 |
| Acetone | 1.25E+00 | 1.33E+00 | 1.37E+00 | 1.37E+00 | 1.28E+00 | 1.19E+00 | 1.10E+00 | 1.03E+00 | 1.00E+00 |
| Acrolein | 4.64E+01 | 4.91E+01 | 5.05E+01 | 5.05E+01 | 4.73E+01 | 4.40E+01 | 4.08E+01 | 3.80E+01 | 3.71E+01 |
| Anthracene | 4.28E-03 | 4.54E-03 | 4.66E-03 | 4.66E-03 | 4.36E-03 | 4.07E-03 | 3.77E-03 | 3.51E-03 | 3.42E-03 |
| Benzene | 1.31E+01 | 1.38E+01 | 1.42E+01 | 1.42E+01 | 1.33E+01 | 1.24E+01 | 1.15E+01 | 1.07E+01 | 1.05E+01 |
| Benzo (a) anthracene | 2.00E-03 | 2.12E-03 | 2.18E-03 | 2.18E-03 | 2.04E-03 | 1.90E-03 | 1.76E-03 | 1.64E-03 | 1.60E-03 |
| Benzo (a) pyrene | 3.39E-05 | 3.59E-05 | 3.69E-05 | 3.69E-05 | 3.45E-05 | 3.22E-05 | 2.98E-05 | 2.78E-05 | 2.71E-05 |
| Benzo (b) fluoranthene | 9.89E-04 | 1.05E-03 | 1.08E-03 | 1.08E-03 | 1.01E-03 | 9.40E-04 | 8.71E-04 | 8.11E-04 | 7.91E-04 |
| Benzo (e) pyrene | 2.47E-03 | 2.62E-03 | 2.70E-03 | 2.70E-03 | 2.52E-03 | 2.35E-03 | 2.18E-03 | 2.03E-03 | 1.98E-03 |
| Benzo (g,h,i) perylene | 2.47E-03 | 2.62E-03 | 2.69E-03 | 2.69E-03 | 2.52E-03 | 2.34E-03 | 2.17E-03 | 2.02E-03 | 1.97E-03 |
| Benzo (k) fluoranthene | 2.54E-05 | 2.69E-05 | 2.77E-05 | 2.77E-05 | 2.59E-05 | 2.41E-05 | 2.23E-05 | 2.08E-05 | 2.03E-05 |
| Biphenyl | 1.26E+00 | 1.34E+00 | 1.38E+00 | 1.38E+00 | 1.29E+00 | 1.20E+00 | 1.11E+00 | 1.04E+00 | 1.01E+00 |
| Bromomethane | 2.67E-03 | 2.83E-03 | 2.91E-03 | 2.91E-03 | 2.72E-03 | 2.53E-03 | 2.35E-03 | 2.19E-03 | 2.13E-03 |
| Butadiene, 1,3- | 4.90E+00 | 5.19E+00 | 5.34E+00 | 5.34E+00 | 5.00E+00 | 4.65E+00 | 4.31E+00 | 4.02E+00 | 3.92E+00 |
| Butane | 4.17E+01 | 4.42E+01 | 4.55E+01 | 4.55E+01 | 4.26E+01 | 3.97E+01 | 3.67E+01 | 3.42E+01 | 3.34E+01 |

Table 7.4-2. Projected Emissions for Years 2010–2018 (Continued)

| Pollutant | 2010 (tons/yr) | 2011 (tons/yr) | 2012 (tons/yr) | 2013 (tons/yr) | 2014 (tons/yr) | 2015 (tons/yr) | 2016 (tons/yr) | 2017 (tons/yr) | 2018 (tons/yr) |
|--|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| Butane, n- | 2.83E+01 | 3.00E+01 | 3.09E+01 | 3.09E+01 | 2.89E+01 | 2.69E+01 | 2.49E+01 | 2.32E+01 | 2.26E+01 |
| Butanone (Methyl Ethyl Ketone), 2- | 1.59E-02 | 1.69E-02 | 1.74E-02 | 1.74E-02 | 1.63E-02 | 1.51E-02 | 1.40E-02 | 1.31E-02 | 1.27E-02 |
| Carbon disulfide | 2.67E-03 | 2.83E-03 | 2.91E-03 | 2.91E-03 | 2.73E-03 | 2.54E-03 | 2.35E-03 | 2.19E-03 | 2.14E-03 |
| Carbon tetrachloride | 3.64E-01 | 3.86E-01 | 3.97E-01 | 3.97E-01 | 3.72E-01 | 3.46E-01 | 3.21E-01 | 2.99E-01 | 2.91E-01 |
| Chlorobenzene | 2.65E-01 | 2.80E-01 | 2.88E-01 | 2.88E-01 | 2.70E-01 | 2.51E-01 | 2.33E-01 | 2.17E-01 | 2.12E-01 |
| Chlorodifluoromethane | 1.03E-03 | 1.10E-03 | 1.13E-03 | 1.13E-03 | 1.05E-03 | 9.82E-04 | 9.10E-04 | 8.48E-04 | 8.27E-04 |
| Chloroethane | 1.39E-02 | 1.47E-02 | 1.51E-02 | 1.51E-02 | 1.41E-02 | 1.32E-02 | 1.22E-02 | 1.14E-02 | 1.11E-02 |
| Chloroform | 2.81E-01 | 2.98E-01 | 3.06E-01 | 3.06E-01 | 2.86E-01 | 2.67E-01 | 2.47E-01 | 2.30E-01 | 2.25E-01 |
| Chloromethane | 2.34E-03 | 2.48E-03 | 2.55E-03 | 2.55E-03 | 2.39E-03 | 2.22E-03 | 2.06E-03 | 1.92E-03 | 1.87E-03 |
| Chlorotoluene, 2- | 3.56E-03 | 3.77E-03 | 3.88E-03 | 3.88E-03 | 3.63E-03 | 3.38E-03 | 3.13E-03 | 2.92E-03 | 2.85E-03 |
| Chrysene | 4.13E-03 | 4.38E-03 | 4.50E-03 | 4.50E-03 | 4.21E-03 | 3.92E-03 | 3.63E-03 | 3.39E-03 | 3.30E-03 |
| Cyclohexane | 3.72E+00 | 3.95E+00 | 4.06E+00 | 4.06E+00 | 3.80E+00 | 3.54E+00 | 3.28E+00 | 3.05E+00 | 2.98E+00 |
| Cyclopentane | 1.35E+00 | 1.43E+00 | 1.47E+00 | 1.47E+00 | 1.38E+00 | 1.29E+00 | 1.19E+00 | 1.11E+00 | 1.08E+00 |
| Decane, n- | 3.70E-01 | 3.92E-01 | 4.03E-01 | 4.03E-01 | 3.77E-01 | 3.51E-01 | 3.25E-01 | 3.03E-01 | 2.96E-01 |
| Dichloro-1,1,2,2- tetrafluoroethane, 1,2- | 2.45E-03 | 2.60E-03 | 2.67E-03 | 2.67E-03 | 2.50E-03 | 2.33E-03 | 2.16E-03 | 2.01E-03 | 1.96E-03 |
| Dichlorodifluoromethane | 2.05E-03 | 2.18E-03 | 2.24E-03 | 2.24E-03 | 2.09E-03 | 1.95E-03 | 1.81E-03 | 1.68E-03 | 1.64E-03 |
| Dichloroethane, 1,1- | 2.33E-01 | 2.47E-01 | 2.54E-01 | 2.54E-01 | 2.38E-01 | 2.21E-01 | 2.05E-01 | 1.91E-01 | 1.86E-01 |
| Dichloropropene, 1,3- | 2.61E-01 | 2.77E-01 | 2.85E-01 | 2.85E-01 | 2.66E-01 | 2.48E-01 | 2.30E-01 | 2.14E-01 | 2.09E-01 |
| Dodecane, n- | 4.14E-02 | 4.39E-02 | 4.52E-02 | 4.52E-02 | 4.23E-02 | 3.94E-02 | 3.65E-02 | 3.40E-02 | 3.31E-02 |
| Ethane | 6.26E+02 | 6.63E+02 | 6.82E+02 | 6.82E+02 | 6.38E+02 | 5.94E+02 | 5.51E+02 | 5.13E+02 | 5.01E+02 |
| Ethylbenzene | 7.68E-01 | 8.14E-01 | 8.37E-01 | 8.37E-01 | 7.83E-01 | 7.29E-01 | 6.75E-01 | 6.29E-01 | 6.14E-01 |
| Ethylene dibromide | 4.37E-01 | 4.64E-01 | 4.77E-01 | 4.77E-01 | 4.46E-01 | 4.16E-01 | 3.85E-01 | 3.59E-01 | 3.50E-01 |
| Ethylene dichloride | 2.51E-01 | 2.67E-01 | 2.74E-01 | 2.74E-01 | 2.57E-01 | 2.39E-01 | 2.21E-01 | 2.06E-01 | 2.01E-01 |
| Ethyltoluene, 4- | 3.58E-01 | 3.80E-01 | 3.90E-01 | 3.90E-01 | 3.65E-01 | 3.40E-01 | 3.15E-01 | 2.94E-01 | 2.86E-01 |

Table 7.4-2. Projected Emissions for Years 2010–2018 (Continued)

| Pollutant | 2010 (tons/yr) | 2011 (tons/yr) | 2012 (tons/yr) | 2013 (tons/yr) | 2014 (tons/yr) | 2015 (tons/yr) | 2016 (tons/yr) | 2017 (tons/yr) | 2018 (tons/yr) |
|--|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| Fluoranthene | 6.62E-03 | 7.01E-03 | 7.21E-03 | 7.21E-03 | 6.75E-03 | 6.28E-03 | 5.82E-03 | 5.42E-03 | 5.29E-03 |
| Fluorene | 3.38E-02 | 3.58E-02 | 3.68E-02 | 3.68E-02 | 3.45E-02 | 3.21E-02 | 2.97E-02 | 2.77E-02 | 2.70E-02 |
| Formaldehyde | 3.29E+02 | 3.49E+02 | 3.59E+02 | 3.59E+02 | 3.36E+02 | 3.13E+02 | 2.89E+02 | 2.70E+02 | 2.63E+02 |
| Heptane | 6.59E+00 | 6.99E+00 | 7.18E+00 | 7.18E+00 | 6.72E+00 | 6.26E+00 | 5.80E+00 | 5.41E+00 | 5.27E+00 |
| Hexachlorobutadiene | 2.27E-02 | 2.41E-02 | 2.47E-02 | 2.47E-02 | 2.31E-02 | 2.16E-02 | 2.00E-02 | 1.86E-02 | 1.82E-02 |
| Hexane | 1.29E+01 | 1.37E+01 | 1.41E+01 | 1.41E+01 | 1.32E+01 | 1.23E+01 | 1.14E+01 | 1.06E+01 | 1.03E+01 |
| Indeno(1,2,3-cd) pyrene | 5.92E-05 | 6.27E-05 | 6.45E-05 | 6.45E-05 | 6.04E-05 | 5.62E-05 | 5.21E-05 | 4.85E-05 | 4.73E-05 |
| Isobutane | 2.23E+01 | 2.37E+01 | 2.44E+01 | 2.44E+01 | 2.28E+01 | 2.12E+01 | 1.97E+01 | 1.83E+01 | 1.79E+01 |
| Isobutyraldehyde | 2.60E+00 | 2.76E+00 | 2.84E+00 | 2.84E+00 | 2.66E+00 | 2.47E+00 | 2.29E+00 | 2.14E+00 | 2.08E+00 |
| Isopentane | 1.45E+01 | 1.54E+01 | 1.58E+01 | 1.58E+01 | 1.48E+01 | 1.38E+01 | 1.28E+01 | 1.19E+01 | 1.16E+01 |
| Isopropylbenzene | 4.97E-02 | 5.26E-02 | 5.41E-02 | 5.41E-02 | 5.07E-02 | 4.72E-02 | 4.37E-02 | 4.07E-02 | 3.97E-02 |
| Isopropyltoluene, 4- | 6.50E-02 | 6.89E-02 | 7.08E-02 | 7.08E-02 | 6.63E-02 | 6.17E-02 | 5.72E-02 | 5.33E-02 | 5.20E-02 |
| Methyl alcohol | 1.82E+01 | 1.93E+01 | 1.99E+01 | 1.99E+01 | 1.86E+01 | 1.73E+01 | 1.60E+01 | 1.50E+01 | 1.46E+01 |
| Methyl Naphthalene, 2- | 1.98E-01 | 2.10E-01 | 2.16E-01 | 2.16E-01 | 2.02E-01 | 1.88E-01 | 1.74E-01 | 1.62E-01 | 1.58E-01 |
| Methyl-2-pentanone, 4- (Methyl Isobutyl Ketone) | 3.13E-02 | 3.32E-02 | 3.41E-02 | 3.41E-02 | 3.19E-02 | 2.97E-02 | 2.76E-02 | 2.57E-02 | 2.51E-02 |
| Methylcyclohexane | 7.33E+00 | 7.77E+00 | 7.99E+00 | 7.99E+00 | 7.48E+00 | 6.96E+00 | 6.45E+00 | 6.01E+00 | 5.86E+00 |
| Methylene chloride | 1.83E+00 | 1.94E+00 | 1.99E+00 | 1.99E+00 | 1.86E+00 | 1.74E+00 | 1.61E+00 | 1.50E+00 | 1.46E+00 |
| Naphthalene | 6.02E-01 | 6.38E-01 | 6.56E-01 | 6.56E-01 | 6.14E-01 | 5.72E-01 | 5.30E-01 | 4.94E-01 | 4.82E-01 |
| Nonane, n- | 5.69E+00 | 6.03E+00 | 6.20E+00 | 6.20E+00 | 5.80E+00 | 5.40E+00 | 5.01E+00 | 4.66E+00 | 4.55E+00 |
| Octane, n- | 8.69E+00 | 9.22E+00 | 9.48E+00 | 9.48E+00 | 8.87E+00 | 8.26E+00 | 7.65E+00 | 7.13E+00 | 6.96E+00 |
| Pentane, n- | 2.60E+01 | 2.75E+01 | 2.83E+01 | 2.83E+01 | 2.65E+01 | 2.47E+01 | 2.28E+01 | 2.13E+01 | 2.08E+01 |
| Perylene | 2.96E-05 | 3.14E-05 | 3.23E-05 | 3.23E-05 | 3.02E-05 | 2.81E-05 | 2.61E-05 | 2.43E-05 | 2.37E-05 |
| Phenanthrene | 6.20E-02 | 6.57E-02 | 6.76E-02 | 6.76E-02 | 6.32E-02 | 5.89E-02 | 5.45E-02 | 5.08E-02 | 4.96E-02 |
| Phenol | 2.51E-01 | 2.66E-01 | 2.73E-01 | 2.73E-01 | 2.56E-01 | 2.38E-01 | 2.21E-01 | 2.06E-01 | 2.01E-01 |

Table 7.4-2. Projected Emissions for Years 2010–2018 (Continued)

| Pollutant | 2010 (tons/yr) | 2011 (tons/yr) | 2012 (tons/yr) | 2013 (tons/yr) | 2014 (tons/yr) | 2015 (tons/yr) | 2016 (tons/yr) | 2017 (tons/yr) | 2018 (tons/yr) |
|--|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| Polycyclic Aromatic Hydrocarbons (PAH) | 8.40E-01 | 8.91E-01 | 9.16E-01 | 9.16E-01 | 8.57E-01 | 7.98E-01 | 7.39E-01 | 6.89E-01 | 6.72E-01 |
| Propane | 2.50E+02 | 2.65E+02 | 2.72E+02 | 2.72E+02 | 2.55E+02 | 2.37E+02 | 2.20E+02 | 2.05E+02 | 2.00E+02 |
| Propylbenzene, n- | 1.55E-01 | 1.64E-01 | 1.68E-01 | 1.68E-01 | 1.58E-01 | 1.47E-01 | 1.36E-01 | 1.27E-01 | 1.24E-01 |
| Propylene | 7.43E-03 | 7.87E-03 | 8.09E-03 | 8.09E-03 | 7.57E-03 | 7.05E-03 | 6.53E-03 | 6.09E-03 | 5.94E-03 |
| Propylene dichloride | 2.66E-01 | 2.82E-01 | 2.90E-01 | 2.90E-01 | 2.71E-01 | 2.53E-01 | 2.34E-01 | 2.18E-01 | 2.13E-01 |
| Pyrene | 8.11E-03 | 8.59E-03 | 8.83E-03 | 8.83E-03 | 8.27E-03 | 7.70E-03 | 7.13E-03 | 6.65E-03 | 6.48E-03 |
| sec-Butylbenzene | 4.40E-02 | 4.66E-02 | 4.80E-02 | 4.80E-02 | 4.49E-02 | 4.18E-02 | 3.87E-02 | 3.61E-02 | 3.52E-02 |
| Styrene | 3.29E-01 | 3.49E-01 | 3.59E-01 | 3.59E-01 | 3.36E-01 | 3.13E-01 | 2.90E-01 | 2.70E-01 | 2.63E-01 |
| Tetrachloroethane, 1,1,2,2- | 3.95E-01 | 4.19E-01 | 4.31E-01 | 4.31E-01 | 4.03E-01 | 3.75E-01 | 3.48E-01 | 3.24E-01 | 3.16E-01 |
| Tetrachloroethene | 6.81E-02 | 7.22E-02 | 7.43E-02 | 7.43E-02 | 6.95E-02 | 6.47E-02 | 6.00E-02 | 5.59E-02 | 5.45E-02 |
| Toluene | 1.08E+01 | 1.15E+01 | 1.18E+01 | 1.18E+01 | 1.10E+01 | 1.03E+01 | 9.52E+00 | 8.87E+00 | 8.66E+00 |
| Trichlorobenzene, 1,2,3- | 3.66E-02 | 3.88E-02 | 3.99E-02 | 3.99E-02 | 3.73E-02 | 3.48E-02 | 3.22E-02 | 3.00E-02 | 2.93E-02 |
| Trichlorobenzene, 1,2,4- | 2.70E-02 | 2.87E-02 | 2.95E-02 | 2.95E-02 | 2.76E-02 | 2.57E-02 | 2.38E-02 | 2.22E-02 | 2.16E-02 |
| Trichloroethane, 1,1,2- | 3.14E-01 | 3.33E-01 | 3.42E-01 | 3.42E-01 | 3.20E-01 | 2.98E-01 | 2.76E-01 | 2.58E-01 | 2.51E-01 |
| Trichlorofluoromethane | 3.02E-03 | 3.20E-03 | 3.29E-03 | 3.29E-03 | 3.08E-03 | 2.87E-03 | 2.65E-03 | 2.47E-03 | 2.41E-03 |
| Trimethylbenzene, 1,2,3- | 2.11E-01 | 2.24E-01 | 2.30E-01 | 2.30E-01 | 2.15E-01 | 2.00E-01 | 1.86E-01 | 1.73E-01 | 1.69E-01 |
| Trimethylbenzene, 1,2,4- | 1.94E+00 | 2.05E+00 | 2.11E+00 | 2.11E+00 | 1.98E+00 | 1.84E+00 | 1.70E+00 | 1.59E+00 | 1.55E+00 |
| Trimethylbenzene, 1,3,5- | 7.07E-01 | 7.49E-01 | 7.70E-01 | 7.70E-01 | 7.21E-01 | 6.71E-01 | 6.22E-01 | 5.79E-01 | 5.65E-01 |
| Trimethylpentane, 2,2,4- | 5.06E+00 | 5.37E+00 | 5.52E+00 | 5.52E+00 | 5.16E+00 | 4.81E+00 | 4.46E+00 | 4.15E+00 | 4.05E+00 |
| Undecane, n- | 8.34E-02 | 8.85E-02 | 9.10E-02 | 9.10E-02 | 8.51E-02 | 7.93E-02 | 7.34E-02 | 6.84E-02 | 6.68E-02 |
| Vinyl acetate | 1.25E-02 | 1.33E-02 | 1.37E-02 | 1.37E-02 | 1.28E-02 | 1.19E-02 | 1.10E-02 | 1.03E-02 | 1.00E-02 |
| Vinyl bromide | 3.23E-03 | 3.43E-03 | 3.52E-03 | 3.52E-03 | 3.30E-03 | 3.07E-03 | 2.84E-03 | 2.65E-03 | 2.59E-03 |
| Vinyl chloride | 1.49E-01 | 1.58E-01 | 1.62E-01 | 1.62E-01 | 1.52E-01 | 1.41E-01 | 1.31E-01 | 1.22E-01 | 1.19E-01 |
| Xylene, o | 2.79E-01 | 2.95E-01 | 3.04E-01 | 3.04E-01 | 2.84E-01 | 2.65E-01 | 2.45E-01 | 2.28E-01 | 2.23E-01 |
| Xylenes (isomers) | 1.60E+00 | 1.69E+00 | 1.74E+00 | 1.74E+00 | 1.63E+00 | 1.52E+00 | 1.41E+00 | 1.31E+00 | 1.28E+00 |
| Xylenes, m-, p- | 2.91E+00 | 3.08E+00 | 3.17E+00 | 3.17E+00 | 2.97E+00 | 2.76E+00 | 2.56E+00 | 2.38E+00 | 2.33E+00 |

7.5 Full Build-Out Estimates Conclusions

Emissions from the production of natural gas in the city of Fort Worth are projected to peak in 2012 and 2013, and in 2015 are projected to decrease to below 2010 levels. The projected peak emission levels occurring in 2012 and 2013 are expected to be 9% higher than emissions during the 2010 baseline year.

As discussed above, natural gas production is primarily dependent on the price that producers will receive. This concept is reflected in the demonstrated relationship between drilling rig and permit activity and natural gas prices. If the wellhead price for natural gas remains relatively low, as it is now, producers do not have economic incentive to invest in new exploration and drilling. Under this scenario, it is expected that total production from currently producing wells and leased wells not yet in production (but currently in development) will increase in the short term, followed by a slow decline.

Should wellhead prices for natural gas unexpectedly increase in future years, natural gas production and associated air emissions may be greater than projected. However, it is important to note that the longer natural gas prices remain flat, the lower the peak production rate will be, even with a spike in the price of natural gas. This is because the overall size of the resource, or the reserves, is finite, and the reserve decreases in size as each year passes. The data used in this analysis shows that, based on a reserve estimate of 30 trillion cubic feet of natural gas in the Barnett Shale, approximately one-third has already been depleted, and over 75% will have been recovered by the end of 2018.

Key Point: Barnett Shale

Based on a reserve estimate of 30 trillion cubic feet of natural gas, over 75% of the available natural gas in the Barnett Shale is projected to be recovered by the end of 2018.

8.0 Conclusions and Recommendations

Commencing with planning activities in July 2010 and field activities in August 2010, the Fort Worth Natural Gas Air Quality Study was a multi-phase project aimed at characterizing the air quality impacts of natural gas exploration and production, determining any potential health risks associated with those impacts, quantifying the total amount of pollutants being emitted, and determining if natural gas sites were in compliance with air quality regulations.

Two primary raw data collection activities were used: 1) an ambient air monitoring network, and 2) a systematic point source testing program. Point source testing data were then used to perform air dispersion modeling, and measured and modeled air concentrations were used in the public health evaluation. Each of these tasks was designed to help city officials answer the following questions:

- How much air pollution is being released by natural gas exploration in Fort Worth?
- Do sites comply with environmental regulation?
- How do releases from these sites affect off-site air pollution levels?
- Are the city's required setbacks for these sites adequate to protect public health?

Section 8.1 provides a summary of the conclusions for each task of this study, Section 8.2 includes answers to the four primary study questions, and Section 8.3 provides specific recommendations for ensuring that emissions from natural gas sites do not cause unhealthy air pollution levels.

8.1 Task Level Conclusions

As discussed previously, the Fort Worth Natural Gas Air Quality Study was multi-faceted and included Ambient Air Monitoring, Point Source Testing, Air Dispersion Modeling, a Public Health Evaluation, a Regulatory Assessment, and Full Build-Out Estimates. The key findings for each of these tasks are provided below.

Key findings of the Ambient Air Monitoring task include:

- 169 ambient air samples from 8 locations in Fort Worth were collected and analyzed, resulting in over 15,000 ambient air data points generated for this study.
- Methane, ethane, propane, and butane were the pollutants found at highest concentrations. However, more toxic pollutants (e.g., benzene) were also found, but generally at much lower levels.
- Concentrations measured at Site S-4 (located in a high-level activity area near compressor stations, well pads, and mobile sources) were generally higher than at the other sites.
- Concentrations measured at Sites S-6 and S-7 (both located within 350 of active well pads) were surprisingly low relative to the other sites.

- Wind patterns observed during the sampling period were consistent with historical wind patterns, indicating proper placement of the ambient air monitors.

Key findings of the Point Source Testing task include:

- At 96 sites, no emissions were detected by the IR camera. Most of these sites contained 3 wells or less.
- The largest source of fugitive emissions detected with the IR camera was leaking tank thief hatches.
- Pneumatic Valve Controllers were the most frequent emission sources encountered at well pads and compressor stations.
- Compressor engines have a significant impact on emissions, especially the large line compressors found at compressor stations.
- There was little difference in average TOC emissions between dry and wet gas sites, but average VOC and HAP emissions from wet gas sites proved to be considerably higher.

Key findings of the Public Health Evaluation task (including analysis of the emissions concentrations predicted under the Air Dispersion Modeling task) include:

- Benzene emissions from tanks could lead to air pollution levels slightly higher than TCEQ's short-term ESL, but only in very close proximity to the highest-emitting tanks.
- Large line engines can emit acrolein and formaldehyde at levels that would cause offsite ambient air concentrations to exceed TCEQ's short-term and long-term screening levels over various distances. This finding is based entirely on estimated emission rates.
- Trace levels of halogenated hydrocarbons detected during the ambient air monitoring program are not likely to be attributable to emissions from natural gas exploration and production activity.

Key findings of the Regulatory Assessment task include:

- Five sites had cumulative VOC emissions greater than the PBR trigger level of 25 tons/yr and/or CO emissions greater than the major source threshold of 100 tons/yr.

Key findings of the Full Build-Out Estimates task include:

- Emissions from the production of natural gas in the city of Fort Worth are projected to peak in 2012 and 2013 at 9% above 2010 levels.

- Total VOC emissions from the production of natural gas in the city of Fort Worth are estimated to peak at approximately 1,012 tons per year in 2012.
- Total HAP emissions from the production of natural gas in the city of Fort Worth are estimated to peak at approximately 550 tons per year in 2012.
- Total methane emissions from the production of natural gas in the city of Fort Worth are estimated to peak at approximately 20,742 tons per year in 2012.

8.2 Study Question Answers

How much air pollution is being released by natural gas exploration in Fort Worth?

During the point source testing, field personnel determined the amount of air pollution released at individual well pads, compressor stations, and other natural gas processing facilities by visiting 388 sites and testing the equipment at each site for emissions. Table 8.2-1 shows the average emissions of TOC, VOCs, and HAPs for each site type that was visited. In the table, the emissions of HAPs are a subset of emissions of VOCs, and the emissions of VOCs are a subset of the TOC emissions. The primary air pollutant emitted at all sites was methane, which is not considered a VOC but constitutes over 94% of the TOC estimate for all sites combined.

Table 8.2-1. Average Emissions by Site Type

| Site Type | Average TOC (tons/yr) | Average VOC (tons/yr) | Average HAP (tons/yr) |
|------------------------------|--------------------------|--------------------------|--------------------------|
| Well Pad | 16 | 0.07 | 0.02 |
| Well Pad with Compressor(s) | 68 | 2 | 0.9 |
| Compressor Station | 99 | 17 | 10 |
| Processing Facility | 1,293 | 80 | 47 |
| Saltwater Treatment Facility | 1.5 | 0.65 | 0.4 |

Under Task 7 (full build-out estimates), the results of the point source testing task were used to estimate total emissions from the gas processing plant and all well pads and compressor stations in the city of Fort Worth. Table 8.2-2 summarizes city-wide emissions from these operations.

Table 8.2-2. Total City-Wide Emissions from Natural Gas Production Activity, by Pollutant Category

| Pollutant | Total Compressor Station Emissions (tons/yr) | Total Well Pad Emissions (tons/yr) | Total Gas Processing Plant Emissions (tons/yr) | Total Emissions (tons/yr) |
|------------|--|---------------------------------------|--|---------------------------------|
| TOC | 2,988 | 16,302 | 1,293 | 20,584 |
| VOCs | 516 | 333 | 80 | 929 |
| Total HAPs | 305 | 152 | 47 | 505 |

Table 8.2-2. Total City-Wide Emissions from Natural Gas Production Activity, by Pollutant Category (Continued)

| Pollutant | Total Compressor Station Emissions (tons/yr) | Total Well Pad Emissions (tons/yr) | Total Gas Processing Plant Emissions (tons/yr) | Total Emissions (tons/yr) |
|-----------------|--|------------------------------------|--|---------------------------|
| Methane | 2,081 | 15,796 | 1,152.60 | 19,030 |
| PM | 10.94 | 13.57 | 1.00 | 25.51 |
| NO _x | 588.88 | 266.76 | 87.74 | 943.38 |
| CO | 4,544.19 | 2,330.62 | 1,038.90 | 7,913.71 |
| SO ₂ | 2.17 | 0.97 | 0.34 | 3.48 |

Do sites comply with environmental regulations?

A number of federal and state air quality regulations could apply to well pads and compressor stations. Each of the potentially applicable rules is discussed in Section 6. While a comprehensive, site-specific regulatory analysis was not possible for each site visited, some broad observations have been made based on the results of the point source testing.

In particular, the primary environmental regulation that would be applicable to the facilities visited under Task 3 is TCEQ's permit-by-rule for oil and gas handling and production facilities. This regulation allows certain sources a streamlined permitting process if they have emissions below 25 tpy of VOCs and 250 tpy of CO. Sites with emissions of CO greater than 100 tpy, of any single HAP greater than 10 tpy, or any combination of HAPs greater than 25 tpy would also be required to operate under a Title V operating permit.

As a result of the point source testing task, five potential sources were identified with site-wide emissions estimates exceeding these thresholds. These larger emitting sites generally had more compressor engine capacity, resulting in higher VOC and CO emissions when compared to sites with fewer, or smaller, engines. Table 8.2-3 lists the sites with estimated emissions exceeding regulatory thresholds.

Table 8.2-3. Sources Above Regulatory Thresholds

| Site ID | Site Type | VOC (tons/yr) | CO (tons/yr) | Total HAP (tons/yr) | Formaldehyde (tons/yr) |
|---------|---------------------|-----------------|-----------------------|---------------------|------------------------|
| PS-159 | Processing Facility | 80 ^a | 1,039 ^{b, c} | 47 ^d | 32 ^e |
| PS-118 | Compressor Station | 43 ^a | 270 ^{b, c} | 25 ^d | 17 ^e |
| PS-119 | Compressor Station | 38 ^a | 240 ^c | 22 | 15 ^c |
| PS-127 | Compressor Station | 24 | 545 ^{b, c} | 14 | 9 |
| 238 | Well Pad | 14 | 219 ^c | 8 | 6 |

^a This site potentially exceeds the 25 tpy VOC threshold under 30 TAC 106, Subchapter O, Section 106.352.

^b This site potentially exceeds the 250 tpy CO threshold under 30 TAC 106, Subchapter O, Section 106.352.

^c This site potentially exceeds the 100 tpy CO threshold under the federal Title V Operating Permit Program.

^d This site potentially exceeds the 25 tpy total HAP threshold under the federal Title V Operating Permit Program.

^e This site potentially exceeds the 10 tpy single HAP threshold under the federal Title V Operating Permit Program.

How do releases from these sites affect off-site air pollution levels?

Under Task 2 of this project, ambient air monitoring was conducted to measure concentrations of selected air toxics present in the air outside the property boundaries of air emissions sources such as a natural gas well pads and compressor stations. Over 160 air samples were collected in September and October of 2010, resulting in over 15,000 data points being generated for this study. Table 8.2-4 provides a summary of these measured off-site air pollution levels for selected pollutants.

Table 8.2-4. Off-Site Air Pollution Levels for Selected Pollutants as Determined Through the Ambient Air Monitoring Network

| Pollutant | Number of Detects | Number of Samples | Average of Detects (ppbv) ^a | Minimum Detected Value (ppbv) | Maximum Detected Value (ppbv) |
|----------------------|-------------------|-------------------|--|-------------------------------|-------------------------------|
| Acetaldehyde | 40 | 40 | 2.813 | 0.83 | 9.06 |
| Benzene | 121 | 129 | 0.291 | 0.0635 | 1.83 |
| Butadiene, 1,3- | 86 | 129 | 0.057 | 0.01 | 0.304 |
| Carbon disulfide | 92 | 92 | 0.243 | 0.008 | 1.64 |
| Carbon tetrachloride | 126 | 129 | 0.112 | 0.053 | 0.142 |
| Formaldehyde | 40 | 40 | 0.931 | 0.41 | 4.45 |
| Tetrachloroethylene | 81 | 129 | 0.043 | 0.01 | 0.218 |

^a These averages only include the average of the detected values for each pollutant.

Under Task 4 of this project, a dispersion modeling was used to predict the downwind concentrations of pollutants emitted from well pads and compressor stations. The modeling provided valuable insights into air quality at locations where, and at times when, ambient air samples were not collected. The modeling was conducted for typical and “worst-case” emissions scenarios. Table 8.2-5 summarizes predicted off-site air concentrations for selected pollutants.

Table 8.2-5. Off-Site Air Pollution Levels for Selected Pollutants as Determined Through Air Dispersion Modeling

| Pollutant | Highest Estimated 1-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Highest Estimated 24-Hour Average Concentration Beyond Well Pad Fence Lines (ppbv) | Highest Estimated Annual Average Concentration at Locations 200 Feet Beyond Fence Lines (ppbv) |
|----------------|---|--|--|
| Acrolein | 2.62 | 1.43 | 0.33 |
| Benzene | 59.5 | 13.4 | 0.24 |
| Butadiene, 1,3 | 0.29 | 0.16 | 0.036 |
| Formaldehyde | 34.7 | 18.9 | 4.34 |

Are the city's required setbacks for these sites adequate to protect public health?

ERG conducted a health screening evaluation to evaluate the health implications of air emissions from natural gas exploration and production activity. This evaluation was based on protective health-based screening values, primarily those published by TCEQ, though consideration was also given to EPA and ATSDR values for the pollutants of greatest concern. The ambient air monitoring data revealed no site-related pollutants with 24-hour average concentrations or program-average concentrations above TCEQ's health-based screening levels. The modeling analysis identified three pollutants—acrolein, benzene, and formaldehyde—with estimated 1-hour average or annual average concentrations above screening levels at some offsite locations. This was most prevalent for sites with multiple, large line compressor engines. However, due to the highly protective nature of the health-based screening values, none of the estimated concentrations reached levels expected to be associated with adverse health effects.

The modeling analysis served as the basis for evaluating the adequacy of setback distances. For the overwhelming majority of sites considered in this study, the modeling results indicate that Fort Worth's 600-foot setback distance is adequate. More specifically, for sites with no engines and for sites with smaller lift engines, no pollutants were found to have estimated 1-hour maximum or annual average concentrations above TCEQ's applicable health-based screening levels beyond the setback distances. For the relatively few sites with multiple, large line engines, the modeling analysis found some areas beyond the setbacks to have estimated acrolein and formaldehyde concentrations greater than TCEQ's ESLs, though not reaching concentrations expected to cause adverse health effects. For both pollutants, ERG's modeling is based entirely on estimated emission rates, and not measured values. This underscores the value of obtaining more detailed acrolein and formaldehyde emissions data for line engines and focused ambient air monitoring to validate these findings. Such studies would provide greater confidence in the adequacy and protectiveness of the city's setbacks.

8.3 Recommendations

Although this study did not reveal any significant health threats beyond setback distances, it is important to remember that the sources of concern for this project—natural gas exploration and production activity—are located in residential settings throughout a metropolitan area. Though the most toxic pollutants these sources emit are released in relatively low quantities, all reasonable precautions to reduce emissions from the well pads and compressor stations should be made. This is particularly important for tanks and line compressor engines, because these two sources accounted for the greatest portion of the risks observed for the pollutants selected for further evaluation. Such precautions would include the installation and operation of the following air pollution control equipment:

Vapor Recovery Units on storage tanks – storage tanks are the highest source of benzene emissions, and vapor recovery units could reduce these emissions by 90% or more. This would be most beneficial at wet gas sites with higher condensate production.

3-way catalysts and/or catalytic oxidizers on compressor station compressor engines – the large compressor engines located at compressor stations are the main source of acrolein and

formaldehyde, the two pollutants of greatest concern from a public health perspective. 3-way catalysts are primarily NO_x control technologies, but have a co-benefit of reducing CO and VOC emissions. Catalytic oxidizers are used to control CO and VOC emissions.

Electric compressor engines – As many of the compressor stations in Fort Worth are located in an urban setting, easy access to the electric grid also provides an opportunity to eliminate emissions from compressor engines completely through the use of electric motors.

Low bleed or no bleed pneumatic valve controllers – Pneumatic valve controllers were the most frequent fugitive emission source found during the point source testing task. Under EPA's voluntary Natural Gas STAR Program, the use of low bleed valve controllers and electric valve controllers is encouraged and has proven effective in reducing VOC (and methane) emissions from natural gas operations.

In addition to these air pollution control equipment recommendations, enhanced inspection and maintenance of equipment at natural gas sites can help ensure that preventable emissions are greatly reduced or eliminated. At a small subset of sites, the point source testing team noted signs of malfunctioning equipment that likely caused increased emissions. For example, some hatches atop tanks were ajar and not closed, and corrosion had apparently caused a hole to form on the roof of at least one tank.

The emission estimates used in this study for acrolein and formaldehyde are based on the best emissions information currently available for compressor engines – emission factors from U.S. EPA's Compilation of Air Pollutant Emission Factors (AP-42).²⁸ As control of acrolein and formaldehyde emissions from compressor engines is not explicitly required under any current regulation, no control efficiency was assumed in our estimates. Options available to confirm our assumptions and findings with regards to these pollutants include:

- Contact compressor station owners and operators to establish the frequency at which their engines have installed controls, and to obtain any existing stack testing results
- Analyze the findings of TCEQ's Phase II Barnett Shale Area Special Inventory efforts to establish the frequency at which compressor engines have installed controls
- Conduct point source stack testing at the exhaust of compressor engines to characterize acrolein and formaldehyde emissions
- Conduct focused ambient air monitoring of acrolein and formaldehyde emissions in close proximity to the larger compressor stations

Finally, ERG fully supports continued ambient air monitoring in and around the city of Fort Worth in order to confirm the key findings of this report. In particular, the results of TCEQ's ongoing monitoring efforts in the Barnett Shale should be monitored for any changes in air quality in Fort Worth as worsening air quality may require additional response such as additional controls or site maintenance requirements.

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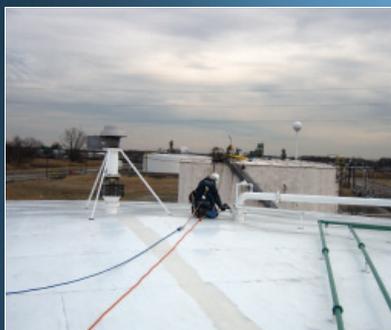
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Leak Detection and Repair

A Best Practices Guide



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Contents

| | | |
|------|--|----|
| 1.0 | Purpose | 1 |
| 2.0 | Why Regulate Equipment Leaks?. | 2 |
| 3.0 | Sources, Causes And Control Of Equipment Leaks | 3 |
| 3.1 | How are emissions from equipment leaks reduced? | 3 |
| 3.2 | What regulations incorporate LDAR programs? | 6 |
| 4.0 | What Are the Benefits of an LDAR Program?. | 7 |
| 4.1 | Reducing Product Losses | 8 |
| 4.2 | Increasing Safety for Facility Workers and Operators | 8 |
| 4.3 | Decreasing Exposure for the Surrounding Community | 8 |
| 4.4 | Potentially Reducing Emission Fees | 8 |
| 4.5 | Avoiding Enforcement Actions | 8 |
| 5.0 | Elements of an LDAR Program | 9 |
| 6.0 | What Compliance Problems Have Been Found With Current LDAR Programs? | 15 |
| 7.0 | Model LDAR Program | 19 |
| 7.1 | Written LDAR Program. | 20 |
| 7.2 | Training | 20 |
| 7.3 | LDAR Audits. | 21 |
| 7.4 | Contractor Accountability. | 22 |
| 7.5 | Internal Leak Definition for Valves and Pumps | 22 |
| 7.6 | More Frequent Monitoring | 23 |
| 7.7 | Repairing Leaking Components. | 23 |
| 7.8 | Delay of Repair Compliance Assurance | 24 |
| 7.9 | Electronic Monitoring and Storage of LDAR Data | 24 |
| 7.10 | QA/QC of LDAR Data | 25 |
| 7.11 | Calibration/Calibration Drift Assessment | 25 |
| 7.12 | Records Maintenance | 26 |
| 8.0 | Sources of Additional Information | 27 |

Tables

| | | |
|-----------|---|---|
| Table 3.1 | Sources of equipment leaks. | 4 |
| Table 3.2 | Equipment component counts at a typical refinery or chemical plant. | 5 |
| Table 3.3 | Uncontrolled VOC emissions at a typical facility. | 5 |
| Table 4.1 | Control effectiveness for an LDAR program at a chemical process unit and a refinery. | 7 |

Appendices

| | | |
|------------|---|----|
| Appendix A | Federal Regulations That Require a Formal LDAR Program With Method 21 | 29 |
| Appendix B | Federal Regulations That Require the Use of Method 21 But Do Not Require a Formal LDAR Program | 30 |
| Appendix C | Method 21 General Procedure | 31 |
| Appendix D | Method 21—Determination of Volatile Organic Compound Leaks | 32 |
| Appendix E | Summary of NEIC Comparative Monitoring Results of Leaking Valves at 17 Refineries | 39 |
| Appendix F | Enforcement Alert | 40 |

1.0 Purpose

In general, EPA has found significant widespread noncompliance with Leak Detection and Repair (LDAR) regulations and more specifically, noncompliance with Method 21 requirements. In 1999, EPA estimated that, as a result of this noncompliance, an additional 40,000 tons of VOCs are emitted annually from valves at petroleum refineries alone.

This document is intended for use by regulated entities as well as compliance inspectors to identify some of the problems identified with LDAR programs focusing in on Method 21 requirements and describe the practices that can be used to increase the effectiveness of an LDAR program. Specifically, this document explains:

- The importance of regulating equipment leaks;
- The major elements of an LDAR program;
- Typical mistakes made when monitoring to detect leaks;
- Problems that occur from improper management of an LDAR program; and
- A set of best practices that can be used to implement effective an LDAR program.

Some of the elements of a model LDAR program, as described in Section 7.0, are required by current Federal regulations. Other model LDAR program elements help ensure continuous compliance although they may not be mandated from a regulatory standpoint. Furthermore, State or local requirements may be more stringent than some elements of the model LDAR program, such as with leak definitions. Prior to developing a written LDAR program plan, all applicable regulations should be reviewed to determine and ensure compliance with the most stringent requirements.

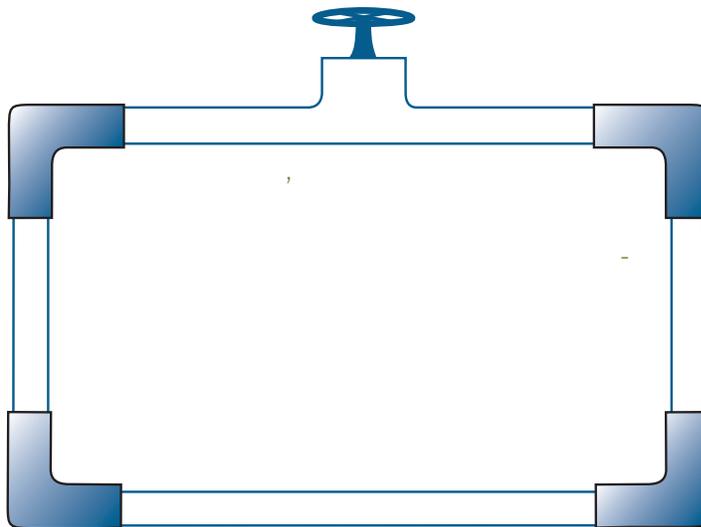
2.0 Why Regulate Equipment Leaks?

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are the largest source of emissions of volatile organic compounds (VOCs) and volatile hazardous air pollutants (VHAPs) from petroleum refineries and chemical manufacturing facilities. The Agency has estimated that approximately 70,367 tons per year of VOCs and 9,357 tons per year of HAPs have been emitted from equipment leaks. Emissions from equipment leaks exceed emissions from storage vessels, wastewater, transfer operations, or process vents.

VOCs contribute to the formation of ground-level ozone. Ozone is a major component of smog, and causes or aggravates respiratory disease, particularly in children, asthmatics, and healthy adults who participate in moderate exercise. Many areas of the United States, particularly those areas

where refineries and chemical facilities are located, do not meet the National Ambient Air Quality Standard (NAAQS) for ozone. Ozone can be transported in the atmosphere and contribute to nonattainment in downwind areas.

Some species of VOCs are also classified as VHAPs. Some known or suspected effects of exposure to VHAPs include cancer, reproductive effects, and birth defects. The highest concentrations of VHAPs tend to be closest to the emission source, where the highest public exposure levels are also often detected. Some common VHAPs emitted from refineries and chemical plants include acetaldehyde, benzene, formaldehyde, methylene chloride, naphthalene, toluene, and xylene.



3.0 Sources, Causes And Control Of Equipment Leaks

A typical refinery or chemical plant can emit 600-700 tons per year of VOCs from leaking equipment, such as valves, connectors, pumps, sampling connections, compressors, pressure-relief devices, and open-ended lines.

Table 3.1 shows the primary sources of emissions from components subject to equipment leak regulations. In a typical facility, most of the emissions are from valves and connectors because these are the most prevalent components and can number in the thousands (Table 3.2). The major cause of emissions from valves and connectors is seal or gasket failure due to normal wear or improper maintenance.

Previous EPA studies have estimated that valves and connectors account for more than 90% of emissions from leaking equipment with valves being the most significant source (Table 3.3). Newer information suggests that open-ended lines and sampling connections may account for as much as 5-10% of total VOC emissions from equipment leaks.

3.1 How are emissions from equipment leaks reduced?

Facilities can control emissions from equipment leaks by implementing a leak detection and repair (LDAR) program or by modifying/replacing leaking equipment with “leakless” components. Most equipment leak regulations allow a combination of both control methods.

- Leaks from open-ended lines, compressors, and sampling connections are usually fixed

by modifying the equipment or component. Emissions from pumps and valves can also be reduced through the use of “leakless” valves and “sealless” pumps. Common leakless valves include bellows valves and diaphragm valves, and common sealless pumps are diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leaks from pumps can also be reduced by using dual seals with or without barrier fluid.

- Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. Installing leakless and sealless equipment components may be a wise choice for replacing individual, chronic leaking components.



LDAR is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. A component that is subject to LDAR requirements must be monitored at specified, regular intervals to determine whether or not it is leaking. Any leaking component must then be repaired or replaced within a specified time frame.

Table 3.1 – Sources of equipment leaks.

Pumps are used to move fluids from one point to another. Two types of pumps extensively used in petroleum refineries and chemical plants are centrifugal pumps and positive displacement, or reciprocating pumps.

Valves are used to either restrict or allow the movement of fluids. Valves come in numerous varieties and with the exception of connectors, are the most common piece of process equipment in industry.

Connectors are components such as flanges and fittings used to join piping and process equipment together. Gaskets and blinds are usually installed between flanges.

Sampling connections are utilized to obtain samples from within a process.

Compressors are designed to increase the pressure of a fluid and provide motive force. They can have rotary or reciprocating designs.

Pressure relief devices are safety devices designed to protect equipment from exceeding the maximum allowable working pressure. Pressure relief valves and rupture disks are examples of pressure relief devices.

Open-ended lines are pipes or hoses open to the atmosphere or surrounding environment.

Leaks from pumps typically occur at the seal.

Leaks from valves usually occur at the stem or gland area of the valve body and are commonly caused by a failure of the valve packing or O-ring.

Leaks from connectors are commonly caused from gasket failure and improperly torqued bolts on flanges.

Leaks from sampling connections usually occur at the outlet of the sampling valve when the sampling line is purged to obtain the sample.

Leaks from compressors most often occur from the seals.

Leaks from pressure relief valves can occur if the valve is not seated properly, operating too close to the set point, or if the seal is worn or damaged. Leaks from rupture disks can occur around the disk gasket if not properly installed.

Leaks from open-ended lines occur at the point of the line open to the atmosphere and are usually controlled by using caps, plugs, and flanges. Leaks can also be caused by the incorrect implementation of the block and bleed procedure.

Table 3.2 – Equipment component counts at a typical refinery or chemical plant.

| Component | Range | Average |
|------------------------|--------------|---------|
| Pumps | 10 – 360 | 100 |
| Valves | 150 – 46,000 | 7,400 |
| Connectors | 600 – 60,000 | 12,000 |
| Open-ended lines | 1 – 1,600 | 560 |
| Sampling connections | 20 – 200 | 80 |
| Pressure relief valves | 5 – 360 | 90 |

Source: “Cost and Emission Reductions for Meeting Percent Leaker Requirements for HON Sources.” Memorandum to Hazardous Organic NESHAP Residual Risk and Review of Technology Standard Rulemaking docket. Docket ID EPA-HQ-OAR-2005-0475-0105.

Table 3.3 – Uncontrolled VOC emissions at a typical facility.

| Component | Average Uncontrolled VOC Emissions (ton/yr) | Percent of Total Emissions |
|------------------------|---|----------------------------|
| Pumps | 19 | 3 |
| Valves | 408 | 62 |
| Connectors | 201 | 31 |
| Open-ended lines | 9 | 1 |
| Sampling connections | 11 | 2 |
| Pressure relief valves | 5 | 1 |
| Total | 653 | |

Source: Emission factors are from Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995, and equipment counts in Table 3.2.

More recent data indicates that open-ended lines and sampling connections each account for approximately 5-10% of total VOC emissions.

3.2 What regulations incorporate LDAR programs?

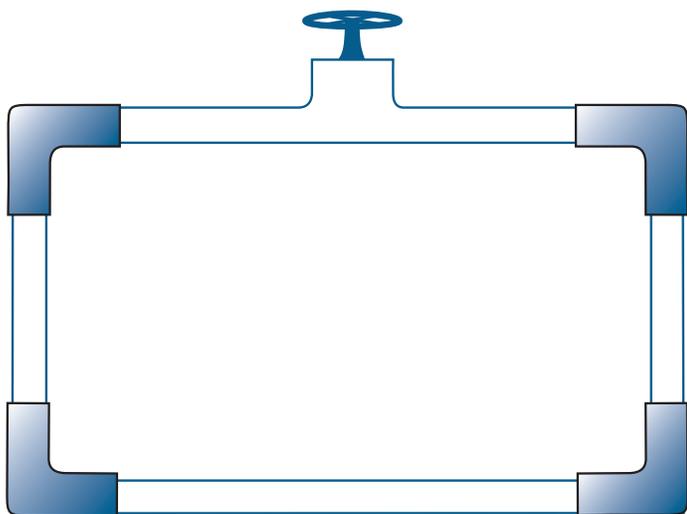
LDAR programs are required by many New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), State Implementation Plans (SIPs), the Resource Conservation and Recovery Act (RCRA), and other state or local requirements. There are 25 federal standards that require facilities to implement LDAR programs. Appendix A shows the 25 federal standards that require the implementation of a formal LDAR program using Method 21. Appendix B lists 28 other federal regulations that require some Method 21 monitoring, but do not require LDAR programs to be in place.

- NSPS (40 CFR Part 60) equipment leak standards are related to fugitive emissions of VOCs and apply to stationary sources that commence construction, modification, or reconstruction after the date that an NSPS is proposed in the Federal Register.
- NESHAP (40 CFR Parts 61, 63, and 65) equipment leak standards apply to both new and

existing stationary sources of fugitive VHAPs.

- RCRA (40 CFR Parts 264 and 265) equipment leak standards apply to hazardous waste treatment, storage, and disposal facilities.
- Many state and local air agencies incorporate federal LDAR requirements by reference, but some have established more stringent LDAR requirements to meet local air quality needs.

A facility may have equipment that is subject to multiple NSPS and NESHAP equipment leaks standards. For example, a number of manufacturing processes listed in the Hazardous Organic NESHAP (HON) equipment leak standard (40 CFR 63, Subpart H) may utilize equipment for which other NESHAP or NSPS equipment leak standards could apply (such as 40 CFR 60, Subpart VV). In addition, one process line may be subject to one rule and another process line subject to another rule. Facilities must ensure that they are complying with the proper equipment leak regulations if multiple regulations apply.



4.0 What Are the Benefits of an LDAR Program?

When the LDAR requirements were developed, EPA estimated that petroleum refineries could reduce emissions from equipment leaks by 63% by implementing a facility LDAR program. Additionally, EPA estimated that chemical facilities could reduce VOC emissions by 56% by implementing such a program.

Table 4.1 presents the control effectiveness of an LDAR program for different monitoring intervals and leak definitions at chemical process units and petroleum refineries.

Emissions reductions from implementing an LDAR program potentially reduce product losses, increase safety for workers and operators, decrease exposure of the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions.

Example – Emissions reductions at a typical SOCM facility.

Applying the equipment modifications and LDAR requirements of the HON to the sources of uncontrolled emissions in the typical facility presented in Tables 3.2 and 3.3 would reduce the emissions per facility by approximately 582 tons per year of emissions, an 89% reduction.

Table 4.1 – Control effectiveness for an LDAR program at a chemical process unit and a refinery.

| Equipment Type and Service | Control Effectiveness (% Reduction) | | |
|--|--|---|---|
| | Monthly Monitoring 10,000 ppmv Leak Definition | Quarterly Monitoring 10,000 ppmv Leak Definition | 500 ppm Leak Definition ^a |
| Chemical Process Unit | | | |
| Valves – Gas Service ^b | 87 | 67 | 92 |
| Valves – Light Liquid Service ^c | 84 | 61 | 88 |
| Pumps – Light Liquid Service ^c | 69 | 45 | 75 |
| Connectors – All Services | | | 93 |
| Refinery | | | |
| Valves – Gas Service ^b | 88 | 70 | 96 |
| Valves – Light Liquid Service ^c | 76 | 61 | 95 |
| Pumps – Light Liquid Service ^c | 68 | 45 | 88 |
| Connectors – All Services | | | 81 |

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

^a Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.

^b Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.

^c Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

4.1 Reducing Product Losses

In the petrochemical industry, saleable products are lost whenever emissions escape from process equipment. Lost product generally translates into lost revenue.

4.2 Increasing Safety for Facility Workers and Operators

Many of the compounds emitted from refineries and chemical facilities may pose a hazard to exposed workers and operators. Reducing emissions from leaking equipment has the direct benefit of reducing occupational exposure to hazardous compounds.

4.3 Decreasing Exposure for the Surrounding Community

In addition to workers and operators at a facility, the population of a surrounding community can be affected by severe, long-term exposure to toxic air pollutants as a result of leaking equipment. Although most of the community exposure may be episodic, chronic health effects can result from long-term exposure to emissions from leaking equipment that is either not identified as leaking or not repaired.

4.4 Potentially Reducing Emission Fees

To fund permitting programs, some states and local air pollution districts charge annual fees that are based on total facility emissions. A facility with an effective program for reducing leaking equipment can potentially decrease the amount of these annual fees.

4.5 Avoiding Enforcement Actions

In setting Compliance and Enforcement National Priorities for Air Toxics, EPA has identified LDAR programs as a national focus. Therefore, facilities can expect an increased number and frequency of compliance inspections and a closer review of compliance reports submitted to permitting authorities in an effort by the Agency to assess LDAR programs and identify potential LDAR problems. A facility with an effective LDAR program decreases the chances of being targeted for enforcement actions and avoids the costs and penalties associated with rule violations.

Example – Cost of product lost.

In previous rulemaking efforts, EPA has estimated that the average value of product lost due to equipment leaks is \$1,370 per ton.^a

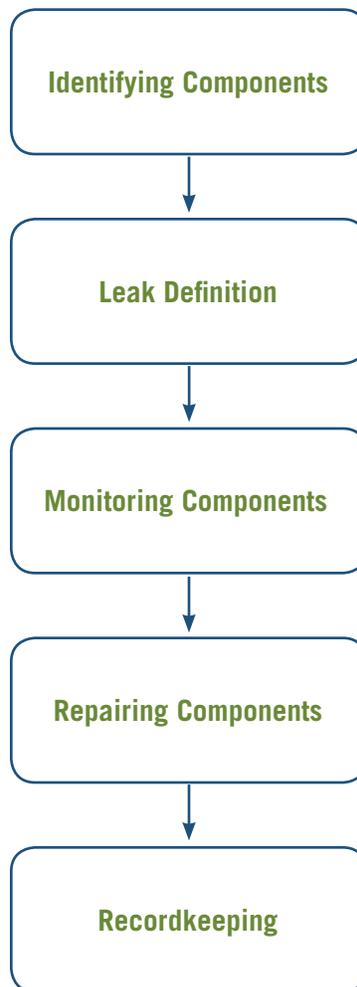
Applying this cost factor results in a potential savings of \$730,000 per year per facility.

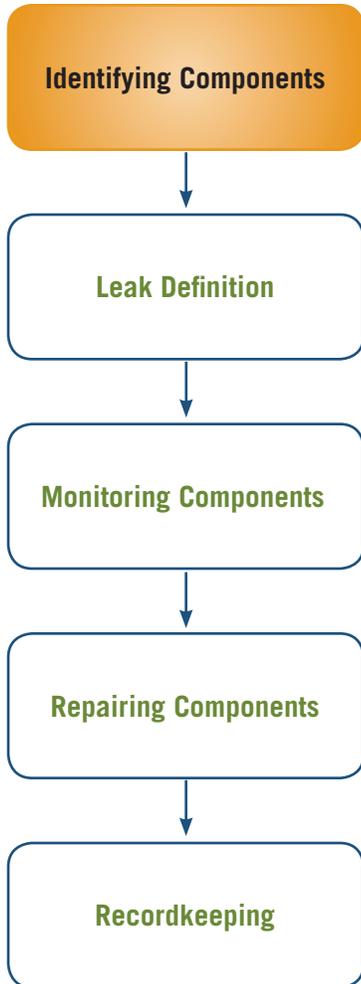
^a Source: Hazardous Air Pollutant Emissions From Process Units in the Synthetic Organic Chemical Manufacturing Industry-Background Information for Proposed Standards, Vol. 1C-Model Emission Sources. Emission Standards Division, US EPA, Office of Air and Radiation, OAQPS, Research Triangle Park, NC. Nov 1992.

5.0 Elements of an LDAR Program

The requirements among the regulations vary, but all LDAR programs consist of five basic elements, which are discussed in detail in Sections 5.1 through 5.5.

For each element, this section outlines the typical LDAR program requirements, common compliance problems found through field inspections, and a set of best practices used by facilities with effective LDAR programs.





Current Requirements

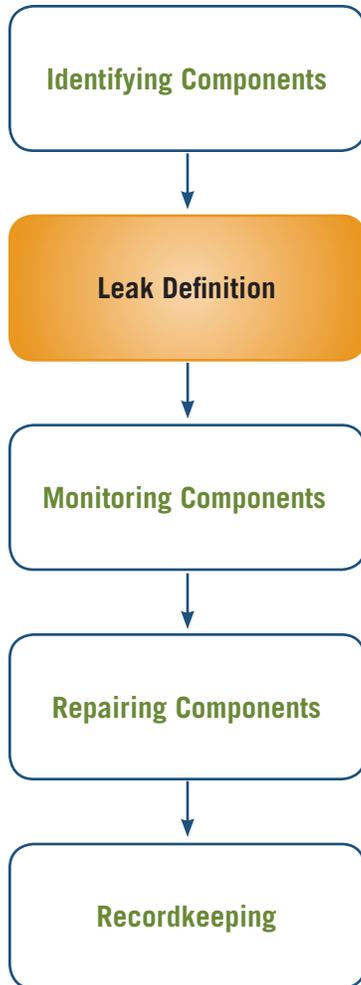
- Assign a unique identification (ID) number to each regulated component.
- Record each regulated component and its unique ID number in a log.
- Physically locate each regulated component in the facility, verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams, and update the log if necessary. Some states require a physical tag on each component subject to the LDAR requirements.
- Identify each regulated component on a site plot plan or on a continuously updated equipment log.
- Promptly note in the equipment log when new and replacement pieces of equipment are added and equipment is taken out of service.

Common Problems

- Not properly identifying all regulated equipment components.
- Not properly documenting exempt components (e.g., <300 hour exemption and <5 (or <10) weight % HAP).

Best Practices

- Physically tag each regulated equipment component with a unique ID number.
- Write the component ID number on piping and instrumentation diagrams.
- Institute an electronic data management system for LDAR data and records, possibly including the use of bar coding equipment.
- Periodically perform a field audit to ensure lists and diagrams accurately represent equipment installed in the plant.



Current Requirements

- Method 21 requires VOC emissions from regulated components to be measured in parts per million (ppm). A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., **leak definition**) for the applicable regulation.
 - Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval.
 - Most NSPS have a leak definition of 10,000 ppm. Many NESHAP use a 500-ppm or 1,000-ppm leak definition.
- Many equipment leak regulations also define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

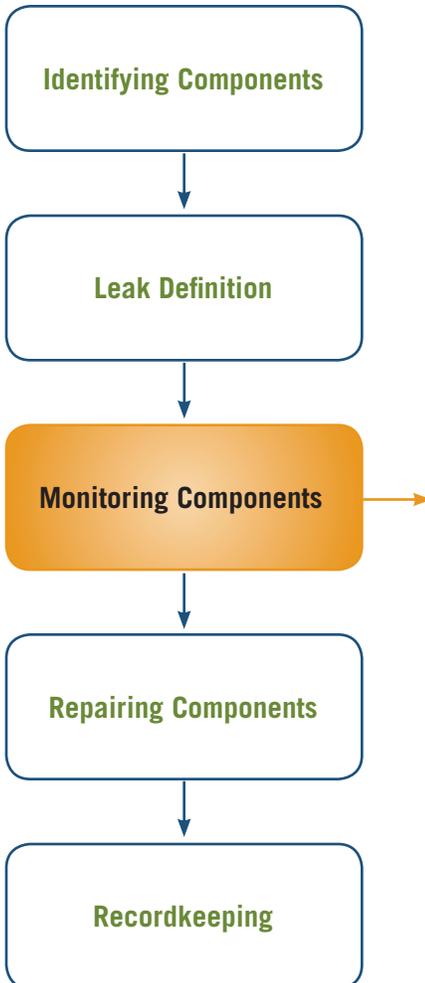
Note: The LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals.

Common Problems

- Using the wrong leak definition for a particular component due to confusion at facilities where multiple LDAR regulations apply.

Best Practices

- Utilize a leak definition lower than what the regulation requires.
- Simplify the program by using the lowest leak definition when multiple leak definitions exist.
- Make the lowest leak definition conservative to provide a margin of safety when monitoring components.
- Keep the lowest leak definition consistent among all similar component types. For example, all valves in a facility might have a leak definition of 500 ppm.



The **monitoring interval** is the frequency at which individual component monitoring is conducted. For example, valves are generally required to be monitored once a month using a leak detection instrument, but the monitoring interval may be extended (e.g. to once every quarter for each valve that has not leaked for two successive months for Part 60 Subpart VV, or on a process unit basis of once every quarter for process units that have less than a 2% leak rate for Part 63 Subpart H).



Current Requirements

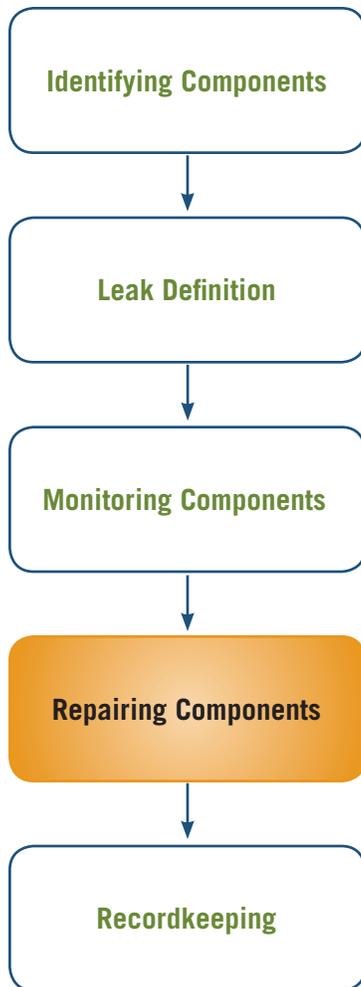
- For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A).
- Method 21 is a procedure used to detect VOC leaks from process equipment using a portable detecting instrument.
- Appendix C of this guide explains the general procedure and Appendix D presents the complete Method 21 requirements.
- Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type.

Common Problems

- Not following Method 21 properly.
- Failing to monitor at the maximum leak location (once the highest reading is obtained by placing the probe on and around the interface, hold the probe at that location approximately two times the response rate of the instrument).
- Not monitoring long enough to identify a leak.
- Holding the detection probe too far away from the component interface. The reading must be taken at the interface.
- Not monitoring all potential leak interfaces.
- Using an incorrect or an expired calibration gas.
- Not monitoring all regulated components.
- Not completing monitoring if the first monitoring attempt is unsuccessful due to equipment being temporarily out of service.

Best Practices

- Although not required by Method 21, use an automatic (electronic) data logger to save time, improve accuracy, and provide an audit record.
- Audit the LDAR program to help ensure that the correct equipment is being monitored, Method 21 procedures are being followed properly, and the required records are being kept.
- Monitor components more frequently than required by the regulations.
- Perform QA/QC of LDAR data to ensure accuracy, completeness, and to check for inconsistencies.
- Eliminate any obstructions (e.g., grease on the component interface) that would prevent monitoring at the interface.
- If a rule allows the use of alternatives to Method 21 monitoring, Method 21 should still be used periodically to check the results of the alternative monitoring method.



Current Requirements

- Repair leaking components as soon as practicable, but not later than a specified number of calendar days (usually 5 days for a first attempt at repair and 15 days for final attempt at repair) after the leak is detected.
- First attempts at repair include, but are not limited to, the following practices where practicable and appropriate:
 - Tightening bonnet bolts
 - Replacing bonnet bolts
 - Tightening packing gland nuts
 - Injecting lubricant into lubricated packing
- If the repair of any component is technically infeasible without a process unit shutdown, the component may be placed on the Delay of Repair list, the ID number is recorded, and an explanation of why the component cannot be repaired immediately is provided. An estimated date for repairing the component must be included in the facility records.

Note: The “drill and tap” method for repairing leaking valves is generally considered technically feasible without requiring a process unit shutdown and should be tried if the first attempt at repair does not fix the leaking valve. See section 6.7 for a discussion of “drill and tap”.

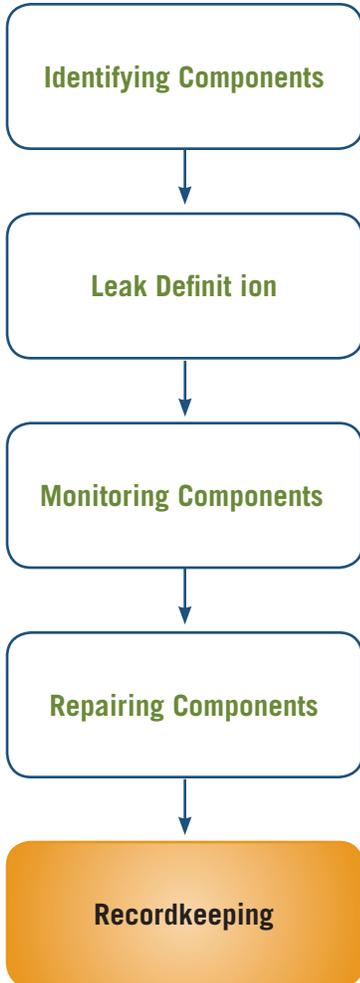
- The component is considered to be repaired only after it has been monitored and shown not to be leaking above the applicable leak definition.

Common Problems

- Not repairing leaking equipment within the required amount of time specified by the applicable regulation.
- Improperly placing components on the Delay of Repair list.
- Not having a justifiable reason for why it is technically infeasible to repair the component without a process unit shutdown.
- Not exploring all available repair alternatives before exercising the Delay of Repair exemption (specifically as it pertains to valves and “drill and tap” repairs).

Best Practices

- Develop a plan and timetable for repairing components.
- Make a first attempt at repair as soon as possible after a leak is detected.
- Monitor components daily and over several days to ensure a leak has been successfully repaired.
- Replace problem components with “leakless” or other technologies.



Current Requirements

For each regulated process:

- Maintain a list of all ID numbers for all equipment subject to an equipment leak regulation.
- For valves designated as “unsafe to monitor,” maintain a list of ID numbers and an explanation/review of conditions for the designation.
- Maintain detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams.
- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

For leaking equipment:

- Attach ID tags to the equipment.
- Maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a list of the dates of each repair attempt and an explanation of the attempted repair method.
- Note the dates of successful repairs.
- Include the results of monitoring tests to determine if the repair was successful.

Common Problems

- Not keeping detailed and accurate records required by the applicable regulation.
- Not updating records to designate new components that are subject to LDAR due to revised regulations or process modifications.

Best Practices

- Perform internal and third-party audits of LDAR records on a regular basis to ensure compliance.
- Electronically monitor and store LDAR data including regular QA/QC audits.
- Perform regular records maintenance.
- Continually search for and update regulatory requirements.
- Properly record and report first attempts at repair.
- Keep the proper records for components on Delay of Repair lists.

6.0 What Compliance Problems Have Been Found With Current LDAR Programs?

Many regulatory agencies determine the compliance status of LDAR programs based on a review of submitted paperwork. Some conduct walk-through inspections to review LDAR records maintained on site and perform a visual check of monitoring practices. However, a records review will not show if monitoring procedures are being followed. Similarly, the typical walkthrough inspection will not likely detect improper monitoring practices since operators will tend to ensure that they are following proper procedures when they are being watched.

EPA's National Enforcement Investigations Center (NEIC) conducted a number of sampling investigations of LDAR programs at 17 petroleum refineries. Appendix E summarizes the comparative monitoring results, and Appendix F contains a copy of the 1999 Enforcement Alert that explains the monitoring results. The investigations consisted of records review and comparative leak monitoring (comparing the leak rate found by NEIC to the facility's historic leak rate) at a subset of the facility's total components. These investigations have shown a pattern of significantly higher equipment leak rates (5%) than what the refineries reported (1.3%). While there have been improvements since 1999, facility audits are still showing significantly elevated leak rates, especially in the chemical manufacturing industries.

The discrepancy in leak rates indicates that monitoring staff may not be complying with Method 21 procedures. Failure to accurately detect leaks may be due to a lack of internal quality control oversight or management accountability for the LDAR pro-

grams regardless of whether the monitoring is done by contractors or in-house personnel.

Each leak that is not detected and repaired is a lost opportunity to reduce emissions. In the October 1999 Enforcement Alert, EPA estimates that an additional 40,000 tons of VOCs are emitted annually from petroleum refineries because leaking valves are not found and repaired.

Several important factors contribute to failing to identify and repair leaking components:

1. Not identifying all regulated components/units in inventory

If a facility does not properly identify all of its regulated components, some leaks may go unidentified. Unidentified components may leak or have existing leaks that will worsen over time if the components are not properly identified, monitored and repaired. Facilities can fail to identify regulated components when new processes are constructed, existing process are modified, or new or revised equipment leak regulations are published.

2. Not monitoring components

In some cases, the number of components reported to have been monitored may indicate problems with monitoring procedures. What facility inspectors have found:

- A data logger time stamp showed valves being monitored at the rate of one per second with two valves occasionally be-

ing monitored within the same 1-second period.

- At one facility, a person reported monitoring 8,000 components in one day (assuming an 8-hour work day, that represents one component every 3.6 seconds).
- Records evaluations showed widely varying component monitoring counts, suggesting equipment might not always be monitored when required.
- Equipment was marked “temporarily out of service” because the initial inspection attempt could not be performed. However, the equipment was in service for most of the period, and no subsequent (or prior) inspection attempts were performed to meet the monitoring requirement.

However, even when records show a realistic number of components are being monitored, if there are no oversight or accountability checks, then there is no guarantee that components are actually being monitored.



3. Insufficient time to identify a leak

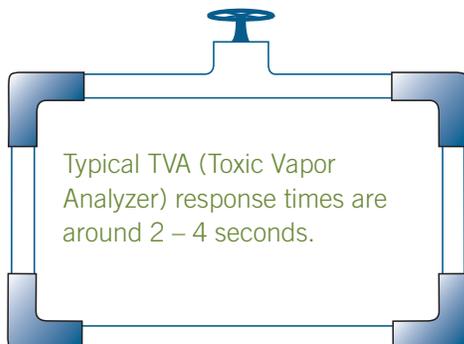
In other cases, facilities are not following proper monitoring procedures, resulting in a lower number of leaking components being reported.

- If a worker moves the probe around the component interface so rapidly that the instrument does not have time to properly respond, then a component may never be identified as leaking.
- If a worker fails to find the maximum leak location for the component and then does not spend twice the response time at that location, then the monitoring instrument will not measure the correct concentration of hydrocarbons and the leak may go undetected. **Optical leak imaging shows the importance of identifying the maximum leak location, as hydrocarbons are quickly dispersed and diluted by air currents around the component.**

4. Holding the probe away from the component interface

The probe must be placed at the proper interface of the component being analyzed. Placing the probe even 1 centimeter from the interface can result in a false reading, indicating that the component is not leaking, when in fact it is leaking. Eliminate any issues (e.g., grease on the component interface) that prevent monitoring at the interface (e.g., remove excess grease from the component before monitoring or use a monitor that won't be impacted by the grease and is easy to clean).

For equipment with rotating shafts (pumps and compressors), Method 21 requires the probe be placed within 1 centimeter of the



shaft-seal interface. Placing the probe at the surface of the rotating shaft is a safety hazard and should be avoided.

5. Failing to properly maintain monitoring instrument

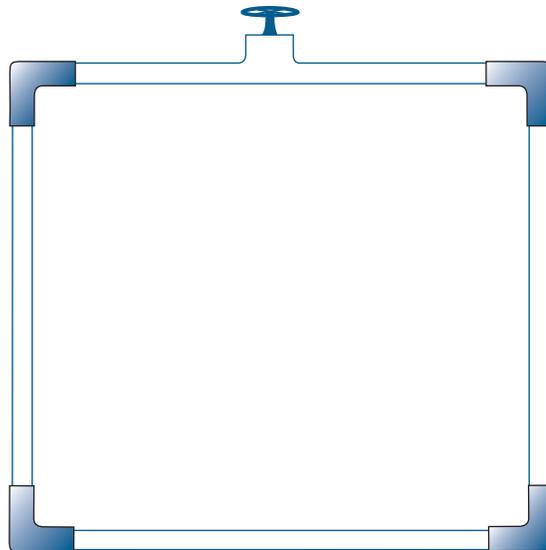
Factors that may prevent the instrument from identifying leaks are:

- Not using an instrument that meets the specifications required in Method 21, section 6.
- Dirty instrument probes;
- Leakage from the instrument probes;
- Not zeroing instrument meter;
- Incorrect calibration gases used; and
- Not calibrating the detection instrument on a daily basis.

6. Improperly identifying components as “unsafe” or “difficult” to monitor

Components that are identified as being “unsafe to monitor” or “difficult to monitor” must be identified as such because there is a safety concern or an accessibility issue that prevents the component from being successfully monitored.

All unsafe or difficult-to-monitor components must be included on a log with identification numbers and an explanation of why the component is “unsafe to monitor” or “difficult to monitor.” Monitoring can be deferred for all such components, but the facility must maintain a plan that explains the conditions under which the components become safe to monitor or no longer difficult to monitor.



7. Improperly placing components/units on the “Delay of Repair” list

Generally, placing a leaking component on the “Delay of Repair” list is permissible only when the component is technically infeasible to repair without a process unit shutdown (e.g., for valves the owner/operator must demonstrate that the emissions from immediate repair will be greater than waiting for unit shutdown).

Repair methods may exist, such as “drill and tap” for valves, that allow leaks to be fixed while the component is still in service. Failing to consider such repair methods before exercising the “Delay of Repair” list may constitute noncompliance with repair requirements (usually 15 days under federal LDAR standards).

Components placed on the “Delay of Repair” list must be accompanied by their ID numbers and an explanation of why they have been placed on the list. These components cannot remain on the list indefinitely – they must be repaired by the end of the next process unit shutdown.



Drill and Tap is a repair method where a hole is drilled into the valve packing gland and tapped, so that a small valve and fitting can be attached to the gland. A packing gun is connected to this fitting and the small valve is opened allowing new packing material to be pumped into the packing gland.

Many companies consider this a permanent repair technique, as newer, pumpable packing types are frequently superior to the older packing types they replace. Packing types can be changed and optimized for the specific application over time.

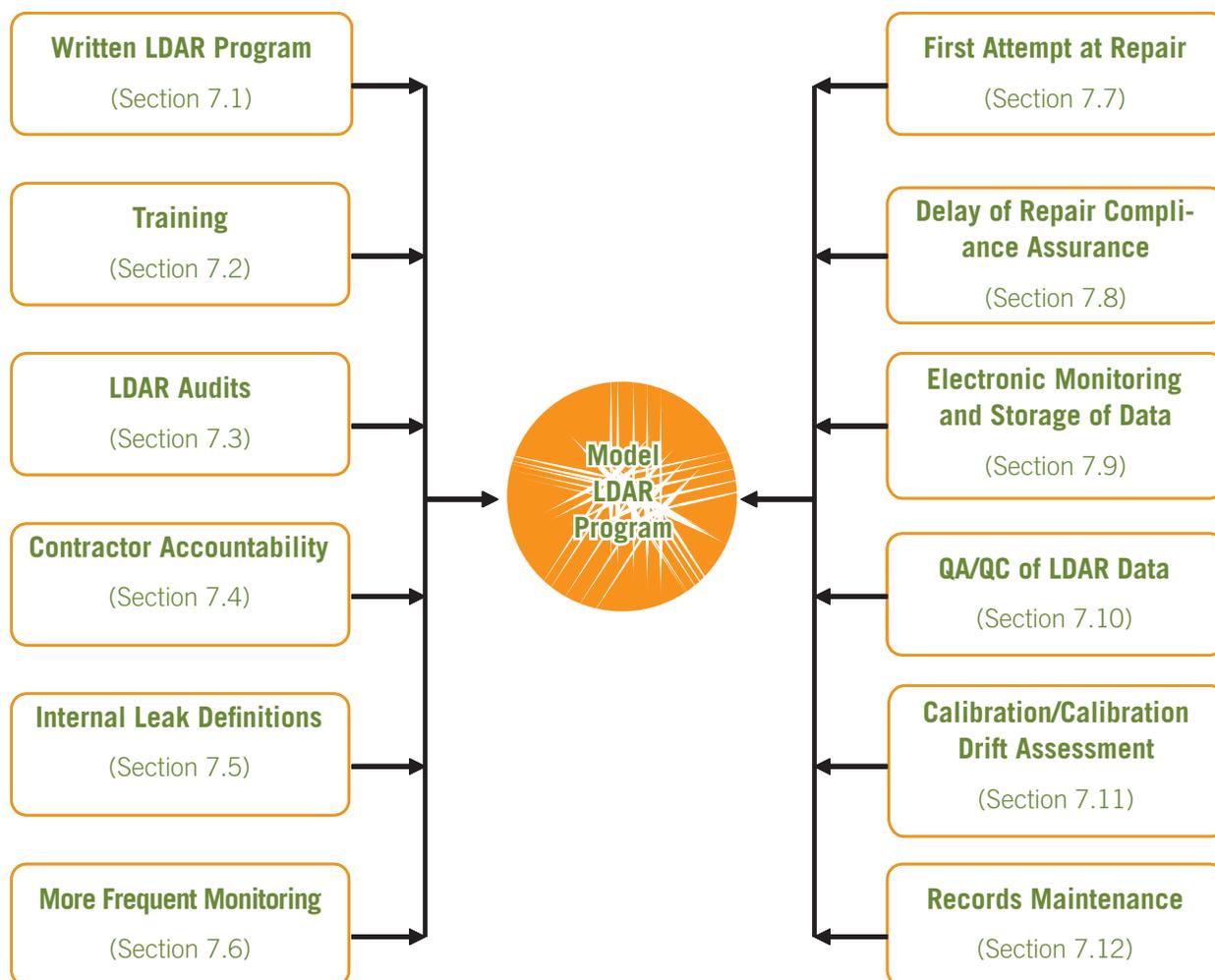
7.0 Model LDAR Program

Experience has shown that facilities with an effective record of preventing leaks integrate an awareness of the benefits of leak detection and repair into their operating and maintenance program. This section outlines some of the major elements of successful LDAR programs. These program elements were developed from:

- Evaluation of best practices identified at facilities with successful LDAR programs, and
- Analysis of the root causes of noncompliance

at facilities that were found to have recurring violations of LDAR regulatory requirements.

LDAR programs that incorporate most or all of the elements described in the following sections have achieved more consistent results in their LDAR programs, leading to increased compliance and lower emissions.



7.1 Written LDAR Program

A written LDAR program specifies the regulatory requirements and facility-specific procedures for recordkeeping certifications, monitoring, and repairs. A written program also delineates the roles of each person on the LDAR team as well as documents all the required procedures to be completed and data to be gathered, thus establishing accountability. The plan should identify all process units subject to federal, state, and local LDAR regulations and be updated as necessary to ensure accuracy and continuing compliance.

Elements:

- An overall, facility-wide leak rate goal that will be a target on a process-unit-by-process-unit basis;
- A list of all equipment in light liquid and/or in gas/vapor service that has the potential to leak VOCs and VHAPs, within process units that are owned and maintained by each facility;
- Procedures for identifying leaking equipment within process units;
- Procedures for repairing and keeping track of leaking equipment;
- A process for evaluating new and replacement equipment to promote the consideration of installing equipment that will minimize leaks or eliminate chronic leakers;
- A list of “LDAR Personnel” and a description of their roles and responsibilities, including the person or position for each facility that has the authority to implement improvements to the LDAR program; and
- Procedures (e.g., a Management of Change program) to ensure that components added to each facility during maintenance and construction are evaluated to determine if they are subject to LDAR requirements, and that affected components are integrated into the LDAR program.

Within thirty (30) days after developing the written facility-wide LDAR program, submit a copy of the Program to EPA and to the appropriate state agency.

7.2 Training

A training program will provide LDAR personnel the technical understanding to make the written LDAR program work. It also will educate members of the LDAR team on their individual responsibilities. These training programs can vary according to the level of involvement and degree of responsibility of LDAR personnel.

Elements:

- Provide and require initial training and annual LDAR refresher training for all facility employees assigned LDAR compliance responsibilities, such as monitoring technicians, database users, QA/QC personnel, and the LDAR Coordinator;
- For other operations and maintenance personnel with responsibilities related to LDAR, provide and require an initial training program that includes instruction on aspects of LDAR that are relevant to their duties (e.g., operators and mechanics performing valve packing and unit supervisors that approve delay of repair work). Provide and require “refresher” training in LDAR for these personnel at least every three years.
- Collect training information and records of contractors, if used.

7.3 LDAR Audits

Whether LDAR monitoring is done in house or contracted to third parties outside the company, the potential exists for LDAR staff not to adhere correctly to the LDAR program. Internal and third-party audits of a facility LDAR program are a critical component of effective LDAR programs. The audits check that the correct equipment is being monitored, Method 21 procedures are being followed, leaks are being fixed, and the required records are being kept. In short, the audits ensure that the LDAR program is being conducted correctly and problems are identified and corrected.

Elements:

- Review records on a regular cycle to ensure that all required LDAR-related records, logs, and databases are being maintained and are up to date.
- Ensure and document that the correct equipment is included in the LDAR program and that equipment identified as leaking is physically tagged with the equipment ID number.
- Observe the calibration and monitoring techniques used by LDAR technicians, in particular to ensure the entire interface is checked and the probe is held at the interface, not away from the interface.
- Retain a contractor to perform a third-party audit of the facility LDAR program at least once every four (4) years.
- Perform facility-led audits every four (4) years.
 - Use personnel familiar with the LDAR program and its requirements from one or more of the company's other facilities or locations (if available).
 - Perform the first round of facility-led LDAR audits no later than two (2) years after completion of the third-party audits outlined above, and every four (4) years thereafter.
 - This rotation ensures that the facility is being audited once every two (2) years.
- If areas of noncompliance are discovered, initiate a plan to resolve and document those issues.
- Implement, as soon as practicable, steps necessary to correct causes of noncompliance, and prevent, to the extent practicable, a recurrence of the cause of the noncompliance.
- Retain the audit reports and maintain a written record of the corrective actions taken in response to any deficiencies identified.

7.4 Contractor Accountability

Contractors performing monitoring are frequently compensated for the number of components they monitor, which might provide an incentive to rush through monitoring procedures and not adhere to Method 21 requirements for response time, monitoring distance, etc. If this happens, some equipment leaks may not be detected. To overcome this potential problem, facilities should have in place sufficient oversight procedures to increase the accountability of contractors.

Elements:

- Write contracts that emphasize the quality of work instead of the quantity of work only.
- Require contractors to submit documentation that their LDAR personnel have been trained on Method 21 and facility-specific LDAR procedures.
- Ensure that the contractor has a procedure in place to review and certify the monitoring data before submitting the data to the facility.
- Review daily results of contractor work to ensure that a realistic number of components are being monitored.
- Perform spot audits in the field to ensure that Method 21 procedures are being followed. This can include spot-checking monitored components with another hydrocarbon analyzer or following LDAR personnel as they perform monitoring.
- Have periodic reviews of contractor performance (e.g., quarterly or semi-annually) to resolve issues and correct problems.

7.5 Internal Leak Definition for Valves and Pumps

The varying leak definitions that can apply to different process units and components can be confusing and lead to errors in properly identifying leaks. To counter this potential problem, operate your LDAR program using an internal leak definition for valves and pumps in light liquid or gas vapor service. The internal leak definition would be equivalent to or lower than the applicable definitions in your permit and the applicable federal, state, and local regulations. Monitoring against a uniform definition that is lower than the applicable regulatory definition will reduce errors and provide a margin of safety for identifying leaking components. The internal leak definition would apply to valves and pumps (and possibly connectors) in light liquid or gas vapor service.

Elements:

- Adopt a 500-ppm or lower internal leak definition for VOCs for all valves in light liquid and/or gas vapor service, excluding pressure relief devices.
- Adopt a 2,000-ppm or lower internal leak definition for pumps in light liquid and/or gas/vapor service.
- Record, track, repair, and monitor leaks in excess of the internal leak definition. Repair and monitor leaks that are greater than the internal leak definitions but less than the applicable regulatory leak definitions within thirty (30) days of detection.

Consent Decrees between EPA and many chemical facilities subject to the HON require using a 250-ppm leak definition for valves and connectors and a 500-ppm leak definition for pumps.

Note: If a state or local agency has lower leak definitions, then the internal leak definition should be set to the lowest definition or even lower to include/allow for margin of error.

7.6 More Frequent Monitoring

Many regulations allow for less frequent monitoring (i.e. skip periods) when good performance (as defined in the applicable regulation) is demonstrated. Skip period is an alternative work practice found in some equipment leak regulations and usually applies only to valves and connectors. After a specified number of leak detection periods (e.g., monthly) during which the percentage of leaking components is below a certain value (e.g., 2% for NSPS facilities), a facility can monitor less frequently (e.g., quarterly) as long as the percentage of leaking components remains low. The facility must keep a record of the percentage of the component type found leaking during each leak detection period.

Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions. To ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time, implement a plan for more frequent monitoring for components that contribute most to equipment leak emissions.

Elements:

- Monitor pumps in light liquid and/or gas vapor service on a monthly basis.
- Monitor valves in light liquid and/or gas vapor service – other than difficult-to-monitor or unsafe-to-monitor valves – with no skip periods.

Consent Decrees between EPA and many chemical facilities subject to the HON require semiannual monitoring of connectors.

7.7 Repairing Leaking Components

To stop detected leaks while they are still small, most rules require a first attempt at repair within 5 days of the leak detection and a final repair within 15 days. However, any component that cannot be repaired within those time frames must be placed on a “Delay of Repair” list to be repaired during the next shutdown cycle.

First attempts at repair include, but are not limited to, the following best practices where practicable and appropriate:

- Tightening bonnet bolts;
- Replacing bonnet bolts;
- Tightening packing gland nuts; and
- Injecting lubricant into lubricated packing.

Elements:

- Schedule the “first attempt at repair” of those components that the monitoring personnel are not authorized to repair consistent with the existing regulatory requirements.
- Monitor the component for which a “first attempt at repair” was performed no later than the next regular business day to ensure the leak has not worsened.
- If the first attempt at repair has not succeeded then other methods, such as “drill and tap” should be employed where feasible. Drill and tap procedures are no longer considered extraordinary practices.

7.8 Delay of Repair Compliance Assurance

Any component that cannot be repaired during the specified repair interval must be placed on a “Delay of Repair” list to be repaired during the next shut-down cycle. Delay of repair compliance assurance procedures ensure that the appropriate equipment is justifiably on the “Delay of Repair” list and that facilities have a plan to fix these components.

Elements:

- Have the unit supervisor approve in advance and certify all components that are technically infeasible to repair without a process unit shut-down.
- Continue to monitor equipment that is placed on the “Delay of Repair” list in the facility’s regular LDAR monitoring. For leaks above the internal leak definition rate and below the regulatory rate, put the equipment on the “Delay of Repair” list within 30 days.
- Implement the following repair policies and procedures within 15 days of implementing the written LDAR program:
 - For valves, other than control valves or pressure relief valves, that are leaking at a rate of 10,000 ppm or greater and cannot be feasibly repaired without a process unit shutdown, use “drill and tap” repair methods to fix the leaking valve, unless you can determine and document that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner.
 - Perform up to two “drill and tap” repair attempts to repair a leaking valve, if necessary, within 30 days of identifying the leak.

7.9 Electronic Monitoring and Storage of LDAR Data

Electronic monitoring and storage of LDAR data will help evaluate the performance of monitoring personnel (via time/date stamps), improve accuracy, provide an effective means for QA/QC, and retrieve records in a timely manner for review purposes. Incorporate and maintain an electronic database for storing and reporting LDAR data. Use data loggers or other data collection devices during all LDAR monitoring.

Elements:

- Use best efforts to transfer, on a daily basis, electronic data from electronic data logging devices to the database.
- For all monitoring events in which an electronic data collection device is used, include a time and date stamp, operator identification, and instrument identification.
- Paper logs can be used where necessary or more feasible (e.g., small rounds, re-monitoring fixed leaks, or when data loggers are not available or broken), and should record, at a minimum, the monitoring technician, date, and monitoring equipment used.
- Transfer any manually recorded monitoring data to the database within 7 days of monitoring.
- Review records to identify “problem” components for preventative maintenance (repair prior to anticipated failure) or for replacement with “leakless” technology.

7.10 QA/QC of LDAR Data

QA/QC audits ensure that Method 21 procedures are being followed and LDAR personnel are monitoring the correct components in the proper manner. Develop and implement a procedure to ensure QA/QC review of all data generated by LDAR monitoring technicians on a daily basis or at the conclusion of each monitoring episode.

Elements:

Some QA/QC procedures include:

- Daily review/sign-off by monitoring technicians of the data they collected to ensure accuracy and validity.
- Periodic review of the daily monitoring reports generated in conjunction with recordkeeping and reporting requirements.
- Quarterly QA/QC of the facility's and contractor's monitoring data including:
 - Number of components monitored per technician;
 - Time between monitoring events; and
 - Abnormal data patterns.

7.11 Calibration/Calibration Drift Assessment

Always calibrate LDAR monitoring equipment using an appropriate calibration gas, in accordance with 40 CFR Part 60, EPA Reference Test Method 21.

Elements:

- Conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum.
- Conduct the calibration drift assessment using, at a minimum, approximately 500 ppm of calibration gas.
- If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, re-monitor all valves that were monitored since the last calibration with a reading of greater than 100 ppm. Re-monitor all pumps that were monitored since the last calibration with a reading of greater than 500 ppm.

7.12 Records Maintenance

Organized and readily available records are one potential indication of an effective LDAR program. Well-kept records may also indicate that the LDAR program is integrated into the facility's routine operation and management. The equipment leak regulations specify recordkeeping and reporting requirements; incorporating the elements below will help ensure your facility LDAR records are thorough and complete.

Elements:

Records to maintain:

- A certification that the facility implemented the “first attempt at repair” program.
- A certification that the facility implemented QA/QC procedures for review of data generated by LDAR technicians.
- An identification of the person/position at each facility responsible for LDAR program performance as defined in the written program.
- A certification that the facility developed and implemented a tracking program for new valves and pumps added during maintenance and construction defined in the written program.
- A certification that the facility properly completed calibration drift assessments.
- A certification that the facility implemented the “delay of repair” procedures.
- The following information on LDAR monitoring:
 - (1) The number of valves and pumps present in each process unit during the quarter;
 - (2) The number of valves and pumps monitored in each process unit;
 - (3) An explanation for missed monitoring if the number of valves and pumps present exceeds the number of valves and pumps monitored during the quarter;
 - (4) The number of valves and pumps found leaking;
 - (5) The number of “difficult to monitor” pieces of equipment monitored;
 - (6) A list of all equipment currently on the “Delay of Repair” list and the date each component was placed on the list;
 - (7) The number of repair attempts not completed promptly or completed within 5 days;
 - (8) The number of repairs not completed within 30 days and the number of components not placed on the “Delay of Repair” list; and
 - (9) The number of chronic leakers that do not get repaired.
- Records of audits and corrective actions. Prior to the first third-party audit at each facility, include in your records a copy of each audit report from audits conducted in the previous calendar year and a summary of the actions planned or taken to correct all deficiencies identified in the audits.
- For the audits performed in prior years, identification of the auditors and documentation that a written plan exists identifying corrective action for any deficiencies identified and that this plan is being implemented.

8.0 Sources of Additional Information

Inspection Manual: Federal Equipment Leak Regulations for the Chemical Manufacturing Industry, EPA/305/B-98/011, December 1998.

<http://cfpub.epa.gov/compliance/resources/publications/assistance/sectors/chemical/index.cfm>

Vol 1: Inspection Manual

<http://www.epa.gov/compliance/resources/publications/assistance/sectors/insmanvol1.pdf>

Vol 2: Chemical Manufacturing Industry Regulations (3 parts on the Internet)

<http://www.epa.gov/compliance/resources/publications/assistance/sectors/insmanvol2pt1.pdf>

<http://www.epa.gov/compliance/resources/publications/assistance/sectors/insmanvol2pt2.pdf>

<http://www.epa.gov/compliance/resources/publications/assistance/sectors/insmanvol2pt3.pdf>

Vol 3: Petroleum Refining Industry Regulations

<http://www.epa.gov/compliance/resources/publications/assistance/sectors/insmanvol3.pdf>

1995 Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

<http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf>

Enforcement Alert, EPA Office of Enforcement and Compliance Assurance, EPA 300-N-99-014, Oct 1999.

<http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/emissions.pdf>

National Petroleum Refinery Initiative, EPA.

<http://www.epa.gov/compliance/resources/cases/civil/caa/refineryinitiative032106.pdf>

Petroleum Refinery Initiative Fact Sheet, EPA.

<http://www.epa.gov/compliance/resources/cases/civil/caa/petroleumrefinery-fcsht.html>

Petroleum Refinery National Priority Case Results.

<http://www.epa.gov/compliance/resources/cases/civil/caa/oil/>

Draft Staff Report, Regulation 8, Rule 18, Equipment Leaks, Bay Area Air Quality Management District, Jul 1997.

http://www.baaqmd.gov/pln/ruledev/8-18/1997/0818_sr_071097.pdf

Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; Proposed Rule, [EPA-HQ-OAR-2006-0699; FRL-] RIN 2060-AN71.

http://www.epa.gov/ttn/oarpg/t3/fr_notices/equip_leak_prop103106.pdf

Industrial Organic Chemicals Compliance Incentive Program, EPA Compliance and Enforcement.

<http://www.epa.gov/compliance/incentives/programs/ioccip.html>

Leak Detection and Repair Program Developments.

<http://www.epa.gov/compliance/neic/field/leak.html>

Compliance and Enforcement Annual Results: Important Environmental Problems / National Priorities.

<http://www.epa.gov/compliance/resources/reports/endofyear/eoy2006/sp-airtoxics-natl-priorities.html>

Portable Instruments User's Manual For Monitoring VOC Sources, EPA-340/1-86-015.

Inspection Techniques For Fugitive VOC Emission Sources, EPA 340/1-90-026a,d,e,f (rev May 1993) Course #380.

Environmental compliance assistance resources can be found at:

<http://cfpub.epa.gov/clearinghouse/>

<http://www.assistancecenters.net/>

<http://www.epa.gov/compliance/assistance/sectors/index.html>

Appendix A Federal Regulations That Require a Formal LDAR Program With Method 21

| 40 CFR | | Regulation Title |
|--------|---------|---|
| Part | Subpart | |
| 60 | VV | SOCMI VOC Equipment Leaks NSPS |
| 60 | DDD | Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry |
| 60 | GGG | Petroleum Refinery VOC Equipment Leaks NSPS |
| 60 | KKK | Onshore Natural Gas Processing Plant VOC Equipment Leaks NSPS |
| 61 | J | National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene |
| 61 | V | Equipment Leaks NESHAP |
| 63 | H | Organic HAP Equipment Leak NESHAP (HON) |
| 63 | I | Organic HAP Equipment Leak NESHAP for Certain Processes |
| 63 | J | Polyvinyl Chloride and Copolymers Production NESHAP |
| 63 | R | Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) |
| 63 | CC | Hazardous Air Pollutants from Petroleum Refineries |
| 63 | DD | Hazardous Air Pollutants from Off-Site Waste and Recovery Operations |
| 63 | SS | Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process |
| 63 | TT | Equipment Leaks – Control Level 1 |
| 63 | UU | Equipment Leaks – Control Level 2 |
| 63 | YY | Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards |
| 63 | GGG | Pharmaceuticals Production |
| 63 | III | Hazardous Air Pollutants from Flexible Polyurethane Foam Production |
| 63 | MMM | Hazardous Air Pollutants for Pesticide Active Ingredient Production |
| 63 | FFFF | Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing |
| 63 | GGGGG | Hazardous Air Pollutants: Site Remediation |
| 63 | HHHHH | Hazardous Air Pollutants: Miscellaneous Coating Manufacturing |
| 65 | F | Consolidated Federal Air Rule – Equipment Leaks |
| 264 | BB | Equipment Leaks for Hazardous Waste TSDFs |
| 265 | BB | Equipment Leaks for Interim Status Hazardous Waste TSDFs |

Note: Many of these regulations have identical requirements, but some have different applicability and control requirements.

Appendix B Federal Regulations That Require the Use of Method 21 But Do Not Require a Formal LDAR Program

| 40 CFR | | Regulation Title |
|--------|---------|---|
| Part | Subpart | |
| 60 | XX | Bulk Gasoline Terminals |
| 60 | QQQ | VOC Emissions from Petroleum Refinery Wastewater Systems |
| 60 | WWW | Municipal Solid Waste Landfills |
| 61 | F | Vinyl Chloride |
| 61 | L | Benzene from Coke By-Products |
| 61 | BB | Benzene Transfer |
| 61 | FF | Benzene Waste Operations |
| 63 | G | Organic Hazardous Air Pollutants from SOCM I for Process Vents, Storage Vessels, Transfer Operations, and Wastewater |
| 63 | M | Perchloroethylene Standards for Dry Cleaning |
| 63 | S | Hazardous Air Pollutants from the Pulp and Paper Industry |
| 63 | Y | Marine Unloading Operations |
| 63 | EE | Magnetic Tape Manufacturing Operations |
| 63 | GG | Aerospace Manufacturing and Rework Facilities |
| 63 | HH | Hazardous Air Pollutants from Oil and Gas Production Facilities |
| 63 | OO | Tanks – Level 1 |
| 63 | PP | Containers |
| 63 | QQ | Surface Impoundments |
| 63 | VV | Oil/Water, Organic/Water Separators |
| 63 | HHH | Hazardous Air Pollutants from Natural Gas Transmission and Storage |
| 63 | JJJ | Hazardous Air Pollutant Emissions: Group IV Polymers and Resins |
| 63 | VVV | Hazardous Air Pollutants: Publicly Owned Treatment Works |
| 65 | G | CFAR – Closed Vent Systems |
| 264 | AA | Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities - Process Vents |
| 264 | CC | Owners and Operators of Hazardous Waste Treatment, Storage and Disposal Facilities - Tanks, Surface Impoundments, Containers |
| 265 | AA | Interim Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities – Process Vents |
| 265 | CC | Interim Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities - Tanks, Surface Impoundments, Containers |
| 270 | B | Hazardous Waste Permit Program – Permit Application |
| 270 | J | Hazardous Waste Permit Program – RCRA Standardized Permits for Storage Tanks and Treatment Units |

Appendix C Method 21 General Procedure

Failure of facilities to follow Method 21 can lead to them not properly identifying and subsequently repairing leaking components. It is critical for facilities to refer to the complete text of Method 21 (see Appendix D) for detailed explanations of each general procedure found below and how to properly perform each step.

1. Evaluate Instrument Performance

Performance criteria for the monitoring instrument:

- For each VOC measured, the response factor should be <10 unless specified in the applicable regulation. Response factor is the ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.
- The calibration precision should be <10 percent of the calibration gas value. Calibration precision is the degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.
- The response time should be ≤30 seconds. Response time is the time interval from a step change

in VOC concentration at the input of the sampling system to the time at which 90% of the corresponding final value is reached as displayed on the instrument readout meter.

2. Calibrate Instrument

Before each monitoring episode:

- Let the instrument warm up.
- Introduce the calibration gas into the instrument probe.
- Adjust the instrument meter readout to match the calibration gas concentration value.

3. Monitor Individual components

When monitoring components:

- Place the probe at the surface of the component interface where leakage could occur.
- Move the probe along the interface periphery while observing the instrument readout.
- Locate the maximum reading by moving the probe around the interface.
- Keep the probe at the location of the maximum reading for 2 times the response factor.
- If the concentration reading on the instrument readout is above the applicable leak definition, then the component is leaking and must be repaired.

Appendix D Method 21—Determination of Volatile Organic Compound Leaks

1.0 Scope and Application

1.1 Analytes.

| Analyte | CAS No. |
|---------------------------------------|-------------------------|
| Volatile Organic Compounds (VOC)..... | No CAS number assigned. |

1.2 Scope. This method is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

3.0 Definitions

3.1 Calibration gas means the VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

3.2 Calibration precision means the degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

3.3 Leak definition concentration means the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

3.4 No detectable emission means a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 % of the specified leak definition concentration. That indicates that a VOC emission (leak) is not present.

3.5 Reference compound means the VOC species selected as the instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition concentration is 10,000 ppm and the reference compound is methane.)

3.6 Response factor means the ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

3.7 Response time means the time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

4.0 Interferences [Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hazardous Pollutants. Several of the compounds, leaks of which may be determined by this

method, may be irritating or corrosive to tissues (e.g., heptane) or may be toxic (e.g., benzene, methyl alcohol). Nearly all are fire hazards. Compounds in emissions should be determined through familiarity with the source. Appropriate precautions can be found in reference documents, such as reference No. 4 in Section 16.0.

6.0 Equipment and Supplies

A VOC monitoring instrument meeting the following specifications is required:

6.1 The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

6.2 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

6.3 The scale of the instrument meter shall be readable to $\pm 2.5\%$ of the specified leak definition concentration.

6.4 The instrument shall be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 l/min (0.004 to 0.1 ft³/min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

6.5 The instrument shall be equipped with a probe or probe extension or sampling not to exceed 6.4 mm (1/4 in) in outside diameter, with a single end opening for admission of sample.

6.6 The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

7.0 Reagents and Standards

7.1 Two gas mixtures are required for instrument calibration and performance evaluation:

7.1.1 Zero Gas. Air, less than 10 parts per million by volume (ppmv) VOC.

7.1.2 Calibration Gas. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration approximately equal to the applicable leak definition specified in the regulation.

7.2 Cylinder Gases. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within 2 % accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life.

7.3 Prepared Gases. Calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within 2 percent. Prepared standards must be replaced each day of use unless it is demonstrated that degradation does not occur during storage.

7.4 Mixtures with non-Reference Compound Gases. Calibrations may be performed using a compound other than the reference compound. In this case, a conversion factor must be determined for the alternative compound such that the resulting meter readings during source surveys can be converted to reference compound results.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Instrument Performance Evaluation. Assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

8.1.1 Response Factor. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

8.1.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. Introduce the calibration gas mixture to the analyzer and record the observed meter reading. Introduce zero gas until a stable reading is obtained. Make a total of three measurements by alternating between the calibration gas and zero gas. Calculate the response factor for each repetition and the average response factor.

8.1.1.2 The instrument response factors for each of the individual VOC to be measured shall be less than 10 unless otherwise specified in the applicable regulation. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regula-

tion, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the individual VOC to be measured.

8.1.1.3 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in References 1–3 of Section 17.0.

8.1.2 Calibration Precision. The calibration precision test must be completed prior to placing the analyzer into service and at subsequent 3-month intervals or at the next use, whichever is later.

8.1.2.1 Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

8.1.2.2 The calibration precision shall be equal to or less than 10 % of the calibration gas value.

8.1.3 Response Time. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

8.1.3.1 Introduce zero gas into the instrument sample probe. When the meter reading has sta-

bilized, switch quickly to the specified calibration gas. After switching, measure the time required to attain 90 % of the final stable reading. Perform this test sequence three times and record the results. Calculate the average response time.

8.1.3.2 The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter that will be used during testing shall all be in place during the response time determination.

8.2 Instrument Calibration. Calibrate the VOC monitoring instrument according to Section 10.0.

8.3 Individual Source Surveys.

8.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

8.3.1.1 Valves. The most common source of leaks from valves is the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample

the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

8.3.1.2 Flanges and Other Connections. For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

8.3.1.3 Pumps and Compressors. Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

8.3.1.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

8.3.1.5 Process Drains. For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

8.3.1.6 Open-ended Lines or Valves. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.7 Seal System Degassing Vents and Accumulator Vents. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.8 Access door seals. Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

8.3.2 Type II—“No Detectable Emission”. Determine the local ambient VOC concentration around the source by moving the probe randomly upwind and downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration as outlined in Section 8.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation. For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:

8.3.2.1 Pump or Compressor Seals. If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described in Section 8.3.2.

8.3.2.2 Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices. If applicable,

observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur upstream of the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in Section 8.3.2 shall be used to determine if detectable emissions exist.

8.3.3 Alternative Screening Procedure.

8.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of Section 8.3.1 or 8.3.2.

8.3.3.2 Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of Section 8.3.1 or 8.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

9.0 Quality Control

| Section | Quality control measure | Effect |
|------------|---|--|
| 8.1.2..... | Instrument calibration precision check. | Ensure precision and accuracy, respectively, of instrument response to standard. |
| 10.0..... | Instrument calibration. | |

10.0 Calibration and Standardization

10.1 Calibrate the VOC monitoring instrument as follows. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

11.0 Analytical Procedures [Reserved]

12.0 Data Analyses and Calculations [Reserved]

13.0 Method Performance [Reserved]

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

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- Factors of VOC Analyzers at a Meter Reading of 10,000 ppmv for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81051. September 1981.
2. Brown, G.E., et al. Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-022. May 1981.
3. DuBose, D.A. et al. Response of Portable VOC Analyzers to Chemical Mixtures. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-110. September 1981.
4. Handbook of Hazardous Materials: Fire, Safety, Health. Alliance of American Insurers. Schaumburg, IL. 1983.

17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

Appendix E Summary of NEIC Comparative Monitoring Results of Leaking Valves at 17 Refineries

| | Refineries Total | NEIC Total |
|--|------------------|------------|
| Valves Monitored | 170,717 | 47,526 |
| Number of Leaks | 2,266 | 2,372 |
| Leak Rate (%) | 1.3 | 5.0 (avg) |
| Emissions Rate (lb/hr) | 1,177.0 | 2,775.5 |
| Potential Emissions from Undetected Leaks (lb/hr)^a | 1,598.5 | |

Source: Enforcement Alert – Proper Monitoring Essential to Reducing ‘Fugitive Emissions’ Under Leak Detection and Repair Programs, EPA 300-N-99-014. US EPA Office of Enforcement and Compliance Assurance. Vol. 2, No. 9, Oct 1999.

^a Potential Emissions from Undetected Leaks (lb/hr) = NEIC Total Emissions Rate (lb/hr) – Refineries Total Emissions Rate (lb/hr)

Appendix F Enforcement Alert

United States
Environmental Protection
Agency

Office of Enforcement
and Compliance
Assurance (2201A)

EPA 300-N-99-014



Enforcement Alert

Volume 2, Number 9

Office of Regulatory Enforcement

October 1999

Proper Monitoring Essential to Reducing 'Fugitive Emissions' Under Leak Detection and Repair Programs

The Clean Air Act requires refineries to develop and implement a Leak Detection and Repair (LDAR) program to control fugitive emissions. Fugitive emissions occur from valves, pumps, compressors, pressure relief valves, flanges, connectors and other piping components.

Comparison monitoring con-

ducted by the U.S. Environmental Protection Agency's (EPA) National Enforcement Investigations Center (NEIC) shows that the number of leaking valves and components is up to 10 times greater than had been reported by certain refineries (see Table, Page 2). EPA believes this great disparity between what refineries are reporting and what EPA is finding may be attributable to refineries not monitoring in the manner prescribed in 40 CFR Part 60, Appendix A, Method 21.

Federal regulations require refiners to routinely monitor for leaks and to fix any equipment found leaking. Failure to identify leaking equipment results in necessary repairs not being made and continuing fugitive emissions of volatile organic chemicals (VOCs) and other hazardous chemicals. EPA estimates that the failure to identify and repair leaks at petroleum refineries could be resulting in additional VOC emissions of 80 million pounds annually. VOCs contribute to ground-level ozone, a principal component of smog, which can cause significant health and environmental problems.

What the Law Requires

Specific requirements for refinery fugitive emissions are identified in 40 CFR Part 60, New Source Performance Standards (NSPS), and 40

CFR Parts 61 and 63, National Emission Standards for Hazardous Air Pollutants (NESHAP). Many State and local air agencies incorporate federal requirements but some have established more stringent requirements as authorized by law. The various regulations require refineries to implement an LDAR program to reduce fugitive emissions from valves, pumps, compressors, pressure relief valves, flanges, connectors, and other

EPA estimates that leaks not found and repaired could be resulting in additional volatile organic chemical emissions of 80 million pounds annually.

piping components.

Valves are usually the single largest source of fugitive emissions. Emissions from any single piece of equipment are usually small. Based on the large number of equipment components that can leak and are subject to LDAR requirements, however, cumulative emissions can be very large. To obtain a proper reading of emissions from leaking components the monitoring equipment must be calibrated cor-

Continued on page 2

About

Enforcement Alert

"Enforcement Alert" is published periodically by the Office of Regulatory Enforcement to inform and educate the public and regulated community of important environmental enforcement issues, recent trends and significant enforcement actions.

This information should help the regulated community anticipate and prevent violations of federal environmental law that could otherwise lead to enforcement action. Reproduction and wide dissemination of this newsletter is encouraged.

See Page 4 for useful EPA Websites and additional resources.

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Enforcement Alert

Continued from page 1

rectly and held at the component interface where leakage could occur (e.g., at the seal between the valve stem and housing) for a sufficient length of time to obtain a valid measurement.

LDAR Programs Should Consist of Several Processes

LDAR programs are generally comprised of four processes. Regulations vary but usually require refineries to:

- Identify components to be included in the program;
- Conduct routine monitoring of identified components;
- Repair any leaking components; and
- Report monitoring results.

Compliance issues associated with each of these processes have resulted in numerous enforcement actions by EPA Regional offices, State agencies, or local air boards, depending on the specific regulations. Common violations include:

- Failure to identify process units and components that must be monitored;
- Failure to follow prescribed monitoring procedures;
- Use of incorrect or expired calibration gasses;

- Failure to repair components within specified timeframes; and
- Failure to submit quarterly reports and maintain appropriate calibration and/or monitoring records.

Refinery Monitoring Reports; What EPA is Finding

During the past several years, NEIC has monitored for leaking components at refineries. For 17 facilities investigated by NEIC, the average leak rate reported by the facilities was

1.3 percent. The average leak rate determined by NEIC and confirmed by the facilities was 5.0 percent. One explanation for this difference in leak rates may be found in a report published by the Bay Area Air Quality Management District ("Rule Effectiveness Study"). The Bay Area Air Quality Management District determined that when valves were inspected at a distance of one centimeter (0.4 inches) from the component instead of at the interface with the component, as the regulations require,

Comparative Monitoring Results

| Refinery | Company Monitoring: Valves/Leaks | NEIC Monitoring: Valves/Leaks | Leak Rate: Company/NEIC (%) | Emissions Rate: Company/NEIC (lb/hr) | Potential Emissions: Undetected Leaks (lb/hr) |
|--------------|----------------------------------|-------------------------------|-----------------------------|--------------------------------------|---|
| A | 7,694/170 | 3,363/354 | 2.3/10.5 | 38.8/106.6 | 67.8 |
| B | 7,879/223 | 3,407/216 | 2.8/6.3 | 44.0/73.5 | 29.5 |
| C | 3,913/22 | 2,008/108 | 0.6/5.4 | 18.3/90.1 | 71.8 |
| D | 2,229/26 | 1,784/24 | 1.2/1.4 | 15.5/17.1 | 1.6 |
| E | 5,555/96 | 2,109/112 | 0.7/5.3 | 50.7/125.8 | 75.1 |
| F | 42,505/124 | 3,053/53 | 0.3/1.7 | 154.7/382.3 | 227.6 |
| G | 14,307/226 | 3,852/236 | 1.6/6.1 | 122.2/369.7 | 247.5 |
| H | 20,719/736 | 3,351/179 | 3.6/5.3 | 332.2/469.7 | 137.5 |
| I | 5,339/9 | 2,754/84 | 0.2/3.1 | 16.9/76.6 | 59.7 |
| J | 8,374/78 | 2,981/55 | 0.9/1.8 | 50.8/78.5 | 27.7 |
| K | 6,997/101 | 1,658/114 | 1.4/6.9 | 56.1/201.2 | 145.1 |
| L | 12,686/26 | 3,228/125 | 0.2/3.8 | 34.9/84.0 | 49.1 |
| M | 4,160/40 | 1,926/222 | 1.0/11.5 | 25.7/192.2 | 166.5 |
| N | 5,944/29 | 2,487/106 | 0.5/4.3 | 26.1/112.3 | 86.2 |
| O | 7,181/112 | 2,897/130 | 1.6/4.5 | 60.8/140.9 | 80.1 |
| P | 8,532/203 | 4,060/181 | 2.4/4.5 | 98.8/167.5 | 68.7 |
| Q | 6,640/36 | 2,608/74 | 0.5/2.8 | 30.5/87.5 | 57.0 |
| Total | 170,717/2,266 | 47,526/2,372 | 1.3/5.0 (avg) | 1,177.0/2,775.5 | 1,598.5 |

Continued on page 3

Enforcement Alert

Continued from page 2

57 percent of the leaking valves would be missed when monitoring above the 500 ppm level.

Fugitive emissions account for 22 percent of all emissions from non-refineries but account for more than 55 percent of all refinery emissions identified in the 1996 Toxic Release Inventory (TRI). Since TRI includes only "reportable" hydrocarbons, total fugitive emissions were significantly larger than the 33 million pounds then identified by reporting refineries.

The failure to identify leaks means that they remain unrepaired and will continue to release VOCs and hazardous substances into the atmosphere. Emission estimates using a 50/50 split between components in gas/light liquid service (see *Table, Page 2*) suggest that these 17 refineries' annual fugitive emissions could be more than 6,000 tons per year greater than previously believed. Extrapolating this difference to all refineries larger than the smallest refinery investigated by NEIC also suggests that there may be an additional 80 million pounds of VOCs

being emitted each year because refinery leaks are not being identified properly and repaired promptly, as required by LDAR programs. Significantly and as recognized by industry, fugitive emissions can be reduced by up to 90 percent if leaks are detected and repaired in a timely manner.

Regulatory Impacts of Inadequate Fugitive Monitoring

By not fully identifying all leaking components, refineries are likely causing the unnecessary release of excess hydrocarbons. The impacts of these additional hydrocarbon releases may result in:

- Additional VOC emissions that could worsen local or transboundary smog problems;
- Under reporting of fugitive emissions on the annual Toxic Reporting Inventory;
- Under reporting of various TRI chemicals on annual Form R submissions; and
- Delayed or denied permits for expansion.

Most LDAR regulations allow for decreased monitoring frequency if certain performance standards are consistently achieved. Monitoring frequency is decreased from quarterly to annual monitoring if less than two percent of the valves within a process unit are found leaking. Conversely, if greater than two percent of the valves are found to be leaking, monitoring must be conducted quarterly. EPA monitoring showing a greater than two percent leak rate has resulted in refineries reverting back to quarterly monitoring.

Improving Leak Detection Monitoring Reliability

Although not required under current LDAR programs, several practices appear to improve the reliability of monitoring data and LDAR compliance:

- Energetic LDAR coordinators (advocates) with the responsibility and authority to make things happen;
- Continuing education/refresher programs for plant operators. Plant operators can have a major impact on LDAR compliance;
- Diligent and well-motivated monitoring personnel;
- Use of a lower than required leak definition. Several refineries use a leak definition lower than the regulatory limit. For example, several refineries use a 500 ppm limit rather than the regulatory limit of 10,000 ppm;
- More frequent monitoring than required. Rather than monitoring annually, some refineries monitor quarterly. More frequent monitoring also may permit lower emissions to be reported on the annual Toxic Reporting Inventory and/or Form Rs; and
- Established Quality Assurance/Quality Control procedures. Several refineries have initiated a program to check the monitoring results submitted by the monitoring team (in-house or contractor).

EPA's Office of Enforcement and Compliance Assurance is encouraged by efforts currently underway by the National Advisory Committee on Environmental Policy and Technology (NACEPT) petroleum refining workgroup to find more cost-effective ways to identify significant leaks

Continued on page 4

EPA Policies for Reducing, Eliminating Penalties for Self-Policing

EPA has adopted two policies designed to encourage the regulated community to comply with environmental laws.

For more information, see EPA's Audit Policy Website at: <http://www.epa.gov/oeca/auditpol.html>, and the Small Business Policy at: <http://www.epa.gov/oeca/smbusi.html>.



United States
Environmental Protection Agency
Office of Regulatory Enforcement
2248A
Washington, D.C. 20460

Official Business
Penalty for Private Use \$300

Continued from page 3

through new technology that allows for quick identification of the most significant losses. Meanwhile, however, the regulated industry is expected to comply fully with existing LDAR requirements.

Contact Ken Garing, National Enforcement Investigations Center, (303)236-6658; Email: garing.ken@epa.gov; Tom Ripp, Office of Compliance, Manufacturing, Energy and Transportation Division, (202)564-7003; Email: ripp.tom@epamail.epa.gov; or Jim Jackson, Office of Regulatory Enforcement, Air Enforcement Division, (202) 564-2002; Email: jackson.james@epamail.epa.gov.

EPA'S Y2K Enforcement Policy

EPA's "Y2K Enforcement Policy is

designed to encourage the expeditious testing of computer associated hardware and software that may be potentially vulnerable to Y2K problems.

Under this policy, which was published in the Federal Register on March 10, 1999, EPA intends to waive 100 percent of the civil penalties and recommend against criminal prosecution for environmental violations resulting from Y2K testing designed to identify and eliminate Y2K-related malfunctions. To receive the policy's benefits (e.g., waiver of penalties due to testing), regulated entities must address specific criteria and conditions identified in the policy.

For more about the Y2K Enforcement Policy, contact Gary Jonesi, Office of Regulatory Enforcement, (202) 564-4002 or E-mail: jonesi.gary@epa.gov.

Useful Websites

EPA's Technical Web site for Information Transfer and Sharing Related to Air Pollution Topics: <http://www.epa.gov/ttn/>

Toxics Release Inventory (TRI): <http://www.epa.gov/opptintr/tri/>

EPA Home Page: <http://www.epa.gov/epahome>

National Enforcement Investigations Center: <http://www.epa.gov/oeca/ocent/ncic/index.html>

EPCRA Hotline: 1-800-424-9346. For callers in the DC area, please call (703) 412-9810. Also, the TDD is (800) 533-7672.

Office of Regulatory Enforcement <http://www.EPA.gov/oeca/ore.html>

EPA Compliance Assistance Centers: <http://www.epa.gov/oeca/mfcaac.html>

Small Business Gateway: <http://www.epa.gov/smallbusiness>



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Office of Enforcement and Compliance Assurance
(mail code)

EPA-305-D-07-001
October 2007
www.epa.gov/compliance



April 13, 2015

SUBMITTED VIA FACSIMILE (307) 777-5616

Mr. Steven A. Dietrich, Administrator
Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 2-E
122 West 25th Street
Cheyenne, WY 82002

**SUBJECT: Comments on Proposed Regulation
WAQSR, Chapter 8, Nonattainment Area Regulations
Section 6, Upper Green River Basin Permit By Rule for Existing Sources**

Dear Mr. Dietrich:

Jonah Energy LLC (Jonah Energy) appreciates the opportunity to provide the following comments for consideration to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) on the Wyoming Air Quality Standards and Regulations (WAQSR) proposed Chapter 8, Section 6 Upper Green River Basin Permit By Rule for Existing Sources. Jonah Energy currently operates in the Jonah Field in Sublette County, Wyoming. As an oil and gas company with significant operations in the Upper Green River Basin and many employees that live in the area impacted by the proposed regulations, Jonah Energy recognizes that a shared responsibility has led to improved air quality in the Upper Green River Basin. We are supportive of a timely implementation of the proposed rule to further aid in continued emission reductions in the Upper Green River Basin. We support the rule as proposed, with some minor suggested changes outlined below.

Jonah Energy has reviewed the latest version of the proposed Chapter 8, Section 6 Upper Green River Basin Permit by Rule for Existing Sources and found we are currently in compliance with the proposed Chapter 8, Section 6 regulation emission control requirements, Leak Detection and Repair (LDAR) requirements and recordkeeping requirements, as applicable to our current operations. Each month, Jonah Energy conducts infrared camera surveys using a FLIR[®] camera at each of our production facility locations. Since the implementation of Jonah Energy's Enhanced Direct Inspection & Maintenance (EDI&M) Program in 2010, we have conducted over 16,000 inspections and have repaired thousands of leaks that were identified by the FLIR camera. Estimated gas savings from the repair of leaks identified

often exceeds the labor and material cost of repairing the identified leaks. The EDI&M program has removed hundreds of tons of volatile organic compound (VOC) emissions since its inception.

The result of Jonah Energy's EDI&M Program has significantly reduced VOC and hazardous air pollutant (HAP) emissions to the Upper Green River Basin airshed, has reduced the amount of sales gas lost due to leaks going undetected, and has reduced the number and severity of enforcement actions from the WDEQ due to fugitive leaks.

We request the WDEQ and EQC consider making the following modification to Section 6(c) of the proposed rule relating to Emptying Frequency of Emergency and Blowdown Tank Liquids:

From:

Section 6(c) Flashing Emissions at an Existing Facility or Source as of January 1, 2014

(C) Emergency, open-top and/or blowdown tanks shall not be used as active storage tanks but may be used for temporary storage.

(II) If emergency, open-top and/or blowdown tanks are utilized, they must be emptied within seven (7) calendar days."

To:

Section 6(c) Flashing Emissions at an Existing Facility or Source as of January 1, 2014

"(C) Emergency, open-top and/or blowdown tanks shall not be used as active storage tanks but may be used for temporary storage.

(II) If emergency, open-top and/or blowdown tanks are utilized; they must be pumped out via the truck loadout line within seven (7) calendar days after the liquid volume reaches __ bbls over the truck loadout line, or no less frequently than monthly for any liquid level above the truck loadout line."

Discussion

We agree with the premise of only utilizing emergency, open-top, and/or blowdown tanks (collectively Blowdown Tanks) for temporary storage to minimize the flashing emissions related to their use. However, emptying the tanks every seven days will not prevent these flash emissions as they occur almost immediately upon emptying liquids into the tank and as the language is currently written in the

proposed rule, applicable tanks with minor amounts of fluid discharged to them would be required to be emptied within seven days. In addition, we suggest changing the term “emptied” to the phrase “pumped out via the truck loadout line” meaning liquids must be removed from tanks down to the liquid level of the truck load out line, which represents the practical limit of pumping fluid from the tank.

Fluid volumes associated with individual blowdown or emergency events can be variable. Low volume discharges to the Blowdown Tank is not able to be pumped by typical water hauling trucks if the fluid level is below the truck loadout line of the Blowdown Tank (located 1 foot 10 inches above the tank bottom for our 210 bbl. Blowdown Tanks.)

Given the number of possible discharges to Blowdown Tanks, including some with volumes less than a barrel, compliance with this requirement would require substantial additional truck traffic from both water haulers, to unload volumes above the truck loadout line, and/or vacuum trucks, to unload volumes below the truck loadout line. We believe the increased emissions from truck traffic may not justify the environmental benefit from emptying these tanks as frequently as within 7 days.

Establishing a volume threshold, a time limit within which to pump down that designated volume, and routine record keeping could be a viable alternative to just a straight time limit. Our operators routinely gauge tanks for a variety of purposes. We could easily have them gauge Blowdown Tanks after each use and maintain monthly logs showing current Blowdown Tank volumes that would be available for WDEQ’s inspection and verification. WDEQ would be able to spot check an operator’s Blowdown Tank logs by gauging tanks to verify liquid level reported on the logs.

In this way, Blowdown Tanks are emptied when there is a sufficient liquid level to justify truck traffic and/or within a specific time frame, such as not less frequently than monthly for liquid levels above the truck loadout line. We would be happy to discuss this in more detail with WDEQ to establish proposed language and process.

Jonah Energy appreciates WDEQ’s consideration of our comments and would welcome working with the Agency on items mentioned herein or raised during the public comment process. Should you have any questions, please feel free to contact me directly.

Respectfully,

A handwritten signature in black ink, appearing to read "Paul Ulrich".

for Paul Ulrich
Director, Government Affairs & Regulatory

* * * Communication Result Report (Apr. 13. 2015 4:50PM) * * *

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April 13, 2015

SUBMITTED VIA FACSIMILE (307) 777-5616

Mr. Steven A. Dietrich, Administrator
Wyoming Department of Environmental Quality
Air Quality Division
Heischler Building, 2-F
122 West 25th Street
Cheyenne, WY 82002

SUBJECT: Comments on Proposed Regulation
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Section 6, Upper Green River Basin Permit By Rule for Existing Sources

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BEFORE THE AIR QUALITY CONTROL COMMISSION, STATE OF COLORADO

**IN THE MATTER OF PROPOSED REVISIONS TO REGULATION NUMBER 3,
PARTS A, B AND C, REGULATION NUMBER 6, PART A, AND REGULATION
NUMBER 7**

**REBUTTAL STATEMENT OF NOBLE ENERGY, INC. AND ANADARKO
PETROLEUM CORPORATION**

I. Executive Summary to Rebuttal Statement

Noble Energy, Inc. and Anadarko Petroleum Corporation (“Noble and Anadarko”) provide the following executive summary of their Rebuttal Statement.

As stated in their Prehearing Statement, Noble and Anadarko support the proposed revisions to Regulation 7 (“Proposed Rules”), with minor technical clarifications. The Proposed Rules will achieve enhanced air quality benefits at an acceptable cost. The Proposed Rules set forth science-based, common-sense measures to reduce VOC and hydrocarbon emissions that have already been adopted by some operators in the oil and natural gas industry.

The Proposed Rules represent input from a wide variety of stakeholders, including Noble and Anadarko. Noble and Anadarko participated with other stakeholders to submit comments, factual information and regulatory proposals to the Air Pollution Control Division (“the Division”) during the informal stakeholder process. Noble and Anadarko have continued to do so since the publication of the Proposed Rules. Other parties have likewise submitted information and proposed regulatory language. Prior revisions to Regulation 7 provide a precedent for the Commission to adopt regulatory text that has been agreed upon by two or more parties.¹ The Commission and Division have provided sufficient opportunities for public participation in the rulemaking process over the past year and have incorporated many proposals from multiple parties into the Proposed Rules.

Many aspects of the Proposed Rules are being vigorously debated by parties who seek to make the proposed revisions more or less stringent in various respects. This allows for a healthy debate on the pros and cons of the various requirements in the Proposed Rules, and helps to inform the Commission on the issues raised by the parties. As set forth in more detail below, Noble and Anadarko believe the science-based, feasible and cost effective Proposed Rules strike an appropriate balance on a wide range of issues raised by the stakeholders and parties to this rulemaking, and should be adopted as proposed with only minor technical clarifications as deemed appropriate.

¹ Regulation 7 § XIX.K (“In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein.”) (December 12, 2008).

In addition to explanations of their objections to certain overarching issues raised in various prehearing statements, contained below in this Rebuttal Statement, Noble and Anadarko also provide a table as **Attachment A** that summarizes Noble's and Anadarko's responses to these and other significant issues raised in other parties' prehearing statements. This table is intended to provide the Commission with an easy reference to Noble's and Anadarko's responses to the significant issues raised in this rulemaking.

II. The Rulemaking Complies With the Procedural Requirements of the Colorado Administrative Procedure Act and Colorado Air Pollution Prevention and Control Act

A. Colorado Administrative Procedure Act

The rulemaking has adhered to the procedures set forth at Section 103 of the Colorado Administrative Procedure Act ("Colorado APA"). C.R.S. § 24-4-103. When the Division began to contemplate proposing revisions to Regulations 3, 6 and 7, it announced its intentions and formed a stakeholder group as described in Section 24-4-103(2). "Meeting Notice: Stakeholders Interested in Air Pollution Reporting and Permitting Requirements and Oil & Gas Operations," APCD (Dec. 27, 2012). The Division began to meet regularly with stakeholders in January 2013 and has continued to do so throughout the rulemaking process.

The Division published the Proposed Rules, factual presentations, public comments and related materials on its website. The Division submitted a plain language statement concerning the subject matter of the rulemaking to the Department of Regulatory Agencies. C.R.S. § 24-4-103(2.5)(a). The Division is preparing and will timely file a cost-benefit analysis and Regulatory Impact Analysis. *Id.*

After the stakeholder meetings, the Commission initiated the formal rulemaking process by publishing in the Colorado Register a notice of Public Rulemaking Hearing, and soliciting public input. 36 Colo. Reg. 23 (December 10, 2013). The Commission provided the public a thorough and complete opportunity to participate in the rulemaking process in accordance with C.R.S. § 24-4-103(3)(a).

The lengthy stakeholder process, which spanned nearly eleven months, fully complied with the procedural requirements of the Colorado APA. The Division solicited and responded to input from a broad spectrum of stakeholders, resulting in the Proposed Rules. The Proposed Rules are proof of the success of the stakeholder process as it contains input, either wholesale or in part, received by a wide spectrum of stakeholders. Moreover, the Division continues to solicit and receive input from parties to refine its Proposed Rules. Furthermore, the current rulemaking process allows additional opportunity for all parties to participate and present testimony and evidence on aspects of the Proposed Rules that are of concern.

Adoption of the Proposed Rules would be consistent with the standards for agency action set forth in the Colorado APA. Agency action must be reasonable and supported by substantial evidence in the record. *Bd. of Assessment Appeals v. AM/FM Int'l*, 940 P.2d 338, 347 (Colo. 1997); *Pilgrim Rest Baptist Church, Inc. v. Prop. Tax Adm'r*, 971 P.2d 270, 272 (Colo. App. 1998); *Echo-Star Satellite, L.L.C. v. Arapahoe County Bd. of Equaliz.*, 171 P.3d 633, 636 (Colo.

App. 2007). Agency action will be upheld on appeal if it is not arbitrary or capricious. Courts have explained that unless a reasonable person considering all the evidence of record would be compelled to reach a different result, the agency decision must be upheld. *Ramseyer v. Colo. Dept. of Soc. Servs.*, 895 P.2d 1188, 1192 (Colo. App. 1995); *see also W. Colo. Congress v. Umetco Minerals*, 919 P.2d 887, 891 (Colo. App. 1996). The Commission may adopt the Proposed Rules because there is substantial evidence in the record to support a conclusion that the Proposed Rules meet the requirements of the Colorado APA and Colorado Air Pollution Prevention and Control Act (the “Act”).

A decision by the Commission to adopt the Proposed Rules would be entitled to deference. *Dept. of Rev. v. Woodmen of the World*, 919 P.2d 806, 817 (Colo. 1996); *Kramer v. Colo. Dept. of Rev.*, 964 P.2d 629, 630 (Colo. App. 1998). The Commission’s decision in cases where the factual questions are “fairly debatable” will be upheld so long as the Commission’s decision is supported by competent evidence and the record does not show a clear abuse of discretion. *Bd. of County Comm’rs v. Simmons*, 177 Colo. 347, 494 P.2d 85, 87 (1972). In rulemaking cases where the relevant issues are primarily founded on policy choices rather than factual determinations, deference to the agency’s administrative expertise is appropriate. *Brighton Pharmacy, Inc. v. Colo. State Pharmacy Bd.*, 160 P.3d 412, 416 (Colo. Ct. App. 2007) (citation omitted).

The cases cited above make it clear that the Commission is not obligated to resolve the parties’ factual disputes. It is reasonable and appropriate for the Commission to adopt a proposal that strikes an appropriate balance between more stringent and less stringent regulatory options. Such is the case with the Proposed Rules.

B. Colorado Air Pollution Prevention and Control Act

The rulemaking also satisfies the procedural requirements found in the Act. C.R.S. § 25-7-101 *et seq.* As detailed further below and in testimony to be presented at the hearing, the Proposed Rules contain requirements that are technically feasible to reduce, prevent, and control air pollution in Colorado, as required by the Act. C.R.S. § 25-7-102. At the same time, the Proposed Rules are structured to be economically reasonable, with benefits that bear a “reasonable relationship to the economic, environmental and energy impacts and other costs.” C.R.S. § 25-7-102. As described in more detail in Section VI, the Proposed Rules meet this balance.

Additionally, the Division timely provided an Initial Economic Impact Analysis (“EIA”) and other documents in compliance with C.R.S. §25-7-110.5(1), and has since submitted an Updated EIA with its Prehearing Statement on January 6, 2014. The Updated EIA is properly based on “reasonably available data” concerning the costs and benefits of the Proposed Rules, as discussed further below in Section V.

III. The Division Has Demonstrated a Basis and Need for the Proposed Rules

Noble and Anadarko believe that the factual record is well developed to support this rulemaking. Among other information, the Division provided statewide oil and natural gas production data, VOC emission inventories, and reports projecting growth in the oil and natural

gas industry. Noble and Anadarko concur that oil and natural gas production in Colorado has grown in recent years and is presently projected to continue to grow with respect to their operations. The Proposed Rules are supported by an ample scientific and factual record that “demonstrates the need for the regulation” as required by the Colorado APA, C.R.S. § 24-4-103(4)(b)(I).

IV. The Commission Is Authorized to Regulate the VOC and Hydrocarbon Emissions Contemplated by This Rulemaking

Anadarko and Noble support the Commission’s authority to regulate VOCs and hydrocarbons in this rulemaking. The Commission’s authority is set forth in the Act. C.R.S. §§ 25-7-102, 25-7-105(1). The Colorado legislature has specifically stated that it is the State’s policy “to use all available practical methods . . . to achieve the maximum practical degree of air purity” in order to foster the “health, welfare, comfort, and convenience of the inhabitants of the state.” C.R.S. § 25-7-102. State law tasks the Commission with legal oversight “to reduce, prevent, and control air pollution.” *Id.* In that capacity, the Commission here seeks to promulgate emission control regulations applicable to VOCs and hydrocarbons.

Section 109 charges the Commission with adopting emission control regulations such as VOCs and hydrocarbons. C.R.S. § 25-7-109(2)(c). Specifically, the language provides:

(2) Such emission control regulations may include, but shall not be limited to, regulations pertaining to:

(c) Sulfur oxides, sulfuric acids, hydrogen sulfide, nitrogen oxides, carbon oxides, hydrocarbons, fluorides, and any other chemical substance;

Id.; see also C.R.S. § 25-7-103(1.5) (defining air pollutant as “any . . . gas which is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive (including source material, special nuclear material, and by-product material)” and including “any precursors to the formation of any air pollutant” to the extent recognized by EPA).

The Commission is properly exercising its authority to regulate the emission sources contemplated by this rulemaking. First, the Commission is authorized to adopt “such rules and regulations as are consistent with the legislative declaration set forth in section 25-7-102” including “[e]mission control regulations in conformity with section 25-7-109.” C.R.S. §§ 25-7-105(1) and (1)(b). Second, Section 109 provides the Commission with the authority to promulgate regulations requiring “the use of effective practical air pollution controls” for, *inter alia*, “each category of significant sources of air pollutants.” C.R.S. § 25-7-109(1)(a). With this rulemaking, the Commission is acting under its express statutory authority to further broaden leak monitoring and repair to incorporate hydrocarbons in addition to VOCs.

The Proposed Rules are consistent with State policy relating to promulgation of air quality control programs because the controls required “bear a reasonable relationship to the economic, environmental, and energy impacts and other costs of such measures.” C.R.S. § 25-7-102. Regulation of hydrocarbons under the Proposed Rules satisfies this policy because the additional costs for regulating hydrocarbons are acceptable, while serving to broaden the scope of transparency, understanding, and accountability for emissions related to the oil and natural gas industry. The value added here not only extends beyond increased environmental stewardship for industrial operations, but further seeks to promote the protection of Colorado’s air quality through the expanded regulation of VOCs and hydrocarbons while maintaining the economic viability of a critical industry to both the State and nation. Noble and Anadarko contend that the Proposed Rules, while tough, do not impose unmanageable burdens on their oil and natural gas operations. In Colorado, Noble and Anadarko already use technologies such as flares and combustors that are effective and widely used to control VOCs. These same controls also control hydrocarbon emissions. By way of the proposed regulations, the control of both VOCs and hydrocarbons will be better documented and more transparent. Similarly, the proposed regulations expand on other control measures, including, but not limited to, leak detection and repair, auto igniters, low bleed pneumatic devices, and best management practices for maintenance and liquids unloading, which also serve to further reduce hydrocarbon emissions as well as VOCs. The Proposed Rules addressing dual control of both VOCs and hydrocarbons present a reasonable cost for the benefits added.

Minimizing leak occurrences and duration will have long-term effects of offsetting some costs of the Proposed Rules by preventing the loss of valuable product which further enhances the economic consideration of the Proposed Rules. Other policy considerations include that the Proposed Rules will lead to increased accountability for hydrocarbon emissions, more transparency, and thereby build public trust and understanding of hydrocarbon emissions.

While further evidence will be introduced at the hearing on the Proposed Rules, the Proposed Rules satisfy the legislative expectation that controls to treat hydrocarbons be available and technically feasible and that control costs are in line with the economic impacts. *See* C.R.S. § 25-7-109(1)(b)(IV). The controls and other requirements in the Proposed Rules are already being implemented at many oil and natural gas operations, thus demonstrating that such controls are available and technically feasible.

Finally, the Proposed Rules also satisfy Section 25-7-102, which sets forth State policy that regulations be based on a current and accurate inventory of actual emissions. Substantial data about VOC and hydrocarbon emissions from oil and natural gas sources are available and have been presented to the Commission. The State already receives extensive emissions reporting data from the oil and natural gas industry, and the Commission also has received several exhibits estimating emissions of hydrocarbons, including methane and ethane. These data cumulatively provide sufficient detail about hydrocarbon emissions in the State to fulfill the legislative declaration requiring use of current and accurate inventory of emissions.

V. The Proposed Rules Are Cost Effective

The data provided in the Updated EIA and the EIA itself satisfy the statutory requirement that the Proposed Rules be cost effective. C.R.S. § 25-7-109(1)(b)(IV). Noble and Anadarko

have undertaken analyses of their own estimated costs to comply with the Proposed Rules as offered herein. Those cost estimates are contained in **Exhibits A and B**, filed with this Rebuttal Statement. This cost data support the Division’s position that the costs of the Proposed Rules are reasonable and cost effective on the basis of dollars per ton of VOC removed.

As evidenced herein and as will be further supported during the hearing, the proposed requirements to control both VOCs and hydrocarbons are readily available to operators, are technically feasible and show that the costs are reasonably related to the benefits. A number of measures illustrate the availability, feasibility, and cost effectiveness of the Proposed Rules. In many cases, the controls and other requirements set forth in the Proposed Rules are already being implemented by oil and natural gas operators. Thus, as an example, where flares or combustion devices are used to control VOC emissions, the Proposed Rules would not generally impose additional costs to control and reduce hydrocarbons. In addition, the Division estimates in the Updated EIA that the cost effectiveness of controlling methane and ethane at compressor stations and well production facilities would be \$321 per ton and \$516 per ton of reduced emissions, respectively. Accordingly, the economic costs of regulating hydrocarbon emissions are low and, indeed, cost effective. *See* C.R.S. § 25-7-109(1)(b)(VII).

A. The Division’s Cost and Cost Effective Estimates Are Appropriate

The Division calculated the costs and cost effectiveness of instrument based monitoring for tanks, compressor stations and well production facilities. The Division’s average cost and cost effectiveness estimates are summarized in the table below.

Division Cost and Cost Effectiveness Estimates

| | Annualized Cost per Facility | \$/ton VOC Removed |
|----------------------------|------------------------------|--------------------|
| Tanks | \$3,949 | \$391 |
| Compressor stations | \$3,720 | \$667 |
| Well production facilities | \$2,199 | \$819 |

Source: APCD Updated EIA, Tables 16, 25 and 27.

The Division appropriately did not include repair and remonitoring costs in its Updated EIA. Noble and Anadarko projections based on the Proposed Rules with assumptions for minor technical clarifications indicate that remonitoring costs will not increase significantly from current levels. Cost effective measures such as the one found in Section XVII.F.8.b of the Proposed Rules that do not require the use of an IR camera for remonitoring keep the costs reasonable and within the required statutory bounds for costs. Method 21 could be used to satisfy the remonitoring requirement, which provides an alternative for the use of a screening procedure to determine whether a source has no detectable emissions. Method 21, “Determination of

Volatile Organic Compound Leaks” § 8.3.3, *available at* <http://www.epa.gov/ttn/emc/promgate/m-21.pdf>.

Based on the information and analyses conducted to date by Noble and Anadarko, the Proposed Rules should not significantly affect the cost of repairs to operators. The companies anticipate that many leaks will likely be discovered and corrected on the spot at minimal cost by the workers performing instrument based monitoring. Also, the repair costs currently incurred under existing monitoring programs could legitimately be excluded from any estimate of the costs of the Proposed Rules.

B. Noble’s and Anadarko’s Cost and Cost Effectiveness Estimates Support the Division’s Estimates

Based on a review of the Proposed Rules with an understanding that minor technical clarifications may be warranted, Noble’s estimates of cost and cost effectiveness support the Division’s Updated EIA. Based on company-specific historic data and certain estimated values, Noble anticipates that LDAR monitoring at well production facilities would cost between approximately \$260 and \$430 per inspection, with cost effectiveness between approximately \$50/ton and \$380/ton VOC removed, depending on the facility size, emission estimates, and other factors.

Similarly, assuming only minor technical clarifications are made to the Proposed Rules, Anadarko’s cost estimates also support the Division’s Updated EIA. Based on company-specific historic data and certain estimated values, Anadarko anticipates that LDAR monitoring would cost approximately \$450 per inspection at well production facilities, and approximately \$1,260 per inspection at compressor stations, depending on the facility size, estimated values, and other factors. Anadarko also estimated the cost of the additional AVO inspections that would be required under the Proposed Rules to be approximately \$135 per inspection. The per inspection cost is lower than LDAR inspections, but due to the high number of AVO inspections, this requirement would increase Anadarko’s annual well production facility monitoring costs by more than approximately \$3.5 million from current levels overall.

The estimates of cost and cost effectiveness submitted by Noble and Anadarko are preliminary and are subject to change as they continue to evaluate the requirements in the Proposed Rules, and any subsequent revisions thereto.

C. Factors Affecting Estimates of Costs and Cost Effectiveness

In reviewing the various prehearing statements of parties as well as that of the proponent of the Proposed Rules, cost and cost effectiveness is the subject of much scrutiny and disagreement. Noble and Anadarko believe that the Division has taken a reasonable position with respect to costs and cost effectiveness of the current Proposed Rules and have data that support the Division’s position. Adoption of other positions could have a significant impact on the figures reported in the Updated EIA. The list below identifies some examples for the Commission’s consideration that could have a significant impact on the Cost and Cost Effectiveness estimates.

1. Time Required to Perform Inspections

The Division assumed IR inspections would be 50% faster than Method 21 inspections for compressor stations and well production facilities, and solicited data on this issue to further inform its analysis. APCD Updated EIA at 16. Noble and Anadarko's experience indicates that travel time has as much or more impact on the time needed for LDAR inspections than the number of components, especially for smaller facilities. Nonetheless Noble and Anadarko find the Division's overall time estimates to be reasonable.

The Division estimates that well production facilities would require an average of 4.75 hours to inspect. Based on company-specific historic data, Noble estimates that one inspector can inspect two to three well production facilities per day and Anadarko estimates that one inspector can inspect up to three well production facilities per day. These estimates are in line with the Division's projections.

2. Emission Reductions From LDAR and STEM Requirements

While Noble and Anadarko do not have complete data on the reductions in VOC and hydrocarbon emissions that will result from the LDAR and STEM programs in the Proposed Rules, they believe these are reasonable, cost effective approaches to reduce VOC and hydrocarbon emissions from oil and natural gas operations. As such, they support these requirements in the Proposed Rules. While some parties contend that the Division's estimate of emission reductions that would be achieved by the Proposed Rules is too high, other parties assert that the Division's estimates are too low. In the absence of a widely accepted protocol for estimating the emission reductions achievable through instrument based monitoring, Noble and Anadarko submit that it is reasonable for the Commission to rely on the Division's emission reduction estimates.

3. Ongoing Benefit of Leak Inspections

The Division assumed that the emissions reduction achieved by the STEM and LDAR programs would remain constant every year. Some parties have asserted that there is a declining benefit from STEM and LDAR inspections, thereby significantly increasing the cost per ton of VOC removed in subsequent years, while other parties have asserted that emission reductions rise as inspections become more frequent.

Based on data collected from its own LDAR monitoring experience, Trihydro estimates the initial component leak rate frequency (before the first LDAR inspection) at new and modified gas processing plants to be 1.7%. WPX – PHS Ex. A. The leak rate frequency falls to 0.4% after the first monitoring period and averages 0.3% over 12 consecutive calendar quarters. *Id.* The Trihydro report appears to be reliable because it is based on actual measured data. While it does support a decline after the first monitoring period, the Trihydro report then evidences a steady state of leak detection after that.

Given the limited data available, and that the only available data supports a limited one-time reduction in leak rate frequency, it is reasonable for the Commission to rely on the Division's assumption that LDAR emission reductions remain constant each year, until further data is developed.

VI. The Proposed Rules Strike an Appropriate Balance

The Proposed Rules strike a balance as required by statute and as illustrated by the competing interest of the parties. The Proposed Rules may not meet each and every party's demands; however, they represent a strong compromise that benefits the environment, while also permitting ongoing development of valuable natural resources. The Commission should adopt the Proposed Rules with only minor technical clarifications because the Proposed Rules are carefully crafted to fulfill the policy goals of C.R.S. § 25-7-102. The Proposed Rules are designed to achieve the maximum practical degree of air purity, are among the most stringent air quality regulations for oil and natural gas facilities in the nation, and would result in Colorado being the first state to directly regulate methane. Gov. Hickenlooper Press Release, "Colorado set to become first state to regulate detection, reduction of methane emissions associated with oil and gas drilling," (Nov. 18, 2013). At the same time, the Proposed Rules are structured to be practical and economically reasonable, with benefits that bear a "reasonable relationship to the economic, environmental and energy impacts and other costs." C.R.S. § 25-7-102. The terms of the Proposed Rules are effective and practical, as required by C.R.S. § 25-7-109(1)(a).

Evidenced by the issues raised in the various parties' prehearing statements, the Proposed Rules find common ground. They do not represent a perfect solution to all involved, but the State is not required to promulgate rules blessed by all stakeholders involved. Rather, the State must adhere to the statutory requirement to protect air quality by means the State determines to be practical and economically reasonable. To illustrate this point, some of the issues where the Prehearing Statements evidence diverging views are described below.

A. Emission Reductions and Costs

The Division projects the Proposed Rules would substantially reduce VOC emissions. Some parties have asserted that the actual emission reductions would be far smaller than projected by the Division because the Division overestimated the current level of VOC emissions, or because the regulation would be less effective than projected. Some parties also argued that the projected reduction in VOCs is not necessary because the VOC reduction might not lead to lower ambient ozone concentrations.

Other parties have asserted that larger emission reductions will or may be obtained, both by using different estimates of the projected emission reductions and arguing that greater reductions could and should be achieved by accelerating the LDAR compliance dates, increasing LDAR inspection frequency, and making the LDAR requirements applicable to additional components.

As discussed above, some parties contended that instrument based inspection costs are significantly higher than the Division's estimates. Other parties asserted that instrument based inspections are profitable. The fact that other parties are arguing for both higher and lower costs and higher and lower emission reductions than the Division relied on in its analysis of the Proposed Rules provides further evidence that the Division's Proposed Rules are balanced. As also discussed above, the Noble and Anadarko data supports the Division's cost estimates, and its finding that the Proposed Rules are cost effective.

B. Frequency of LDAR Inspections

The proposed monitoring schedule varies from one-time monitoring at the smallest facilities to monthly monitoring at the largest. The proposed schedule appropriately places greater compliance burdens on facilities that have higher levels of air emissions.

Some parties seek to increase or decrease the frequency of inspections. For example, one party argues that tank and well production facilities with less than six tons per year of emissions should be inspected every two years, rather than one time over the life of the facility. Another party contends that facilities near buildings or outdoor activities should be subject to more frequent inspections. Conversely, yet another party seeks to add a skip monitoring provision that would reduce LDAR frequency if inspections indicate declining levels of discovered leaks; facilities where the number of leaks remains below certain thresholds would reduce their monitoring frequency over time. Thus, again, these divergent views on more frequent and less frequent inspections suggest that the inspection frequency in the Proposed Rule is a balanced approach that accommodates the competing interests of the parties.

C. Implementation Dates

The Proposed Rules contain compliance dates that are intended to implement the rule as expeditiously as possible, while allowing oil and natural gas operators sufficient time to buy and install equipment and to make necessary changes to their operations to begin the extensive new LDAR and STEM requirements, and implement new control requirements. The implementation deadlines reflect concerns that sufficient quantities of IR cameras and emission control devices might not be immediately available from vendors.

Some parties argue that implementation should be delayed beyond the dates in the Proposed Rules. Conversely, other parties seek to accelerate the implementation dates and compliance deadlines. Noble and Anadarko believe that the Proposed Rules contain a reasonable and achievable implementation schedule that balances the concerns of various stakeholders. Noble and Anadarko also believe that the phased implementation schedule set forth in the Proposed Rules is necessary to allow industry to acquire the necessary equipment to ensure successful compliance with the regulation.

Some parties have raised a concern with meeting the leak detection rate of 500 ppm and have proposed a delay in the implementation of that requirement. However, it has been Noble's and Anadarko's experience that vendors have indicated they can presently meet the 500 ppm leak detection rate. Thus, again, the Proposed Rules' implementation schedule is technically feasible and reasonable.

Additional bases of disagreement among the parties, with some wanting a more stringent rule, and others wanting a less stringent rule, are summarized and set forth in a table, attached to this Rebuttal Statement and incorporated herein as if fully set forth herein. **Attachment A.** As this table demonstrates, the rules could be made less stringent or they could be made more stringent. The important point is that a complex rule such as the Proposed Rules forces the Commission to make a large number of decisions about discrete technical issues. Parties can and do have diverse viewpoints about the most appropriate decision for each issue. Given these

divergent viewpoints, there is no single best course of action for the Commission to take. The Colorado APA does not hold the Commission to such an exacting standard. Instead, the Commission's charge is to make reasonable decisions that comply with the statute, are within its scope of authority, and are supported by substantial evidence in the record as a whole. *Dept. of Rev. v. Woodmen of the World*, 919 P.2d 806, 817 (Colo. 1996); *Kramer v. Colo. Dept. of Rev.*, 964 P.2d 629, 631 (Colo. App. 1998); *Ohlson v. Weil*, 953 P.2d 939, 941 (Colo. App. 1997). Thus, the guiding posts for adoption of regulations will focus on evidentiary support that shows the regulations to be protective of the environment, be balanced, be cost effective, and be feasible for operators to implement.

VII. The Proposed Rules Should be Adopted Without Further Substantive Changes

The Proposed Rules impose significant new costs and control requirements on the oil and natural gas industry, and require implementation of entirely new monitoring and recordkeeping programs to document the new LDAR, STEM and AVO inspections. This entails the ordering of large quantities of new monitoring instruments and equipment, hiring and training large numbers of new personnel, setting up extensive new recordkeeping systems that interface with existing monitoring and recordkeeping conducted at the facilities -- all in the space of a one to two-year time frame. The scope and extent of this program is unprecedented and will require significant effort to properly implement and conform to these new monitoring and recordkeeping requirements.

Noble and Anadarko are supportive of the Proposed Rules for the reasons detailed above and as expressed in their joint Prehearing Statement, and believe the commitments represented by the Proposed Rules, with consideration only of further minor technical clarifications being incorporated, are reasonable and cost effective. However, the companies oppose any attempt to make the Proposed Rules more stringent. Noble and Anadarko do not support changes to the Proposed Rules that would impose either fewer or additional requirements or the expansion or contraction of currently proposed monitoring and recordkeeping requirements in any manner that would impact the carefully, properly balance approach to ensure protection of the environment through controls that are technically feasible and cost effective.

Further expansion of already ambitious proposed regulations would jeopardize the industry's ability to implement this new precedent setting monitoring and control program. Further contraction of the ambitious proposed regulations would impact the potential achievement of further air quality benefits at an acceptable cost. The companies believe the Proposed Rules, with minimal technical clarifications, are structured to strike an appropriate and fair balance of costs and requirements with the benefits of reduced VOC and hydrocarbon emissions from oil and natural gas operations in the state of Colorado. There is a tipping point for industry, beyond which more stringent requirements will simply overwhelm the industry's ability to implement meaningful monitoring and control requirements.

For these reasons, Noble and Anadarko urge the Commission to resist attempts to alter the careful balance achieved in the Proposed Rules. Some parties have submitted alternate proposals that would substantially affect this balance. Such proposals are not factually supported or warranted. Many of these proposals simply assert that additional requirements could be imposed or proposed requirements could be reduced without any detailed analysis supporting the

additional requirements. Some proposals are accompanied by (faulty) cost data and arguments that the weaker or stricter requirements would either ensure cost effectiveness or be cost effective. A careful review and analysis of these competing cost analyses fail to support such claims. For all of the reasons stated above, Noble and Anadarko urge the Commission to retain the balance represented by the Proposed Rules.

A. STEM Monitoring and LDAR Inspections Should Not be More Frequent

Inspection frequencies should not be increased from those stated in the Proposed Rules. The Proposed Rules call for significantly more inspections than are currently required. They would impose new requirements to use infrared cameras or other instrument based monitoring techniques. The Commission should adopt the proposed STEM and LDAR inspection requirements. Their effectiveness may be reviewed after more data is collected. STEM or LDAR frequency may be adjusted in a future rulemaking as needed after sufficient data is gathered from the implementation of the requirements from the Proposed Rules.

No legitimate rationale has been presented for increasing inspection frequencies. One party seeks to increase inspection frequencies by revising the way compressor station emissions are determined. The party proposes to use a facility's total potential to emit ("PTE") to determine the inspection frequency, rather than fugitive emissions. However, the only reason provided for this change is that relying on PTE would push compressor stations into a higher tier, resulting in more inspections. Fugitive emissions provide a reasonable proxy for the size and significance of compressor station emissions, and should be used to determine frequency as proposed.

The Commission should reject the arbitrary and unsupported requests for greater inspection frequencies.

B. STEM and LDAR Inspection Phase-in Timelines Should Not be Accelerated or Eliminated

Some parties have advanced conclusory statements that the implementation dates for STEM and LDAR inspections should be earlier than proposed. These parties did not provide any convincing justification for their positions. The parties asserted their unsupported belief that the proposed dates are too far in the future, and that STEM and LDAR inspections could begin sooner.

No attempt has been made to show that an earlier deadline is feasible or would allow adequate time for facilities to implement the Proposed Rules' significant new requirements. The proposed earlier deadline would impose an unreasonable burden. The cumulative burden of simultaneously beginning and implementing the extensive instrument based monitoring program at all operations without the proposed implementation schedule would render the STEM and LDAR program requirements infeasible and impracticable.

C. Additional Recordkeeping and Reporting Requirements Should Not be Imposed

Several parties seek to impose additional recordkeeping or reporting requirements. The parties' alternate proposals would require that STEM plans be submitted to the Division; require all STEM-related records be retained for five years; extend LDAR records retention from two years to five years; and require companies to maintain pneumatic controller records for five years instead of three.

The Division's proposed recordkeeping requirements appropriately balance compliance costs with the Division's ability to inspect facilities and review records. Compiling and maintaining records places a significant burden on owners and operators. Receiving, managing and reviewing reports places a substantial burden on the Division. The Commission should consider the fact that recordkeeping and reporting have value only to the extent they enhance air quality. The purpose and rationale for any such requirements should be clearly articulated. Records lose their value over time and should be destroyed when they are no longer necessary or useful. Reports should not be submitted to the Division unless the Division has the resources to timely review them, while continuing to perform its existing duties. It is quite common for regulatory programs to require that records be kept and made available for inspection, with no submission requirement.

No basis was provided for the various proposals to extend the records retention periods other than the parties' unsupported opinion that two- and three-year retention periods are too short. The proposal to submit STEM reports to the Division is likewise unjustified. The Division's Updated EIA estimates that 5,312 tanks would be subject to STEM. The proposal fails to address whether or how the Division might review or utilize this volume of reports. The parties' alternate recordkeeping proposals are unwarranted and should be rejected.

VIII. The Proposed Rules Do Not Require A Photochemical Modeling-Based Justification

There is no requirement to perform photochemical modeling before revising State-only regulations that limit the emission of VOCs from a source category. The Act requires the Commission to find that "the rule shall result in a demonstrable reduction in air pollution." C.R.S. § 25-7-110.8(1)(b). This demonstration must be supported by substantial evidence in the record as a whole. *Bd. of Assessment Appeals v. AM/FM Int'l*, 940 P.2d 338, 347 (Colo. 1997); *Pilgrim Rest Baptist Church, Inc. v. Prop. Tax Adm'r*, 971 P.2d 270, 272 (Colo. App. 1998); *Echo-Star Satellite, L.L.C. v. Arapahoe County Bd. of Equaliz.*, 171 P.3d 633, 636 (Colo. App. 2007). Emission inventories and projections that the Proposed Rules will substantially reduce VOC emissions are sufficient to demonstrate a reduction in air pollution. The statute does not specifically require photochemical modeling.

The Commission has the authority to limit VOC emissions as a forward-looking measure to facilitate future attainment of the ozone standards without a detailed calculation of the resulting change in ozone concentrations. The Commission has discretion to make this policy choice, and its administrative expertise is entitled to deference. *Brighton Pharm., Inc. v. Colo. State. Pharm. Bd.*, 160 P.3d 412, 416 (Colo. App. 2007)(citations omitted). The Commission made a similar choice in 2006 when it placed statewide VOC limits on tanks, dehydrators and

engines. The Statement of Basis and Purpose accompanying the 2006 revision did not cite photochemical ozone modeling as a basis for that revision. Regulation 7 § XIX.J. Similarly, there is no such requirement for the adoption of the Proposed Rules.

IX. Response to the Division's Proposed Revisions

The Division submitted certain technical corrections, clarifications, and substantive changes to the Proposed Rules. Several of these changes appear to adopt language proposed by DCP Midstream from its Prehearing Statement, including certain new definitions, new provisions for compressor seals and open-ended valves or lines, and emission reductions from glycol dehydrators. Noble and Anadarko support these revisions.

X. Exhibits and Attachments

Noble and Anadarko submit the following exhibits and attachments for the Commission's consideration as it evaluates the information and testimony presented at the hearing:

1. Noble cost spreadsheet. **Exhibit A.**
2. Anadarko cost spreadsheet. **Exhibit B.**
3. Noble and Anadarko Responses to Significant Issues Raised in Prehearing Statements. **Attachment A.**
4. Legal Memorandum Opposing Expansion of Regulation to Address Hazardous Air Pollutants. **Attachment B.**
5. Legal Memorandum Opposing Conservation Group's Request for an Order Requiring the Division to Perform Ozone Modeling and Propose an Ozone Plan that Demonstrates Ozone Attainment. **Attachment C.**

XI. Rebuttal Witnesses

Witnesses who may testify at the hearing on behalf of Noble and Anadarko include:

1. Denise Kennedy
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2. Brian Lockard
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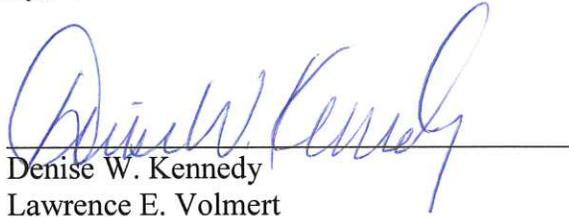
These witnesses were previously identified as witnesses for Noble and Anadarko's case in chief. They may testify regarding the legal and factual issues raised in Noble and Anadarko's Prehearing Statement, Rebuttal Statement, or both.

XII. Written Testimony

At this time, Noble and Anadarko do not have written testimony to present. Consistent with the hearing officer's statements at the Prehearing Conference, Noble and Anadarko reserve the right to present additional written testimony prior to the hearing date.

Respectfully submitted this 30th day of January, 2014.

By:



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CERTIFICATE OF SERVICE

I certify that on January 30, 2014, I served copies of the foregoing Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation to the following by electronic mail:

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BEFORE THE AIR QUALITY CONTROL COMMISSION, STATE OF COLORADO

In the Matter of Proposed Revisions to Ambient Air Quality Standards Regulation, Regulation Numbers 3, 7, and 11 for the Denver Metropolitan and North Front Range Ozone Action Plan

FINAL JOINT PREHEARING STATEMENT OF ANADARKO PETROLEUM CORPORATION, NOBLE ENERGY, INC., and WILLIAMS PRODUCTION RMT COMPANY

Anadarko Petroleum Corporation (“Anadarko”), Noble Energy, Inc. (“Noble”), and Williams Production RMT Company (“Williams”) (collectively the “Well Operators”) jointly submit this Final Prehearing Statement (“Final Statement”) pursuant to the Air Quality Control Commission’s (“AQCC” or the “Commission”) procedural rules, 5 CCR 1001-1, Section 1.5.5(5)(c), in connection with the Commission’s consideration of proposed revisions to the Ambient Air Quality Standards Regulations, Regulation Numbers 3, 7, and 11, for the Denver Metropolitan and North Front Range Ozone Action Plan (“Ozone Action Plan”).

Some of the Well Operators have been actively involved in the rulemaking process surrounding ozone dating back to adoption of controls to meet the obligations of the former 8-hour ozone Early Action Compact (“EAC”) in 2004, and have supported Colorado’s prior efforts to achieve compliance with the 8-hour ozone NAAQS in the non-attainment area (“NAA”). The Well Operators continue to support Colorado’s goal of achieving long-term compliance, and wish to promote Environmental Protection Agency’s (“EPA’s”) future classification of the Denver Metropolitan and Northern Front Range areas as “attainment” for the 8-hour ozone National Air Ambient Quality Standard. They have participated in most, if not all, of the numerous stakeholder meetings held as part of the ozone State Implementation Plan (“SIP”) development process for more than a year, and while the Well Operators do support many aspects of the Ozone Action Plan, they oppose the adoption by this Commission of other portions for reasons set forth and to be set forth in their witnesses testimony, their exhibits, and this Final Statement.

This Final Statement contains: an Executive Summary (Section I); statement of factual and legal issues (Section II); a list of issues to be resolved by the Commission (Section III); a list of the exhibits that will be introduced at the hearing, including the Well Operators’ Alternate Proposals and supporting documentation (Section IV); a list of witnesses submitting written testimony, some or all of whom may be called to summarize that testimony and respond to questions at the hearing (Sections V and VI); a brief description of the Alternate Proposals advocated by the Well Operators (Section VII); reservations made by the Well Operators (Section VIII); and a brief conclusion (Section IX).

I. EXECUTIVE SUMMARY

A. The Well Operators

1. Denver-Julesburg Basin (“DJ Basin”) Operators.

Anadarko and Noble are two of the largest oil and gas producers in DJ Basin northwest of Denver, a more than 600-square-mile area that is the sixth-largest natural gas producing field in the country. Their combined production accounts for approximately 65% of the gas and condensate production in the DJ Basin.

Anadarko operates over 3,600 active natural gas wells, over 2,000 wellhead tank batteries and multiple compressor stations with various types of natural gas compression, dehydration, and condensate removal and storage equipment. Anadarko currently has installed and operates approximately 808 flares and 15 vapor recovery units (“VRU”) to comply with the present Regulation Number 7 requirements. Anadarko currently installs approximately five (5) emission control devices (“ECD”) per week (to control new wells and refracs) at a cost of \$15,000.00 per ECD, for a total of \$75,000.00 per week. On average it costs Anadarko \$3,500.00 per week to maintain compliance with Regulation Number 7, which includes reporting, inspections, and spreadsheet maintenance, but excludes the capital and installation costs of ECDs.

Noble operates over 5,000 active natural gas wells and over 2,700 wellhead tank batteries in the DJ Basin. Noble currently has installed and operates approximately 1,288 flares at a total capital cost of \$13,722,500.00 and installation cost of \$2,060,800.00. In addition to the flares, Noble has installed 113 VRUs at a total capital cost of \$2,825,000.00 and installation cost of \$452,000.00. Including these costs, maintenance, inspection, reporting and spreadsheet maintenance costs, Noble estimates its total costs for complying with the present Regulation Number 7 at \$2,100,000.00 per year.

2. West Slope Operators.

Williams operates active natural gas wells in the Piceance and San Juan Basins located on the Western Slope of Colorado and its facilities include, among others, wellhead tank batteries that collect and store natural gas condensate. Williams operate reciprocating internal combustion engines (“RICE”) to drive compressor units in its natural gas gathering systems, compressor stations and gas processing plants in the Piceance Basin.

Noble also operates over 150 natural gas wells in the Piceance Basin located in Garfield and Mesa Counties on the Western Slope of Colorado. Its facilities there include, among others, wellhead tank batteries that collect and store natural gas condensate.

B. Rulemaking Considerations

As this Commission well knows, there are a number of legal requirements to which its rulemaking is subject. Although the Commission is to have “maximum flexibility in developing an effective air quality control program,” any adopted regulations must still be “economically reasonable so as to reduce, prevent, and control air pollution,” and “the air pollution control measures utilized [must] bear a reasonable relationship to the economic, environmental, and

energy impacts and other costs of such measures.” Colorado Air Pollution Prevention and Control Act (“State Act”), C.R.S. § 25-7-102. In reviewing the proposed Ozone Action Plan and the alternative proposals that will come before the Commission, the Commissioners must bear this in mind, taking a careful look at the estimated ozone benefits to be realized from each of the proposals in relation to the estimated costs, as well as whether the proposal(s) fall squarely within the scope of this rulemaking.

Moreover, the Commission should be mindful of the initial scope of this rulemaking as set forth in the Commission Notice of Proposed Rulemaking:

The Air Quality Control Commission will consider a proposal from the Denver Metropolitan Area’s Air Quality Council, the North Front Range Transportation & Air Quality Planning Council and the Colorado Department of Public Health and Environment Air Pollution Control Division to adopt an ozone action plan for the Denver Metropolitan and North Front Range 8-house ozone nonattainment area.

In order to evaluate the estimated ozone benefits to be realized in relation to the estimated costs, the Commission should rely on the best scientific data available to first identify the problem to be addressed by the proposed rule(s). Of course, high ozone concentrations in the non-attainment area are the overarching problem, and the first question to ask is what are the sources that actually contribute most to ozone formation in the non-attainment area? Secondly, the Commission must carefully evaluate the proposed controls to ensure that they address the core problem in a reasonably efficient and cost-effective manner. A very significant tool available to the Commission in meeting these requirements is the Ozone Source Apportionment Tool (“OSAT”) analysis derived from the CAMx photochemical modeling outputs. The OSAT results show in dramatic fashion why lower cost-per-ton controls in one sector that contributes much less to ozone formation may be less effective than higher cost-per-ton controls of sources that contribute more greatly to ozone formation. Those results are summarized and graphically displayed in a number of the Well Operators’ exhibits, identified below, and to be filed with their Final Statement.

C. Proposed Ozone Action Plan Measures Supported by the Well Operators

The Well Operators do support many of the measures proposed in the Ozone Action Plan, including:

1. Incorporating more stringent cut-points adopted last February by AQCC for the Inspection and Maintenance (“I/M”) Program in the seven-county Denver Metropolitan Area (“DMA”) into the SIP.
2. Requiring 7.8 pounds per square inch Reid Vapor Pressure (“RVP”) gasoline be sold exclusively in the entire NAA, also as a SIP requirement.
3. Requiring low-bleed control devices on all new and existing pneumatic devices for oil and gas facilities in the NAA by 2009, except where their

installation is technically infeasible or not warranted due to safety concerns.

4. Expanding current Regulation Number 7 to require the installation of reasonably available control technology on VOC stationary sources across the entire NAA, except where inconsistent with system-wide tank controls.
5. Removing current Regulation Number 3 APEN exemptions for selected small sources of VOCs, except to the extent inconsistent with system-wide tank controls.
6. Implementing a motor vehicle I/M program in the North Front Range (“NFR”), except the Well Operators support implementing that program starting January 1, 2010.
7. Continuing to implement the high-emitter pilot program in the DMA.
8. Tightening the collector car license plate requirements under state law to limit it to true collector motor vehicles thereby closing a loophole that allows high-emitting vehicles to more easily escape testing and repair.
9. Requiring the installation of auto-igniters on combustion systems controlling condensate tank emissions.

D. SIP Proposed Measures Not Supported

The Well Operators do not support the following portions of the Ozone Action Plan proposed for inclusion in the SIP on multiple grounds, one of which being that proposed changes are not supported by the State’s own data and modeling. More specifically, the Well Operators oppose:

1. Abandoning the present system-wide control approach to regulating condensate storage tanks in favor of mandatory controls for all tanks with emissions above 2 tpy, which will significantly burden operators and complicate the scheme for regulating tanks, while delivering few, if any, additional emission reduction benefits in the 2010 attainment year relative to the existing regulatory approach at an increased control percentage of 85% for tanks emitting 1 tpy or more;
2. Requiring the installation of electronic surveillance systems (“ESS”), in addition to auto-igniters, on combustion systems controlling condensate tank emissions;
3. Establishing the proposed ESS requirements by the proposed effective date for all tanks to be controlled under the Division’s proposal, because they can simply not be achieved by then; and

4. Revising the definition of a “modified” source for condensate tanks to include any well refracting or stimulation, because it is unnecessary, unprecedented and unjustified.

E. State-Only Proposed Measures Not Supported

1. RICE Controls: The Well Operators oppose the inclusion of state-wide RICE controls in the Ozone Action Plan that focus solely on existing and modified lean-burn and rich-burn natural gas fired reciprocating internal combustion engines (“ICE”) of 500 horsepower (“HP”) or greater. The Well Operators oppose these state-wide RICE controls because they exceed the scope of the notice of rulemaking, they are not tailored to doing what this Commission has intended to do in its oil and gas strategy (“keeping clean areas clean”), and the controls will not appreciably contribute to improvements in ozone as modeled by contractors for the Division and the Regional Air Quality Council (“RAQC”). Additionally, the Division has failed to accurately quantify the emission reduction benefits such a state-only rule would deliver, and will arbitrarily require the installation and operation of control devices irrespective of an engine’s ability to comply with emission limitations. Furthermore, the Division has failed to account for emission reduction benefits that are already built into two recently adopted United States EPA New Source Performance Standards (“NSPS”) applicable to ICE. Specifically, NSPS IIII and JJJJ (“Quad I” and “Quad J”) establish emission limitations for both compression ignition (“CI”), and spark ignition (“SI”) ICE. Quad I, which became effective March 2008, regulates engines as far back as June 2006 and will produce quantifiable emission reductions as early as 2009. Finally, the Division’s rush to control certain specific natural gas RICE is inconsistent with the Division’s planned comprehensive review of all or most NOx sources starting as early as the first quarter of 2009.

2. NFR Motor Vehicle I/M: Although the Well Operators fully support the implementation of a vehicle I/M program in the NFR, some or all of the Well Operators propose moving up the implementation date of the program from January 1, 2012 to January 1, 2010. This is the subject of an alternate proposal that is separately described below at Section VII of this Final Statement and contained in exhibits submitted with this Final Statement. The State’s own I/M program contractor has stated that the program can be up and running by January 1, 2010, which would allow the NAA to begin to benefit from substantial emissions reductions in the NFR during the all-important 2010 ozone season. Moreover, some or all of the Well Operators believe it would be inconsistent with the Governor’s letter directive of July 26, 2007 to delay the full implementation of this I/M program until 2013 or 2014, essentially ignoring one of the largest contributors to ozone formation in the NAA, as graphically confirmed by the state’s own OSAT results.

F. Time Needed to Present Testimony

The Well Operators have provided written testimony for nine (9) witnesses in support of their positions and alternate proposals, the full text of which is submitted with this Final Statement. At the hearing, the Well Operators’ witnesses will verbally present a brief summary of their written testimony to provide the proper context for the Commission regarding this rulemaking and further provide the opportunity for limited questions and possible cross-examination. In light of this approach, the Well Operators anticipate they will need two and one-

half (2.5) hours to present testimony and introduce exhibits, inclusive of their rebuttal testimony, and exclusive of possible cross-examination by the Division's counsel or other parties, or significant questioning by the Commission.

II. THE WELL OPERATORS' STATEMENT OF FACTUAL AND LEGAL ISSUES

A. Generalizations About Growth in Oil and Gas Industry Emissions State-Wide are not Consistent with the Hard Data on DJ Basin Gas Production and the Industry's Major Reductions in Emissions Since 2004.

The DJ Basin is a mature natural gas field. While high gas prices fuel the drilling of new wells to keep production up, new wells in the DJ Basin are "infill" wells under applicable COGCC rules, and frequently produce to existing, consolidated tank batteries that are already controlled under Regulation Number 7. Such growth in the number of wells does not translate directly into growth in emissions for the DJ Basin. The Division's simplified approach that growth in production has outpaced reductions in emissions, is therefore inaccurate and misleading with respect to the DJ Basin. *See* Well Operators' Exhibit Numbers 1 and 3, displaying DJ Basin gas production and flash emission reductions over time. Oil and gas industry emissions of VOCs have been reduced more since 2004 than they have grown as a result of increased production, especially if voluntary pneumatic device control replacement is taken into account.

B. SIP Proposed Measures

1. The Proposed Changes in the Ozone Action Plan are Inconsistent with the State's Own Data and Modeling.

Because the control measures in the Ozone Action Plan were developed before source apportionment results became available on September 4, 2008, they do not reflect the unexpectedly heavy contribution of NOx emissions to ozone formation that was identified. Indeed, the September 8, 2008 Draft Final OSAT Report describes several trends that emerged from the source apportionment results. First, more than two-thirds of ozone contribution to the NAA comes from outside the 12 km domain. Second, the largest and most significant contributors to ozone formation in the DMA are mobile and non-road mobile sources. Third, at the two Ft. Collins monitors and the Greeley monitor, the largest contributors again are mobile sources, followed by non-road mobile sources, and then oil and gas sources. *See* September 8, 2008 Draft Final OSAT Report, pp. 3-9. Nevertheless, the Ozone Action Plan is predominantly focused on controlling VOC emissions from the oil and gas industry, seeking a reduction of 109 tons per day ("tpd") and a NOx reduction of only 10 tpd. This is completely opposite to the source apportionment results, which show many times more ozone attributed to anthropogenic sources of NOx than to anthropogenic sources of VOCs. And when it comes to VOCs, source apportionment also shows that lower reactivity VOCs from oil and gas sources play a much smaller role than higher reactivity VOCs from on-road and non-road mobile sources. *See* Testimony of Bruce Macdonald, and the Well Operators' exhibits referred to therein. Thus, the Ozone Action Plan is far less effective than it would be if it contained more NOx controls than VOC controls, and did not rely so heavily, if not exclusively, on oil and gas sources of VOCs,

which are a comparatively minor contributor of VOCs that actually form ozone, according to the best available modeling results.

The OSAT analysis, employing outputs from the CAMx model, with its refined gridded data and various physical and chemical algorithms embedded in the model, represents the best approach to evaluating sources and impacts related to ozone generation currently available. The Division's "weight of evidence" ("WOE") analysis is not as technically sound as the CAMx modeling results. While the WOE may be required for USEPA evaluation, the implementation of a control strategy should focus on the CAMx OSAT analysis. The following issues are raised regarding the technical and WOE analysis:

- Comparing tons of VOCs from different source categories without regard to their photochemical reactivity is misleading, and has contributed to our almost total reliance on oil and gas VOC controls as an ozone reduction strategy;
- Back trajectory analysis employing the NOAA HYSPLIT model tells us nothing about the conversion of ozone precursors in a parcel of air as it moves around, and its use over complex terrain is not recommended; and
- The observed correlation of high ozone events and 500 millibar (pressure) heights within the atmosphere is also inconclusive, and does not provide a basis for ignoring OSAT results.

Concerns about emission inventory accuracy affecting modeling results are appropriately raised, but weigh as heavily (if not more heavily), for mobile source VOC emissions as for oil and gas VOC emissions. In fact, a prior evaluation of doubling and tripling mobile source VOCs showed better model performance. *See* the testimony of Dr. Bruce Macdonald concerning these and related issues.

2. Abandonment of the System-Wide Control Approach to Regulating Condensate Storage Tanks in Favor of Mandatory Controls for all Facilities with Emissions above an Applicability Threshold is not Warranted.

The current regulatory framework for Regulation Number 7 is based on a "system-wide" control approach that requires each company to achieve a percentage-emission reduction level during the ozone season and a slightly lower percentage-emission reduction level during the non-ozone season (to enable periodic maintenance of control devices in the "off-season"). The system-wide approach provides oil and gas operators needed flexibility to service and reposition their ECDs as production levels in the field change, and that approach was adopted by the Commission in 2004 with the strong support of the oil and gas industry. Each and every year thereafter under the system-wide approach, the oil and gas industry has met and exceeded the required emission reductions, even as that requirement increased from 37.5% in 2004 to the present 75%. And while the required emission reductions stayed at 75% in 2007-2008, the oil and gas industry continued to increase its overall reductions from 79% in 2007 to 84% in 2008, which is further evidence of the strong incentive to over-control at work in the existing regulatory approach.

The Ozone Action Plan would abandon the system-wide control approach in favor of a threshold approach. This represents a fundamental shift that is more onerous for industry and would not generate any greater environmental benefit in 2010 than the Well Operators' Alternate Proposal, which is described in detail in Section VII.A. The Ozone Action Plan mandates controls on all facilities above an applicability threshold, plus it requires controls on all tanks during the first 90 days of production. Due to the fluctuating and dynamic nature of oil and gas production, the threshold-based approach will require that operators constantly evaluate production and emission levels to determine whether the applicability threshold has been triggered for any given tank. As a result of this ongoing need to evaluate condensate production levels at all tanks and add more controls as necessary based on those changes, the Ozone Action Plan's threshold approach is more burdensome to operators than the system-wide approach. It also represents a wholesale change from the existing Regulation Number 7 requirements, after only four years since their adoption, and thus is likely to promote greater confusion and compliance uncertainty in the regulated community, especially over the next four years.

Additionally, because it appears that any burner outage or correction of condensate production data indicating the need for controls on a tank that has none may be a violation under the proposed rule, the Ozone Action Plan will: (1) require industry and the Division to devote more resources to reporting outages under the upset provisions of Regulation Number 3; and/or (2) result in multiple minor violations for companies, again requiring company and Division resources to resolve them. As an example, Noble estimates that even at a very respectable 0.27% flare downtime, a figure it has worked very hard to achieve in recent months, the Company would have on average 4.6 violations per day to report to the Division under the threshold approach. This sort of penalty exposure is arbitrary, in that it does not deter bad conduct, but merely punishes the statistically inevitable. In contrast, the system-wide approach encourages companies to over-comply, resulting in lower levels of actual emissions while reducing an operator's risk of noncompliance due to isolated burner malfunctions or production data corrections.

Under the system-wide approach, operators also have an incentive to engage in pollution prevention and/or pursue more expensive alternatives to VOC emissions control, like vapor recovery, reducing line pressure (which lowers flash emission potential) or condensate stabilization. The Ozone Action Plan removes such flexibility and incentives without producing greater environmental benefit. Instead, the Ozone Action Plan will inefficiently force industry to monitor production at thousands of unmanned remote production facilities and will likely lead to a higher focus on enforcement by the Division. Such a result is neither necessary, nor desirable, in the Well Operators' view.

This fundamental change in the regulatory approach to condensate storage tanks will not lessen the burden on operators, large or small. Operators will need to constantly reevaluate where to install controls on tanks as emissions fluctuate due to production changes. Also, this change will require enforcement for every minor flare outage even if field-wide compliance remains high. Most importantly, the proposed change will eliminate the present flexibility and incentives for operators to "over-comply" and engage in pollution prevention. Accordingly, the Well Operators have prepared and submitted with this Final Statement an Alternate Proposal that retains the system-wide control approach for condensate storage tanks, but at the higher emission control level of 85% for tanks emitting 1 tpy or more of VOCs. That Alternate Proposal is

described below at Section VII.A. of this Final Statement, and is fully documented in the Well Operators' Exhibit Numbers 43, 44, and 45.

In addition to the above factors favoring system-wide tank controls, there are important "disbenefits" associated with pushing the control of VOCs down to very low-emitting tanks, and those disbenefits have not been adequately addressed by the Division. The disbenefits concern (1) the increased carbon footprint associated with the flaring of flash emissions, relative to emitting those emissions, and consideration of these disbenefits by the Commission also weighs in favor of the Well Operators' alternate proposal for condensate tank controls, rather than putting a flare on every tank emitting as little as 2 tpy of VOCs, or even less; and (2) the increased NOx emissions associated with flare controls on very low-emitting tanks.

Examination of available data reveals that, on average, there is a 40% greater emission of greenhouse gases ("GHGs") associated with the flaring of condensate tank flash emissions, and this disbenefit is ignored or discounted by the Division. As the Commission well knows, the Colorado Climate Action Plan calls for a 20% reduction in GHG emissions by 2020, as measured against 2005 emissions. Because 2005 is the year in which tank controls were first required at 37.5% for the ozone season, the increases associated with flaring of tank emissions in the DJ Basin are quite significant in the aggregate since that baseline year. *See* the Well Operators' Exhibit Numbers ___ and ___ regarding GHG disbenefits associated with flaring tank emissions of VOCs from condensate.

Additionally, although the NOx emissions associated with flaring tank emissions are significantly lower than the tons of VOCs controlled through flaring, they are not insignificant, especially when adjusted to reflect the OSAT results that account for ozone formation potential and photoreactivity. See the written testimony of Curtis O. Rueter regarding NOx disbenefits associated with flaring tank emissions of VOCs. Moreover, the flaring of tank emission for low-emitting tanks, between 5 tpy and 2 tpy, entails the combustion of significant volumes of fuel gas to keep pilots lit between intermittent periods of "slug" production to wellhead tanks. These NOx emission increases contribute to ozone formation and therefore diminish further the asserted benefits of attempting to control the lowest emitting condensate tanks operating in the DJ Basin.

3. The Division's Proposal Requires the Installation of Both Auto-Igniters and ESS on Combustion Systems Controlling Condensate Tank Emissions.

The Well Operators believe the requirement to install both auto-igniters and ESS is burdensome, redundant and unnecessary. By design, auto-igniters should provide essentially continuous operation of burners, unless a well, tank battery and burner is shut down by operating personnel. The ESS just tracks pilot light temperature and does not provide any direct air quality benefit.

ESS will generate a staggering amount of data. As proposed, an ESS will record a temperature measurement every 15 minutes, 24 hours a day, 7 days a week. This equates to 672 data points per week for one flare. Anadarko estimates that it will need to install ESS on 2,000 control devices in 2009, and Noble estimates it will need to install 1,288 ESS in 2009, both based

upon the threshold approach proposed in the Ozone Action Plan Exhibit Numbers 23 and 24. If installed, Anadarko's ESS will produce 1,344,000 data points weekly, and Noble's will produce 865,536 data points each week. That is 2,209,536 data points *every week*, from just two operators in the DJ Basin. Once an ESS generates the data, it still has to be collected and analyzed to determine if any flare outages are indicated. Regardless of who will have to collect and/or analyze it, that much data will create a substantial burden on the operators and further strain the Division's limited resources.

In addition, the cost of purchasing and installing the ESS are quite significant. Anadarko estimates capital costs at \$3,800.00 per flare and Noble at \$3,600.00 per flare. Based upon the numbers above, Anadarko's total cost for purchasing and installing ESS would be \$7,600,000 by 2011 and Noble's would be \$4,636,000 in 2009. That is an extraordinary expense for a piece of equipment that will not provide any direct air quality benefit, and is not providing data that are dispositive of the question whether emissions are being controlled, *i.e.*, the data only indicate if the flare pilot light is on.

4. The Proposed Monitoring Requirements Simply Cannot be Achieved by the Effective Date of the Proposed Revisions.

The Ozone Action Plan would mandate controls on all new and modified tanks greater than 2 tpy by 2009, all existing tanks greater than 10 tpy by 2010, all existing tanks greater than 5 tpy by 2011, and all existing tanks greater than 2 tpy by 2012. To meet these proposed requirements, the oil and gas industry would need to install approximately 2,000 to 4,000 data loggers plus 2,000 to 4,000 auto-igniters in 2009. Moreover, an additional complement of control devices, possibly numbering in the hundreds, would be required by the Division's proposed "first 90 days" control requirement.

Based on their own actual compliance experience with the current Regulation Number 7, the Well Operators do not believe that data logger and auto-igniter manufacturers can provide enough devices and/or that industry will be able to adequately test and install such systems as well as procure and install the necessary data management systems within the timeline proposed in the Ozone Action Plan. Nor does the Ozone Action Plan provide any flexibility on the proposed deadlines should the manufacturers fail to meet demand or if complications arise from installing and testing the ESS, which have not been field-proven for conditions in the DJ Basin. Such an approach further exposes the oil and gas industry to enforcement for unavoidable circumstances, making compliance virtually impossible.

5. The Proposed Definition of a Modified Source for Condensate Tanks to Include Well Refracting.

The Well Operators believe that a well or condensate tank should only be considered a modified source if refracting results in a net increase in emissions above the originally permitted or APENed emissions level. This approach to well/tank modification protects the environment because it acknowledges that, in most cases, the original registration and/or permitting of condensate tanks will reflect their highest levels of production, when a new well is initially brought into production. It does not exempt condensate tanks from being considered "modified" if reworking a well does, in fact, result in a net emissions increase above initially permitted or

registered levels, which does occur from time to time. This approach is also consistent with other states in which oil and gas sources are significant, such as Texas and Oklahoma.

Well reworking and refracing that does not result in emissions above initially permitted or registered levels should not be considered a modification, and changing the definition of source modification in this unprecedented manner will just increase the paperwork burden on operators and the Division without providing any air quality benefits. Moreover, this unprecedented departure from the long-established definition of “modification” of a source is only necessitated by the Division’s desire to move to a threshold-based regulatory scheme from the established and effective system-wide approach followed for the last four years. Retention of the system-wide approach at a higher control percentage, as proposed by the Well Operators, will eliminate the need to tinker with this universal air quality definition and will eliminate a substantial paperwork burden for operators and regulators alike.

C. State-Only Proposed Measures

1. Proposed State-Wide RICE Controls.

The proposed adoption of state-wide engine controls should be deferred for consideration among a broad range of NOx controls in 2009. The Well Operators oppose the proposed adoption of state-wide RICE controls at this time for a variety of reasons, including:

- The ozone reduction benefits of such controls have not been properly estimated and would appear to be negligible;
- Recently adopted federal NSPSs will help “keep clean areas clean,” as intended by the AQCC, without overlap of and potential inconsistency with state engine requirements proposed by the Division;
- The Division has failed to account for the benefits of the federal engine NSPSs in making its case for state-wide RICE controls; and
- The proposed RICE controls would arbitrarily require specific engine technology regardless of emissions performance, which are not mandated under the noted NSPS.

These and other problems are addressed in greater detail below.

As proposed, the state-wide RICE controls would single out the oil and gas sector by requiring those who own or operate modified and existing stationary SI lean-burn and rich-burn natural gas-fired ICE of greater than or equal to 500 HP to control emissions from those engines and install and operate after-treatment control devices on those engines. The majority of larger natural gas-fired ICE in Colorado are in service in the oil and gas industry. The Division’s proposed rule does not impose similar requirements on SI ICE fired with other fuels (like the NSPSs), nor does it impose similar requirements on CI ICE (like the NSPSs). Even the Division’s proposed retention of a previous emission limitation for those stationary SI natural gas ICE of greater than 100 HP excludes SI ICE fired with other fuels and all CI ICE. These

shortcomings, coupled with negligible or non-existent ozone benefits, weigh heavily in favor of deferring state-wide RICE controls for further consideration by the Commission in 2009.

- a. The proposed state-wide RICE controls are outside the scope of the noticed rulemaking.

As an initial matter, the proposed state-wide RICE controls are outside the scope of the notice of the proposed OAP, in violation of the Colorado Administrative Procedure Act. Finally adopted rules must be consistent with the subject matter as set forth in the notice of proposed rule-making. C.R.S. § 24-4-103(4)(c). The OAP rulemaking notice focused specifically and exclusively on the consideration of a proposal “to adopt an ozone action plan for the *DMA and the NFR 8-hour ozone non-attainment area*.” See Commission Notice of Proposed Rulemaking. The proposed state-wide RICE control rule is just that—*state-wide*. The proposed state-wide RICE control rule does not limit its application to the DMA and NFR area, but instead extends to the far reaches of the four corners of our state. Even the RAQC modeling indicates that emission reductions from state-wide RICE controls will not appreciably improve ozone in the NAA. See Testimony of Martha Hyder. Thus, the adoption of such a state-wide rule under the proposed notice is clearly outside the scope of the rule-making and should not be considered in this rule-making.

Additionally, a related issue concerns the definition of the NAA itself, and how air quality control regions are supposed to develop a SIP to bring those regions into attainment with federal NAAQS. As the Well Operators have previously noted, the State of Colorado opposed EPA’s attempt to expand the NAA even more than it last did, and in so doing made a cogent argument about the sources contributing most significantly to ozone being primarily within a smaller NAA. See the Well Operators’ Exhibit Number 40, memo dated May 20, 2008 regarding NAA boundary designation for the Denver and NFR areas. Of course, Colorado prevailed in keeping the NAA boundary where it is today, and the Division has not proposed expanding it as part of the 8-hour ozone SIP development process. Accordingly, state-wide RICE controls should not be included in the Ozone Action Plan.

- b. The Division has failed to adequately characterize the emission benefits of its proposed state-wide RICE controls.

The Division has been unable to provide a specific estimate of the emission reductions to be delivered by several standards that are already “on the books,” including the federal NSPSs and the state’s own existing Regulation Number 7 requirements for new and relocated engines. At best, the Division has shown a “marginal” benefit from state-wide reductions in NO_x emissions from oil and gas and point sources through its sensitivity analyses. See testimony of Martha Hyder. Modeling of the Division’s state-wide control scenario, which included not only overestimated NO_x emissions reductions from engines, but also: (1) additional VOC reductions in the NAA due to condensate tank controls that will not be effective until 2011 and 2012, well after the 2010 attainment date; and (2) vehicle I/M program benefits as though fully implemented by 2010 when discontinued in 2006 showed only minor improvements in ozone in the NFR area.] *Id.* Based on the sensitivity analyses and OSAT results, such improvements are most likely due to the 2011 and 2012 condensate tank controls and/or vehicle I/M program controls rather than the state-wide RICE controls. *Id.* The modeling, in fact, showed large areas with

small ozone increases over most of the Western Slope, undoubtedly due to the additional NO_x controls in that NO_x limited region. *Id.* Finally, the OSAT modeling showed that very little of the ozone at NAA monitors can be ascribed to emissions outside of the NAA. *Id.* Thus, it is remarkably unclear as to what benefits will accrue relative to ozone formation in the NAA, if any, through the adoption of the Division's state-wide RICE control proposal.

- c. The Division requires the installation and operation of after-treatment control devices irrespective of compliance with the proposed emission limitations.

The installation and operation of after-treatment control devices on stationary lean-burn and rich-burn natural gas SI ICE with greater than 500 HP are required under the Division's proposal as of May 1, 2010, regardless of whether an engine applicable emission standards without such controls. Many of the engines in place can meet or exceed the current Regulation Number 7 emissions limitations that apply to new and relocated engines, without after-treatment control devices. *See* Testimony of Dr. Daniel B. Olsen, P.E. Requiring specific after-treatment technology for existing and modified engines is therefore arbitrary, wasteful and unwise. By mandating specific after-treatment technology, the Division is taking operational field decisions away from the owner and operator, who is in a better position to know what operational modifications or other types of control technology may be cost-effective and efficient to comply with an identified emission limitation. *Id.* For example, certain after-treatment may create additional NH₃, which will effectively neutralize any NO_x emission reduction benefits. *Id.* Moreover, other technologies are available for lean-burn engines to reduce emissions, and the installation and operation of exhaust after-treatment is expensive and imposes additional backpressure on engines, which results in efficiency loss. *Id.* If any control of existing and modified engines is warranted, it should be in the form of a performance standard, not the arbitrary imposition of a specific control technology, as prescribed by the Division's proposal.

- d. The Division did not consider or account for projected emission reductions realized through EPA's Quad I and Quad J.

Surprisingly, the Division did not factor in or account—in any way—for the emission reduction benefits that Colorado would see—both in attainment areas and its NAA—through the installation, reconstruction, modification, and operation of CI and SI ICE of various sizes and fuel types regulated under the fully-promulgated and effective NSPSs. *See* the Well Operators' Exhibit Number 33. Irrespective of the State's failure thus far to adopt Quad I and Quad J through incorporation into the AQCC's rules, owners and operators are obligated to comply with these federal regulations, and their compliance will most certainly result in significant emission reduction benefits. Any emission reduction benefits that the Division hoped to attain through the proposed state-wide RICE controls will be largely realized through the two previously promulgated and fully effective NSPS. *See* Testimony of Martha Hyder and Dr. Olsen.

EPA's NSPS JJJJ in 2009 alone is estimated to provide more than a 60,000 tpy reduction of NO_x, 29,000 tpy reduction of CO, 800 tpy of VOC, and 311 of HAP nationally. *See* Memorandum from Tanya Parise, Alpha-Gamma Technologies, Inc. to Jaime Pagan, EPA Energy Strategies Group (Dec. 18, 2007). Even assuming Colorado accounts for only five percent of the national emission reductions, the State would still realize a projected emission

reduction benefit of 3,000 tpy for NO_x, 1,450 tpy for CO, 45 tpy of VOC, and 15.5 tpy of HAPs. By 2015, EPA estimates that the two NSPSs will reduce NO_x by 115,000 tpy, CO by 63,000 tpy, VOC by 2,000 tpy, HAP by 800 tpy, PM by 3,000 tpy, NMHC by 600 tpy, and SO₂ by 9,000, nationally. *See* 71 Fed. Reg. 39154, 39168 (July 11, 2006); 73 Fed. Reg. 3568, 3586 (Jan. 18, 2008). Again, even assuming that Colorado accounts for only five percent of the national emission reductions to be realized through Quad I and Quad J, the State would realize a projected emission reduction benefit of 5,750 tpy of NO_x, 3,150 tpy of CO, 100 tpy of VOC, 40 tpy of HAP, 150 tpy of PM, 30 tpy of NMHC and 450 tpy of SO₂.

In light of the foregoing, the Division's proposed state-wide RICE controls should not be promulgated. Instead, the Division should acknowledge and consider the projected emission reduction benefits associated with NSPSs Quad I and Quad J in advance of any further sector-specific emission reduction strategies for which it cannot meaningfully articulate ozone reduction benefits. State-wide engine controls are more appropriately reserved for the Division's proposed 2009 plan to more thoughtfully consider and comprehensively review a variety of NO_x sources.

2. Implementation of the I/M program in the NFR should be moved forward to January 1, 2010.

The Ozone Action Plan proposes to expand the existing motor vehicle inspection and maintenance (I/M") program currently applicable in the seven county DMA to the AIR Program area in Larimer and Weld Counties. The Well Operators generally support this proposal and agree that the establishment of an I/M program in the NFR is an important component of any serious effort to demonstrate: (1) attainment with the 0.08 ppm ozone standard, and (2) further progress toward attaining a lowered ozone NAAQS of 0.075 ppm.

The OSAT results indicate that on-road mobile sources in the NFR are one of largest source contributors to ozone formation in that area, due to their VOC and NO_x emissions. The OSAT results further indicate that the majority of ozone formed is attributed to anthropogenic NO_x sources. These two conclusions underscore the need to reduce NO_x emissions from mobile sources in the NFR sooner rather than later.

The Well Operators assert that it is unwise to delay implementation of a reinstated I/M program in the NFR until 2012. Waiting until January 1, 2012 to begin to implement a vehicle I/M program in the NFR means that the full ozone reduction benefits of the program will not be realized until the beginning of 2014. This is hardly consistent with Governor Ritter's directive to begin to work toward attaining a lowered 8-hour ozone standard, and it flies in the face of this Commission's well-documented resolve to move quickly to address our ozone non-attainment status and protect public health. There is simply no good reason for such delay, and no more important task at hand for the Mobile Source Program of the APCD. By moving up the implementation date to 2010 as described in the Well Operators' Alternate Proposal in Section VII.B., the first half of the vehicles brought into the program will be tested in that year, and the remaining vehicles will be tested in 2011. By January 1, 2012 the program will be fully implemented.

Perhaps ironically, it is this very Commission that acted to dissolve the prior I/M program in the NFR just two years ago, over the objections of the NFRMPO and others, and that unfortunate decision most certainly contributed to our collective failure to avoid non-attainment designation via the EAC. It is well-documented that the vehicle fleet in the NFR is older and higher-emitting than in the DMA, and since dissolution of mandatory testing and repair, the NFR vehicle fleet is likely even dirtier, and not much newer. It is also well documented that a significant portion of the NFR vehicle fleet, perhaps as high as 20%, commutes into the DMA on a routine basis, and should therefore be tested under existing law, but we have failed to enforce that requirement! Delaying the reinstatement of an I/M program in the NFR under these circumstances simply can't be justified, and the state's own experience implementing the former NFR I/M program in the early nineties, and the contractor's experience here and in other states, indicates that 2010 implementation is achievable. In light of the foregoing, the Well Operators urge the Commission to reject the Division's proposed 2012 start date for an NFR I/M program and instead adopt the Well Operators' Alternate Proposal, as described in Section VII.B. to start this important program in 2010.

These factual and legal issues are the subject of written testimony, live testimony and exhibits to be presented by the Well Operators prior to and at the hearing, as summarized and listed below.

III. LIST OF ISSUES TO BE RESOLVED BY THE COMMISSION

A. SIP Proposed Measures

1. Source Apportionment Results are not Adequately Reflected in the Ozone Action Plan Controls.
2. NAA Tank Controls: System-Wide v. Threshold Approach.
3. NAA Tank Controls: Whether ESS in Addition to Auto-Igniters is Beneficial.
4. NAA Tank Controls: ESS Compliance Schedule.
5. Whether Inclusion of Well Refracting in Definition of Modified Source is Necessary or Helpful.

B. State Only Proposed Measures

1. Adoption/Deferral of State-wide RICE Controls.
2. Implementation Date of I/M program in NFR.

IV. EXHIBITS THAT WILL BE INTRODUCED AT THE HEARING

A. Oil and Gas Production Growth and Emission Reductions

1. Well Operator (“WO”) Exhibit 1: Graphic of John D. Wright, Ph.D., President, Oil & Gas Services and Chief Petroleum Engineer of Norwest Corporation, showing growth from 1999 to 2007 and projected future growth through 2012 of natural gas condensate production in Weld County, Colorado.
2. WO Exhibit 2: Graphic showing 8-Hour Denver Ozone Design Values from 1993 – 2007, based on data from the Division.
3. WO Exhibit 3: Graphic showing the levels of controlled emissions during the ozone season for the DJ Basin Operators and all operators in the DJ Basin, from 2005 - 2008.
4. WO Exhibit 4: Chart showing the expenditures to date by the DJ Basin Operators on ECDs to control condensate tank VOC emissions in the DJ Basin.
5. WO Exhibit 5: March 11, 2008 letter from Anadarko to Mr. Kenneth H. Lloyd, Executive Director of the Regional Air Quality Council, agreeing to voluntarily replace high-bleed pneumatics with low-bleed pneumatics, as well as other voluntary measures to reduce ozone impacts in the NAA.
6. WO Exhibit 6: March 11, 2008 letter from Noble to Mr. Kenneth H. Lloyd, Executive Director of the Regional Air Quality Council agreeing to voluntarily replace high-bleed pneumatics with low-bleed pneumatics, as well as other voluntary measures to reduce ozone impacts in the NAA.

B. Source Apportionment Results

1. WO Exhibit 7: Maps of the NAA and location of air monitors within the NAA.
2. WO Exhibit 8: Comments submitted to the Regional Air Quality Council on March 11, 2008, providing Guiding Principles for the Adoption of Ozone Controls.
3. WO Exhibit 9: Ozone Source Apportionment Modeling Results, Appendix C—Bar Charts demonstrating source apportionment results at each air monitor for each day modeled.
4. WO Exhibit 10: Graphic showing average contribution of O3N and O3V to Ozone formation at the Ft. Collins air monitor.

5. WO Exhibit 11: Graphic showing average contribution of O3N and O3V to Ozone formation at the Ft. Collins West air monitor.
6. WO Exhibit 12: Graphic showing average contribution of O3N and O3V to Ozone formation at the Weld County Tower air monitor.
7. WO Exhibit 13: Graphic showing average contribution of O3N and O3V to Ozone formation at the Rocky Flats North air monitor.
8. WO Exhibit 14: Graphic showing average contribution of O3N and O3V to Ozone formation at the CAMP air monitor.
9. WO Exhibit 15: Graphic showing average contribution of O3N and O3V to Ozone formation at the Chatfield Reservoir air monitor.
10. WO Exhibit 16: Graphic showing average contribution of O3N and O3V to Ozone formation in the NAA.
11. WO Exhibit 17: Chart summarizing occurrences of Design Value Days from June – July 2006 in the Ozone Modeling/OSAT Results.
12. WO Exhibit 18 & 19: Did not use.

C. System-Wide v. Threshold Tank Controls

1. WO Exhibit 20: Graphic demonstrating oil and gas operator compliance under system-wide approach from 2005 to 2008 based upon Regulation Number 7 spreadsheets.
2. WO Exhibit 21: Chart showing the requirements of the Colorado Climate Action Plan.
3. WO Exhibit 22: Graphic & charts showing the green house gas disbenefit from flaring, as opposed to venting, flash gas from condensate tanks.

D. Auto-Igniters and ESS for Tanks

1. WO Exhibit 23: Graphics/charts demonstrating the total cost and cost per ton of emissions reduced of installing and maintaining ESS as proposed under the threshold approach.
2. WO Exhibit 24: Chart demonstrating the number of data points generated every day, week and month by ESS as proposed under the threshold approach.
3. WO Exhibit 25: Charts demonstrating the estimated number of flares in non-compliance under the threshold approach on a daily basis assuming a 0.5% downtime rate.

E. Modified Source

1. WO Exhibit 26: Memorandum documenting the regulatory approach taken by several other oil and gas producing states regarding when a well or wellhead tank becomes a modified source.

F. State-Wide RICE

1. WO Exhibit 27: Graphic from OSAT results demonstrating origin of regional anthropogenic ozone precursors for an average of days with elevated ozone at Rocky Flats North monitor.
2. WO Exhibit 28: Graphic from OSAT results demonstrating origin of regional anthropogenic ozone precursors and boundary conditions for an average of days with elevated ozone at Rocky Flats North monitor.
3. WO Exhibit 29: Graphic from OSAT results demonstrating origin of regional anthropogenic ozone precursors for an average of days with elevated ozone at Fort Collins West monitor.
4. WO Exhibit 30: Graphic from OSAT results demonstrating origin of regional anthropogenic ozone precursors and boundary conditions for an average of days with elevated ozone at Fort Collins West monitor.
5. WO Exhibit 31: OSAT results Figure ES-2 showing projected 2010 8-hour ozone design values.
6. WO Exhibit 32: OSAT results Figure ES-3 showing the differences in ozone concentrations (future design values) for the two control scenarios and the 2010 base case.
7. WO Exhibit 33: November 3, 2008 APCD response to Emissions Inventory Questions.
8. WO Exhibit 34: December 18, 2007 Memorandum from Tanya Parise, Alpha-Gamma Technologies, Inc. to Jaime Pagan, EPA Energy Strategies Group.
9. WO Exhibit 35: June 20, 2005 Memorandum from Tanya Parise, Alpha-Gamma Technologies, Inc. to Sims Roy.
10. WO Exhibit 36: Regulatory Impact Analysis for the Standards of Performance for the Stationary Spark Ignition New Source Performance Standard and New Area Source NESHAP EPA-452/R-07-015 (Dec. 2007).
11. WO Exhibit 37: Regulatory Impact Analysis for the Standards of Performance for the Compression Ignition New Source Performance

Standard and New Area Source NESHAP EPA-452/R-06-003 (June 2006).

12. WO Exhibit 38: W-mail from Amnon Bar-Ilan, Ph.D, Environ International Corporation, Doug Henderer, Buys and Associates, and Kathleen Sgamma, IPAMS (Nov. 7, 2008, 13:21:36 MST).
13. WO Exhibit 39: M. DeFoort, D, Olsen, and B. Wilson, The Effect of Air-Fuel Ratio Control Strategies on Nitrogen Compound Formation in Three-Way Catalysts, International Journal of Engine Research (Aug. 6, 2003).
14. WO Exhibit 40: Comments submitted to the Regional Air Quality Council on May 20, 2008, providing comments on behalf of the DJ Basin Operators on the Role of Non-Attainment Boundaries in Ozone SIP Development.

G. Rebuttal Exhibits

1. Rebuttal exhibits will be identified in the Well Operators' Rebuttal Statement.

H. Vehicle Inspection and Maintenance Program

1. WO Exhibit 41: Graphics demonstrating that by not implementing a vehicle inspection and maintenance program in the NFR in 2010, the state is allowing mobile sources to emit 1018.35 tons of ozone precursors every year and demonstrating that VOC emissions from mobile and non-mobile sources are approximately two times more photoreactive the oil & gas VOC emissions.
2. WO Exhibit 42: Graphic demonstrating that by delaying a vehicle inspection and maintenance program in the NFR from 2010 until 2012, a total of approximately 3000 tons of ozone precursors will be released in the NAA by mobile sources.

I. Alternate Proposals

1. WO Exhibit 43: Alternate Proposal for System-Wide Tank Controls in the NAA (redline and strikeout of existing affected provisions).
2. WO Exhibit 44: Economic Impact Statement for Alternate Proposal for System-Wide Tank Controls in the NAA.
3. WO Exhibit 45: Statement of Basis and Purpose for Alternate Proposal for System-Wide Tank Controls in the NAA.
4. WO Exhibit 46: Alternate Proposal for NFR Vehicle I/M program (2010 implementation)(redline and strikeout of Division's proposal).

5. WO Exhibit 47: Economic Impact Statement for NFR Vehicle I/M program (2010 implementation).
6. WO Exhibit 48: Statement of Basis and Purpose for NFR Vehicle I/M program (2010 implementation).

V. THE WELL OPERATORS PLAN TO CALL THE FOLLOWING WITNESSES AT THE HEARING IN THIS MATTER

1. Brian Lockard, Air Quality Manager, Noble Energy, Inc.—testimony on compliance with Regulation Number 7; on the estimated costs of condensate tank controls, ESS auto-igniters required by the Ozone Action Plan; amount of data generated by ESS under the Ozone Action Plan; problems with compliance under the Ozone Action Plan; NO_x and green-house gas disbenefits of the threshold approach; benefits of the Well Operators’ Alternate Proposal; on the flexibility and incentives to over comply afforded by the Well Operators’ Alternate Proposal and its system-wide control approach; and reasons to refrac a well and any increase of emissions there from.
2. Phil Schlagel, Environmental and Regulatory Supervisor, Anadarko Petroleum Corporation—testimony on compliance with Regulation Number 7; on the estimated costs of condensate tank controls, ESS auto-igniters required by the Ozone Action Plan; amount of data generated by ESS under the Ozone Action Plan; problems with compliance under the Ozone Action Plan; benefits of the Well Operators’ Alternate Proposal; on the flexibility and incentives to “over comply” afforded by the Well Operators’ Alternate Proposal and its “system-wide control approach”; and reasons to refrac a well and any associated increase of emissions.
3. Rick Matar, Air Quality Practice Manager, Williams Production RMT Company—testimony on the costs and operational burdens of the Division’s proposed state-wide RICE controls and their comparison with the likely benefits of recently adopted federal engine standards (NSPS Quad J) in greatly reducing engine emissions from new and reconstructed engines in gas-producing basins that are undergoing rapid development within Colorado.
4. Curtis O. Rueter, P.E., Air Quality Manager for North America, Noble Energy, Inc.—testimony on NO_x and green-house gas disbenefits of the Division’s threshold approach to control of condensate tanks in the NAA, in contravention of the Colorado Climate Action Plan.
5. Dr. Bruce C. Macdonald, Regional Vice President for the Air Quality Practice Area, AECOM Environment (a subsidiary of AECOM, Inc., formerly ENSR Inc.)—testimony on ozone modeling, including results, modeling assumptions, parameters, inputs, results, and sensitivity analyses

including OSAT results, with analysis of the Division’s prior use of air mass modeling to perform “back-trajectory analyses” in connection with the Weight of Evidence analysis.

6. Martha Hyder, Wind River Environmental Group LLC—testimony on ozone modeling, including results, modeling assumptions, parameters, inputs, results, sensitivity analyses including OSAT results, and agreement and/or disagreement with ambient monitoring and meteorological data, and specific analysis of the Division’s intention to regulate state-wide RICE through limited application of controls to natural gas fired ICE and exclusion of emission reduction benefits associated with Quad I and Quad J.
7. Dr. Daniel P. Olsen, P.E.—testimony on the Division’s intention to regulate state-wide RICE through the: (1) limited application of natural gas fired ICE; (2) required installation and operation of control technology devices regardless of the ICE’s ability to meet emission limitation requirements; and (3) exclusion of emission reduction benefits associated with Quad I and Quad J.
8. Dr. Lisa A. McDonald, Senior Economist, Louis Berger Group, Inc.—testimony on the incremental costs associated with increasing pollution control requirements for flash emissions from condensate tanks as proposed by the Division and by the Well Operators’ Alternate Proposal; on the incremental costs associated with implementing the I/M program in the NFR beginning in 2010 as opposed to 2012 (the latter date proposed in the Ozone Action Plan).
9. Dr. John D. Wright, Ph.D., Norwest Questa Engineering Corp.—testimony concerning historic and projected growth in condensate production in the DJ Basin.

VI. WRITTEN TESTIMONY

The written testimony/expert reports of the Well Operators’ witnesses listed above are submitted with this Final Statement.

VII. ALTERNATE PROPOSAL

The following Alternate Proposals, along with a redline and strike-through of affected provisions of AQCC Rule a proposed Statement of Basis and Purpose and an Economic Impact Analysis for each, will be attached as exhibits to the Well Operators’ Final Statement.

A. The Well Operators’ Alternate Proposal for Condensate Tank Controls in the NAA

The Well Operators propose that condensate tank controls in the NAA under Regulation Number 7 keep the current system-wide approach, but increase the required control percentage

for all tanks emitting 1 tpy or more to 85% by May 1, 2010. The current requirement is 75% system-wide control for tanks emitting approximately 5 tpy or more. Supplemental modeling of this control scenario confirms that it produces the same or greater benefits than the proposed Ozone Action Plan in the attainment year 2010. The Well Operators have attached their proposed rule language, economic impact statement and statement of basis and purpose as exhibits to this Final Statement.

B. I/M 2010

Some or all of the Well Operators propose moving forward the commencement date of the NFR vehicle I/M program from January 1, 2012 to January 1, 2010. Under the Ozone Action Plan's proposal, vehicles in the NFR will not begin being tested until January 2012, which means that the program will not be fully implemented until January 1, 2014. Under this alternate proposal, vehicles would begin being tested in 2010 and the program would be fully implemented by January 1, 2012. To delay this control strategy until 2012, as the Ozone Action Plan proposes, is inconsistent with Governor Ritter's directive to begin working toward attaining the lowered ozone standard, and essentially ignores thousands of tons of ozone precursor emissions from one of the largest contributing sources to ozone in the NAA, the on-road mobile source category.

VIII. RESERVATIONS

The Well Operators reserve the right to present additional testimony, witnesses and exhibits for purposes of rebuttal, to use demonstrative aids at the hearing that contain information already provided in exhibits and testimony, and to address very recent changes and any future changes to the Division's proposal and any alternate proposal(s) of the Division or any other party in their rebuttal filings and at the hearing, as necessary.

IX. CONCLUSION

The Well Operators urge the Commission to consider the data and modeling results carefully in their deliberations on the proposed Ozone Action Plan and various alternative proposals, along with the testimony of fact and expert witnesses. If the Commission members do this, being mindful of the legal requirements for rulemaking by a regulatory authority, the Well Operators believe the Commission should adopt the Ozone Action Plan in part, but should defer state-wide RICE controls, and adopt the Well Operators' alternate proposals concerning tank controls and the NFR vehicle I/M program. Those alternate proposals will preserve the current system-wide approach to condensate tank controls, but at a control percentage requirement of 85% for tanks emitting 1 tpy or more, and will implement an I/M program for the NFR beginning in 2010, instead of 2012. Such a result is better supported by the CAMx modeling results and OSAT results, and more likely will make progress toward attainment of a lowered 8-hour ozone NAAQS of 0.075 ppm, consistent with Governor Ritter's directive.

Dated this 17th day of November, 2008.

Respectfully submitted,

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WILLIAMS PRODUCTION RMT COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the attached **FINAL JOINT PREHEARING STATEMENT OF ANADARKO PETROLEUM CORPORATION, NOBLE ENERGY, INC., and WILLIAMS PRODUCTION RMT COMPANY** was filed and served by electronic mail on the 17th day of November, 2008, upon the following:

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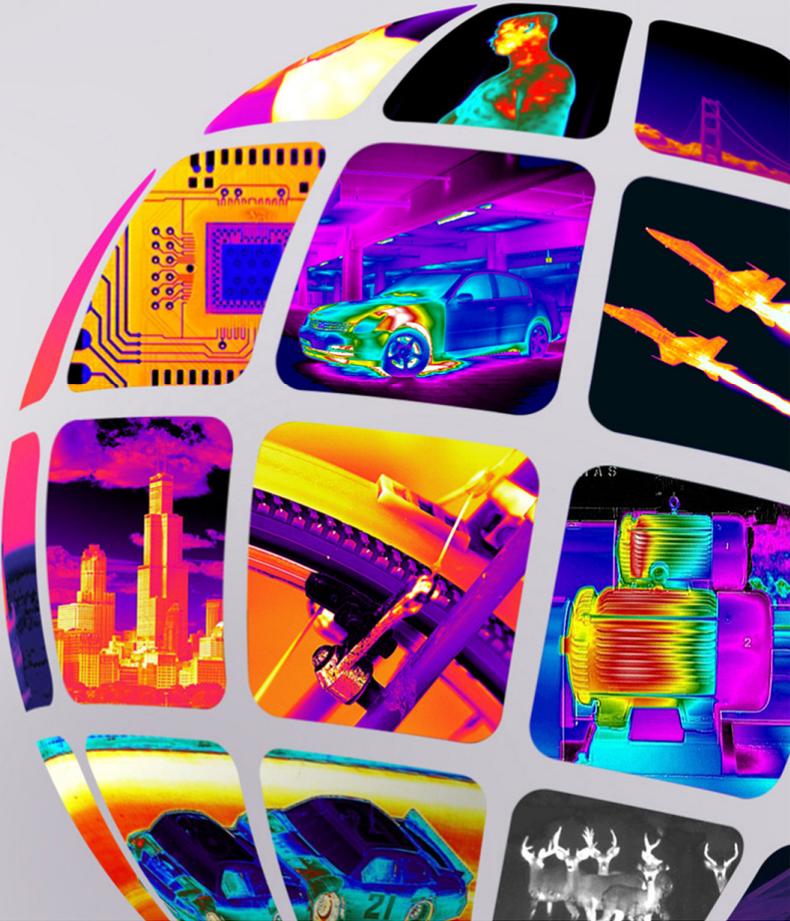
s/ Christine M. Thompson

OGI Service Provider Survey

March 2016



The World's Sixth Sense™



Company A

Business Details

- 95% of service work done upstream and 5% midstream
- Trained operator, insured with many expenses (that would be involved with a company doing their own inspections) like camera, trucks, etc.

Pricing

- If per hour; \$250 per hour. This would include mileage but there would be a per diem from travel (per hour for travel) and lodging, food, etc.
- If per well site; \$300 per well pad (a basic well pad*). Add \$50 per tank above a basic well pad
 - Plus mileage
 - Often this includes an “odor complaint” inspection
 - Discounted rate if hired for companywide inspection for many pad sites
 - Sometimes has “crews” of the hiring company to fix the finds from the camera and he will rescan at no charge. If they repair and he has to revisit there is usually a charge associated.

* NOTE: a “basic well pad” is 4 tanks (3 oil and 1 water), 1 separator and/or heater, 1 combustor, 1 VRU

Scans

- Estimates 5-6 well pads to be scanned per day (about 45 minutes per site/onsite)
- Has done as many as 15 in one day

Company B

Business Details

- Trained operator, insured with many expenses (that would be involved with a company doing their own inspections) like camera, trucks, etc.
- Also has aerial survey capabilities.

Pricing

- If per well site; \$800 per well pad.
 - Plus mileage, travel, lodging, etc.
 - Discounted rate if hired for companywide inspection for many pad sites
- Aerial surveys at \$1100 per hour plus expenses.

Scans

- Estimates about 15 well pads to be scanned per day.
- Estimates about 30 minutes per well pad.



**Regulatory Impact Analysis of the
Final Oil and Natural Gas Sector: Emission
Standards for New, Reconstructed, and
Modified Sources**

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**Regulatory Impact Analysis of the Final Oil and Natural Gas Sector:
Emission Standards for New, Reconstructed, and Modified Sources**

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
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TABLE OF CONTENTS

| | |
|---|------------|
| TABLE OF CONTENTS | V |
| LIST OF TABLES..... | VII |
| LIST OF FIGURES | IX |
| 1 EXECUTIVE SUMMARY | 1-1 |
| 1.1 BACKGROUND..... | 1-1 |
| 1.2 MARKET FAILURE | 1-3 |
| 1.3 REGULATORY OPTIONS ANALYZED IN THIS RIA..... | 1-3 |
| 1.4 SUMMARY OF RESULTS | 1-5 |
| 1.5 SUMMARY OF NSPS IMPACTS CHANGES FROM THE PROPOSAL RIA..... | 1-10 |
| 1.6 ORGANIZATION OF THIS REPORT..... | 1-12 |
| 2 INDUSTRY PROFILE | 2-1 |
| 2.1 INTRODUCTION | 2-1 |
| 2.2 PRODUCTS OF THE CRUDE OIL AND NATURAL GAS INDUSTRY | 2-2 |
| 2.2.1 Crude Oil | 2-2 |
| 2.2.2 Natural Gas | 2-3 |
| 2.2.3 Condensates | 2-3 |
| 2.2.4 Other Recovered Hydrocarbons..... | 2-4 |
| 2.2.5 Produced Water | 2-4 |
| 2.3 OIL AND NATURAL GAS PRODUCTION PROCESSES | 2-4 |
| 2.3.1 Exploration and Drilling | 2-4 |
| 2.3.2 Production..... | 2-5 |
| 2.3.3 Natural Gas Processing..... | 2-7 |
| 2.3.4 Natural Gas Transmission and Distribution..... | 2-8 |
| 2.4 RESERVES AND MARKETS | 2-8 |
| 2.4.1 Domestic Proved Reserves | 2-9 |
| 2.4.2 Domestic Production..... | 2-13 |
| 2.4.3 Domestic Consumption..... | 2-21 |
| 2.4.4 International Trade..... | 2-25 |
| 2.4.5 Forecasts | 2-27 |
| 2.5 INDUSTRY COSTS | 2-32 |
| 2.5.1 Finding Costs | 2-32 |
| 2.5.2 Lifting Costs | 2-33 |
| 2.5.3 Operating and Equipment Costs | 2-35 |
| 2.6 FIRM CHARACTERISTICS | 2-37 |
| 2.6.1 Ownership..... | 2-37 |
| 2.6.2 Size Distribution of Firms in Affected NAICS..... | 2-38 |
| 2.6.3 Trends in National Employment and Wages | 2-39 |
| 2.6.4 Horizontal and Vertical Integration | 2-41 |
| 2.6.5 Firm-level Information | 2-43 |
| 2.6.6 Financial Performance and Condition..... | 2-3 |
| 2.7 REFERENCES | 2-7 |
| 3 EMISSIONS AND ENGINEERING COSTS..... | 3-1 |
| 3.1 INTRODUCTION | 3-1 |
| 3.2 SECTOR EMISSIONS OVERVIEW..... | 3-1 |
| 3.3 EMISSIONS POINTS AND POLLUTION CONTROLS ASSESSED IN THE RIA | 3-2 |
| 3.4 ENGINEERING COST ANALYSIS | 3-5 |
| 3.4.1 Regulatory Options | 3-6 |
| 3.4.2 Projection of Incrementally Affected Facilities | 3-8 |

| | | |
|----------|--|------------|
| 3.4.3 | Emissions Reductions | 3-12 |
| 3.4.4 | Product Recovery..... | 3-13 |
| 3.4.5 | Engineering Compliance Costs..... | 3-15 |
| 3.4.6 | Comparison of Regulatory Alternatives | 3-17 |
| 3.5 | ENGINEERING COST SENSITIVITY ANALYSIS..... | 3-19 |
| 3.5.1 | Compliance Costs Estimated Using 3 and 7 Percent Discount Rates | 3-19 |
| 3.5.2 | Sensitivity of Compliance Costs to Natural Gas Prices | 3-20 |
| 3.6 | DETAILED IMPACTS TABLES | 3-22 |
| 4 | BENEFITS OF EMISSIONS REDUCTIONS..... | 4-1 |
| 4.1 | INTRODUCTION | 4-1 |
| 4.2 | EMISSION REDUCTIONS FROM THE FINAL NSPS | 4-4 |
| 4.3 | METHANE CLIMATE EFFECTS AND VALUATION..... | 4-5 |
| 4.4 | VOC AS A PM _{2.5} PRECURSOR..... | 4-20 |
| 4.4.1 | PM _{2.5} Health Effects and Valuation | 4-20 |
| 4.4.2 | Organic PM Welfare Effects..... | 4-24 |
| 4.4.3 | Visibility Effects..... | 4-25 |
| 4.5 | VOC AS AN OZONE PRECURSOR | 4-25 |
| 4.5.1 | Ozone Health Effects and Valuation..... | 4-26 |
| 4.5.2 | Ozone Vegetation Effects | 4-27 |
| 4.5.3 | Ozone Climate Effects | 4-27 |
| 4.6 | HAZARDOUS AIR POLLUTANT (HAP) BENEFITS | 4-28 |
| 4.6.1 | Benzene | 4-33 |
| 4.6.2 | Toluene..... | 4-34 |
| 4.6.3 | Carbonyl Sulfide..... | 4-35 |
| 4.6.4 | Ethylbenzene..... | 4-35 |
| 4.6.5 | Mixed Xylenes..... | 4-36 |
| 4.6.6 | n-Hexane..... | 4-37 |
| 4.6.7 | Other Air Toxics..... | 4-37 |
| 4.7 | SECONDARY AIR EMISSIONS IMPACTS | 4-37 |
| 4.8 | REFERENCES | 4-41 |
| 5 | COMPARISON OF BENEFITS AND COSTS | 5-1 |
| 5.1 | COMPARISON OF BENEFITS AND COSTS ACROSS REGULATORY OPTIONS..... | 5-1 |
| 5.2 | UNCERTAINTIES AND LIMITATIONS..... | 5-4 |
| 6 | ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS..... | 6-1 |
| 6.1 | INTRODUCTION | 6-1 |
| 6.2 | ENERGY MARKETS IMPACTS ANALYSIS..... | 6-1 |
| 6.2.1 | Description of the Department of Energy National Energy Modeling System..... | 6-2 |
| 6.2.2 | Inputs to National Energy Modeling System..... | 6-3 |
| 6.2.3 | Energy Markets Impacts | 6-7 |
| 6.3 | FINAL REGULATORY FLEXIBILITY ANALYSIS | 6-10 |
| 6.3.1 | Reasons why the Action is Being Considered | 6-11 |
| 6.3.2 | Significant Issues Raised | 6-11 |
| 6.3.3 | Small Business Administration Comments..... | 6-15 |
| 6.3.4 | Description and Estimate of Affected Small Entities | 6-15 |
| 6.3.5 | Projected Reporting, Recordkeeping and Other Compliance Requirements | 6-18 |
| 6.3.6 | Regulatory Flexibility Alternatives..... | 6-24 |
| 6.4 | EMPLOYMENT IMPACT ANALYSIS | 6-26 |
| 6.4.1 | Employment Impacts of Environmental Regulation..... | 6-26 |
| 6.4.2 | Labor Estimates Associated with Final Requirements..... | 6-30 |
| 6.5 | REFERENCES | 6-37 |

LIST OF TABLES

| | | |
|------------|---|------|
| Table 1-1 | Emissions Sources and Controls Evaluated for the NSPS | 1-4 |
| Table 1-2 | Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$) | 1-8 |
| Table 1-3 | Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Finalized Option) in 2020 and 2025 (2012\$)..... | 1-9 |
| Table 1-4 | Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$) | 1-10 |
| Table 2-1 | Technically Recoverable Crude Oil and Natural Gas Resource | 2-10 |
| Table 2-2 | Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1990-2014..... | 2-11 |
| Table 2-3 | Crude Oil and Dry Natural Gas Proved Reserves by State, 2013 | 2-13 |
| Table 2-4 | Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price, 1990-2014..... | 2-14 |
| Table 2-5 | Natural Gas Production and Well Productivity, 1990-2014 | 2-16 |
| Table 2-6 | Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2010 | 2-17 |
| Table 2-7 | U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007..... | 2-19 |
| Table 2-8 | U.S. Oil and Natural Gas Pipeline Mileage, 2010-2014 | 2-21 |
| Table 2-9 | Crude Oil Consumption by Sector, 1990-2012..... | 2-22 |
| Table 2-10 | Natural Gas Consumption by Sector, 1990-2014 | 2-24 |
| Table 2-11 | Total Crude Oil and Petroleum Products Trade (Million Bbl),..... | 2-26 |
| Table 2-12 | Natural Gas Imports and Exports, 1990-2014..... | 2-27 |
| Table 2-13 | Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2040..... | 2-28 |
| Table 2-14 | Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2012-2040 | 2-29 |
| Table 2-15 | Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price 2012-2040 | 2-31 |
| Table 2-16 | SBA Size Standards and Size Distribution of Oil and Natural Gas Firms | 2-39 |
| Table 2-17 | Oil and Natural Gas Industry Employment by NAICS, 1990-2014..... | 2-40 |
| Table 2-18 | Oil and Natural Gas Industry Average Wages by NAICS, 1990-2014 (2012 dollars) | 2-41 |
| Table 2-19 | Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012 | 2-44 |
| Table 2-20 | Top 20 Natural Gas Processing Firms (Based on Throughput), 2009 | 2-2 |
| Table 2-21 | Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2014 | 2-3 |
| Table 2-22 | Selected Financial Items from Income Statements (Billion 2008 Dollars)..... | 2-5 |
| Table 2-23 | Return on Investment for Lines of Business (all FRS), for 1998, 2003, 2008, and 2009 (percent)... | 2-6 |
| Table 2-24 | Income and Production Taxes, 1990-2009 (Million 2008 Dollars) | 2-7 |
| Table 3-1 | Emissions Sources and Controls Evaluated for the NSPS | 3-7 |
| Table 3-2 | Incrementally Affected Sources under Final NSPS, 2016 to 2025 on an Annual Basis | 3-10 |
| Table 3-3 | Total Number of Affected Sources for the NSPS in 2020 and 2025 | 3-11 |
| Table 3-4 | Emissions Reductions for Final NSPS Option 2, 2020 and 2025 | 3-13 |
| Table 3-5 | Estimated Natural Gas Recovery (Mcf) for selected Option 2 in 2020 and 2025..... | 3-15 |
| Table 3-6 | Engineering Compliance Cost Estimates for Final NSPS Option 2 in 2020 and 2025 (millions 2012\$) | 3-16 |
| Table 3-7 | Comparison of Regulatory Alternatives | 3-18 |
| Table 3-11 | Annualized Costs using 3 and 7 Percent Discount Rates for Final NSPS Option 2 in 2020 and 2025 (millions 2012\$) | 3-19 |
| Table 3-12 | Annualized Costs Using Natural Gas Prices from \$2 to \$5 per Mcf | 3-21 |
| Table 3-13 | Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020 | 3-23 |
| Table 3-14 | Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025 | 3-24 |
| Table 3-15 | Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2020..... | 3-25 |
| Table 3-16 | Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2025..... | 3-26 |
| Table 3-17 | Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020 | 3-27 |
| Table 3-18 | Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025 | 3-28 |
| Table 4-1 | Climate and Human Health Effects of Emission Reductions from this Rule..... | 4-2 |
| Table 4-2 | Direct Emission Reductions across NSPS Regulatory Options in 2020 and 2025 | 4-5 |

| | | |
|------------|---|------|
| Table 4-3 | Social Cost of Methane (SC-CH ₄), 2012 – 2050 ^a [in 2012\$ per metric ton] (Source: Marten <i>et al.</i> , 2014 ^b) | 4-16 |
| Table 4-4 | Estimated Global Benefits of Methane Reductions* (in millions, 2012\$)..... | 4-18 |
| Table 4-5 | Monetized Benefits-per-Ton Estimates for VOC in 9 Urban Areas and Nationwide based on Fann, Fulcher, and Hubbell (2009) in (2012\$) | 4-23 |
| Table 4-6 | Increases in Secondary Air Pollutant Emissions (short tons per year)..... | 4-38 |
| Table 4-7 | Summary of Emissions Changes (short tons per year, except where noted)..... | 4-41 |
| Table 5-1 | Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$) | 5-1 |
| Table 5-2 | Summary of the Monetized Benefits, Costs, and Net Benefits for Selected Option 2 in 2020 and 2025 (2012\$) | 5-2 |
| Table 5-3 | Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$) | 5-3 |
| Table 5-4 | Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted) | 5-4 |
| Table 6-1 | Per Well Costs for Environmental Controls Entered into NEMS (2012\$) | 6-6 |
| Table 6-2 | Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)..... | 6-8 |
| Table 6-3 | Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States) | 6-8 |
| Table 6-4 | Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012\$) | 6-9 |
| Table 6-5 | Net Imports of Natural Gas and Crude Oil | 6-10 |
| Table 6-6 | SBA Size Standards by NAICS Code..... | 6-15 |
| Table 6-7 | Distribution of Estimated Compliance Costs Across Sources | 6-16 |
| Table 6-8 | No. of Completions in 2012 by Preliminary Firm Size..... | 6-17 |
| Table 6-9 | No. of Completions in 2012 by Firm Size | 6-18 |
| Table 6-10 | No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size | 6-21 |
| Table 6-11 | Distribution of Estimated Compliance Costs ¹ across Firm Size Classes | 6-21 |
| Table 6-12 | Compliance Costs-to-Sales ¹ Ratios across Firm Size Classes for Primary Scenario and Low Oil Price Scenario ² | 6-23 |
| Table 6-6 | Estimates of Labor Required to Comply with NSPS for Hydraulically Fractured Oil Well Completions, 2020 and 2025 | 6-33 |
| Table 6-7 | Estimates of Labor Required to Comply with NSPS for Fugitive Emissions, 2020 and 2025 | 6-34 |
| Table 6-8 | Estimates of Labor Required to Comply with NSPS for Reciprocating and Centrifugal Compressors, 2020 and 2025 | 6-35 |
| Table 6-9 | Estimates of Labor Required to Comply with NSPS for Pneumatic Controllers and Pumps, 2020 and 2025 | 6-36 |
| Table 6-10 | Estimates of Labor Required to Comply with NSPS, 2020 and 2025 | 6-37 |

LIST OF FIGURES

| | | |
|-------------|---|------|
| Figure 2-1 | A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013..... | 2-12 |
| Figure 2-2 | A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2014..... | 2-15 |
| Figure 2-3 | U.S. Produced Water Volume by Management Practice, 2007 | 2-20 |
| Figure 2-4 | Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2012 | 2-23 |
| Figure 2-5 | Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2012..... | 2-25 |
| Figure 2-6 | Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040 | 2-30 |
| Figure 2-7 | Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008 | 2-32 |
| Figure 2-8 | Finding Costs for FRS Companies, 1981-2009 | 2-33 |
| Figure 2-9 | Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-year Running Average) | 2-34 |
| Figure 2-10 | Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009..... | 2-36 |
| Figure 2-11 | Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009 | 2-37 |
| Figure 4-1 | Path from GHG Emissions to Monetized Damages..... | 4-12 |
| Figure 4-2 | 2011 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory | 4-30 |
| Figure 4-3 | 2011 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory | 4-31 |

1 EXECUTIVE SUMMARY

1.1 Background

The action analyzed in this regulatory impact analysis (RIA) amends the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this rule because methane is a greenhouse gas (GHG), and the oil and natural gas category is the country's largest emitter of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

The EPA is amending the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are establishing both methane and VOC standards for several emission sources not covered by the 2012 NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites, compressor stations, pneumatic pumps). In addition, we are establishing methane standards for certain emission sources that are regulated for VOC under the 2012 NSPS (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). However, we do not expect any incremental benefits or costs as a result from regulating methane for VOC sources regulated under the 2012 NSPS.

With respect to certain equipment that are used across the source category, the 2012 NSPS regulates only a subset of this equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The new amendments establish methane standards for these equipment across the source category and extend the VOC standards from the 2012 NSPS to the remaining unregulated equipment. Lastly, amendments to the 2012 NSPS are established that improve several aspects of the 2012 standards related to implementation. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the 2012 NSPS for the oil and natural gas sector and related amendments. Except for these implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the 2012

standards.

As part of the regulatory process, the EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed \$100 million annually. The EPA estimates the final NSPS will have costs that exceed \$100 million, so the Agency has prepared an RIA. This RIA includes an economic impact analysis and an analysis of the climate, health, and welfare impacts anticipated from the final NSPS.¹ We also estimate potential impacts of the rule on national energy markets using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using 3 and 7 percent discount rates.

This analysis estimates regulatory impacts for the analysis years of 2020 to represent the near-term impacts of the rule, and 2025 to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 through 2024 that are assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically-fractured oil wells, capture methane and VOC emissions that otherwise would be vented to the atmosphere. The averted methane emissions can be directed into natural gas production streams and sold. The revenues derived from natural gas recovery are expected to offset a portion of the engineering costs of implementing the NSPS. In this RIA, we present

¹ The analysis in this RIA and the RIA that accompanied the proposal together constitute the economic assessment required by CAA section 317. In the EPA's judgment, the assessment is as extensive as practicable taking into account the EPA's time, resources, and other duties and authorities.

results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The baseline used for the impacts analysis of our NSPS takes into account emissions reductions conducted pursuant to state regulations covering the relevant operations. A detailed discussion on the derivation of the baseline is presented in Section 3 of this RIA.

1.2 Market Failure

Many regulations are promulgated to correct market failures, which lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address “negative externalities” whereby the market does not internalize the full cost of production that is borne by society, as public goods such as air quality are unpriced.

Greenhouse Gas (GHG) and VOC emissions impose costs on society, such as negative climate, health, and welfare impacts. These impacts are not reflected in the market price of the goods produced through the polluting process and are referred to as negative externalities. For this regulatory action, the goods produced, processed, transported, or stored are crude oil, natural gas, and other hydrocarbon products. If an oil and natural gas firm pollutes the atmosphere while extracting, processing, transporting, or storing goods, this cost will not be borne by the polluting firm but by society as a whole. The market price of the products will fail to incorporate the full cost to society of the pollution related to production. All else held equal, the quantity of oil and natural gas produced in a competitive market will not be at the socially optimal level. More oil and natural gas will be produced than would occur if the oil and natural gas producers had to account for the full cost of production, including the negative externality. Consequently, absent a regulation on emissions, the marginal social cost of the last units of oil and natural gas produced will exceed its marginal social benefit.

1.3 Regulatory Options Analyzed in this RIA

In this RIA, we examine three broad regulatory options. Table 1-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for promulgation.

Table 1-1 Emissions Sources and Controls Evaluated for the NSPS

| Emissions Point | Emissions Control | Option 1 | Option 2 (final) | Option 3 |
|---|--------------------------------------|-----------------|-------------------------|-----------------|
| Well Completions and Recompletions | | | | |
| Hydraulically Fractured Development Oil Wells | REC / Combustion | X | X | X |
| Hydraulically Fractured Wildcat and Delineation Oil Wells | Combustion | X | X | X |
| Fugitive Emissions | | | | |
| Well Sites | Planning, Monitoring and Maintenance | Annual | Semiannual | Quarterly |
| Gathering and Boosting Stations | Planning, Monitoring and Maintenance | Semiannual | Quarterly | Quarterly |
| Transmission Compressor Stations | Monitoring and Maintenance | Semiannual | Quarterly | Quarterly |
| Pneumatic Pumps | | | | |
| Well Sites | Route to control | X | X | X |
| Pneumatic Controllers | | | | |
| Natural Gas Transmission and Storage | Emissions limit | X | X | X |
| Reciprocating Compressors | | | | |
| Natural Gas Transmission and Storage | Maintenance | X | X | X |
| Centrifugal Compressors | | | | |
| Natural Gas Transmission and Storage | Route to control | X | X | X |

Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers and pumps.

Options 1 and 3 differ from the finalized Option 2 with respect to the requirements for fugitive emissions. Well site fugitive requirements under Option 1 are annual, while new or

modified gathering and boosting station and new or modified transmission and storage compressor stations require a semiannual fugitive emission survey and repair program. Less frequent survey requirements lead to lower costs as well as lower emissions reduction compared to the selected Option 2. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in greater emission reductions, however there are also increased costs, resulting in a net effect of lower net benefits compared to the finalized Option 2.

1.4 Summary of Results

For the final NSPS, a summary of the key results of the RIA for the final standards (Option 2) follow. Key results for Options 1 through 3 are summarized in Table 1-2 through Table 1-4, respectively. Note all dollar estimates are in 2012 dollars:

- **Emissions Analysis:** The final NSPS is anticipated to prevent significant new emissions, including 300,000 short tons of methane, 150,000 tons of VOCs and 1,900 tons of hazardous air pollutants (HAP) in 2020, increasing to 510,000 short tons of methane, 210,000 tons of VOCs, and 3,900 tons of HAP prevented in 2025.² The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025.
- **Benefits Analysis:** The monetized benefits in this RIA include those from reducing methane emissions, which are valued using the social cost of methane (SC-CH₄).³ The EPA estimates that, in 2020, the rule will yield monetized climate benefits of \$160 million to approximately \$950 million; the mean SC-CH₄ at the 3% discount rate results in an estimate of about \$360 million in 2020. In 2025, the EPA estimates monetized climate benefits of \$320 million to approximately \$1.8 billion; the mean SC-CH₄ at the 3% discount rate results in an estimate of about \$690 million in 2025.⁴ While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in negative health effects associated with exposure to HAP, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule.⁵ This is not to imply that there are no health benefits

² Estimates are presented in short tons.

³ The social cost of methane (SC-CH₄) is the monetary value of impacts associated with a marginal change in methane emissions in a given year.

⁴ The range of estimates reflects four SC-CH₄ estimates and are associated with different discount rates (model average at 2.5, 3 and 5 percent; 95th percentile at 3 percent). See Section 4.3 for a complete discussion.

⁵ Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient PM_{2.5} levels and the health effects associated with PM_{2.5} exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in

anticipated from the final NSPS; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits.

- **Engineering Cost Analysis:** The EPA estimates the total capital cost of the final NSPS to be \$250 million for affected sources in 2020 and \$360 million for affected sources in 2025. The estimate of total annualized engineering costs of the final NSPS is \$390 million in 2020 and \$640 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the NSPS are estimated to be \$320 million in 2020 and \$530 million in 2025, assuming a wellhead natural gas price of \$4/thousand cubic feet (Mcf). The estimated engineering compliance costs that include product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can influence estimated engineering costs. For example, \$1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about \$16 million in 2020 and \$27 million in 2025, given the EPA estimates that about 16 million Mcf in 2020 and 27 million Mcf of natural gas will be recovered by implementing the NSPS. When using a 3 percent discount rate, the estimate of total annualized engineering costs of the final NSPS is \$380 million in 2020 and \$630 million in 2025, or \$320 million in 2020 and \$520 million in 2025, when estimated revenues from additional natural gas are included.
- **Energy Markets Impacts Analysis:** The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy markets. We estimate that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period relative to the baseline (by about 0.17 percent for natural gas wells and about 0.02 percent for crude oil wells). Natural gas production decreases slightly over the 2020 to 2025 period under the rule relative to the baseline (by about 0.03 percent), while crude oil production does not vary appreciably. Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (about 0.20 percent). Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period (by about 0.11 percent) relative to the baseline. Crude oil net imports are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline.
- **Small Entity Analyses:** To understand the potential impact of the rule on small entities, the EPA conducted a screening analysis of the potential impacts by estimating the ratio of potential compliance costs to firm sales (i.e. a cost-to-sales test). Based on the results of this screening analysis, the EPA concluded that it is unable to certify that the final rule

that study are derived from total VOC emissions across all sectors. Larger uncertainties about the relationship between VOC emissions and PM_{2.5} coupled with the highly localized nature of air quality responses associated with VOC reductions, lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). The EPA convened a Small Business Advisory Review panel and completed an Initial Regulatory Flexibility Analysis before proposing the rule. The EPA also completed a Final Regulatory Flexibility Analysis for the final rule.

- **Employment Impacts Analysis:** The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment and control activities, as well as the labor associated with new reporting and recordkeeping requirements. The EPA estimated one-time and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The one-time labor requirement to comply with the final NSPS is estimated at about 270 FTEs in 2020 and in 2025. The annual labor requirement to comply with the NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. The EPA notes that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 1-2 presents the summary results for Option 1, Table 1-3 presents summary results for Option 2, and Table 1-4 presents summary results for Option 3.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|---|---|
| Total Monetized Benefits ¹ | \$290 million | \$540 million |
| Total Costs ² | \$240 million | \$360 million |
| Net Benefits ³ | \$54 million | \$180 million |
| | Non-monetized climate benefits | Non-monetized climate benefits |
| Non-monetized Benefits | Health effects of PM2.5 and ozone exposure from 130,000 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 170,000 tons of VOC reduced |
| | Health effects of HAP exposure from 1,300 tons of HAP reduced | Health effects of HAP exposure from 2,700 tons of HAP reduced |
| | Health effects of ozone exposure from 250,000 tons of methane | Health effects of ozone exposure from 390,000 tons of methane |
| | Visibility impairment | Visibility impairment |
| | Vegetation effects | Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$130 million to \$780 million in 2020 and \$250 million to \$1.4 billion in 2025 for Option 1, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 5.6 million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

Table 1-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Finalized Option) in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|---|---|
| Total Monetized Benefits ¹ | \$360 million | \$690 million |
| Total Costs ² | \$320 million | \$530 million |
| Net Benefits ³ | \$35 million | \$170 million |
| Non-monetized Benefits | Non-monetized climate benefits | Non-monetized climate benefits |
| | Health effects of PM2.5 and ozone exposure from 150,000 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 210,000 tons of VOC reduced |
| | Health effects of HAP exposure from 1,900 tons of HAP reduced | Health effects of HAP exposure from 3,900 tons of HAP reduced |
| | Health effects of ozone exposure from 300,000 tons of methane | Health effects of ozone exposure from 510,000 tons of methane |
| | Visibility impairment | Visibility impairment |
| | Vegetation effects | Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$160 million to \$950 million in 2020 and \$320 million to \$1.8 billion in 2025 for Option 2, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

Table 1-4 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|--|---|
| Total Monetized Benefits ¹ | \$420 million | \$840 million |
| Total Costs ² | \$490 million | \$880 million |
| Net Benefits ³ | -\$75 million | -\$38 million |
| Non-monetized Benefits | Non-monetized climate benefits | Non-monetized climate benefits |
| | Health effects of PM2.5 and ozone exposure from 160,00 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 230,000 tons of VOC reduced |
| | Health effects of HAP exposure from 2,400 tons of HAP reduced | Health effects of HAP exposure from 5,000 tons of HAP reduced |
| | Health effects of ozone exposure from 350,000 tons of methane | Health effects of ozone exposure from 610,000 tons of methane |
| | Visibility impairment Vegetation effects | Visibility impairment Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$190 million to \$1.1 billion in 2020 and \$390 million to \$2.2 billion in 2025 for this more stringent option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 8 million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

1.5 Summary of NSPS Impacts Changes from the Proposal RIA

This section summarizes major changes from the proposal version of the RIA. These changes were a result of revised assumptions and technical factors, as well as changes in the rule itself from proposal. With respect to changes in the rule’s provisions from proposal, we focus on changes that have an effect on estimates of emissions reductions, costs, and benefits.

Changes resulting from revised assumptions and technical factors include:

- **Annual Energy Outlook and National Energy Modeling System updates:** At proposal, the Energy Information Administration (EIA) 2014 Annual Energy Outlook (AEO) was used to derive projections of oil and natural gas well drilling activities. For this RIA, we used the 2015 AEO, the latest version available at the time of the signature of the rule. Section 3.4.2 presents a brief discussion comparing the 2014 and 2105 AEOs.

The EPA also updated the version of the NEMS model from 2014 to 2015 to develop the energy markets impacts presented in Section 6.2 of this RIA.

- **EPA Greenhouse Gas Inventory updates:** The EPA updated the unit-level cost and emissions analyses where possible to reflect recent updates to the Greenhouse Gas Inventory. In particular, data from the Greenhouse Gas Reporting program and the Greenhouse Gas Inventory was used to update the equipment and component counts and potential emissions of the model plants for fugitive emissions.
- **Revised first year of regulatory program:** At proposal, 2020 was assumed to represent a single year of potential impacts. However, NSPS-affected facilities are facilities that are new or modified since the proposal in September 2015. In this final RIA, affected facilities in 2020 are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. As a result, the years of analysis in this RIA are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period. This methodological change results in a higher estimate of the number of affected facilities than at proposal and better represents the impacts of the rule.
- **New hydraulically fractured oil well completions with insufficient pressure to implement REC required to combust completions emissions:** Using the formula estimated to identify hydraulically fractured well completions that would not have sufficient pressure to perform a REC, approximately 40 percent of oil well completions that would otherwise be required to perform a REC would be required to combust emissions rather than implement a REC. The overall proportion of completions that are assumed to be feasible to REC remains unchanged from the proposal analysis at 50 percent. More detailed discussion is presented in a technical memorandum on this subject in the docket.⁶
- **Revised unit-level emissions and cost estimates:** The EPA revised the cost of control estimates for fugitive emissions monitoring and pneumatic pumps based on information provided by commenters.
- **Revised approach to projecting affected facilities from historical activity data:** Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years.

The changes in the rules requirements that affect emissions, cost, and benefit estimates include:

- **Fugitive emissions:** The EPA proposed to exclude low production well sites (e.g., well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for the collection of fugitive emissions components at well sites. Based on

⁶ [Placeholder for title of low pressure well equation technical memo]

analysis in response to comments, the EPA is finalizing the requirement that low production well sites are regulated under a monitoring and repair standard based on semiannual monitoring. With respect to fugitive emissions at compressor stations, based on analysis in response to comments, the EPA is finalizing the requirement to implement the fugitives program at compressor stations on a quarterly basis, as opposed to the proposed semiannual (twice per year) basis.

- **Hydraulically fractured oil well completions:** For the final rule, the EPA refined requirements that require wells that are not low GOR, low pressure, or exploration/delineation wells to have a separator on site during completion flowback. Wells with low GOR (less than 300 scf/of gas per stock barrel of oil produced) are still excluded from well completion requirements, but, unlike at proposal, they are considered affected facilities and their exclusion from requirements is provided the owner or operator maintains records of the low GOR certification, and submit a claim signed by the certifying official.
- **Pneumatic pumps:** The EPA changed the definition of an affected pneumatic pump facility to include only natural gas driven pumps in order to incentivize the use of lower emitting alternatives. The EPA also exempted chemical injection pumps and portable or temporary pumps from control requirements.

1.6 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents a comparison of benefits and costs. Section 6 presents energy markets impact, employment impact, and small entity impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS require controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the final NSPS.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2014, the Energy Information Administration (EIA) estimates that about 515,000 producing natural gas wells are operating in the U.S. The latest available information from EIA indicates that there were about 536,000 producing oil wells in the U.S. as of 2011. Domestic dry natural gas production was 25.7 trillion cubic feet (tcf) in 2014, the highest annual production level in U.S. history. The leading five natural gas producing states in 2014 were Texas, Pennsylvania, Oklahoma, Louisiana and Wyoming. Domestic crude oil production in 2014 was 3,200 million barrels (bbl), the highest annual level in the U.S. since 1991. The leading five crude oil producing states in 2014 were Texas, North Dakota, California, Alaska, and Oklahoma.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the NSPS. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analyses in this RIA. The Industry Profile relies heavily on background material from the EPA's "Economic Analysis of Air Pollution Regulations: Oil and

Natural Gas Production” (1996), the EPA’s “Sector Notebook Project: Profile of the Oil and Gas Extraction Industry” (2000), and the EPA’s “Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry” (2012).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and the natural gas as well as the reservoir characteristics are likely to be different across all reservoirs.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another method to classify hydrocarbons, including crude oil, is through the measurement of API gravity. API gravity is a weight per-unit of volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with an API gravity of 20° or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has an API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase may be referred to as live crudes. Live crudes contain entrained or dissolved gases that may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 *Natural Gas*

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist in a gaseous phase or in a solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H₂S), CO₂, mercaptans, and entrained solids.

Natural gas may be classified as a wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas is classified as acid, sour or sweet. Acid gas contains CO₂ and/or H₂S, where the concentration of H₂S is below the threshold to be classified as sour. Acid gas may contain other contaminants. Natural gas is classified as sour when it contains an H₂S concentration of greater than 0.25 grains per 100 standard cubic feet. Sour gas may also contain other contaminants. Concentrations of H₂S and CO₂, along with organic sulfur compounds, vary widely among sour gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening, most commonly performed through amine treating. A majority of total onshore natural gas production and nearly all offshore natural gas production is classified as sweet.

2.2.3 *Condensates*

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40° or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 *Other Recovered Hydrocarbons*

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 *Produced Water*

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 *Exploration and Drilling*

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either well completion if hydrocarbons are found in sufficient quantities, or to abandonment otherwise.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper, sections of drill pipe are added. A mix of fluids called drilling mud are released down into the drill pipe, which then push up the walls of the well bore, removing drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out (“blowing out”). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse, to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore

allowing more oil or natural gas to move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as “fracking”) has been performed since the 1940s (U.S. DOE, 2013). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant, a mixture of sand and other materials, is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because the well is usually drilled into the bottom, oil-heavy portion of a formation to recover most of the liquid first, with the natural gas

cap sitting on top. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction**, pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). When the well lacks enough pressure itself to drive the resource to the surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery**). Finally, **in tertiary extraction** or **enhanced recovery**, gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock, sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2013). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional oil and natural gas resource types relevant for this rule include:

- **Shale Oil and Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2013).
- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2013).
- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 *Natural Gas Processing*

As natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems. Natural gas conditioning is the process of removing impurities from the gas stream so it is of sufficient quality to pass through transportation systems and to be used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline.

One concern in natural gas processing is posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquid at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid desiccant, a solid desiccant, or refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract water molecules. The solids can be regenerated by heating them above the boiling point of water and then be reused as well. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

The most significant impurity in natural gas is H_2S , which may or may not be contained in natural gas. H_2S is toxic and potentially fatal, at certain concentrations, to humans and it is corrosive to pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Sweetening, the procedure in which H_2S and sometimes CO_2 are removed from the gas stream, is most commonly performed using amine treatment. In this process, the gas stream is

exposed to an amine solution, which will react with H₂S and separate it from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 *Natural Gas Transmission and Distribution*

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to increase pressure to improve the movement of natural gas through transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and dry natural gas proved reserves, unproved reserves, and total technically recoverable resources as of 2009. The EIA⁷ defines these concepts as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.
- **Unproved resources:** additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology.
- **Total technically recoverable resources:** resources that are producible using current technology without reference to the economic viability of production.

According to the EIA, dry natural gas is consumer-grade natural gas. The dry natural gas volumes reported in Table 2-1 reflect the amount of gas remaining after the liquefiable portion and any non-hydrocarbon gases that render it unmarketable have been removed from the natural gas. The sum of proved reserves and unproved reserves equal the total technically recoverable resources. As seen in Table 2-1, as of 2009, proved domestic crude oil reserves accounted for about 10 percent of the total technically recoverable crude oil resources.

Total proved natural gas reserves, accounted for about 12 percent of the total technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and in offshore areas. While dry natural gas proved reserves were estimated at 272.5 tcf in 2009, wet natural gas reserves were estimated at 283.9 tcf. Of the 283.9 tcf, 250.5 tcf (about 88 percent) were considered to be wet non-associated natural gas, while 33.3 tcf (about 12 percent) were considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas, according to EIA, is natural gas that occurs in crude oil reservoirs as free natural gas or in solution with crude oil.

⁷ U.S. Department of Energy, Energy Information Administration, Glossary of Terms
<<http://www.eia.doe.gov/glossary/index.cfm?id=P>> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2009

| Region | Proved Reserves | Unproved Resources | Total Technically Recoverable Resources |
|--|-----------------|--------------------|---|
| Crude Oil and Lease Condensate (billion barrels) | | | |
| 48 States Onshore | 14.2 | 112.6 | 126.7 |
| 48 States Offshore | 4.6 | 50.3 | 54.8 |
| Alaska | 3.6 | 35.0 | 38.6 |
| Total U.S. | 22.3 | 197.9 | 220.2 |
| Dry Natural Gas (trillion cubic feet) | | | |
| Conventionally Reservoired Fields | 105.5 | 904.0 | 1,009.5 |
| 48 States Onshore ¹ | 81.4 | 369.7 | 451.1 |
| 48 States Offshore | 15.0 | 262.6 | 277.6 |
| Alaska | 9.1 | 271.7 | 280.8 |
| Tight Gas, Shale Gas and Coalbed Methane | 167.1 | 1,026.7 | 1,193.8 |
| Total U.S. | 272.5 | 1,930.7 | 2,203.3 |

Source: U.S. Energy Information Administration, **Annual Energy Review 2012**. Totals may not sum due to independent rounding.

¹ Includes associated-dissolved natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2014. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. Cumulative production is the accumulated crude oil or dry natural gas that has been produced over time. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources. Annual production (the difference in cumulative production over one year) as a percentage of proved reserves has declined over time for both crude oil and natural gas from around 11 percent in the early 1990s to between 8 and 10 percent over the period from 2006 to 2014 for crude oil and from about 10 percent during the early 1990s to between 7 and 9 percent from 2006 to 2014 for natural gas.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1990-2014

| | Crude Oil and Lease Condensate (million barrels) | | | Dry Natural Gas (Billion Cubic Feet or bcf) | | |
|------|---|--------------------|-------------------------|--|--------------------|-------------------------|
| | Cumulative Production | Proved Reserves | Proved Ult. Recovery | Cumulative Production | Proved Reserves | Proved Ult. Recovery |
| 1990 | 158,175 | 26,254 | 184,429 | 744,546 | 169,346 | 913,892 |
| 1991 | 160,882 | 24,682 | 185,564 | 762,244 | 167,062 | 929,306 |
| 1992 | 163,507 | 23,745 | 187,252 | 780,084 | 165,015 | 945,099 |
| 1993 | 166,006 | 22,957 | 188,963 | 798,179 | 162,415 | 960,594 |
| 1994 | 168,437 | 22,457 | 190,894 | 817,000 | 163,837 | 980,837 |
| 1995 | 170,831 | 22,351 | 193,182 | 835,599 | 165,146 | 1,000,745 |
| 1996 | 173,197 | 22,017 | 195,214 | 854,453 | 166,474 | 1,020,927 |
| 1997 | 175,552 | 22,546 | 198,098 | 873,355 | 167,223 | 1,040,578 |
| 1998 | 177,834 | 21,034 | 198,868 | 892,379 | 164,041 | 1,056,420 |
| 1999 | 179,981 | 21,765 | 201,746 | 911,211 | 167,406 | 1,078,617 |
| 2000 | 182,112 | 22,045 | 204,157 | 930,393 | 177,427 | 1,107,820 |
| 2001 | 184,229 | 22,446 | 206,675 | 950,009 | 183,460 | 1,133,469 |
| 2002 | 186,326 | 22,677 | 209,003 | 968,937 | 186,946 | 1,155,883 |
| 2003 | 188,388 | 21,891 | 210,279 | 988,036 | 189,044 | 1,177,080 |
| 2004 | 190,379 | 21,371 | 211,750 | 1,006,627 | 192,513 | 1,199,140 |
| 2005 | 192,270 | 21,757 | 214,027 | 1,024,677 | 204,385 | 1,229,062 |
| 2006 | 194,127 | 20,972 | 215,099 | 1,043,181 | 211,085 | 1,254,266 |
| 2007 | 195,981 | 21,317 | 217,298 | 1,062,447 | 237,726 | 1,300,173 |
| 2008 | 197,811 | 19,121 | 216,932 | 1,082,605 | 244,656 | 1,327,261 |
| 2009 | 199,765 | 20,682 | 220,447 | 1,103,229 | 272,509 | 1,375,738 |
| 2010 | 201,764 | 23,267 | 225,031 | 1,124,545 | 304,625 | 1,429,170 |
| 2011 | 203,822 | 26,544 | 230,366 | 1,147,447 | 334,067 | 1,481,514 |
| 2012 | 206,192 | 30,529 | 236,721 | 1,171,480 | 308,036 | 1,479,516 |
| 2013 | 208,913 | 33,371 | 242,284 | 1,195,685 | 338,264 | 1,533,949 |
| 2014 | 212,092 | 36,385 | 248,477 | 1,221,414 | 368,704 | 1,590,118 |

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17.

<<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>>. Accessed January 15, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>>. Accessed January 22, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.

<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbb1_a.htm>. Accessed on January 29, 2016.

Note: Cumulative Crude Oil Production includes Crude Oil plus Lease Condensate Production.

Note: The EIA reports Proved Reserves for Crude Oil and Proved Reserves for Crude Oil plus Lease Condensate separately. We have reported Proved Reserves for Crude Oil here.

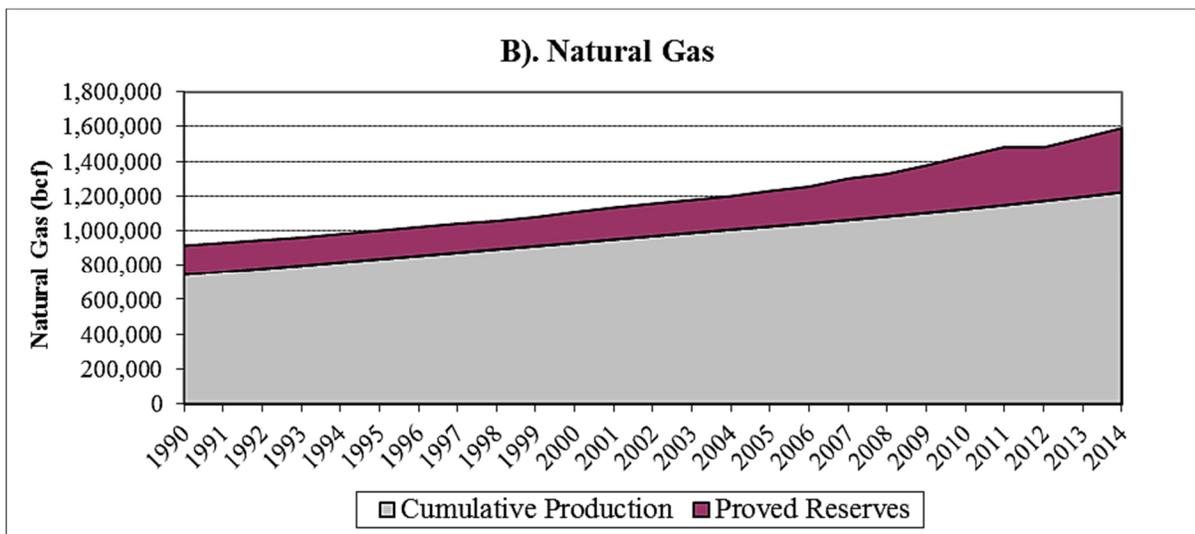
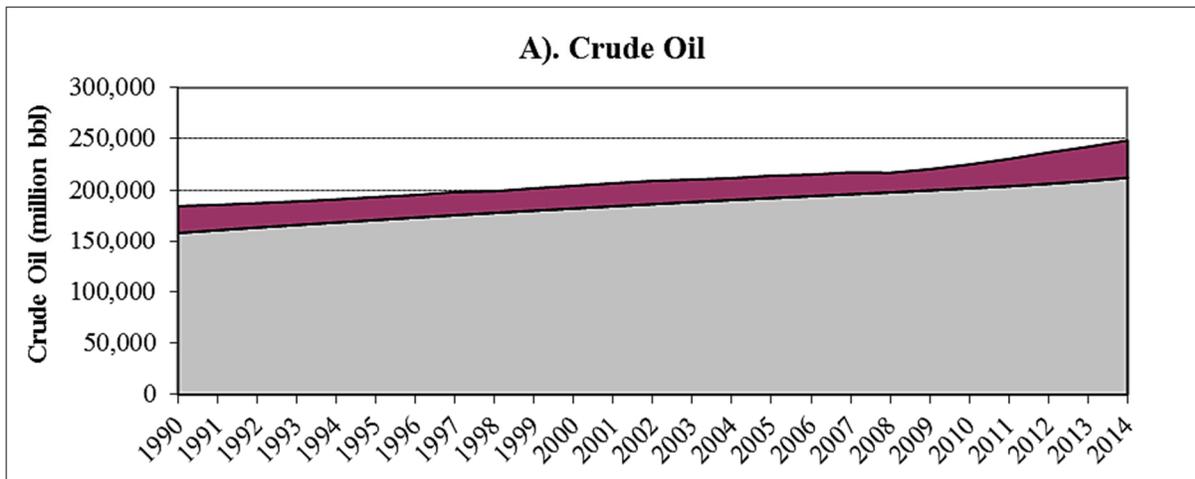


Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17. <<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>>. Accessed January 15, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014. <<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>>. Accessed January 22, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production. <http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbbl_a.htm>. Accessed on January 29, 2016.

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2014. Five areas currently account for 79 percent of total proved reserves of crude oil in the U.S., led by Texas and followed by North Dakota, U.S. Federal Offshore, Alaska, and California. The top five states in terms of proved reserves of natural gas, Texas,

Pennsylvania, Oklahoma, West Virginia, and Wyoming, account for about 67 percent of the U.S. total proved natural gas reserves.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2013

| State/Region | Crude Oil (million bbls) | Dry Natural Gas (bcf) | Crude Oil (% of total) | Dry Natural Gas (% of total) |
|------------------------------|-------------------------------------|----------------------------------|-----------------------------------|---|
| Alabama | 66 | 2,036 | 0.2 | 0.6 |
| Alaska | 2,855 | 6,745 | 7.8 | 1.8 |
| Arkansas | 65 | 12,789 | 0.2 | 3.5 |
| California | 2,854 | 2,107 | 7.8 | 0.6 |
| Colorado | 1,200 | 20,851 | 3.3 | 5.7 |
| Florida | 70 | 0 | 0.2 | 0.0 |
| Kansas | 414 | 4,359 | 1.1 | 1.2 |
| Kentucky | 16 | 1,611 | 0.0 | 0.4 |
| Louisiana | 534 | 22,975 | 1.5 | 6.2 |
| Michigan | 53 | 1,845 | 0.1 | 0.5 |
| Miscellaneous States ** | 84 | 2,976 | 0.2 | 0.8 |
| Mississippi | 230 | 558 | 0.6 | 0.2 |
| Montana | 444 | 667 | 1.2 | 0.2 |
| New Mexico | 1,476 | 15,283 | 4.1 | 4.1 |
| New York | * | 143 | * | 0.0 |
| North Dakota | 6,043 | 6,034 | 16.6 | 1.6 |
| Ohio | 78 | 6,723 | 0.2 | 1.8 |
| Oklahoma | 1,241 | 31,778 | 3.4 | 8.6 |
| Pennsylvania | 22 | 59,873 | 0.1 | 16.2 |
| Texas | 12,272 | 97,154 | 33.7 | 26.4 |
| U.S. Federal Offshore | 4,849 | 8,527 | 13.3 | 2.3 |
| Utah | 555 | 6,685 | 1.5 | 1.8 |
| West Virginia | 11 | 29,432 | 0.0 | 8.0 |
| Wyoming | 953 | 27,553 | 2.6 | 7.5 |
| Total Proved Reserves | 36,385 | 368,704 | 100.0 | 100.0 |

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17.

<<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>>. Accessed January 15, 2016.

Total may not sum due to independent rounding.

* New York crude oil reserves are included in miscellaneous states

**Miscellaneous for crude oil includes Arizona, Idaho, Missouri, Nevada, New York, South Dakota, Tennessee & Virginia as well as Illinois, Indiana, and Nebraska.

**Miscellaneous for dry natural gas includes Arizona, Idaho, Illinois, Indiana, Maryland, Missouri, Nebraska, Oregon, South Dakota & Tennessee as well as Virginia.

2.4.2 Domestic Production

Domestic oil production was in a state of decline that began in 1970 and continued to a low point in 2008. As of 2014, domestic oil production has recovered to the highest levels since 1991. Table 2-4 shows U.S. production in 2014 at 3,179 million bbl per year.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price, 1990-2014

| | Total Production (million barrels) | Producing Wells (1000s) | Avg. Well Productivity (bbl/well) | US Average First Purchase Price/Barrel (nominal dollars) | US Average First Purchase Price/Barrel (2012 dollars) |
|------|---|------------------------------------|--|---|--|
| 1990 | 2,685 | 602 | 4,460 | 20.03 | 31.56 |
| 1991 | 2,707 | 614 | 4,409 | 16.54 | 25.22 |
| 1992 | 2,625 | 594 | 4,419 | 15.99 | 23.84 |
| 1993 | 2,499 | 584 | 4,279 | 14.25 | 20.75 |
| 1994 | 2,431 | 582 | 4,178 | 13.19 | 18.81 |
| 1995 | 2,394 | 574 | 4,171 | 14.62 | 20.42 |
| 1996 | 2,366 | 574 | 4,122 | 18.46 | 25.32 |
| 1997 | 2,355 | 573 | 4,110 | 17.23 | 23.24 |
| 1998 | 2,282 | 562 | 4,060 | 10.87 | 14.50 |
| 1999 | 2,147 | 546 | 3,932 | 15.56 | 20.45 |
| 2000 | 2,131 | 534 | 3,990 | 26.72 | 34.33 |
| 2001 | 2,118 | 530 | 3,995 | 21.84 | 27.44 |
| 2002 | 2,097 | 529 | 3,963 | 22.51 | 27.85 |
| 2003 | 2,062 | 513 | 4,019 | 27.56 | 33.43 |
| 2004 | 1,991 | 510 | 3,905 | 36.77 | 43.41 |
| 2005 | 1,891 | 498 | 3,798 | 50.28 | 57.51 |
| 2006 | 1,857 | 497 | 3,737 | 59.69 | 66.24 |
| 2007 | 1,853 | 500 | 3,706 | 66.52 | 71.90 |
| 2008 | 1,830 | 526 | 3,479 | 94.04 | 99.69 |
| 2009 | 1,954 | 526 | 3,715 | 56.35 | 59.29 |
| 2010 | 1,999 | 520 | 3,844 | 74.71 | 77.66 |
| 2011 | 2,058 | 536 | 3,840 | 95.73 | 97.50 |
| 2012 | 2,370 | N/A | N/A | 94.52 | 94.52 |
| 2013 | 2,721 | N/A | N/A | 95.99 | 94.45 |
| 2014 | 3,179 | N/A | N/A | 87.39 | 84.60 |

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.

<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbb1_a.htm>. Accessed on January 29, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). U.S. Crude Oil First Purchase Price.

<https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f000000__3&f=a>. Accessed on January 22, 2016.

Source: Federal Reserve Bank of St. Louis. Economic Research. Gross Domestic Product: Implicit Price Deflator.

<<https://research.stlouisfed.org/fred2/series/GDPDEF>>. Accessed February 3, 2016.

Note: First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. Prices adjusted using GDP Implicit Price Deflator.

Note: Total Production includes Crude Oil plus Lease Condensate Production.

Average well productivity has also generally decreased since 1990 (Table 2-4 and Figure 2-2), though there are signs of a slight rebounding starting around 2008. These overall production and productivity decreases are in spite of the fact that average first purchase prices have generally shown an increasing trend with some decline in 2014.

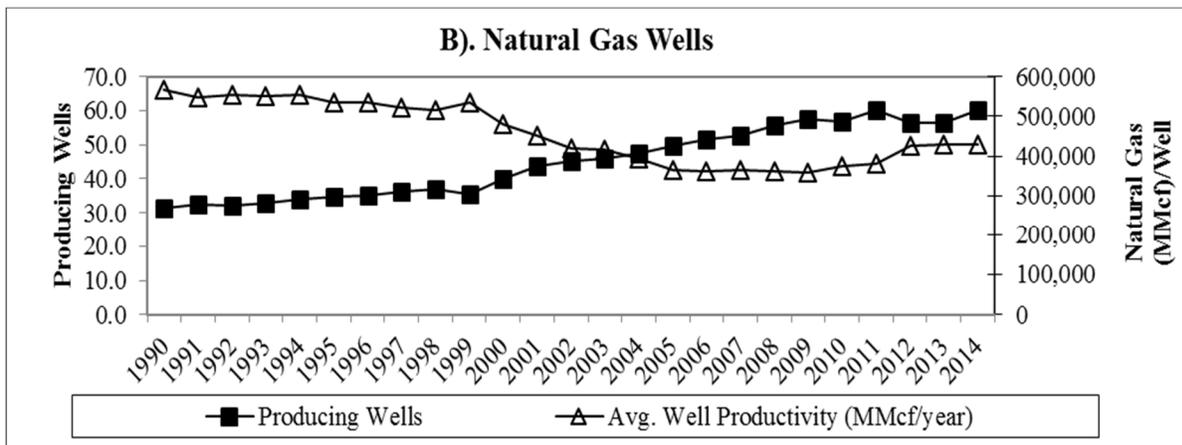
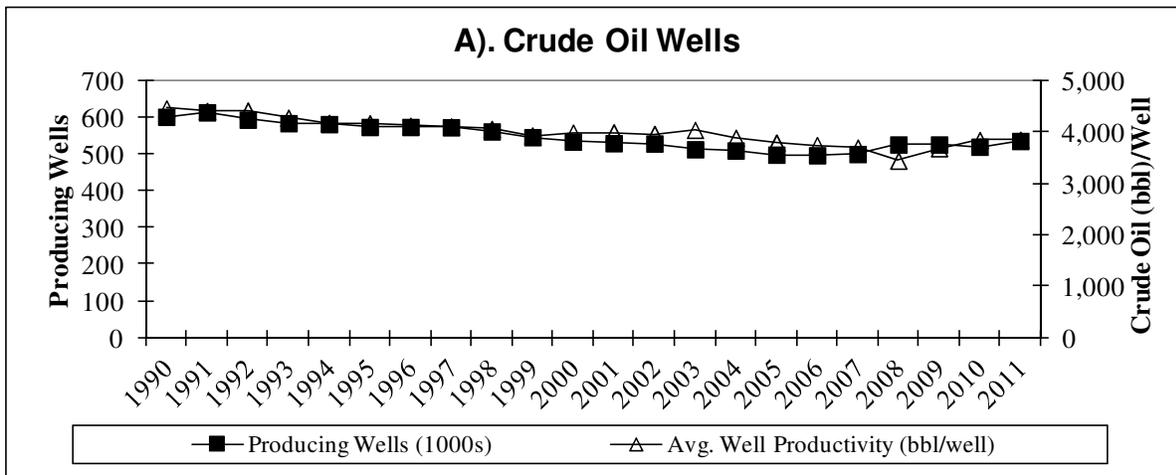


Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2014.
 Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014. <<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>>. Accessed January 22, 2016.

Annual production of natural gas from natural gas wells has increased more than 8000 bcf from the 1990 to 2014 (Table 2-5). The number of wells producing natural gas has nearly doubled between 1990 and 2014 (Figure 2-2B). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies. Average well productivity has shown slight improvements since 2009.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2014

| | Natural Gas Gross Withdrawals (Billion Cubic Feet) | | Natural Gas Well Productivity | |
|------|---|------------------------------------|----------------------------------|--|
| | Total | Dry Gas Production ¹ | Producing Wells | Avg. Well Productivity Million Cubic Feet/Year) |
| 1990 | 21,523 | 17,810 | 269,790 | 66.0 |
| 1991 | 21,750 | 17,698 | 276,987 | 63.9 |
| 1992 | 22,132 | 17,840 | 276,014 | 64.6 |
| 1993 | 22,726 | 18,095 | 282,152 | 64.1 |
| 1994 | 23,581 | 18,821 | 291,773 | 64.5 |
| 1995 | 23,744 | 18,599 | 298,541 | 62.3 |
| 1996 | 24,114 | 18,854 | 301,811 | 62.5 |
| 1997 | 24,213 | 18,902 | 310,971 | 60.8 |
| 1998 | 24,108 | 19,024 | 316,929 | 60.0 |
| 1999 | 23,823 | 18,832 | 302,421 | 62.3 |
| 2000 | 24,174 | 19,182 | 341,678 | 56.1 |
| 2001 | 24,501 | 19,616 | 373,304 | 52.5 |
| 2002 | 23,941 | 18,928 | 387,772 | 48.8 |
| 2003 | 24,119 | 19,099 | 393,327 | 48.6 |
| 2004 | 23,970 | 18,591 | 406,147 | 45.8 |
| 2005 | 23,457 | 18,051 | 425,887 | 42.4 |
| 2006 | 23,535 | 18,504 | 440,516 | 42.0 |
| 2007 | 24,664 | 19,266 | 452,945 | 42.5 |
| 2008 | 25,636 | 20,159 | 476,652 | 42.3 |
| 2009 | 26,057 | 20,624 | 493,100 | 41.8 |
| 2010 | 26,816 | 21,316 | 487,627 | 43.7 |
| 2011 | 28,479 | 22,902 | 514,637 | 44.5 |
| 2012 | 29,542 | 24,033 | 482,822 | 49.8 |
| 2013 | 29,523 | 24,206 | 484,994 | 49.9 |
| 2014 | 31,346 | 25,728 | 514,786 | 50.0 |

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>>. Accessed January 22, 2016.

¹ Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2010, crude oil well drilling showed significant increases, although the 1992-2004 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from the increasing trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2010 period. Like crude oil drilling, 2009 and 2010 saw a relatively low level of natural gas drillings. The

success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to a peak of 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in well drilling and completion. Similarly, average well depth has increased by an estimated 1,227 feet during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2010

| Year | Wells Drilled | | | Total | Successful Wells (%) | Average Depth (ft) |
|-------|---------------|-------------|-----------|--------|----------------------|--------------------|
| | Crude Oil | Natural Gas | Dry Holes | | | |
| 1990 | 12,445 | 11,126 | 8,496 | 32,067 | 75 | 4,881 |
| 1991 | 12,035 | 9,611 | 7,882 | 29,528 | 75 | 4,920 |
| 1992 | 9,019 | 8,305 | 6,284 | 23,608 | 75 | 5,202 |
| 1993 | 8,764 | 10,174 | 6,513 | 25,451 | 75 | 5,442 |
| 1994 | 7,001 | 9,739 | 5,515 | 22,255 | 77 | 5,795 |
| 1995 | 7,827 | 8,454 | 5,319 | 21,600 | 77 | 5,636 |
| 1996 | 8,760 | 9,539 | 5,587 | 23,886 | 79 | 5,617 |
| 1997 | 10,445 | 11,186 | 5,955 | 27,586 | 79 | 5,691 |
| 1998 | 6,979 | 11,127 | 4,805 | 22,911 | 80 | 5,755 |
| 1999 | 4,314 | 11,121 | 3,504 | 18,939 | 83 | 5,090 |
| 2000 | 8,090 | 17,051 | 4,146 | 29,287 | 86 | 4,961 |
| 2001 | 8,888 | 22,072 | 4,598 | 35,558 | 87 | 5,087 |
| 2002 | 6,775 | 17,342 | 3,754 | 27,871 | 87 | 5,232 |
| 2003 | 8,129 | 20,722 | 3,982 | 32,833 | 88 | 5,426 |
| 2004 | 8,789 | 24,186 | 4,082 | 37,057 | 89 | 5,547 |
| 2005 | 10,779 | 28,590 | 4,653 | 44,022 | 89 | 5,508 |
| 2006 | 13,385 | 32,838 | 5,206 | 51,429 | 90 | 5,613 |
| 2007 | 13,371 | 32,719 | 4,981 | 51,071 | 90 | 6,064 |
| 2008 | 16,633 | 32,246 | 5,423 | 54,302 | 90 | 5,964 |
| 2009* | 11,190 | 18,088 | 3,525 | 32,803 | 90 | 6,202 |
| 2010* | 15,753 | 16,696 | 4,162 | 36,611 | 89 | 6,108 |

Source: U.S. Energy Information Administration

* Average Depth values for 2009-2010 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of

flowback water from hydraulic fracturing activities (ANL 2009). As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low produced water to oil ratios compared to states like Illinois, Florida, Missouri, Indiana and Kansas.

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

| State | Crude Oil (1000 bbl) | Total Gas (bcf) | Produced Water (1000 bbl) | Total Oil and Natural Gas (1000 bbls oil equivalent) | Barrels Produced Water per Barrel Oil Equivalent |
|----------------------|-------------------------|--------------------|------------------------------|---|--|
| Alabama | 5,028 | 285 | 119,004 | 55,758 | 2.13 |
| Alaska | 263,595 | 3,498 | 801,336 | 886,239 | 0.90 |
| Arizona | 43 | 1 | 68 | 221 | 0.31 |
| Arkansas | 6,103 | 272 | 166,011 | 54,519 | 3.05 |
| California | 244,000 | 312 | 2,552,194 | 299,536 | 8.52 |
| Colorado | 2,375 | 1,288 | 383,846 | 231,639 | 1.66 |
| Florida | 2,078 | 2 | 50,296 | 2,434 | 20.66 |
| Illinois | 3,202 | no data | 136,872 | 3,202 | 42.75 |
| Indiana | 1,727 | 4 | 40,200 | 2,439 | 16.48 |
| Kansas | 36,612 | 371 | 1,244,329 | 102,650 | 12.12 |
| Kentucky | 3,572 | 95 | 24,607 | 20,482 | 1.20 |
| Louisiana | 52,495 | 1,382 | 1,149,643 | 298,491 | 3.85 |
| Michigan | 5,180 | 168 | 114,580 | 35,084 | 3.27 |
| Mississippi | 20,027 | 97 | 330,730 | 37,293 | 8.87 |
| Missouri | 80 | no data | 1,613 | 80 | 20.16 |
| Montana | 34,749 | 95 | 182,266 | 51,659 | 3.53 |
| Nebraska | 2,335 | 1 | 49,312 | 2,513 | 19.62 |
| Nevada | 408 | 0 | 6,785 | 408 | 16.63 |
| New Mexico | 59,138 | 1,526 | 665,685 | 330,766 | 2.01 |
| New York | 378 | 55 | 649 | 10,168 | 0.06 |
| North Dakota | 44,543 | 71 | 134,991 | 57,181 | 2.36 |
| Ohio | 5,422 | 86 | 6,940 | 20,730 | 0.33 |
| Oklahoma | 60,760 | 1,643 | 2,195,180 | 353,214 | 6.21 |
| Pennsylvania | 1,537 | 172 | 3,912 | 32,153 | 0.12 |
| South Dakota | 1,665 | 12 | 4,186 | 3,801 | 1.10 |
| Tennessee | 350 | 1 | 2,263 | 528 | 4.29 |
| Texas | 342,087 | 6,878 | 7,376,913 | 1,566,371 | 4.71 |
| Utah | 19,520 | 385 | 148,579 | 88,050 | 1.69 |
| Virginia | 19 | 112 | 1,562 | 19,955 | 0.08 |
| West Virginia | 679 | 225 | 8,337 | 40,729 | 0.20 |
| Wyoming | 54,052 | 2,253 | 2,355,671 | 455,086 | 5.18 |
| State Total | 1,273,759 | 21,290 | 20,258,560 | 5,063,379 | 4.00 |
| Federal Offshore | 467,180 | 2,787 | 587,353 | 963,266 | 0.61 |
| Tribal Lands | 9,513 | 297 | 149,261 | 62,379 | 2.39 |
| Federal Total | 476,693 | 3,084 | 736,614 | 1,025,645 | 0.72 |
| U.S. Total | 1,750,452 | 24,374 | 20,995,174 | 6,089,024 | 3.45 |

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

Figure 2-3 shows the distribution of produced water management practices in 2007. More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. About one third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) was discharged into surface water when it met water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

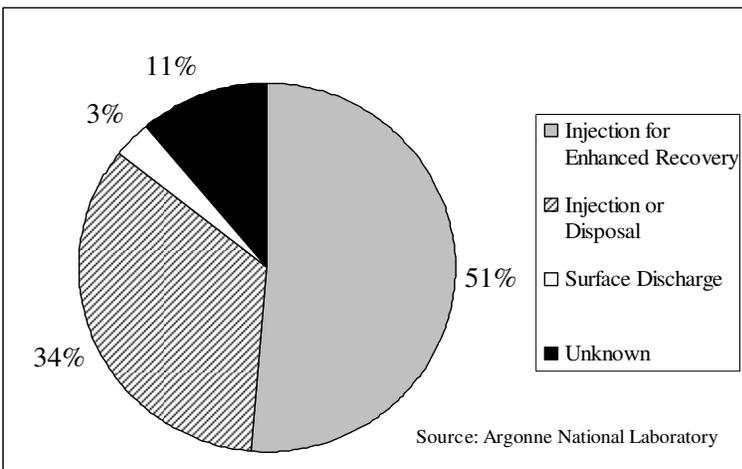


Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage decreased during the 1990-2010 period, appearing to follow the downward supply trend shown in Table 2-4. Since 2010, total crude oil pipeline mileage has increased by over 12,000 miles (Table 2-8).

Table 2-8 splits natural gas pipelines into four types: distribution mains, distribution service, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites and deliver it directly to gas processing plants or compression stations which connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants and distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Mileage on the distribution side, distribution mains and

distribution service, has increased while transmission pipeline and gathering line mileage has decreased. Since 2010, total natural gas pipeline has increased by over 61,000 miles.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 2010-2014

| | Natural Gas Pipelines (miles) | | | | | Crude Oil Pipelines (miles) |
|------|--------------------------------------|-----------------------------|-------------------------------|------------------------|--------------|------------------------------------|
| | Distribution mains | Distribution Service | Transmission pipelines | Gathering lines | Total | Total |
| 2010 | 1,229,725 | 872,466 | 304,805 | 19,626 | 2,426,622 | 54,631 |
| 2011 | 1,238,947 | 881,955 | 305,058 | 19,350 | 2,445,310 | 56,100 |
| 2012 | 1,247,231 | 890,361 | 303,341 | 16,532 | 2,457,465 | 57,463 |
| 2013 | 1,255,145 | 894,283 | 302,827 | 17,369 | 2,469,624 | 61,087 |
| 2014 | 1,266,039 | 902,772 | 301,806 | 17,621 | 2,488,238 | 66,700 |

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Annual Report Mileage Summary Statistics*, available at <<http://phmsa.dot.gov/pipeline/library/data-stats>> as of January 4, 2016.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2012 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008, when total consumption basically leveled off as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the percentage of the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2012.

Table 2-9 Crude Oil Consumption by Sector, 1990-2012

| | Total (million barrels) | Percent of Total | | | |
|------|-------------------------------|-------------------------------|------------|--------------------------|-------------------|
| | | Residential and Commercial | Industrial | Transportation Sector | Electric Power |
| 1990 | 6,178 | 7.3 | 25.1 | 64.3 | 3.3 |
| 1991 | 6,068 | 7.3 | 24.9 | 64.7 | 3.2 |
| 1992 | 6,209 | 7.1 | 26.1 | 64.3 | 2.6 |
| 1993 | 6,277 | 6.9 | 25.3 | 65.0 | 2.9 |
| 1994 | 6,439 | 6.6 | 26.0 | 64.8 | 2.6 |
| 1995 | 6,402 | 6.4 | 25.7 | 66.0 | 1.9 |
| 1996 | 6,627 | 6.7 | 26.1 | 65.2 | 2.0 |
| 1997 | 6,726 | 6.3 | 26.4 | 65.1 | 2.2 |
| 1998 | 6,837 | 5.7 | 25.4 | 65.8 | 3.1 |
| 1999 | 7,053 | 6.1 | 25.6 | 65.5 | 2.8 |
| 2000 | 6,984 | 4.6 | 25.1 | 67.6 | 2.6 |
| 2001 | 6,963 | 4.6 | 25.1 | 67.4 | 2.9 |
| 2002 | 6,990 | 4.2 | 25.2 | 68.3 | 2.2 |
| 2003 | 7,091 | 4.6 | 24.8 | 67.9 | 2.7 |
| 2004 | 7,399 | 4.4 | 25.3 | 67.7 | 2.6 |
| 2005 | 7,530 | 5.8 | 24.2 | 67.3 | 2.6 |
| 2006 | 7,506 | 5.0 | 24.8 | 68.9 | 1.4 |
| 2007 | 7,517 | 5.1 | 24.1 | 69.5 | 1.4 |
| 2008 | 7,095 | 5.5 | 23.0 | 70.4 | 1.1 |
| 2009 | 6,849 | 5.5 | 22.2 | 71.4 | 1.0 |
| 2010 | 6,994 | 5.2 | 22.8 | 71.0 | 0.9 |
| 2011 | 7,013 | 5.0 | 23.2 | 71.1 | 0.7 |
| 2012 | 6,902 | 5.0 | 23.4 | 71.1 | 0.5 |

Source: U.S. Energy Information Administration.

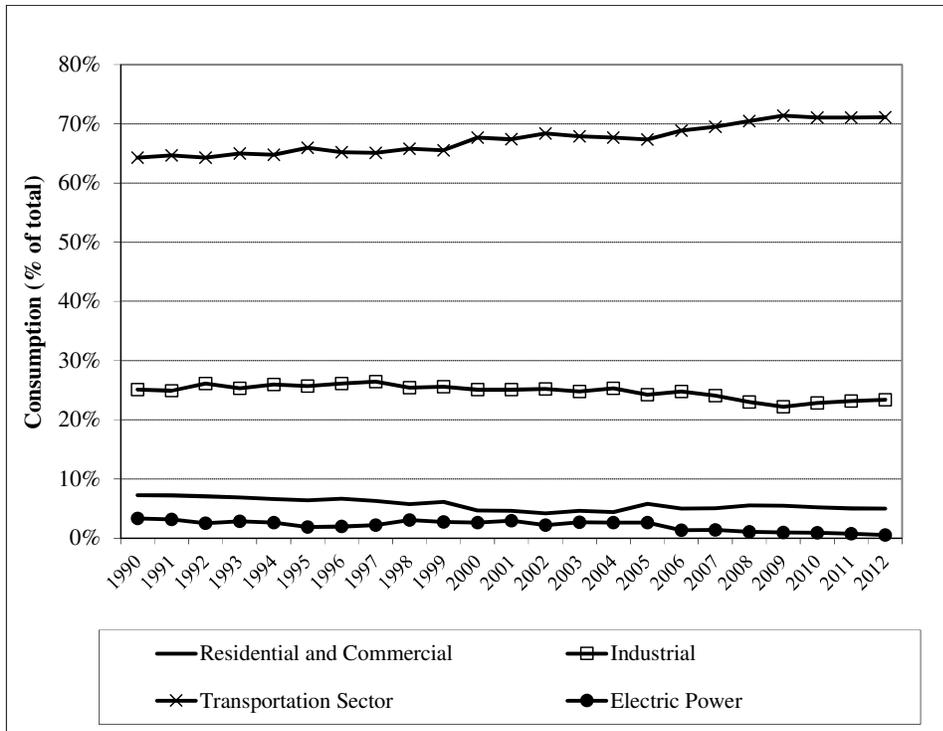


Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2012

Natural gas consumption has increased over the last twenty years. From 1990 to 2014, total U.S. consumption increased by an average of about 1.6 percent per year (Table 2-10 and Figure 2-5). Over this period, the percentage of natural gas consumed by the industrial sector declined, whereas the percent of total natural gas used for electric power generation increased dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential sector demand has bounced around between about 23 and 19 percent, where the lower percentage of total demand falls mainly in the years post 2008 with slightly larger dip in 2012. Commercial sector demand hovered around 13 and 14 percent, also with a slight dip in 2012. The transportation sector has maintained a fairly constant consumption level of right around 3 percent between 1990 and 2014.

Table 2-10 Natural Gas Consumption by Sector, 1990-2014

| | Percent of Total | | | | | |
|------|------------------|-------------|------------|------------|----------------|----------------|
| | Total (tcf) | Residential | Commercial | Industrial | Electric Power | Transportation |
| 1990 | 19.17 | 22.9 | 13.7 | 43.1 | 16.9 | 3.4 |
| 1991 | 19.56 | 23.3 | 13.9 | 42.7 | 17.0 | 3.1 |
| 1992 | 20.23 | 23.2 | 13.9 | 43.0 | 17.0 | 2.9 |
| 1993 | 20.79 | 23.8 | 13.8 | 42.7 | 16.7 | 3.0 |
| 1994 | 21.25 | 22.8 | 13.6 | 42.0 | 18.4 | 3.2 |
| 1995 | 22.21 | 21.8 | 13.6 | 42.3 | 19.1 | 3.2 |
| 1996 | 22.61 | 23.2 | 14.0 | 42.8 | 16.8 | 3.2 |
| 1997 | 22.74 | 21.9 | 14.1 | 42.7 | 17.9 | 3.3 |
| 1998 | 22.25 | 20.3 | 13.5 | 42.7 | 20.6 | 2.9 |
| 1999 | 22.41 | 21.1 | 13.6 | 40.9 | 21.5 | 2.9 |
| 2000 | 23.33 | 21.4 | 13.6 | 39.8 | 22.3 | 2.8 |
| 2001 | 22.24 | 21.5 | 13.6 | 38.1 | 24.0 | 2.9 |
| 2002 | 23.03 | 21.2 | 13.7 | 37.5 | 24.6 | 3.0 |
| 2003 | 22.28 | 22.8 | 14.3 | 37.1 | 23.1 | 2.7 |
| 2004 | 22.40 | 21.7 | 14.0 | 37.3 | 24.4 | 2.6 |
| 2005 | 22.01 | 21.9 | 13.6 | 35.0 | 26.7 | 2.8 |
| 2006 | 21.70 | 20.1 | 13.1 | 35.3 | 28.7 | 2.8 |
| 2007 | 23.10 | 20.4 | 13.0 | 34.1 | 29.6 | 2.8 |
| 2008 | 23.28 | 21.0 | 13.5 | 33.9 | 28.6 | 2.9 |
| 2009 | 22.91 | 20.9 | 13.6 | 32.5 | 30.0 | 3.0 |
| 2010 | 24.09 | 19.9 | 12.9 | 33.7 | 30.7 | 2.9 |
| 2011 | 24.48 | 19.3 | 12.9 | 34.0 | 30.9 | 2.9 |
| 2012 | 25.54 | 16.2 | 11.3 | 33.8 | 35.7 | 3.0 |
| 2013 | 26.16 | 18.7 | 12.6 | 34.1 | 31.3 | 3.3 |
| 2014 | 26.69 | 19.1 | 13.0 | 34.2 | 30.5 | 3.3 |

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by Sector data. < <http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-13-14>>. Accessed February 3, 2016.

Note: Industrial Consumption is reported as Lease and Plant Fuel, Other Industrial: CHP, and Other Industrial: Non-CHP

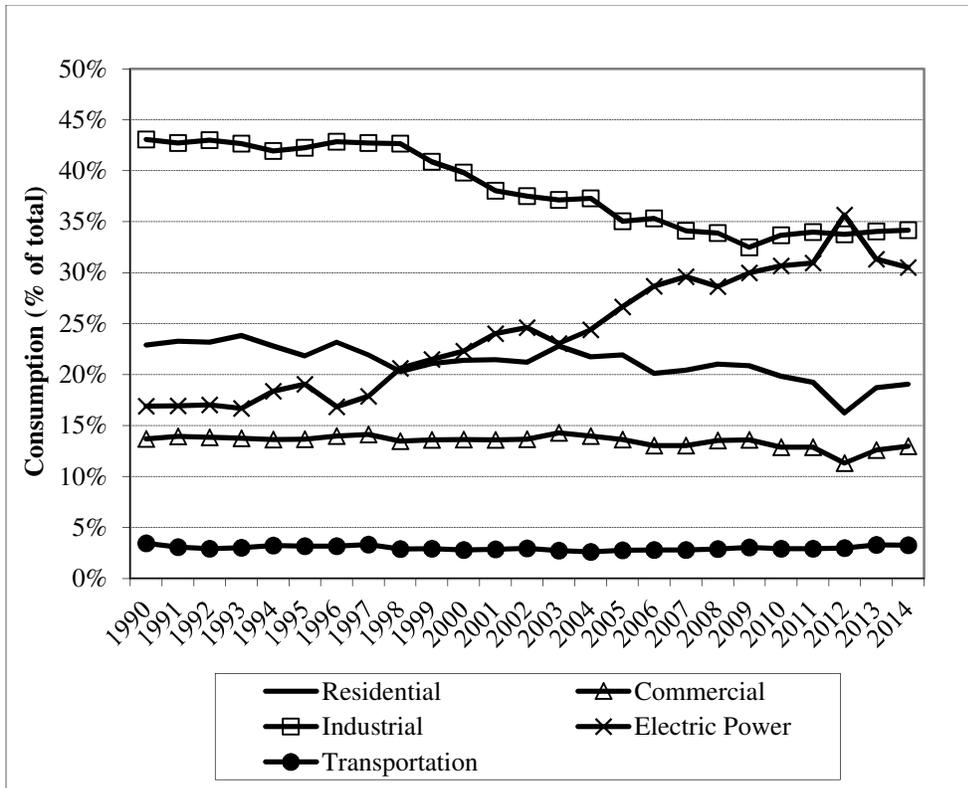


Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2012

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by Sector data. < <http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-13-14>>. Accessed February 3, 2016.

2.4.4 International Trade

Until 2006, net trade of crude oil and refined petroleum products increased, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S. (Table 2-11). Since then, however, imports have been declining while exports have been rising, leading to significant declines in net trade or crude oil and petroleum products.

Table 2-11 Total Crude Oil and Petroleum Products Trade (Million Bbl), 1990-2014

| | Imports | | | Exports | | | Net Imports | | |
|------|-----------|--------------------|-------|-----------|--------------------|-------|-------------|--------------------|-------|
| | Crude Oil | Petroleum Products | Total | Crude Oil | Petroleum Products | Total | Crude Oil | Petroleum Products | Total |
| 1990 | 2,151 | 775 | 2,926 | 40 | 273 | 313 | 2,112 | 502 | 2,614 |
| 1991 | 2,111 | 673 | 2,784 | 42 | 323 | 365 | 2,068 | 350 | 2,418 |
| 1992 | 2,226 | 661 | 2,887 | 32 | 315 | 348 | 2,194 | 345 | 2,539 |
| 1993 | 2,477 | 669 | 3,146 | 36 | 330 | 366 | 2,441 | 339 | 2,780 |
| 1994 | 2,578 | 706 | 3,284 | 36 | 308 | 344 | 2,542 | 398 | 2,940 |
| 1995 | 2,639 | 586 | 3,225 | 35 | 312 | 346 | 2,604 | 274 | 2,878 |
| 1996 | 2,748 | 721 | 3,469 | 40 | 319 | 359 | 2,708 | 403 | 3,110 |
| 1997 | 3,002 | 707 | 3,709 | 39 | 327 | 366 | 2,963 | 380 | 3,343 |
| 1998 | 3,178 | 731 | 3,908 | 40 | 305 | 345 | 3,137 | 426 | 3,564 |
| 1999 | 3,187 | 774 | 3,961 | 43 | 300 | 343 | 3,144 | 474 | 3,618 |
| 2000 | 3,320 | 874 | 4,194 | 18 | 362 | 381 | 3,301 | 512 | 3,813 |
| 2001 | 3,405 | 928 | 4,333 | 7 | 347 | 354 | 3,398 | 581 | 3,979 |
| 2002 | 3,336 | 872 | 4,209 | 3 | 356 | 359 | 3,333 | 517 | 3,849 |
| 2003 | 3,528 | 949 | 4,477 | 5 | 370 | 375 | 3,523 | 579 | 4,102 |
| 2004 | 3,692 | 1119 | 4,811 | 10 | 374 | 384 | 3,682 | 745 | 4,427 |
| 2005 | 3,696 | 1310 | 5,006 | 12 | 414 | 425 | 3,684 | 896 | 4,580 |
| 2006 | 3,693 | 1310 | 5,003 | 9 | 472 | 481 | 3,684 | 838 | 4,523 |
| 2007 | 3,661 | 1255 | 4,916 | 10 | 513 | 523 | 3,651 | 742 | 4,393 |
| 2008 | 3,581 | 1146 | 4,727 | 10 | 649 | 659 | 3,570 | 497 | 4,068 |
| 2009 | 3,290 | 977 | 4,267 | 16 | 723 | 739 | 3,274 | 255 | 3,528 |
| 2010 | 3,363 | 942 | 4,305 | 15 | 843 | 859 | 3,348 | 98 | 3,446 |
| 2011 | 3,261 | 913 | 4,174 | 17 | 1073 | 1,090 | 3,244 | -160 | 3,084 |
| 2012 | 3,121 | 758 | 3,879 | 25 | 1148 | 1,173 | 3,096 | -390 | 2,706 |
| 2013 | 2,821 | 777 | 3,598 | 49 | 1273 | 1,322 | 2,773 | -496 | 2,277 |
| 2014 | 2,681 | 692 | 3,373 | 128 | 1396 | 1,524 | 2,552 | -704 | 1,849 |

Sources: U.S. Energy Information Administration (U.S. EIA). U.S. Imports by Country of Origin. <http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbb1_a.htm>. Accessed January 22, 2016.
U.S. Energy Information Administration (U.S. EIA). U.S. Exports by Destination. <https://www.eia.gov/dnav/pet/pet_move_expc_a_EP00_EEX_mbb1_a.htm>. Accessed January 22, 2016.

From 1990 to 2007, natural gas imports have increased steadily in both volume and percentage terms (Table 2-12). Imported natural gas constituted a lower percentage of domestic natural gas consumption from 2007 through 2014 compared to earlier years. Until recent years, industry analysts have forecasted that LNG imports would continue to grow as a percentage of U.S. consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, is reducing the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2014

| | Total Imports (bcf) | Total Exports (bcf) | Net Imports (bcf) | Percent of U.S. Consumption |
|------|--------------------------------|--------------------------------|------------------------------|--|
| 1990 | 1,532 | 86 | 1,447 | 7.5 |
| 1991 | 1,773 | 129 | 1,644 | 8.4 |
| 1992 | 2,138 | 216 | 1,921 | 9.5 |
| 1993 | 2,350 | 140 | 2,210 | 10.6 |
| 1994 | 2,624 | 162 | 2,462 | 11.6 |
| 1995 | 2,841 | 154 | 2,687 | 12.1 |
| 1996 | 2,937 | 153 | 2,784 | 12.3 |
| 1997 | 2,994 | 157 | 2,837 | 12.4 |
| 1998 | 3,152 | 159 | 2,993 | 13.4 |
| 1999 | 3,586 | 163 | 3,422 | 15.3 |
| 2000 | 3,782 | 244 | 3,538 | 15.2 |
| 2001 | 3,977 | 373 | 3,604 | 16.2 |
| 2002 | 4,015 | 516 | 3,499 | 15.2 |
| 2003 | 3,944 | 680 | 3,264 | 14.8 |
| 2004 | 4,259 | 854 | 3,404 | 15.5 |
| 2005 | 4,341 | 729 | 3,612 | 16.7 |
| 2006 | 4,186 | 724 | 3,462 | 16.2 |
| 2007 | 4,608 | 822 | 3,785 | 16.6 |
| 2008 | 3,984 | 963 | 3,021 | 13.2 |
| 2009 | 3,751 | 1,072 | 2,679 | 11.7 |
| 2010 | 3,741 | 1,137 | 2,604 | 10.8 |
| 2011 | 3,468 | 1,506 | 1,962 | 8.0 |
| 2012 | 3,138 | 1,619 | 1,519 | 5.9 |
| 2013 | 2,883 | 1,572 | 1,311 | 5.0% |
| 2014 | 2,695 | 1,514 | 1,181 | 4.4% |

Source: U.S. Energy Information Administration (U.S. EIA). U.S. Natural Gas Imports & Exports by State. <https://www.eia.gov/dnav/ng/NG_MOVE_STATE_DCU_NUS_A.htm>. Accessed January 21, 2016.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the most current forecast information available from the EIA, the 2014 and 2015 Annual Energy Outlook. The 2014 and 2015 Annual Energy Outlook was produced using the National Energy Modeling System (NEMS), which the EPA uses to analyze the impacts of the final NSPS on the national economy as is discussed in detail in Section 7.

Table 2-13 present forecasts of successful wells drilled in the U.S. from 2010 to 2040. Crude oil well forecasts for the lower 48 states show a rise up to the year 2025 then a gradual

decline until 2040. Meanwhile, the forecast shows an increase in natural gas drilling in the lower 48 states from the present to 2040, more than doubling during this 25-year period.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2040

| Year | Totals | |
|------|-----------|-------------|
| | Crude Oil | Natural Gas |
| 2010 | 19,316 | 19,056 |
| 2011 | 23,048 | 14,355 |
| 2012 | 26,749 | 11,011 |
| 2013 | 25,248 | 11,507 |
| 2014 | 22,274 | 14,099 |
| 2015 | 22,706 | 14,076 |
| 2016 | 22,552 | 15,004 |
| 2017 | 22,355 | 15,773 |
| 2018 | 22,421 | 18,340 |
| 2019 | 22,525 | 20,188 |
| 2020 | 24,765 | 20,396 |
| 2021 | 25,017 | 23,427 |
| 2022 | 25,400 | 24,945 |
| 2023 | 25,981 | 24,999 |
| 2024 | 26,917 | 24,745 |
| 2025 | 27,763 | 24,831 |
| 2026 | 26,258 | 25,445 |
| 2027 | 25,830 | 26,895 |
| 2028 | 25,270 | 28,341 |
| 2029 | 24,801 | 29,019 |
| 2030 | 24,310 | 28,799 |
| 2031 | 23,972 | 29,681 |
| 2032 | 23,607 | 31,406 |
| 2033 | 23,283 | 31,749 |
| 2034 | 23,057 | 32,882 |
| 2035 | 22,740 | 33,278 |
| 2036 | 22,494 | 33,456 |
| 2037 | 22,343 | 33,536 |
| 2038 | 22,075 | 33,944 |
| 2039 | 21,911 | 34,001 |
| 2040 | 21,750 | 33,656 |

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2014**.

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and Figure 2-6 depicts these trends graphically. Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2012 to 2040, with an increase of 49 percent overall. This increment is smaller than the forecast increase in production from the lower 48 states during this period, 52 percent, showing production is forecast to grow

more rapidly than reserves. In addition, Table 2-14 shows average wellhead prices increasing more than 41 percent from 2012 to 2040, from \$96.38 per barrel to \$136.13 per barrel in 2013 dollar terms.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2012-2040

| | Domestic Production (million bbls) | | | | | | | Lower 48 End of Year Reserves (million bbls) | Lower 48 Average Wellhead Price (2013 dollars per barrel) |
|------|------------------------------------|------------------|-------------------|--------|--------------------|-------------|--------------------|--|---|
| | Total Domestic | Lower 48 Onshore | Lower 48 Offshore | Alaska | Other Crude Supply | Net Imports | Total Crude Supply | | |
| 2012 | 2,373 | 1,678 | 503 | 192 | 16 | 3,088 | 5,476 | 30,051 | 96.38 |
| 2013 | 2,715 | 2,032 | 495 | 188 | 97 | 2,773 | 5,584 | 29,441 | 96.51 |
| 2014 | 3,151 | 2,422 | 549 | 180 | 47 | 2,563 | 5,761 | 31,131 | 90.37 |
| 2015 | 3,404 | 2,640 | 599 | 164 | 78 | 2,343 | 5,826 | 31,966 | 53.49 |
| 2016 | 3,486 | 2,691 | 637 | 158 | 51 | 2,307 | 5,845 | 33,549 | 68.35 |
| 2017 | 3,651 | 2,790 | 699 | 162 | 0 | 2,156 | 5,807 | 34,747 | 72.44 |
| 2018 | 3,786 | 2,865 | 757 | 164 | 0 | 2,055 | 5,841 | 35,948 | 72.34 |
| 2019 | 3,861 | 2,906 | 797 | 158 | 0 | 1,995 | 5,857 | 37,002 | 73.79 |
| 2020 | 3,870 | 2,933 | 785 | 153 | 0 | 2,012 | 5,882 | 37,403 | 75.16 |
| 2021 | 3,837 | 2,923 | 770 | 145 | 0 | 2,086 | 5,924 | 37,760 | 76.97 |
| 2022 | 3,812 | 2,918 | 757 | 137 | 0 | 2,131 | 5,943 | 38,137 | 79.27 |
| 2023 | 3,785 | 2,918 | 738 | 129 | 0 | 2,181 | 5,966 | 38,605 | 81.68 |
| 2024 | 3,786 | 2,932 | 732 | 122 | 0 | 2,189 | 5,975 | 39,066 | 84.11 |
| 2025 | 3,752 | 2,924 | 712 | 116 | 0 | 2,222 | 5,974 | 39,389 | 86.57 |
| 2026 | 3,692 | 2,869 | 712 | 110 | 0 | 2,285 | 5,977 | 39,908 | 89.27 |
| 2027 | 3,682 | 2,850 | 729 | 103 | 0 | 2,300 | 5,982 | 40,633 | 92.03 |
| 2028 | 3,700 | 2,837 | 766 | 97 | 0 | 2,291 | 5,991 | 41,497 | 94.89 |
| 2029 | 3,681 | 2,802 | 787 | 92 | 0 | 2,321 | 6,002 | 42,109 | 97.86 |
| 2030 | 3,665 | 2,773 | 805 | 86 | 0 | 2,349 | 6,014 | 42,593 | 100.92 |
| 2031 | 3,573 | 2,688 | 804 | 82 | 0 | 2,454 | 6,027 | 42,708 | 104.19 |
| 2032 | 3,495 | 2,622 | 795 | 77 | 0 | 2,533 | 6,028 | 42,665 | 107.44 |
| 2033 | 3,448 | 2,587 | 787 | 73 | 0 | 2,604 | 6,052 | 42,795 | 110.82 |
| 2034 | 3,424 | 2,578 | 777 | 69 | 0 | 2,657 | 6,081 | 43,066 | 113.86 |
| 2035 | 3,425 | 2,580 | 780 | 66 | 0 | 2,683 | 6,108 | 43,425 | 117.20 |
| 2036 | 3,407 | 2,571 | 773 | 62 | 0 | 2,723 | 6,130 | 43,609 | 120.77 |
| 2037 | 3,404 | 2,557 | 766 | 81 | 0 | 2,752 | 6,156 | 43,808 | 124.33 |
| 2038 | 3,422 | 2,541 | 774 | 107 | 0 | 2,748 | 6,170 | 44,124 | 128.36 |
| 2039 | 3,420 | 2,534 | 761 | 126 | 0 | 2,766 | 6,187 | 44,234 | 132.37 |
| 2040 | 3,440 | 2,527 | 790 | 123 | 0 | 2,768 | 6,208 | 44,779 | 136.13 |

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < [http://www.eia.gov/forecasts/aeo/pdf/0383\(2015\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf)>. Accessed January 25, 2016.

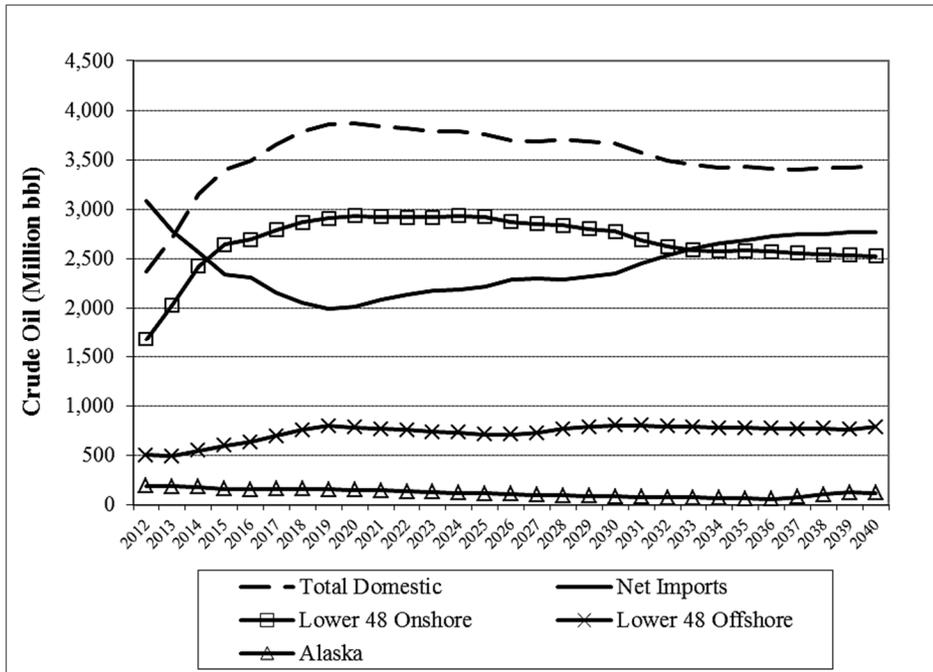


Figure 2-6 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040
 Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < [http://www.eia.gov/forecasts/aeo/pdf/0383\(2015\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf)>. Accessed January 25, 2016.

Table 2-15 shows domestic natural gas production is forecast to increase until 2040. Meanwhile, imports of natural gas via pipeline are eliminated during the forecast period, from 1.37 tcf in 2012 to -2.33 tcf in 2040. Imports of LNG are also expected to be eliminated during the forecast period, from 0.15 tcf in 2012 to -3.29 tcf in 2040. Dry Gas Production increases about 47 percent, from 24.06 tcf in 2012 to 35.45 in 2040. Total supply increases about 17 percent, from 25.64 tcf in 2012 to 29.90 tcf in 2040.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price 2012-2040

| | Domestic Production (tcf) | | Net Imports (tcf) | | Total Supply | Lower 48 End of Year Dry Reserves (tcf) | Average Henry Hub Spot Price (2013 dollars per million Btu) |
|------|---------------------------|--------------------------|------------------------|-------------------|--------------|---|---|
| | Dry Gas Production | Supplemental Natural Gas | Net Imports (Pipeline) | Net Imports (LNG) | | | |
| 2012 | 24.06 | 0.06 | 1.37 | 0.15 | 25.64 | 298.5 | 2.79 |
| 2013 | 24.40 | 0.05 | 1.20 | 0.09 | 25.75 | 293.2 | 3.73 |
| 2014 | 25.57 | 0.06 | 1.09 | 0.05 | 26.77 | 299.0 | 4.37 |
| 2015 | 26.43 | 0.06 | 0.83 | -0.03 | 27.29 | 300.8 | 3.69 |
| 2016 | 27.30 | 0.06 | 0.58 | -0.23 | 27.71 | 301.5 | 3.70 |
| 2017 | 27.18 | 0.06 | 0.23 | -0.69 | 26.78 | 303.7 | 3.80 |
| 2018 | 27.68 | 0.06 | -0.07 | -1.05 | 26.62 | 305.5 | 4.21 |
| 2019 | 28.27 | 0.06 | -0.29 | -1.52 | 26.53 | 307.5 | 4.55 |
| 2020 | 28.82 | 0.06 | -0.48 | -2.08 | 26.33 | 308.9 | 4.88 |
| 2021 | 29.17 | 0.06 | -0.58 | -2.37 | 26.28 | 310.6 | 5.02 |
| 2022 | 29.53 | 0.06 | -0.72 | -2.49 | 26.39 | 312.1 | 5.09 |
| 2023 | 29.85 | 0.06 | -0.83 | -2.49 | 26.60 | 313.3 | 5.25 |
| 2024 | 30.17 | 0.06 | -0.91 | -2.49 | 26.84 | 314.7 | 5.35 |
| 2025 | 30.51 | 0.06 | -1.01 | -2.49 | 27.07 | 315.7 | 5.46 |
| 2026 | 30.78 | 0.06 | -1.09 | -2.49 | 27.27 | 316.8 | 5.67 |
| 2027 | 31.37 | 0.06 | -1.21 | -2.69 | 27.54 | 319.2 | 5.67 |
| 2028 | 31.94 | 0.06 | -1.31 | -2.89 | 27.80 | 322.2 | 5.67 |
| 2029 | 32.50 | 0.06 | -1.41 | -3.09 | 28.06 | 325.3 | 5.71 |
| 2030 | 33.01 | 0.06 | -1.52 | -3.29 | 28.27 | 328.7 | 5.69 |
| 2031 | 33.19 | 0.06 | -1.60 | -3.29 | 28.37 | 330.8 | 5.91 |
| 2032 | 33.40 | 0.06 | -1.69 | -3.29 | 28.49 | 332.7 | 6.09 |
| 2033 | 33.63 | 0.06 | -1.77 | -3.29 | 28.63 | 334.5 | 6.27 |
| 2034 | 33.84 | 0.06 | -1.83 | -3.29 | 28.79 | 336.5 | 6.45 |
| 2035 | 34.14 | 0.06 | -1.90 | -3.29 | 29.01 | 338.3 | 6.60 |
| 2036 | 34.46 | 0.06 | -2.00 | -3.29 | 29.24 | 339.9 | 6.76 |
| 2037 | 34.75 | 0.06 | -2.09 | -3.29 | 29.44 | 341.5 | 6.84 |
| 2038 | 35.04 | 0.06 | -2.19 | -3.29 | 29.62 | 343.3 | 7.02 |
| 2039 | 35.28 | 0.06 | -2.30 | -3.29 | 29.75 | 344.3 | 7.38 |
| 2040 | 35.45 | 0.06 | -2.33 | -3.29 | 29.90 | 345.2 | 7.85 |

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < [http://www.eia.gov/forecasts/aeo/pdf/0383\(2015\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf)>. Accessed January 19, 2016

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-7).

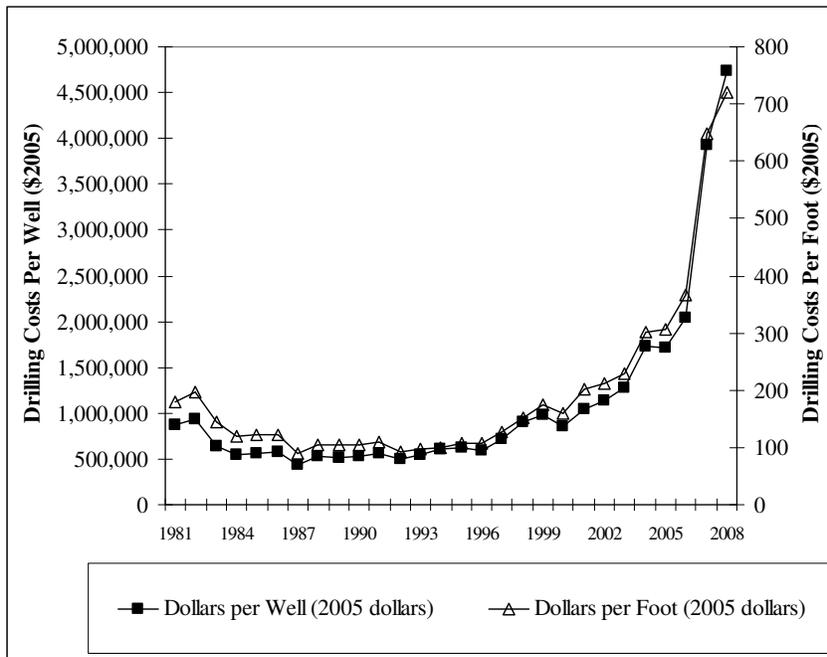


Figure 2-7 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by the EIA add an additional level of detail to drilling costs, in that finding costs incorporate the broader costs associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. The EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-8 shows average domestic onshore, offshore and foreign finding costs for the sample of U.S. firms in the EIA's Financial Reporting System (FRS) database from 1981 to 2009. The costs are reported in 2009 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic

finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore, offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore, offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-7 and finding costs in Figure 2-8 present similar trends overall.

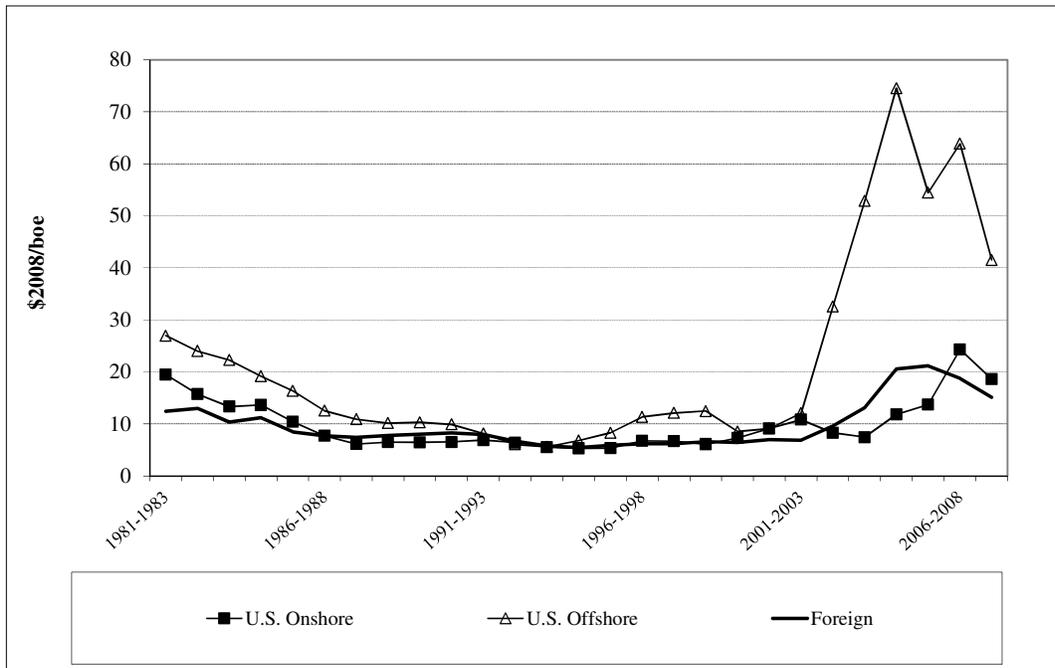


Figure 2-8 Finding Costs for FRS Companies, 1981-2009

Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy Producers, 2009. Figure 17 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January 19, 2016.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. The EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, the EIA reports average lifting costs for FRS firms in 2009 dollars on a barrel of oil equivalent basis.

Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-9 depicts direct lifting cost trends from 1981 to 2009 for domestic and foreign production.

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than \$2 per barrel of oil equivalent between 1981 and 1985, then declined almost \$5 per barrel of oil equivalent by 2000. From 2000 to 2009, domestic lifting costs increased sharply, just over \$8 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, with foreign lifting costs lower than domestic costs during this period. After 1991, foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2009.

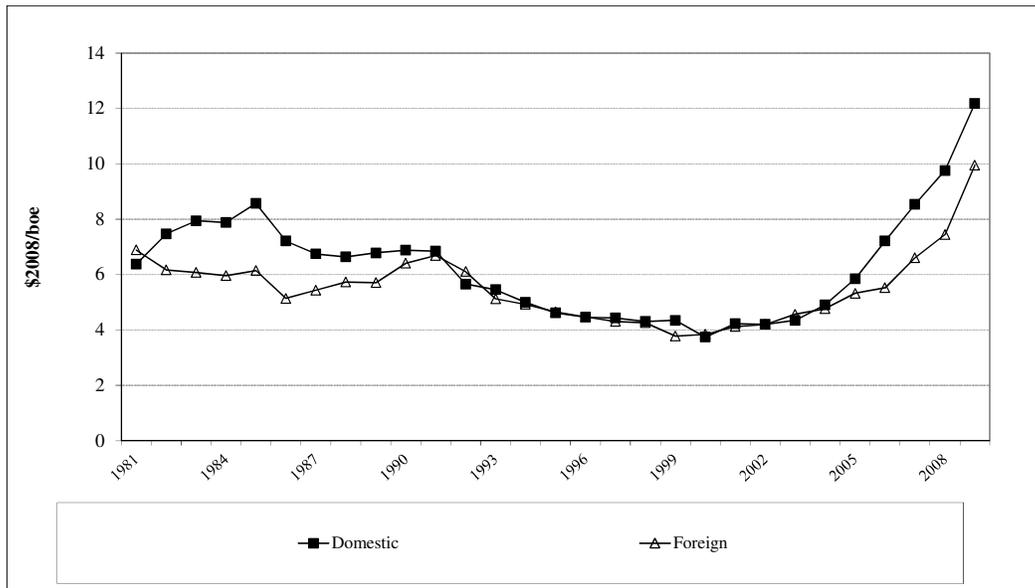


Figure 2-9 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-year Running Average)

Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy Producers, 2009. Figure 15 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January 19, 2016.

2.5.3 *Operating and Equipment Costs*

The EIA report, “Oil and Gas Lease Equipment and Operating Costs 1994 through 2009”⁸, contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-10 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, but operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s. Oil costs and prices again generally rose between 2000 and 2009, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

⁸ U.S. Energy Information Administration. “Oil and Gas Lease Equipment and Operating Costs 1994 through 2009.” September 28, 2010.
<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

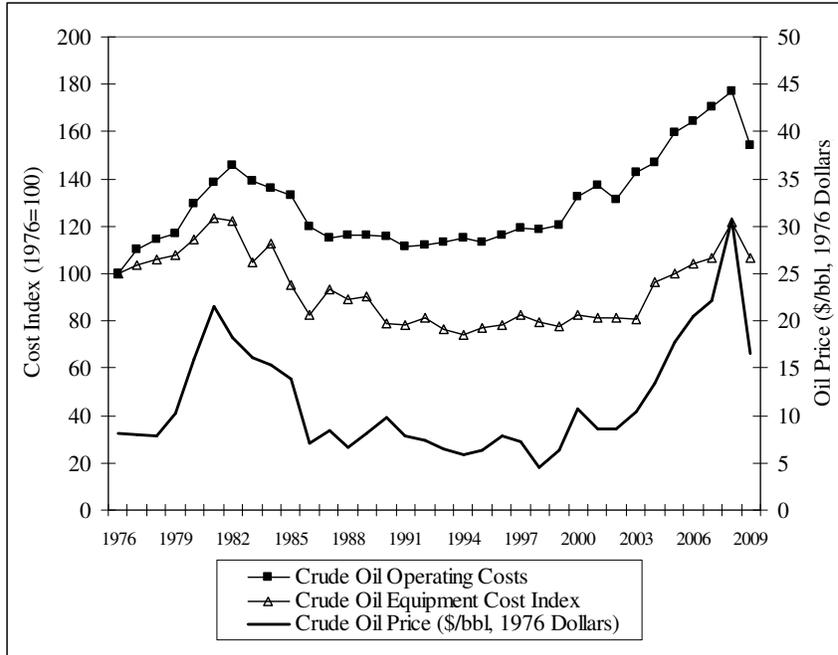


Figure 2-10 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009⁹

Source: U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010.

<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

Figure 2-11 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid-1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

⁹ The last release date for the EIA's *Oil and Gas Lease Equipment and Operating Costs* analysis was September 2010. Updates have been discontinued.

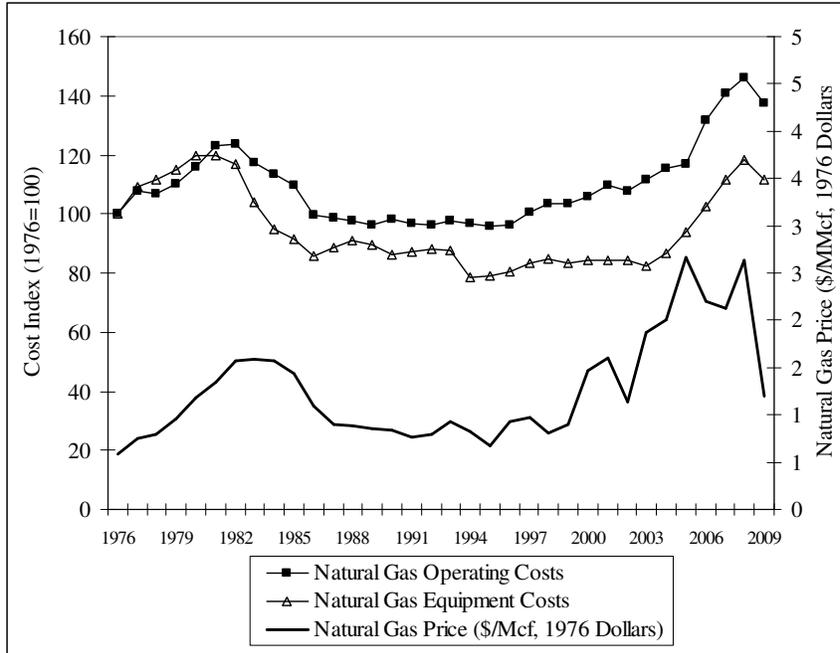


Figure 2-11 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Source: U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010.

<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plants and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production,

transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 54 percent of domestic crude oil, 85 percent of domestic natural gas, and drill almost 95 percent of the wells in the U.S (IPAA, 2012-13). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected NAICS

As of 2012, there were 6,679 firms within the 211111 and 211112 NAICS codes, of which 6,551 (98 percent) were considered small entities (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for almost 61 percent of employment listed under these NAICS. The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 56 percent of employment. Within NAICS 486210, large firms compose about 43 percent of total firms and about 95 percent of employment.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

| NAICS | NAICS Description | SBA Size Standard** (Employees or Annual Receipts) | *Small Firms | *Large Firms | *Total Firms |
|--------------------------------------|---|---|--------------|--------------|--------------|
| Number of Firms by Firm Size | | | | | |
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 ¹ | 6,444 | 92 | 6,536 |
| 211112 | Natural Gas Liquid Extraction | 500 ² | 107 | 36 | 143 |
| 213111 | Drilling Oil and Gas Wells | 500 ³ | 2,085 | 59 | 2,144 |
| 213112 | Support Activities for Oil and Gas Operations | \$38.5 million | 8,750 | 127 | 8,877 |
| 486210 | Pipeline Transportation of Natural Gas | \$27.5 million | 92 | 46 | 138 |
| Total Employment by Firm Size | | | | | |
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 47,528 | 66,996 | 114,524 |
| 211112 | Natural Gas Liquid Extraction | 500 | 1,709 | 8,768 | 10,477 |
| 213111 | Drilling Oil and Gas Wells | 500 | 39,628 | 66,740 | 106,368 |
| 213112 | Support Activities for Oil and Gas Operations | \$38.5 million | 126,523 | 145,834 | 272,357 |
| 486210 | Pipeline Transportation of Natural Gas | \$27.5 million | 1,503 | 31,823 | 33,326 |

*These numbers are reported by Enterprise Employment Size <500 and 500+

Sources: U.S. Census Bureau. Statistics of U.S. Businesses. Accessed January 18, 2016.

U.S. Government Publishing Office. Electronic Code of Regulation, Title 13, Chapter 1, Part 121. Accessed January 18, 2016.

U.S. Small Business Administration, Office of Advocacy. 2014. Firm Size Data. Accessed January 5, 2016.

**The SBA size standards for some of the NAICS were updated in February, 2016.

1. Updated to 1,250 employees
2. Updated to 750 employees
3. Updated to 1,000 employees.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2014. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of about 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-2014

| | Crude Petroleum and Natural Gas Extraction (NAICS 211111) | Natural Gas Liquid Extraction (NAICS 211112) | Drilling of Oil and Natural Gas Wells (NAICS 213111) | Support Activities for Oil and Gas Ops. (NAICS 213112) | Pipeline Trans. of Crude Oil (NAICS 486110) | Pipeline Trans. of Natural Gas (NAICS 486210) | Total |
|------|--|---|---|---|--|--|--------------|
| 1990 | 182,848 | 8,260 | 52,365 | 109,497 | 11,112 | 47,533 | 411,615 |
| 1991 | 177,803 | 8,443 | 46,466 | 116,170 | 11,822 | 48,643 | 409,347 |
| 1992 | 169,615 | 8,819 | 39,900 | 99,924 | 11,656 | 46,226 | 376,140 |
| 1993 | 159,219 | 7,799 | 42,485 | 102,840 | 11,264 | 43,351 | 366,958 |
| 1994 | 150,598 | 7,373 | 44,014 | 105,304 | 10,342 | 41,931 | 359,562 |
| 1995 | 142,971 | 6,845 | 43,114 | 104,178 | 9,703 | 40,486 | 347,297 |
| 1996 | 139,016 | 6,654 | 46,150 | 107,889 | 9,231 | 37,519 | 346,459 |
| 1997 | 137,667 | 6,644 | 55,248 | 117,460 | 9,097 | 35,698 | 361,814 |
| 1998 | 133,137 | 6,379 | 53,943 | 122,942 | 8,494 | 33,861 | 358,756 |
| 1999 | 124,296 | 5,474 | 41,868 | 101,694 | 7,761 | 32,610 | 313,703 |
| 2000 | 117,175 | 5,091 | 52,207 | 108,087 | 7,657 | 32,374 | 322,591 |
| 2001 | 119,099 | 4,500 | 62,012 | 123,420 | 7,818 | 33,620 | 350,469 |
| 2002 | 116,559 | 4,565 | 48,596 | 120,536 | 7,447 | 31,556 | 329,259 |
| 2003 | 115,636 | 4,691 | 51,526 | 120,992 | 7,278 | 29,684 | 329,807 |
| 2004 | 117,060 | 4,285 | 57,332 | 128,185 | 7,073 | 27,340 | 341,275 |
| 2005 | 121,535 | 4,283 | 66,691 | 145,725 | 6,945 | 27,341 | 372,520 |
| 2006 | 130,188 | 4,670 | 79,818 | 171,127 | 7,202 | 27,685 | 420,690 |
| 2007 | 141,239 | 4,842 | 84,525 | 197,100 | 7,975 | 27,431 | 463,112 |
| 2008 | 154,898 | 5,183 | 92,640 | 223,635 | 8,369 | 27,080 | 511,805 |
| 2009 | 155,150 | 5,538 | 67,756 | 193,589 | 8,753 | 26,753 | 457,539 |
| 2010 | 153,490 | 4,833 | 74,491 | 201,685 | 8,893 | 26,708 | 470,100 |
| 2011 | 164,900 | 5,835 | 87,272 | 241,490 | 8,959 | 27,320 | 535,776 |
| 2012 | 181,473 | 6,529 | 92,340 | 282,447 | 9,348 | 27,595 | 599,732 |
| 2013 | 189,804 | 6,928 | 93,261 | 296,891 | 10,059 | 26,981 | 623,924 |
| 2014 | 189,222 | 7,482 | 98,208 | 326,353 | 10,708 | 28,242 | 660,215 |

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014 ,
<<http://data.bls.gov/cgi-bin/dsrv>>. Accessed on January 19, 2016.

From 1990 to 2014, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry. Employees in the NAICS 211 codes earn the highest average wages in the oil and natural gas industry, while employees in the NAICS 213 codes have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2014 (2012 dollars)

| | Crude Petroleum and Natural Gas Extraction (211111) | Natural Gas Liquid Extraction (211112) | Drilling of Oil and Natural Gas Wells (213111) | Support Activities for Oil and Gas Ops. (213112) | Pipeline Trans. of Crude Oil (486110) | Pipeline Trans. of Natural Gas (486210) | Total |
|------|--|---|---|---|--|--|--------------|
| 1990 | 74,510 | 69,910 | 44,213 | 48,033 | 71,265 | 64,482 | 62,274 |
| 1991 | 76,016 | 70,026 | 45,614 | 49,601 | 72,311 | 68,260 | 63,916 |
| 1992 | 80,259 | 72,319 | 45,704 | 51,379 | 77,977 | 70,505 | 67,466 |
| 1993 | 81,252 | 72,271 | 47,508 | 52,674 | 76,481 | 70,810 | 67,765 |
| 1994 | 83,014 | 74,311 | 46,739 | 52,590 | 79,827 | 71,838 | 68,090 |
| 1995 | 85,381 | 70,906 | 48,485 | 53,319 | 82,756 | 75,453 | 69,667 |
| 1996 | 88,360 | 72,290 | 51,280 | 55,426 | 80,627 | 80,141 | 71,760 |
| 1997 | 94,353 | 83,408 | 54,780 | 58,370 | 82,343 | 86,898 | 75,390 |
| 1998 | 97,915 | 94,471 | 55,718 | 60,473 | 83,066 | 88,409 | 77,429 |
| 1999 | 103,283 | 93,896 | 57,242 | 62,786 | 86,666 | 99,165 | 83,007 |
| 2000 | 115,071 | 117,532 | 63,817 | 63,535 | 85,034 | 136,971 | 91,032 |
| 2001 | 116,471 | 116,567 | 64,822 | 64,328 | 87,404 | 128,302 | 89,458 |
| 2002 | 115,367 | 108,753 | 65,257 | 62,876 | 91,806 | 96,055 | 86,280 |
| 2003 | 116,216 | 118,377 | 64,125 | 64,398 | 91,831 | 96,154 | 86,755 |
| 2004 | 127,383 | 124,432 | 66,282 | 65,703 | 98,426 | 98,531 | 91,002 |
| 2005 | 133,983 | 134,481 | 74,521 | 70,786 | 96,951 | 95,061 | 95,074 |
| 2006 | 145,726 | 140,751 | 78,083 | 74,119 | 96,738 | 104,104 | 100,131 |
| 2007 | 143,333 | 140,394 | 86,745 | 76,134 | 101,563 | 111,528 | 101,771 |
| 2008 | 153,226 | 132,644 | 86,886 | 78,468 | 107,886 | 105,176 | 105,060 |
| 2009 | 141,818 | 131,569 | 85,894 | 74,614 | 106,237 | 106,647 | 102,241 |
| 2010 | 152,145 | 132,041 | 86,337 | 77,810 | 108,906 | 112,910 | 106,572 |
| 2011 | 156,107 | 120,995 | 91,928 | 81,479 | 114,764 | 116,320 | 108,914 |
| 2012 | 155,735 | 136,353 | 92,266 | 80,222 | 120,292 | 139,127 | 108,872 |
| 2013 | 152,884 | 122,618 | 92,610 | 80,405 | 116,055 | 116,460 | 106,881 |
| 2014 | 157,827 | 123,305 | 95,454 | 83,364 | 109,590 | 116,679 | 108,807 |

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014, annual wages per employee <<http://www.bls.gov/cew/>>. Accessed on January 21, 2016.

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one

level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasingly performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms. Typically, wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independent firms have to rely solely on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated.

Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, though now it has been reduced to the top 150. In 2014, 143 public companies are listed; in 2013 there were 139 firms.¹⁰ The 2012 list contains four companies that were not on the list in the previous year. Table 2-19 lists selected statistics for the top 20 companies in 2014. The results presented in the table reflect a decline in U.S. oil prices.

Net income for the top 134 companies fell about 17.5% between 2013 and 2014 to about \$74 billion. Revenues for these companies increased by about \$6 billion from 2013 to 2014, reaching \$920.5 billion. Even though net revenue decreased in 2014, companies continued to invest. Capital and exploratory spending for the companies in 2014 totaled \$226.4 billion, up 9.3% from 2013.

The total worldwide liquids production for the 143 firms increased 8.41 percent 3.32 billion bbl, while total worldwide gas production increased 0.54 percent to a total of 17 tcf (*Oil and Gas Journal*, September 7, 2015). Meanwhile, the firms increased both oil and natural gas production and reserves from 2013 to 2014. Domestic production of liquids increased about 16.73 percent from 2013 to 1.97 billion bbl, and domestic natural gas production was up about 3.95 percent to 12.4 tcf in 2014. US liquids reserves from the OGJ150 firms increased by 9.85% up to 25.53 billion bbl, and US natural gas reserves increased by 8.56% to 172.92 tcf. For context, the OGJ150 domestic crude production represents about 62 percent of total domestic production (3.18 billion bbl, according to EIA) in 2014. The OGJ150 natural gas production represents about 48 percent of total domestic production (31.3 tcf, according to EIA) in 2014.

¹⁰ Oil and Gas Journal. "OGJ150 Earnings Down as US Production Climbs." September 2, 2013.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012

| Rank by Total Assets | Company | Employees | Total Assets (\$Million) | Total Revenue (\$Million) | Net Income (\$Million) | Worldwide Production | | US Production | | Net Wells Drilled |
|----------------------------|-------------------------------|-----------|--------------------------------|---------------------------------|------------------------------|-----------------------------|-------------------------|-----------------------------|-------------------------|-------------------------|
| | | | | | | Liquids (Million bbl) | Natural Gas (Bcf) | Liquids (Million bbl) | Natural Gas (Bcf) | |
| 1 | ExxonMobil Corp. | 75,300 | 349,493 | 411,939 | 33615 | 631 | 2,645 | 111 | 1,346 | 732 |
| 2 | Chevron Corp. | 64,700 | 266,026 | 211,970 | 19310 | 508 | 1,744 | 166 | 456 | 1125 |
| 3 | ConocoPhillips | 19,100 | 116,539 | 55,517 | 6938 | 270 | 1,443 | 172 | 679 | 492 |
| 4 | Anadarko Petroleum Corp. | 6,100 | 61,689 | 18,470 | -1563 | 154 | 951 | 118 | 951 | 854.6 |
| 5 | Occidental Petroleum Corp. | 11,700 | 56,259 | 21,947 | 630 | 163 | 331 | 87 | 173 | 478.8 |
| 6 | Apache Corp. | 4,950 | 55,952 | 13,851 | -5060 | 142.2 | 580 | 70.25 | 215.8 | 816.5 |
| 7 | Devon Energy Corp. | 6,600 | 50,637 | 19,566 | 1691 | 129 | 701 | 67 | 660 | 481 |
| 8 | Chesapeake Energy Corp. | 5,500 | 40,751 | 20,951 | 2056 | 75.4 | 1095 | 75.4 | 1095 | 682 |
| 9 | Hess Corp. | 3,045 | 38,578 | 11,439 | 2374 | 89 | 197 | 54 | 66 | 211 |
| 10 | Marathon Oil Corp. | 3,330 | 36,011 | 11,258 | 3046 | 118 | 295 | 68 | 113 | 666 |
| 11 | EOG Resources Inc. | 3,000 | 34,763 | 18,035 | 2915 | 134.7 | 506.3 | 132 | 348.4 | 869 |
| 12 | Noble Energy Inc. | 2,735 | 22,553 | 5,101 | 1214 | 49 | 362 | 32 | 189 | 324.4 |
| 13 | Freeport-McMoRan Inc. | 35,000 | 20,834 | 4,710 | -4479 | 43 | 82 | 43 | 82 | 210 |
| 14 | Murphy Oil Corp. | 1,712 | 16,742 | 5,476 | 906 | 55.4 | 162.8 | 25 | 32.3 | 189 |
| 15 | Linn Energy LLC | 1,800 | 16,424 | 4,983 | -452 | 38.8 | 209 | 38.8 | 209 | 699 |
| 16 | Continental Resources Inc. | 300 | 15,145 | 4,802 | 977 | 44.53 | 114 | 44.53 | 114 | 388.5 |
| 17 | Pioneer Natural Resources Co. | 4,075 | 14,926 | 5,055 | 930 | 48.48 | 154.4 | 48.48 | 154.4 | 502 |
| 18 | Southwestern Energy Corp. | 2,781 | 14,925 | 4,038 | 924 | 0.466 | 765 | 0.466 | 765 | 221 |
| 19 | Whiting Petroleum Corp. | 1282 | 14,020 | 3,085 | 65 | 36.77 | 30.22 | 36.77 | 30.22 | 257.1 |
| 20 | Denbury Resources Corp. | 1,523 | 12,728 | 2,435 | 635 | 25.77 | 8.379 | 25.77 | 8.379 | 55.9 |

Source: Oil and Gas Journal. "OGJ150" September 7, 2015. The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S.

Notes: The source for employment figures is Hoovers, a D&B Company. (Data accessed on January 20, 2016. Employee numbers are for 2014)

The OGJ also releases a period report entitled “Worldwide Gas Processing Survey”, which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughput of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, with large firms owning multiple facilities, which also tend to be relatively large (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264, or 46 percent, of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

| Rank | Company | Processing Plants (No.) | Natural Gas Capacity (MMcf/day) | Natural Gas Throughput (MMcf/day) |
|-------------------------|-----------------------------------|--------------------------------|--|--|
| 1 | BP PLC | 19 | 13,378 | 11,420 |
| 2 | DCP Midstream Inc. | 64 | 9,292 | 5,586 |
| 3 | Enterprise Products Operating LP— | 23 | 10,883 | 5,347 |
| 4 | Targa Resources | 16 | 4,501 | 2,565 |
| 5 | Enbridge Energy Partners LP— | 19 | 3,646 | 2,444 |
| 6 | Williams Cos. | 10 | 4,826 | 2,347 |
| 7 | Martin Midstream Partners | 16 | 3,384 | 2,092 |
| 8 | Chevron Corp. | 23 | 1,492 | 1,041 |
| 9 | Devon Gas Services LP | 6 | 1,038 | 846 |
| 10 | ExxonMobil Corp. | 6 | 1,238 | 766 |
| 11 | Occidental Petroleum Corp | 7 | 776 | 750 |
| 12 | Kinder Morgan Energy Partners | 9 | 1,318 | 743 |
| 13 | Enogex Products Corp. | 8 | 863 | 666 |
| 14 | Hess Corp. | 3 | 1,060 | 613 |
| 15 | Norcen Explorer | 1 | 600 | 500 |
| 16 | Copano Energy | 1 | 700 | 495 |
| 17 | Anadarko | 18 | 816 | 489 |
| 18 | Oneok Field Services | 10 | 1,751 | 472 |
| 19 | Shell | 4 | 801 | 446 |
| 20 | DTE Energy | 1 | 800 | 400 |
| TOTAL FOR TOP 20 | | 264 | 63,163 | 40,028 |
| TOTAL FOR ALL COMPANIES | | 579 | 73,767 | 45,472 |

Source: *Oil and Gas Journal*. “Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009.” June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 165 companies in 2014 (*Oil and Gas Journal*, September 7, 2015, “Gas Pipeline Table,” pp. 126-128). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2014. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of Top 20 pipeline companies and the Top 20 firms from the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional markets.

The top 20 companies maintain about 58 percent of the total pipeline mileage and transport about 52 percent of the total volume of the industry (Table 2-21). Operating revenues

of the top 20 companies equaled \$13.2 billion, representing 54 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 69 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2014

| Rank | Company | Transmission (miles) | Vol. trans for others (MMcf) | Operating Revenue (\$000s) | Net Income (\$000s) |
|-------------------------|--|----------------------|------------------------------|----------------------------|---------------------|
| 1 | Tennessee Gas Pipeline Co. | 11,917 | 2,990,155 | 1,192,621 | 331,768 |
| 2 | Texas Eastern Transmission LP | 9,592 | 2,610,451 | 1,165,248 | 318,519 |
| 3 | Dominion Transmission Inc. | 3,842 | 1,151,691 | 1,042,755 | 308,512 |
| 4 | Transcontinental Gas Pipe Line Co. LLC | 9,183 | 4,655,090 | 1,413,206 | 289,463 |
| 5 | Florida Gas Transmission Co. LLC | 5,324 | 902,592 | 795,990 | 234,412 |
| 6 | Columbia Gas Transmission LLC | 9,641 | 1,379,418 | 1,116,715 | 200,271 |
| 7 | Northern Natural Gas Co. | 14,781 | 1,025,465 | 749,039 | 150,275 |
| 8 | Southern Natural Gas Co. | 7,033 | 961,725 | 577,037 | 146,469 |
| 9 | ETC Tiger Pipeline LLC | 196 | 340,851 | 279,299 | 130,851 |
| 10 | Kinder Morgan Louisiana Pipeline LLC | 136 | 2,803 | 265,334 | 130,678 |
| 11 | Natural Gas Pipeline Co. of America | 9,122 | 1,417,903 | 651,548 | 116,693 |
| 12 | Rockies Express Pipeline LLC | 1,712 | 789,454 | 805,485 | 116,630 |
| 13 | El Paso Natural Gas Co. | 10,222 | 1,318,671 | 577,604 | 113,429 |
| 14 | Colorado Interstate Gas Co. | 4,225 | 839,291 | 402,882 | 108,983 |
| 15 | Northwest Pipeline LLC | 3,890 | 686,974 | 470,050 | 107,172 |
| 16 | Dominion Cove Point LNG LP | 136 | 92,710 | 296,555 | 97,654 |
| 17 | Texas Gas Transmission LLC | 5,766 | 1,154,029 | 406,562 | 97,237 |
| 18 | Enable Gas Transmission LLC | 5,902 | 913,254 | 494,067 | 93,115 |
| 19 | Lake Charles LNG Co. LLC1 (new) | - | - | 216,247 | 92,236 |
| 20 | Equitrans LP | 900 | 635,883 | 268,052 | 92,036 |
| TOTAL FOR TOP 20 | | 113,520 | 23,868,410 | 13,186,296 | 3,276,403 |
| TOTAL FOR ALL COMPANIES | | 195,194 | 46,293,010 | 24,514,239 | 4,776,194 |

Source: *Oil and Gas Journal*. September 7, 2015. "Gas Pipeline Table" pp.126-128.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the major U.S. energy producers and reports summary information in the publication "The Performance Profiles of Major Energy Producers".¹¹ This information is used in annual report to Congress, and is released to the public in aggregate form. While the companies that report information to the FRS each year changes,

¹¹ The "Performance Profiles of Major Energy Producers 2009" released on February 25, 2011 is the most recent release of this report.

the EIA makes an effort to retain sufficient consistency to reliably evaluate trends. For 2009, 30 companies in the FRS¹² accounted for 43 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 78 percent of U.S. refining capacity, and 0.3 percent of U.S. electricity net generation (U.S. EIA, 2011). Table 2-22 aggregates a series of financial trends selected from the FRS firms' financial statements presented in 2008 dollars. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well, followed by all three financial factors dropping off significantly in 2009. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, though the decrease in net income spans both 2008 and 2009 mainly as a factor of oil and natural gas prices declining significantly during the latter half of 2008.

¹² Alenco, Alon USA, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chalmette, Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., Western Refining, WRB Refining LLC, and XTO Energy, Inc.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

| Year | Operating Revenues | Operating Expenses | Operating Income | Interest Expense | Other Income* | Income Taxes | Net Income |
|------|--------------------|--------------------|------------------|------------------|---------------|--------------|------------|
| 1990 | 766.9 | 706.4 | 60.5 | 16.8 | 13.6 | 24.8 | 32.5 |
| 1991 | 673.4 | 635.7 | 37.7 | 14.4 | 13.4 | 15.4 | 21.3 |
| 1992 | 670.2 | 637.2 | 33.0 | 12.7 | -5.6 | 12.2 | 2.5 |
| 1993 | 621.4 | 586.6 | 34.8 | 11.0 | 10.3 | 12.7 | 21.5 |
| 1994 | 606.5 | 565.6 | 40.9 | 10.8 | 6.8 | 14.4 | 22.5 |
| 1995 | 640.8 | 597.5 | 43.3 | 11.1 | 12.9 | 17.0 | 28.1 |
| 1996 | 706.8 | 643.3 | 63.6 | 9.1 | 13.4 | 26.1 | 41.8 |
| 1997 | 673.6 | 613.8 | 59.9 | 8.2 | 13.4 | 23.9 | 41.2 |
| 1998 | 614.2 | 594.1 | 20.1 | 9.2 | 11.0 | 6.0 | 15.9 |
| 1999 | 722.9 | 682.6 | 40.3 | 10.9 | 12.7 | 13.6 | 28.6 |
| 2000 | 1,114.3 | 1,011.8 | 102.5 | 12.9 | 18.4 | 42.9 | 65.1 |
| 2001 | 961.8 | 880.3 | 81.5 | 10.8 | 7.6 | 33.1 | 45.2 |
| 2002 | 823.0 | 776.9 | 46.2 | 12.7 | 7.9 | 17.2 | 24.3 |
| 2003 | 966.9 | 872.9 | 94.0 | 10.1 | 19.5 | 37.2 | 66.2 |
| 2004 | 1,188.5 | 1,051.1 | 137.4 | 12.4 | 20.1 | 54.2 | 90.9 |
| 2005 | 1,447.3 | 1,263.8 | 183.5 | 11.6 | 34.6 | 77.1 | 129.3 |
| 2006 | 1,459.0 | 1,255.0 | 204.0 | 12.4 | 41.2 | 94.8 | 138.0 |
| 2007 | 1,475.0 | 1,297.7 | 177.3 | 11.1 | 47.5 | 86.3 | 127.4 |
| 2008 | 1,818.1 | 1,654.0 | 164.1 | 11.4 | 32.6 | 98.5 | 86.9 |
| 2009 | 1,136.8 | 1,085.9 | 50.8 | 10.8 | 18.7 | 29.5 | 29.3 |

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

* Other Income includes other revenue and expenses (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

Table 2-23 shows the estimated return on investments in percentage terms for a variety of business lines in 1998, 2003, 2008, and 2009 for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production was the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent in 1998, 2003, and 2008, with a significant decrease in 2009. Returns to foreign oil and natural gas production rose above domestic production in 2008 and 2009. Electric power generation and sales emerged as a highly profitable line of business in 2008 for the FRS companies quickly followed by a significant decline in 2009.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, 2008, and 2009 (percent)

| Line of Business | 1998 | 2003 | 2008 | 2009 |
|--------------------------------|-------------|-------------|-------------|-------------|
| Petroleum | 10.8 | 13.4 | 11.9 | 4.5 |
| U.S. Petroleum | 10 | 13.7 | 8.1 | 0.4 |
| Oil and Natural Gas Production | 12.5 | 16.5 | 10.7 | 3.5 |
| Refining/Marketing | 6.6 | 9.3 | 2.4 | -6.6 |
| Pipelines | 6.7 | 11.5 | 2.4 | 4.7 |
| Foreign Petroleum | 11.9 | 13.0 | 17.8 | 10.3 |
| Oil and Natural Gas Production | 12.5 | 14.2 | 16.3 | 11 |
| Refining/Marketing | 10.6 | 8.0 | 26.2 | 5.8 |
| Downstream Natural Gas* | - | 8.8 | 5.1 | 9.6 |
| Electric Power | - | 5.2 | 181.4 | -32 |
| Other Energy | 7.1 | 2.8 | -2.1 | 5.1 |
| Non-energy | 10.9 | 2.4 | -5.3 | 2.8 |

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Note: Return on investment measured as contribution to net income/net investment in place.

* The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2009 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit (\$198 million in 2008)¹³ and the effect of the Alternative Minimum Tax (\$34 million in 2008). Income taxes paid to state and local authorities were \$3,060 million in 2008¹³, about 13 percent of the total paid to U.S. authorities.

The difference between total current taxes and U.S. federal, state, and local taxes includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24 foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

¹³ Data was withheld in 2009 to avoid disclosure.

Table 2-24 Income and Production Taxes, 1990-2009 (Million 2008 Dollars)

| Year | US Federal, State, and Local Taxes Paid or Accrued | Total Current | Total Deferred | Total Income Tax Expense | Other Production Taxes Paid |
|-------|--|---------------|-------------------|-----------------------------|-----------------------------------|
| 1990 | 9,568 | 25,056 | -230 | 24,826 | 4,341 |
| 1991 | 6,672 | 18,437 | -3,027 | 15,410 | 3,467 |
| 1992 | 4,994 | 16,345 | -4,116 | 12,229 | 3,097 |
| 1993 | 3,901 | 13,983 | -1,302 | 12,681 | 2,910 |
| 1994 | 3,348 | 13,556 | 887 | 14,443 | 2,513 |
| 1995 | 6,817 | 17,474 | -510 | 16,965 | 2,476 |
| 1996 | 8,376 | 22,493 | 3,626 | 26,119 | 2,922 |
| 1997 | 7,643 | 20,764 | 3,141 | 23,904 | 2,743 |
| 1998 | 1,199 | 7,375 | -1,401 | 5,974 | 1,552 |
| 1999 | 2,626 | 13,410 | 140 | 13,550 | 2,147 |
| 2000 | 14,308 | 36,187 | 6,674 | 42,861 | 3,254 |
| 2001 | 10,773 | 28,745 | 4,351 | 33,097 | 3,042 |
| 2002 | 814 | 17,108 | 46 | 17,154 | 2,617 |
| 2003 | 9,274 | 30,349 | 6,879 | 37,228 | 3,636 |
| 2004 | 19,661 | 50,185 | 4,024 | 54,209 | 3,990 |
| 2005 | 29,993 | 72,595 | 4,529 | 77,125 | 5,331 |
| 2006 | 29,469 | 85,607 | 9,226 | 94,834 | 5,932 |
| 2007 | 28,332 | 84,119 | 2,188 | 86,306 | 7,501 |
| 2008 | 23,199 | 95,590 | 2,866 | 98,456 | 12,507 |
| 2009* | -1,655 | 35,478 | -5,988 | 29,490 | -173 |

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*In 2009, data on the U.S. Federal Investment Tax Credit and U.S. State and Local Income Taxes were withheld to avoid disclosure.

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This chapter describes the emissions and engineering cost analysis for the final NSPS. The first section discusses the emissions points and control options. The following section describes each step in the emissions and engineering cost analysis and presents an overview of results. Detailed tables describing the impacts for each source and option can be found at the end of the chapter. We provide reference to the detailed Technical Support Document (TSD) prepared by the EPA for the reader interested in a greater level of detail.¹⁴

3.2 Sector Emissions Overview

This section provides estimates of overall emissions from the crude oil and natural gas industry to provide context for estimated reductions as a result of the rule. Crude oil and natural gas production sector VOC emissions are approximately 2.8 million tons, according to the 2011 EPA National Emissions Inventory (NEI). The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt CO₂ Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all CO₂ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016).

For the analysis supporting this final action, including this RIA, we used the methane 100-year global warming potential (GWP) of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of Greenhouse Gas Emissions and Sinks (GHG Inventory) and the Greenhouse Gas Reporting Program (GHGRP).¹⁵ The use of

¹⁴ U.S. EPA. 2016. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.

¹⁵ See, for example Table A-1 to subpart A of 40 C.F.R. part 98.

the 100-year GWP of 25 for methane value is currently required by the UNFCCC for reporting of national inventories, such as the GHG Inventory. Updated estimates for methane GWP have been developed by IPCC (2013).¹⁶ The most recent 100-year GWP estimates for methane, which are presented in the IPCC Fifth Assessment Report (AR5, 2013), range from 28-36. In discussing the science and impacts of methane emissions generally, we use the GWP range of 28-36. When presenting emissions estimates, we use the GWP of 25 for consistency and comparability with other emissions estimates in the U.S. and internationally.

3.3 Emissions Points and Pollution Controls assessed in the RIA

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. Additional technical details on the engineering and cost basis of the analysis is presented in the TSD.

Completions of Hydraulically Fractured and Re-fractured Oil Wells: Well completion activities include multiple steps after the well bore hole has reached the target depth. The highest emissions are from venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. The TSD separately considers developmental wells and exploratory wells. Developmental wells are wells drilled within known boundaries of a proven oil or gas field, while exploratory or "wildcat" wells are wells drilled in areas of new or unknown potential.

The EPA considered techniques that have been proven to reduce emissions from well completions: reduced emissions completions (RECs) and completion combustion, as well as re-injecting the natural gas back into the well or another well, using the gas as an on-site fuel source, or use for another beneficial purpose. The use of a REC not only reduces emissions but delivers natural gas product that would typically be vented to the sales meter. Completion combustion destroys the organic compounds. Technical barriers to the operation of a separator

¹⁶ IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.

such as well pressure and flowback composition can limit the feasibility of RECs in some situations. Other barriers, such as proximity of pipelines, may prevent recovered gas from being routed to a sales line, but do not necessarily prevent reinjection or on-site use.

Fugitive Emissions: There are several potential sources of fugitive emissions throughout the oil and natural gas sector. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and pressure or mechanical stresses can also cause components or equipment to leak. Potential sources of fugitive emissions include valves, connectors, pressure relief devices, open-ended lines, flanges, closed vent systems, and thief hatches or other openings on a controlled storage unit. These fugitive emissions do not include devices that vent as part of normal operations.

The TSD considers fugitive emissions from production wellsites and compressor stations. The EPA considered two options for reducing methane and VOC emissions from leaking components: a leak monitoring program based on individual component monitoring using EPA Method 21 for leak detection combined with a leak correction, and a leak monitoring program based on the use of OGI leak detection combined with leak correction. In addition, alternative frequencies for fugitive emissions surveys were considered: annual, semiannual, and quarterly.

Pneumatic Controllers: Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These “non-gas driven” pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non-gas-driven controllers are typically used. Continuous bleed pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. The EPA evaluated the impact of replacing high-bleed controllers with low-bleed controllers.

Pneumatic Pumps: Pneumatic pumps are devices that use gas pressure to drive a fluid

by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or a set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996) and can be a significant source of methane and VOC emissions. Pneumatic chemical and methanol injection pumps are generally used to pump small volumes of chemicals or methanol into well bores, surface equipment, and pipelines. Typically, these pumps include plunger pumps with a diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure. They are typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are used widely in the onshore oil and gas sector to move larger volumes of liquids per unit of time at lower discharge pressures than chemical and methanol injection pumps. The usage of these pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and circulation of heat trace medium at wellsites in cold climates during winter months.

For both of these types of pumps, emissions occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratio's between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump. As discussed in the white papers, several options for reducing methane and VOC emissions were identified: replace a natural gas-assisted pump with an instrument air pump, replace a natural gas-assisted pump with a solar-charged direct current pump (solar pumps), replace a natural gas-assisted pump with an electric pump, and route pneumatic pump emissions to a control device. The EPA evaluated the impact of routing pump emissions to a pre-existing on-site control device.

Centrifugal and Reciprocating Compressors: Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. Centrifugal compressors use either wet or dry seals.

Emissions from compressors occur when natural gas leaks around moving parts in the

compressor. In a reciprocating compressor, emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. Over time, during operation of the compressor, the rod packing system becomes worn and will need to be replaced to prevent excessive leaking from the compression cylinder. The control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

Emissions from centrifugal compressors depend on the type of seal used: either “wet”, which use oil circulated at high pressure, or “dry”, which use a thin gap of high pressure gas. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency. Limiting or reducing the emission from the rotating shaft of a centrifugal compressor using a mechanical dry seal system was evaluated. For centrifugal compressors equipped with wet seals, a flare was evaluated as an option for reducing emissions from centrifugal compressors.

3.4 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make to comply with the NSPS. A detailed discussion of the methodology used to estimate cost impacts is presented in the TSD.

The following sections describe each step in the engineering cost analysis. First, representative facilities are established for each source category, including baseline emissions and control options. Second, the number of incrementally affected facilities for each type of equipment or facility are projected. National emissions reductions and cost estimates are calculated by multiplying representative factors, from the first step, by the estimated number of affected facilities in each projection year, from the second step. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted for useful processes or sold. The national cost estimates include estimated revenue from product recovery where applicable.

3.4.1 Regulatory Options

For each emissions source, point, and control option, the TSD develops a representative facility. The characteristics of this facility include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. In this RIA, we examine three broad regulatory options. Table 3-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for promulgation.

Table 3-1 Emissions Sources and Controls Evaluated for the NSPS

| Emissions Point | Emissions Control | Option 1 | Option 2 (final) | Option 3 |
|---|--------------------------------------|-------------------|-----------------------------|------------------|
| Well Completions and Recompletions | | | | |
| Hydraulically Fractured Development Oil Wells | REC / Combustion | X | X | X |
| Hydraulically Fractured Wildcat and Delineation Oil Wells | Combustion | X | X | X |
| Fugitive Emissions | | | | |
| Well Sites | Planning, Monitoring and Maintenance | Annual | Semiannual | Quarterly |
| Gathering and Boosting Stations | Planning, Monitoring and Maintenance | Semiannual | Quarterly | Quarterly |
| Transmission Compressor Stations | Monitoring and Maintenance | Semiannual | Quarterly | Quarterly |
| Pneumatic Pumps | | | | |
| Well Sites | Route to control | X | X | X |
| Pneumatic Controllers | | | | |
| Natural Gas Transmission and Storage | Emissions limit | X | X | X |
| Reciprocating Compressors | | | | |
| Natural Gas Transmission and Storage | Maintenance | X | X | X |
| Centrifugal Compressors | | | | |
| Natural Gas Transmission and Storage | Route to control | X | X | X |

The selected Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers throughout the oil and natural gas source category.

The unselected Options 1 and 3 differ from the selected Option 2 with respect to the requirements for fugitive emissions. Option 1 requires fugitive emissions survey and repair

programs be performed annually at the affected newly drilled or refractured oil and natural gas well sites, and semiannually at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Fewer surveys being performed leads to lower costs and emissions reductions than under the selected Option 2. Finally, the more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in higher costs and higher emissions reductions than Option 2.

3.4.2 Projection of Incrementally Affected Facilities

The second step in estimating national costs and emissions impacts of the final rule is projecting the number of incrementally affected facilities. Incrementally affected facilities are facilities that would be expected to change their emissions control activities as a result of the NSPS. Facilities in states with similar state-level requirements and facilities with only recordkeeping requirements are not included within incrementally affected facilities.

The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. Over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. In 2025, affected facilities include facilities newly established or modified in 2025, and also facilities which were newly established or modified from 2016 through 2024 and are still operating in 2025. The analysis has assumed that all new equipment and facilities established from 2016 through 2024 are still in operation in 2025. This approach differs from the way affected facilities were estimated in the proposal RIA. At proposal, 2020 was assumed to represent a single year of potential impacts, and 2025 included newly established or modified facilities from 2020 through 2024. This methodological

change results in a higher estimate of the number of affected facilities than at proposal and better represents the impacts of the rule.

The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels taken from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year changes over the past ten years in the GHG Inventory. New and modified hydraulically fractured oil well completions and wellsites are based on projections and growth rates consistent with the drilling activity in the Annual Energy Outlook. For the final RIA, the projections have been updated to reflect the projections in the 2015 Annual Energy Outlook. In addition, while the projections used in the proposal RIA were based on the long-term growth trajectory from 2012 to 2025, the current analysis is based on the full times series in the 2015 AEO reference scenario.

The 2015 Annual Energy Outlook was the most recent projection available at the time the analysis underlying this RIA was being prepared. The 2015 AEO includes the growth in U.S. crude oil production over the last two years, along with the late-2014 drop in global crude oil prices, and reflects how these factors have altered the economics of the oil market. In comparison to the 2014 AEO reference case, the 2015 AEO reference case shows higher crude oil production (18 percent higher for 2025 in the 2015 AEO), slightly lower natural gas production (about 4 percent lower for 2025 in the 2015 AEO), lower Brent spot and West Texas Intermediate crude oil prices, and lower total wells drilled in the lower 48 states (about 20 percent lower for 2025 in the 2015 AEO).

While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to largely because of the limited information available on the turnover rate of emissions sources and controls. For this RIA, we have used the U.S. EIA's National Energy Modelling System (NEMS) to generate a limited set of future year projections to inform impact estimates for subset of affected sources. We also used the model to estimate key market impacts of the rules, based upon EPA's parameterization of regulatory costs and natural gas capture in the model. While NEMS produces highly regarded projections of production and well drilling, and is useful to estimate market impacts of the NSPS, it is not a compliance model and does not directly model

affected units. In addition, in a dynamic industry like oil and natural gas, technological progress in control technology is also likely to be dynamic. These factors make it reasonable to use 2025 as the latest year of analysis as extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.

We also reviewed state regulations and permitting requirements which require mitigation measures for many emission sources in the oil and natural gas sector. State regulations in Colorado and Wyoming both require RECs for hydraulically fractured oil and gas wells, and North Dakota requires combustion of completion emissions. Sources in Colorado, Wyoming, Utah, and Ohio are subject to fugitive emissions requirements. Applicable facilities in these states are not included in the estimates of incrementally affected facilities presented in the RIA, as sources in those states are already subject to similar requirements to the federal standards. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements (e.g., to comply with the on-site separator requirement) are not reflected in this RIA. A more detailed discussion on the derivation of the baseline for this rule is presented for each emissions source in the TSD. In section 4.3.1 of the TSD, Table 4-3 provides a detailed breakout of affected oil well completions.

Table 3-2 Incrementally Affected Sources under Final NSPS, 2016 to 2025 on an Annual Basis

| Emissions Sources | Incrementally Affected Sources ¹ | | | | | | | | | |
|--|---|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Oil Well Completions and Recompletions | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 14,000 | 14,000 |
| Fugitive Emissions | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 20,000 | 20,000 | 21,000 |
| Pneumatic Pumps | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 |
| Compressors | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Pneumatic Controllers | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| Total | 32,000 | 32,000 | 33,000 | 33,000 | 33,000 | 33,000 | 33,000 | 34,000 | 35,000 | 35,000 |

¹ Incrementally affected sources includes sources that have to change their control activity as a result of the rule. The table does not include estimate counts of a) affected facilities in states with similar state-level requirements to the NSPS, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except in the case of oil well completions and fugitive emissions at wellsites.

Table 3-2 presents the number of affected sources for each year of analysis after generally accounting for state regulations. In addition to the caveats regarding facilities affected by state regulations described above, facilities with only recordkeeping requirements are also not

included within incrementally affected facilities (e.g., wells with low GOR are not included in the estimate of facilities affected by the oil well completion requirements).

Table 3-3 Total Number of Affected Sources for the NSPS in 2020 and 2025

| Emissions Sources | Affected Sources ¹ | |
|---|-------------------------------|---------------------|
| | 2020 | 2025 |
| Hydraulically Fractured and Re-fractured Oil Well Completions | 13,000 ³ | 14,000 ³ |
| Fugitive Emissions | 94,000 | 190,000 |
| Pneumatic Pumps | 3,900 | 7,900 |
| Compressors | 170 | 330 |
| Pneumatic Controllers | 480 | 960 |
| Total ² | 110,000 | 220,000 |

¹ In addition to newly affected sources in 2020, total affected sources in 2020 include sources that become affected in the 2016-2019 period and are assumed to be in continued operation in 2020. Similarly, affected sources in 2025 reflect sources newly constructed or modified from 2016 to 2025, assumed to still be in operation in 2025. The table does not include estimate counts of: a) affected facilities in states already regulating those sources, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except for oil well completions and fugitive emissions at wellsites. Estimates are rounded to two significant digits.

² Totals may not sum due to independent rounding.

³ Affected oil well completions include a mix of RECs and flaring based on subcategory and technical infeasibility criteria. Exploratory and delineation wells are required to combust emissions. Of development oil well completions, 50% are estimated to be feasible to perform a REC; the remainder would combust emissions (either because they are unable to implement a REC due to low pressure or other technical infeasibility reasons). See section 4.3.1 of the TSD for a detailed breakout of affected oil well completions

Table 3-3 presents estimates of the total number of affected sources for this final rule. Note that hydraulically fractured and re-fractured oil well completions do not grow significantly from 2020 to 2025, while other sources do. This is a result of completions being a one-time activity in a given year, while other sources are affected and remain affected as they continue to operate, thus these sources accumulate over time. The estimates for hydraulically fractured and re-fractured oil well completions and fugitive emissions at wellsites (a large fraction of the incrementally affected sources under the fugitive emissions provisions) include both new and modified sources.

The estimates for other sources are based upon projections of new sources alone, and do not include replacement or modification of existing sources. While some of these sources are unlikely to be modified, particularly pneumatic pumps and controllers, the impact estimates may be under-estimated due to the focus on new sources. In the proposal, the EPA solicited comments on these projection methods as well as solicits information that would improve our

estimate of the turnover rates or rates of modification of relevant sources, as well as the number of wells on wellsites. While the EPA received comments on the projection methods used in the proposal RIA, we did not receive comments with sufficient information to further incorporate modification and turnover in the projection methodologies. The EPA has modified its methodology for using historical inventory information to estimate new sources reflecting comments received, resulting in lower estimates of the number of new compressor stations, pumps, compressors, and pneumatic controllers constructed each year. Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and pneumatic controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years. In years when the total count of equipment decreased, there were assumed to be no newly constructed units.

3.4.3 Emissions Reductions

Table 3-4 summarizes the national emissions reductions for the evaluated NSPS emissions sources and points for 2020 and 2025. These reductions are estimated by multiplying the unit-level emissions reductions associated with each applicable control and facility type by the number of incrementally affected sources. The detailed description of emissions controls is provided in the TSD. Please note that all results have been rounded to two significant digits.

Table 3-4 Emissions Reductions for Final NSPS Option 2, 2020 and 2025

| Source/Emissions Point | Emissions Reductions, 2020 | | | |
|--|----------------------------|------------------|------------------|---|
| | Methane (short tons) | VOC (short tons) | HAP (short tons) | Methane (metric tons CO ₂ Eq.) |
| Oil Well Completions and Recompletions | 120,000 | 97,000 | 12 | 2,600,000 |
| Fugitive Emissions | 170,000 | 46,000 | 1,700 | 3,800,000 |
| Pneumatic Pumps | 13,000 | 3,600 | 140 | 290,000 |
| Compressors | 4,000 | 110 | 3 | 92,000 |
| Pneumatic Controllers | 1,300 | 37 | 1 | 30,000 |
| Total | 300,000 | 150,000 | 1,900 | 6,900,000 |
| Source/Emissions Point | Emissions Reductions, 2025 | | | |
| | Methane (short tons) | VOC (short tons) | HAP (short tons) | Methane (metric tons CO ₂ Eq.) |
| Oil Well Completions and Recompletions | 120,000 | 100,000 | 12 | 2,800,000 |
| Fugitive Emissions | 350,000 | 94,000 | 3,600 | 7,900,000 |
| Pneumatic Pumps | 26,000 | 7,200 | 270 | 590,000 |
| Compressors | 8,100 | 220 | 7 | 180,000 |
| Pneumatic Controllers | 2,700 | 74 | 2 | 61,000 |
| Total | 510,000 | 210,000 | 3,900 | 11,000,000 |

3.4.4 Product Recovery

The annualized cost estimates presented below include revenue from additional natural gas recovery. Several emission controls for the NSPS capture methane and VOC emissions that would otherwise be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For the environmental controls that avert the emission of saleable natural gas, we base the estimated revenues from

averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year.

The controls that result in natural gas recovery are: RECs at hydraulically fractured oil wells, fugitive emissions monitoring and repair, rod packing replacement in reciprocating compressors, and the use of low-bleed pneumatic devices. The requirements for completions at exploration and delineation wells, pneumatic pumps, and centrifugal compressors do not result in natural gas recovery. In some of these cases, alternative control strategies do result in natural gas recovery, but these alternative controls were not assumed as part of this analysis. For example, alternatives to routing pneumatic pump emissions to a control device include substituting a solar or electric pump where a gas-driven pump would have otherwise been used.

Table 3-5 summarizes natural gas recovery and revenue included in annualized cost calculations. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The EIA's 2015 Annual Energy Outlook reference case projects Henry Hub natural gas prices to be \$4.88/MMBtu in 2020 and \$5.46/MMBtu in 2025 in 2013 dollars.¹⁷ After adjusting to \$/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are \$4.94/Mcf in 2020 and \$5.52 in 2025. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The \$4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.¹⁸

Operators in the gathering and boosting, and transmission and storage parts of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and presented in Volume 1 of

¹⁷ Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

¹⁸ An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price. See <http://www.eia.gov/oiaf/analysispaper/henryhub/>.

the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Table 3-5 Estimated Natural Gas Recovery (Mcf) for selected Option 2 in 2020 and 2025

| Source/Emissions Point | 2020 | | 2025 | |
|--|--------------------|-------------------|--------------------|-------------------|
| | Gas recovery (Mcf) | Value of recovery | Gas recovery (Mcf) | Value of recovery |
| Oil Well Completions and Recompletions | 5,700,000 | \$23,000,000 | 6,100,000 | \$24,000,000 |
| Fugitive Emissions | 9,800,000 | \$39,000,000 | 20,000,000 | \$80,000,000 |
| Pneumatic Pumps | 0 | \$0 | 0 | \$0 |
| Compressors | 180,000 | \$720,000 | 360,000 | \$1,400,000 |
| Pneumatic Controllers | 69,000 | \$280,000 | 140,000 | \$550,000 |
| Total | 16,000,000 | \$63,000,000 | 27,000,000 | \$110,000,000 |

As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. In addition, there is geographic variability in wellhead prices, which can also influence estimated engineering costs. For Option 2, a \$1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about 5 percent. Section 3.5.2 further examines the sensitivity of national compliance costs to natural gas prices.

3.4.5 Engineering Compliance Costs

Table 3-6 summarizes the capital and annualized costs and revenue from product recovery for the evaluated emissions sources and points. The capital costs represent total capital cost expenditures associated with affected units in 2020 and 2025, including capital cost expenditures made prior to the analysis year. The detailed description of cost estimates is provided in TSD. To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. This approach is mathematically equivalent to establishing an overall, representative project time horizon and annualizing costs after consideration of control options that would need to be replaced periodically within the given time horizon.

Table 3-6 Engineering Compliance Cost Estimates for Final NSPS Option 2 in 2020 and 2025 (millions 2012\$)

| Source/Emissions Point | Compliance Costs, 2020 | | | |
|--|----------------------------|------------------------------------|-------------------------------|---|
| | Capital Costs ¹ | Annualized Costs (without savings) | Revenue from Product Recovery | Nationwide Annualized Costs with Addl. Revenue (2012\$) |
| Oil Well Completions and Recompletions | \$150 | \$150 | \$23 | \$130 |
| Fugitive Emissions | \$77 | \$230 | \$39 | \$190 |
| Pneumatic Pumps | \$21 | \$3 | \$0 | \$3.1 |
| Compressors | \$1.4 | \$0.9 | \$0.7 | \$0.2 |
| Pneumatic Controllers | \$0.1 | \$0.0 | \$0.3 | -\$0.27 |
| Reporting and Recordkeeping | \$0 | \$6.3 | \$0 | \$6.3 |
| Total | \$250 | \$390 | \$63 | \$320 |

| Source/Emissions Point | Compliance Costs, 2025 | | | |
|--|----------------------------|------------------------------------|-------------------------------|---|
| | Capital Costs ¹ | Annualized Costs (without savings) | Revenue from Product Recovery | Nationwide Annualized Costs with Addl. Revenue (2012\$) |
| Oil Well Completions and Recompletions | \$160 | \$160 | \$24 | \$130 |
| Fugitive Emissions | \$160 | \$460 | \$80 | \$380 |
| Pneumatic Pumps | \$43 | \$6 | \$0 | \$6 |
| Compressors | \$2.9 | \$1.8 | \$1.4 | \$0.3 |
| Pneumatic Controllers | \$0.2 | \$0.0 | \$0.6 | -\$0.5 |
| Reporting and Recordkeeping | \$0.0 | \$6.3 | \$0 | \$6.3 |
| Total | \$360 | \$640 | \$110 | \$530 |

¹ Capital costs represent total capital costs associated with control of affected sources in 2020 and 2025, including expenditures made in previous years. Sums may not total due to independent rounding.

Engineering capital costs were annualized using a 7 percent interest rate. Section 3.4

provides a comparison to using a 3 percent interest rate. Different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used to annualize capital costs of emissions controls:

- Reduced emissions completions and combustion devices: 1 year
- Fugitive emissions monitoring program design: 8 years
- Reciprocating compressors rod packing: 3.8 – 4.4 years
- Centrifugal compressors and pneumatic pumps: 10 years
- Pneumatic controllers: 15 years

Note the large majority of capital costs are required for the completions fugitive emissions requirements. Alternative assumptions of the lifetimes of these expenditures are most likely influence estimates of total compliance costs, where alternative assumptions for compressors, pumps, and controllers would likely to have relatively small effects.

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this final rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Preamble for more detail). The 2020 and 2025 reporting and recordkeeping costs in this RIA are assumed to be equal to the third year cost reporting in the ICR cost estimates (\$6.3 million). These recordkeeping and recordkeeping costs are estimated for the selected Option 2 for all new and modified facilities regardless of whether they implement additional controls as a result of the NSPS. While these costs may differ across regulatory options as a result of the varying frequency of the fugitives program across the options, we do not have the information to estimate the ICR burden for the unselected Option 1 and 3. As a result, we assume all options have the same recordkeeping and reporting cost burden. Note also that reporting and recordkeeping costs are included for all affected entities, regardless of whether they are in states with regulatory requirements similar to the final NSPS.

3.4.6 Comparison of Regulatory Alternatives

Table 3-7 presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025. The requirements between the options vary with respect to the fugitive emissions requirements. The less stringent Option 1 requires annual monitoring for well sites under the fugitive emissions program and semi-annual for compressor stations. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. Annual, semi-annual, and quarterly fugitive emissions surveys are assumed to result in reductions in emissions of 40 percent, 60 percent and 80 percent, respectively.¹⁹ For more information on these assumptions, please see Section 4.3.2.2 of the TSD. Natural gas recovery also varies as a result of survey frequency. Variation in natural gas recovery, capital and annualized costs reflect these differences in the number of affected facilities and frequency of fugitive emissions surveys. In addition, the ratio between national compliance costs and national emissions reductions is presented using both the single pollutant and multipollutant approach.

Table 3-7 Comparison of Regulatory Alternatives

| | Regulatory Alternative | | |
|---|------------------------|---------------------|---------------|
| | Option 1 | Option 2 (final) | Option 3 |
| Impacts in 2020 | | | |
| Affected Sources | 110,000 | 110,000 | 110,000 |
| Emissions Reductions | | | |
| Methane Emissions Reduction (short tons/year) | 250,000 | 300,000 | 350,000 |
| VOC Emissions Reduction (short tons/year) | 130,000 | 150,000 | 160,000 |
| Natural Gas Recovery (Mcf) | 13,000,000 | 16,000,000 | 19,000,000 |
| Compliance Costs | | | |
| Capital Costs (2012\$) | \$240,000,000 | \$250,000,000 | \$260,000,000 |
| Annualized Costs Without Addl. Revenue (2012\$) | \$290,000,000 | \$390,000,000 | \$570,000,000 |
| Annualized Costs With Addl. Revenue (2012\$) | \$240,000,000 | \$320,000,000 | \$490,000,000 |
| Impacts in 2025 | | | |
| Affected Sources | 220,000 | 220,000 | 220,000 |
| Emissions Reductions | | | |
| Methane Emissions Reduction (short tons/year) | 390,000 | 510,000 | 610,000 |
| VOC Emissions Reduction (short tons/year) | 170,000 | 210,000 | 230,000 |

¹⁹ The EPA performed a sensitivity analysis based on the midpoints of the Method 21 emission reduction efficiency percentages, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. Even based on this conservative analysis, the EPA finds that the chosen monitoring frequencies are the BSER for these sources. The EPA additionally concluded that the 40, 60, and 80 percent emission reduction efficiency percentages are reasonable and accurate. See section 4.3.2.2 of the final TSD for further information.

| | | | |
|---|---------------|---------------|-----------------|
| Natural Gas Recovery (Mcf) | 20,000,000 | 27,000,000 | 33,000,000 |
| Compliance Costs | | | |
| Capital Costs (2012\$) | \$350,000,000 | \$360,000,000 | \$380,000,000 |
| Annualized Costs Without Addl. Revenue (2012\$) | \$440,000,000 | \$640,000,000 | \$1,000,000,000 |
| Annualized Costs With Addl. Revenue (2012\$) | \$360,000,000 | \$530,000,000 | \$880,000,000 |

3.5 Engineering Cost Sensitivity Analysis

This section illustrates the sensitivity of engineering cost and emissions analysis results of Option 2 to choice of discount rate and natural gas prices.

3.5.1 Compliance Costs Estimated Using 3 and 7 Percent Discount Rates

Table 3-8 shows that the choice of discount rate has minor effects on the nationwide annualized costs of the final rule.

Table 3-8 Annualized Costs using 3 and 7 Percent Discount Rates for Final NSPS Option 2 in 2020 and 2025 (millions 2012\$)

| | Nationwide Annualized Costs, 2020 | | Nationwide Annualized Costs, 2025 | |
|---|-----------------------------------|--------------|-----------------------------------|--------------|
| | 7 percent | 3 percent | 7 percent | 3 percent |
| Oil Well Completions and Re Completions | \$130 | \$130 | \$130 | \$130 |
| Fugitive Emissions | \$190 | \$190 | \$380 | \$380 |
| Pneumatic Pumps | \$3.1 | \$2.5 | \$6.1 | \$5 |
| Compressors | \$0.16 | \$0.12 | \$0.31 | \$0.24 |
| Pneumatic Controllers | -\$0.27 | -\$0.27 | -\$0.53 | -\$0.54 |
| Reporting and Recordkeeping | \$6.3 | \$6.3 | \$6.3 | \$6.3 |
| Total | \$320 | \$320 | \$530 | \$520 |

The choice of discount rate has a small effect on nationwide annualized costs. Discount rate generally affects estimates of annualized costs for controls with high capital costs relative to annual costs. The compliance costs related to oil well completions and fugitive emissions surveys occur in each year, so the interest rate has little impact on annualized costs for these sources. The annualized costs for pneumatic pumps, compressors, and pneumatic controllers are

sensitive to interest rate, but these constitute a relatively small part of the total compliance cost estimates for the rule.

3.5.2 Sensitivity of Compliance Costs to Natural Gas Prices

The annualized compliance cost estimates presented in this RIA include revenue from additional natural gas recovery, and therefore national compliance costs depend the price of natural gas. This section examines the sensitivity of national compliance costs to varying natural gas prices. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. As discussed earlier, the \$4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.

EPA recognizes that current natural gas prices are below \$4/Mcf. In 2015, the Henry Hub Natural Gas Spot Price ranged between about \$2 and \$3 dollars per MMBtu (about \$1.94/Mcf and \$2.91/Mcf, respectively).²⁰ The models used to forecast natural gas prices in the Annual Energy Outlook are deterministic. A deterministic model does not incorporate potential stochastic influences and will therefore produces the same result for each model run using all else equal. While the Annual Energy Outlook is a commonly referenced publication that provides mid-term forecasts, the U.S. EIA also produces the Short-Term Energy Outlook (STEO), which provides confidence intervals for some energy prices over a shorter time frame based on the prices paid for financial derivatives (e.g., options) based on natural gas. To better understand the uncertainty associated with the 2020 and 2025 natural gas price assumed in this analysis, EPA reviewed the March 2016 STEO, which includes monthly forecasted natural gas prices through 2017.²¹ While the STEO analysis only extends to the end of 2017, the published

²⁰ Assuming the average heat context of natural gas is 1,028 Btu per cubic foot, 1 Mcf = 1.028 MMBtu. Based on this assumption, to convert natural gas prices denominated in MMBtu to Mcf, the \$/MMBtu is multiplied by 1/1.028 or 0.973.

²¹ U.S. Energy Information Administration (U.S. EIA). 2016. Short-Term Energy Outlook, March 8, 2016. <<http://www.eia.gov/forecasts/steo/report/natgas.cfm>> March 8, 2016.

confidence intervals for future natural gas prices can provide some basis for understanding the potential uncertainty around slightly longer-term forecasts.

In the STEO, forecasted prices are traded futures contracts. Based on this information the STEO also presents a 95% confidence interval for the price of natural gas through 2017. However, that the probability analysis uses the Henry Hub spot price, rather than the wellhead price paid to producer. The EIA analysis projects an expected December 2017 Henry Hub price of \$3.31 per MMBtu (\$3.22/Mcf) with a 95 percent confidence interval of \$1.45 to \$5.25 per MMBtu (\$1.41/Mcf to \$5.10/Mcf). While this confidence interval is not for wellhead natural gas prices, it is relevant for understating the challenges associated with precisely predicting future natural gas prices.

To analyze the sensitivity of the engineering costs of the rule to assumed natural gas prices, Table 3-12 presents nationwide annualized costs for each source category assuming natural gas prices of \$2, \$3, \$4, and \$5 per Mcf.

Table 3-9 Annualized Costs Using Natural Gas Prices from \$2 to \$5 per Mcf

| Source/Emissions Point | Nationwide Annualized Costs (million 2012\$), 2020 | | | | Nationwide Annualized Costs (million 2012\$), 2025 | | | |
|--|--|--------------|--------------|--------------|--|--------------|--------------|--------------|
| | \$2/Mcf | \$3/Mcf | \$4/Mcf | \$5/Mcf | \$2/Mcf | \$3/Mcf | \$4/Mcf | \$5/Mcf |
| Oil Well Completions and Recompletions | \$140 | \$130 | \$130 | \$120 | \$150 | \$140 | \$130 | \$130 |
| Fugitive Emissions | \$210 | \$200 | \$190 | \$180 | \$420 | \$400 | \$380 | \$360 |
| Pneumatic Pumps | \$3.1 | \$3.1 | \$3.1 | \$3.1 | \$6.1 | \$6.1 | \$6.1 | \$6.1 |
| Compressors | \$0.52 | \$0.34 | \$0.16 | -\$0.023 | \$1 | \$0.68 | \$0.31 | -\$0.046 |
| Pneumatic Controllers | -\$0.13 | -\$0.20 | -\$0.27 | -\$0.33 | -\$0.25 | -\$0.39 | -\$0.53 | -\$0.67 |
| Reporting and Recordkeeping | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 |
| Total | \$350 | \$340 | \$320 | \$310 | \$580 | \$560 | \$530 | \$500 |

Note that all figures are rounded to two significant digits. Annualized costs are estimated using a 7 percent discount rate. Totals may not sum due to independent rounding.

For Option 2, a \$1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about \$16 million in 2020 and \$27 million in 2025, in 2012 dollars. In percentage terms, a \$1/Mcf reduction in the wellhead price causes about a 5 percent increase in national compliance costs in either 2020 or 2025. These amounts include revenue from product recovery in all segments. As described above, this approach differs with respect to

the gathering and boosting and transmission segments between the unit-level cost and emissions reduction analysis supporting BSER decisions (which is focused on control costs borne by regulated sources) and this RIA (which is focused on societal costs). Operators in the gathering and boosting and transmission and storage segments may not own the natural gas they transport, and so may not be able to offset compliance costs with revenue from product recovery in the short term. Changes in costs are affected for the oil well completions, fugitive emissions sources, reciprocating compressors, and pneumatic controllers because control of these sources results in product recovery. Costs for pumps and centrifugal compressors are not affected because routing emissions to a control does not result in product recovery. Valued at \$4/Mcf, estimated national gas recovery as a result of the NSPS in the gathering and boosting segment would be about \$3 million in 2020 and \$6 million in 2025 and in the transmission and storage segment would be about \$2 million in 2020 and \$4 million in 2025.

3.6 Detailed Impacts Tables

The following tables show the full details of the costs and emissions reductions by emissions sources for each regulatory option in 2020 and 2025.

Table 3-10 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 12,000 | 110,000 | 89,000 | 11 | 2,400,000 | \$140,000,000 | \$120,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 990 | 9,100 | 7,600 | 1 | 210,000 | \$3,700,000 | \$3,700,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 94,000 | 100,000 | 28,000 | 1,100 | 2,300,000 | \$71,000,000 | \$100,000,000 |
| Gathering and Boosting Stations | 480 | 10,000 | 2,800 | 110 | 230,000 | \$1,100,000 | \$4,200,000 |
| Tranmission Compressor Stations | 45 | 2,600 | 73 | 2 | 59,000 | \$740,000 | \$360,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 3,900 | 13,000 | 3,600 | 140 | 290,000 | \$21,000,000 | \$3,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 160 | 3,500 | 96 | 3 | 79,000 | \$1,100,000 | -\$410,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 5 | 560 | 15 | 0 | 13,000 | \$360,000 | \$570,000 |
| Centrifugal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 480 | 1,300 | 37 | 1 | 30,000 | \$110,000 | -\$270,000 |
| Reporting and Recordkeeping | All | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 110,000 | 250,000 | 130,000 | 1,300 | 5,600,000 | \$240,000,000 | \$240,000,000 |

Table 3-11 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 13,000 | 110,000 | 95,000 | 11 | 2,600,000 | \$150,000,000 | \$130,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 1,100 | 10,000 | 8,400 | 1 | 230,000 | \$4,000,000 | \$4,000,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 190,000 | 210,000 | 58,000 | 2,200 | 4,700,000 | \$150,000,000 | \$200,000,000 |
| Gathering and Boosting Stations | 960 | 20,000 | 5,600 | 210 | 460,000 | \$2,300,000 | \$8,300,000 |
| Tranmission Compressor Stations | 90 | 5,200 | 150 | 4 | 120,000 | \$1,500,000 | \$710,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 7,900 | 26,000 | 7,200 | 270 | 590,000 | \$43,000,000 | \$6,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 320 | 7,000 | 190 | 6 | 160,000 | \$2,200,000 | -\$830,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 10 | 1,100 | 31 | 1 | 25,000 | \$720,000 | \$1,100,000 |
| Centrifigal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 960 | 2,700 | 74 | 2 | 61,000 | \$220,000 | -\$530,000 |
| Reporting and Recordkeeping | All | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 220,000 | 390,000 | 170,000 | 2,700 | 8,900,000 | \$350,000,000 | \$360,000,000 |

Table 3-12 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2020

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 12,000 | 110,000 | 89,000 | 11 | 2,400,000 | \$140,000,000 | \$120,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 990 | 9,100 | 7,600 | 1 | 210,000 | \$3,700,000 | \$3,700,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 94,000 | 150,000 | 42,000 | 1,600 | 3,500,000 | \$75,000,000 | \$180,000,000 |
| Gathering and Boosting Stations | 480 | 13,000 | 3,800 | 140 | 310,000 | \$1,100,000 | \$8,900,000 |
| Tranmission Compressor Stations | 45 | 3,500 | 97 | 3 | 79,000 | \$740,000 | \$880,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 3,900 | 13,000 | 3,600 | 140 | 290,000 | \$21,000,000 | \$3,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 160 | 3,500 | 96 | 3 | 79,000 | \$1,100,000 | -\$410,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 5 | 560 | 15 | 0 | 13,000 | \$360,000 | \$570,000 |
| Centrifigal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 480 | 1,300 | 37 | 1 | 30,000 | \$110,000 | -\$270,000 |
| Reporting and Recordkeeping | 0 | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 110,000 | 300,000 | 150,000 | 1,900 | 6,900,000 | \$250,000,000 | \$320,000,000 |

Table 3-13 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2025

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 13,000 | 110,000 | 95,000 | 11 | 2,600,000 | \$150,000,000 | \$130,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 1,100 | 10,000 | 8,400 | 1 | 230,000 | \$4,000,000 | \$4,000,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 190,000 | 310,000 | 87,000 | 3,300 | 7,100,000 | \$150,000,000 | \$360,000,000 |
| Gathering and Boosting Stations | 960 | 27,000 | 7,500 | 280 | 610,000 | \$2,300,000 | \$18,000,000 |
| Tranmission Compressor Stations | 90 | 7,000 | 190 | 6 | 160,000 | \$1,500,000 | \$1,800,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 7,900 | 26,000 | 7,200 | 270 | 590,000 | \$43,000,000 | \$6,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 320 | 7,000 | 190 | 6 | 160,000 | \$2,200,000 | -\$830,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 10 | 1,100 | 31 | 1 | 25,000 | \$720,000 | \$1,100,000 |
| Centrifigal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 960 | 2,700 | 74 | 2 | 61,000 | \$220,000 | -\$530,000 |
| Reporting and Recordkeeping | 0 | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 220,000 | 510,000 | 210,000 | 3,900 | 11,000,000 | \$360,000,000 | \$530,000,000 |

Table 3-14 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 12,000 | 110,000 | 89,000 | 11 | 2,400,000 | \$140,000,000 | \$120,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 990 | 9,100 | 7,600 | 1 | 210,000 | \$3,700,000 | \$3,700,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 94,000 | 200,000 | 57,000 | 2,100 | 4,600,000 | \$83,000,000 | \$350,000,000 |
| Gathering and Boosting Stations | 480 | 13,000 | 3,800 | 140 | 310,000 | \$1,100,000 | \$8,900,000 |
| Tranmission Compressor Stations | 45 | 3,500 | 97 | 3 | 79,000 | \$740,000 | \$880,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 3,900 | 13,000 | 3,600 | 140 | 290,000 | \$21,000,000 | \$3,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 160 | 3,500 | 96 | 3 | 79,000 | \$1,100,000 | -\$410,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 5 | 560 | 15 | 0 | 13,000 | \$360,000 | \$570,000 |
| Centrifigal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 480 | 1,300 | 37 | 1 | 30,000 | \$110,000 | -\$270,000 |
| Reporting and Recordkeeping | 0 | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 110,000 | 350,000 | 160,000 | 2,400 | 8,000,000 | \$260,000,000 | \$490,000,000 |

Table 3-15 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025

| Source/Emissions Point | Projected No. of Affected Units For Which Federal Regulations Require Further Action | Nationwide Emissions Reductions | | | | National Costs | |
|---|--|---------------------------------|-----------------------|-----------------------|----------------------------|----------------------|--------------------------------------|
| | | Methane (short tons/year) | VOC (short tons/year) | HAP (short tons/year) | Methane (metric tons CO2e) | Capital Costs | Annualized Costs With Addl. Revenues |
| Well Completions and Recompletions | | | | | | | |
| Hydraulically Fractured Development Oil Wells | 13,000 | 110,000 | 95,000 | 11 | 2,600,000 | \$150,000,000 | \$130,000,000 |
| Hydraulically Fractured Wildcat and Dilineation Oil Wells | 1,100 | 10,000 | 8,400 | 1 | 230,000 | \$4,000,000 | \$4,000,000 |
| Fugitive Emissions | | | | | | | |
| Well Pads | 190,000 | 420,000 | 120,000 | 4,400 | 9,400,000 | \$170,000,000 | \$710,000,000 |
| Gathering and Boosting Stations | 960 | 27,000 | 7,500 | 280 | 610,000 | \$2,300,000 | \$18,000,000 |
| Tranmission Compressor Stations | 90 | 7,000 | 190 | 6 | 160,000 | \$1,500,000 | \$1,800,000 |
| Pneumatic Pumps | | | | | | | |
| Well Pads | 7,900 | 26,000 | 7,200 | 270 | 590,000 | \$43,000,000 | \$6,100,000 |
| Pneumatic Controllers - | | | | | | | |
| Natural Gas Transmission and Storage Stations | 320 | 7,000 | 190 | 6 | 160,000 | \$2,200,000 | -\$830,000 |
| Reciprocating Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 10 | 1,100 | 31 | 1 | 25,000 | \$720,000 | \$1,100,000 |
| Centrifigal Compressors | | | | | | | |
| Natural Gas Transmission and Storage Stations | 960 | 2,700 | 74 | 2 | 61,000 | \$220,000 | -\$530,000 |
| Reporting and Recordkeeping | 0 | 0 | 0 | 0 | 0 | \$0 | \$6,300,000 |
| TOTAL | 220,000 | 610,000 | 230,000 | 5,000 | 14,000,000 | \$380,000,000 | \$880,000,000 |

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The final NSPS is designed to prevent new emissions from the oil and gas sector. For the NSPS, we predict that there will be climate and ozone benefits from methane reductions, ozone and PM_{2.5} health benefits from VOC reductions, and HAP “co-benefits”. These co-benefits would occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions. The NSPS is anticipated to prevent 300,000 tons of methane, 150,000 tons of VOC, and 1,900 tons of HAP from new sources in 2020. In 2025, the NSPS is estimated to prevent 510,000 tons of methane, 210,000 tons of VOC, and 3,900 tons of HAP. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are estimated to be 6.9 million metric tons in 2020 and 11 million metric tons in 2025. As described in the subsequent sections, these pollutants are associated with substantial climate, health, and welfare effects. The only benefits monetized in this RIA are methane-related climate benefits. The methane-related climate effects are estimated to be \$360 million and \$690 million using a 3 percent discount rate in 2020 and 2025, respectively.²² The specific control techniques for the NSPS are anticipated to have minor emissions disbenefits (e.g., increases in emissions of carbon dioxide (CO₂), nitrogen oxides (NO_x), PM, carbon monoxide (CO), and total hydrocarbons (THC)) and emission changes associated with the energy markets impacts.

While we expect that the avoided VOC emissions will also result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, fine particulate matter (PM_{2.5}), and HAP, we have determined that quantification of the VOC-related health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that these benefits do not exist; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With the data available, we are not able to provide credible health benefits estimates for this rule, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and

²² Table 4-3 presents the methane-related climate effects based on SC-CH₄ at discount rates of 2.5, 3, and 5 percent.

VOC reductions.²³ In this chapter, we provide a qualitative assessment of the health benefits associated with reducing exposure to these pollutants, as well as visibility impairment and ecosystem benefits. Table 4-1 summarizes the quantified and unquantified benefits in this analysis.

Table 4-1 Climate and Human Health Effects of Emission Reductions from this Rule

| Category | Specific Effect | Effect Has Been Quantified | Effect Has Been Monetized | More Information | |
|---|---|--|---------------------------|--|---------------------|
| Improved Environment | | | | | |
| Reduced climate effects | Global climate impacts from methane and carbon dioxide (CO ₂) | — ¹ | ✓ | Marten <i>et al.</i> (2014), SC-CO ₂ TSDs | |
| | Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts) | — | — | IPCC, Ozone ISA, PM ISA ² | |
| Improved Human Health | | | | | |
| Reduced incidence of premature mortality from exposure to PM _{2.5} | Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30) | — | — | PM ISA ³ | |
| | Infant mortality (age <1) | — | — | PM ISA ³ | |
| | Non-fatal heart attacks (age > 18) | — | — | PM ISA ³ | |
| | Hospital admissions—respiratory (all ages) | — | — | PM ISA ³ | |
| | Hospital admissions—cardiovascular (age >20) | — | — | PM ISA ³ | |
| | Emergency room visits for asthma (all ages) | — | — | PM ISA ³ | |
| | Acute bronchitis (age 8-12) | — | — | PM ISA ³ | |
| | Lower respiratory symptoms (age 7-14) | — | — | PM ISA ³ | |
| | Upper respiratory symptoms (asthmatics age 9-11) | — | — | PM ISA ³ | |
| | Reduced incidence of morbidity from exposure to PM _{2.5} | Asthma exacerbation (asthmatics age 6-18) | — | — | PM ISA ³ |
| | | Lost work days (age 18-65) | — | — | PM ISA ³ |
| | | Minor restricted-activity days (age 18-65) | — | — | PM ISA ³ |
| | | Chronic Bronchitis (age >26) | — | — | PM ISA ³ |
| Emergency room visits for cardiovascular effects (all ages) | | — | — | PM ISA ³ | |
| Strokes and cerebrovascular disease (age 50-79) | | — | — | PM ISA ³ | |
| Other cardiovascular effects (e.g., other ages) | | — | — | PM ISA ² | |
| Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations) | — | — | PM ISA ² | | |

²³ Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect those emissions have on ambient PM_{2.5} levels and the health effects associated with PM_{2.5} exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and PM_{2.5} and the highly localized nature of air quality responses associated with VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

| Category | Specific Effect | Effect Has Been Quantified | Effect Has Been Monetized | More Information |
|---|--|----------------------------|---------------------------|----------------------------|
| Reduced incidence of mortality from exposure to ozone | Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc) | — | — | PM ISA ^{2,4} |
| | Cancer, mutagenicity, and genotoxicity effects | — | — | PM ISA ^{2,4} |
| | Premature mortality based on short-term study estimates (all ages) | — | — | Ozone ISA ³ |
| | Premature mortality based on long-term study estimates (age 30–99) | — | — | Ozone ISA ³ |
| Reduced incidence of morbidity from exposure to ozone | Hospital admissions—respiratory causes (age > 65) | — | — | Ozone ISA ³ |
| | Hospital admissions—respiratory causes (age <2) | — | — | Ozone ISA ³ |
| | Emergency department visits for asthma (all ages) | — | — | Ozone ISA ³ |
| | Minor restricted-activity days (age 18–65) | — | — | Ozone ISA ³ |
| | School absence days (age 5–17) | — | — | Ozone ISA ³ |
| | Decreased outdoor worker productivity (age 18–65) | — | — | Ozone ISA ³ |
| | Other respiratory effects (e.g., premature aging of lungs) | — | — | Ozone ISA ² |
| Cardiovascular and nervous system effects | — | — | Ozone ISA ² | |
| | Reproductive and developmental effects | — | — | Ozone ISA ^{2,4} |
| Reduced incidence of morbidity from exposure to HAP | Effects associated with exposure to hazardous air pollutants such as benzene | — | — | ATSDR, IRIS ^{2,3} |
| Improved Environment | | | | |
| Reduced visibility impairment | Visibility in Class 1 areas | — | — | PM ISA ³ |
| | Visibility in residential areas | — | — | PM ISA ³ |
| Reduced effects from PM deposition (organics) | Effects on Individual organisms and ecosystems | — | — | PM ISA ² |
| Reduced vegetation and ecosystem effects from exposure to ozone | Visible foliar injury on vegetation | — | — | Ozone ISA ³ |
| | Reduced vegetation growth and reproduction | — | — | Ozone ISA ³ |
| | Yield and quality of commercial forest products and crops | — | — | Ozone ISA ³ |
| | Damage to urban ornamental plants | — | — | Ozone ISA ² |
| | Carbon sequestration in terrestrial ecosystems | — | — | Ozone ISA ³ |
| | Recreational demand associated with forest aesthetics | — | — | Ozone ISA ² |
| | Other non-use effects | — | — | Ozone ISA ² |
| | Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition) | — | — | Ozone ISA ² |

¹ The global climate and related impacts of CO₂ and CH₄ emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CO₂ and SC-CH₄. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in CO₂ emissions.

² We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

³ We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

⁴ We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

4.2 Emission Reductions from the Final NSPS

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for methane, VOC, and HAP, including wells, wellsites, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing this rule, emission controls may lead to reductions in ambient PM_{2.5} and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and PM_{2.5} formation to VOC emission reductions, we are unable to determine how this rule might affect attainment status without air quality modeling data.²⁴ Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources.²⁵ By contrast, the emission reductions for implementation rules, including this rule, are generally from a specific class of well-characterized sources. In general, the EPA is more confident in the magnitude and location of the emission reductions for implementation rules rather than illustrative NAAQS analyses. Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining future NAAQS.

²⁴ The responsiveness of ozone and PM_{2.5} formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

²⁵ NAAQS RIAs hypothesize, but do not predict, the control strategies States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, some costs and benefits estimated in this RIA may account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

Table 4-2 shows the direct emissions reductions anticipated for this rule, across the regulatory options examined. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of PM_{2.5} and ozone and reducing these emissions would reduce exposure to these secondary pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas, and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 4-2 Direct Emission Reductions across NSPS Regulatory Options in 2020 and 2025

| Pollutant | Option 1 | Option 2 (Final) | Option 3 |
|---|----------|---------------------|----------|
| | | 2020 | |
| Methane (short tons/year) | 250,000 | 300,000 | 350,000 |
| VOC (short tons/year) | 130,000 | 150,000 | 160,000 |
| HAP (short tons/year) | 1,300 | 1,900 | 2,400 |
| Methane (metric tons) | 230,000 | 280,000 | 320,000 |
| Methane (million metric tons CO ₂ Eq.) | 5.6 | 6.9 | 8.0 |
| | | 2025 | |
| Methane (short tons/year) | 390,000 | 510,000 | 610,000 |
| VOC (short tons/year) | 170,000 | 210,000 | 230,000 |
| HAP (short tons/year) | 2,700 | 3,900 | 5,000 |
| Methane (metric tons) | 360,000 | 460,000 | 550,000 |
| Methane (million metric tons CO ₂ Eq.) | 8.9 | 11 | 14 |

4.3 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m² of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO₂. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.97 W/m² of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions.

The oil and gas category emits significant amounts of methane. The public Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt CO₂ Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all CO₂ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016c).

Actions taken to comply with the NSPS are anticipated to significantly decrease methane emissions from the oil and natural gas sector in the United States. The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons CO₂ Eq. in 2020 and by about 12 million metric tons CO₂ Eq. in 2025. It is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; however, the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking. To give a sense of the magnitude of the reductions, the methane reductions estimated for 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the U.S. GHG Inventory for 2014 (about 232 million metric tons CO₂ Eq. are from petroleum and natural gas production and gas processing, transmission, and storage). Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of reductions from total emissions in 2020 and 2025.

We calculated the global social benefits of methane emissions reductions expected from the NSPS using estimates of the social cost of methane (SC-CH₄), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The SC-CH₄ estimates applied in this analysis were developed by Marten *et al.* (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO₂ (SC-CO₂), provides important context for understanding the Marten *et al.* SC-CH₄ estimates. Estimates of the SC-CO₂ have been used by the EPA and other federal agencies to value the impacts of CO₂ emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO₂ is a metric that estimates the monetary value of impacts associated with marginal changes in CO₂ emissions in a given year. Similar the SC-CH₄ includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.

The SC-CO₂ estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO₂ estimates and recommended four global values for use in regulatory analyses. The SC-CO₂ estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO₂ Technical Support Document (2010 SC-CO₂ TSD) provides a complete discussion of the

methods used to develop these estimates and the current SC-CO₂ TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).²⁶

One key methodological aspect discussed in the SC-CO₂ TSDs is the global scope of the estimates. The SC-CO₂ estimates represent global measures because of the distinctive nature of the climate change, which is highly unusual in at least three respects. First, emissions of most GHGs contribute to damages around the world independent of the country in which they are emitted. The SC-CO₂ must therefore incorporate the full (global) damages caused by GHG emissions to address the global nature of the problem. Second, the U.S. operates in a global and highly interconnected economy, such that impacts on the other side of the world can affect our economy. This means that the true costs of climate change to the U.S. are larger than the direct impacts that simply occur within the U.S. Third, climate change represents a classic public goods problem because each country's reductions benefit everyone else and no country can be excluded from enjoying the benefits of other countries' reductions, even if it provides no reductions itself. In this situation, the only way to achieve an economically efficient level of emissions reductions is for countries to cooperate in providing mutually beneficial reductions beyond the level that would be justified only by their own domestic benefits. In reference to the public good nature of mitigation and its role in foreign relations, thirteen prominent academics noted that these "are compelling reasons to focus on a global SCC" (Pizer et al., 2014). In addition, the IWG recently noted that there is no bright line between domestic and global damages. Adverse impacts on other countries can have spillover effects on the United States, particularly in the areas of national security, international trade, public health and humanitarian concerns.²⁷

The 2010 SC-CO₂ TSD also noted a number of limitations to the SC-CO₂ analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently IAMs do not assign value to all of the important physical, ecological, and economic

²⁶ Both the 2010 SC-CO₂ TSD and the current SC-CO₂ TSD are available at:
<<https://www.whitehouse.gov/omb/oira/social-cost-of-carbon>>

²⁷ See Response to Comments: Social Cost of Carbon For Regulatory Impact Analysis Under Executive Order 12866, July 2015, page 31, at <<https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>>

impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research.²⁸ The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SC-CO₂ estimates, though taken together they suggest that the SC-CO₂ estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007), which was the most current IPCC assessment available at the time of the IWG’s 2009-2010 review, concluded that “It is very likely that [SC-CO₂ estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts.” Since then, the peer-reviewed literature has continued to support this conclusion. For example, the IPCC Fifth Assessment report (2014) observed that SC-CO₂ estimates continue to omit various impacts, such as “the effects of the loss of biodiversity among pollinators and wild crops on agriculture.”²⁹ Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO₂ reductions to inform benefit-cost analysis. The new versions of the models offer some improvements in these areas, although further work is warranted.

Accordingly, the EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. The EPA and other agencies also continue to consider feedback on the SC-CO₂ estimates from stakeholders through a range of channels, including public comments on Agency rulemakings that use the SC-CO₂ in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO₂ methodology used by the IWG. In addition, OMB sought public

²⁸ Climate change impacts and social cost of greenhouse gases modeling is an area of active research. For example, see: (1) Howard, Peter, “Omitted Damages: What’s Missing from the Social Cost of Carbon.” March 13, 2014, http://costofcarbon.org/files/Omitted_Damages_Whats_Missing_From_the_Social_Cost_of_Carbon.pdf; and (2) Electric Power Research Institute, “Understanding the Social Cost of carbon: A Technical Assessment,” October 2014, www.epri.com.

²⁹ Oppenheimer, M., M. Campos, R. Warren, J. Birkmann, G. Luber, B. O’Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

comment on the approach used to develop the SC-CO₂ estimates through a separate comment period and published a response to those comments in 2015.³⁰

After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO₂ estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans in July 2015 to obtain expert independent advice from the National Academies of Sciences, Engineering and Medicine to ensure that the SC-CO₂ estimates continue to reflect the best available scientific and economic information on climate change.³¹ The Academies then convened a committee, “Assessing Approaches to Updating the Social Cost of Carbon,” (Committee) that is reviewing the state of the science on estimating the SC-CO₂, and will provide expert, independent advice on the merits of different technical approaches for modeling and highlight research priorities going forward. While the Committee’s review focuses on the SC-CO₂ methodology, recommendations on how to update many of the underlying modeling assumptions will also likely pertain to the SC-CH₄ estimates. EPA will evaluate its approach based upon any feedback received from the Academies’ panel.

To date, the Committee has released an interim report, which recommended against doing a near term update of the SC-CO₂ estimates. For future revisions, the Committee recommended the IWG move efforts towards a broader update of the climate system module consistent with the most recent, best available science, and also offered recommendations for how to enhance the discussion and presentation of uncertainty in the SC-CO₂ estimates. Specifically, the Committee recommended that “the IWG provide guidance in their technical support documents about how [SC-CO₂] uncertainty should be represented and discussed in individual regulatory impact analyses that use the [SC-CO₂]” and that the technical support document for each update of the estimates present a section discussing the uncertainty in the overall approach, in the models used, and uncertainty that may not be included in the estimates.³² At the time of this writing, the IWG

³⁰ See <<https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>>.

³¹ The Academies’ review will be informed by public comments and focus on the technical merits and challenges of potential approaches to improving the SC-CO₂ estimates in future updates. See <<https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>>.

³² National Academies of Sciences, Engineering, and Medicine. (2016). *Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update*. Committee on Assessing Approaches to Updating the Social Cost of Carbon, Board on Environmental Change and Society. Washington, DC: The National Academies Press. doi: 10.17226/21898. See Executive Summary, page 1, for quoted text.

is reviewing the interim report and considering the recommendations. EPA looks forward to working with the IWG to respond to the recommendations and will continue to follow IWG guidance on SC-CO₂.

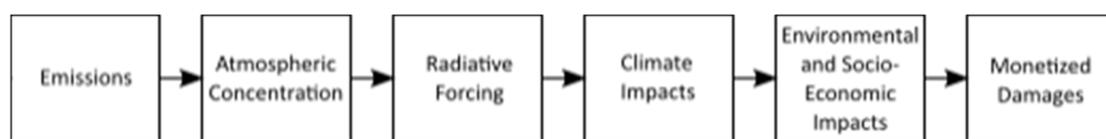
The four SC-CO₂ estimates are: \$13, \$45, \$67, and \$130 per metric ton of CO₂ emissions in the year 2020 (2012 dollars).³³ The first three values are based on the average SC-CO₂ from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the SC-CO₂ for several discount rates are included because the literature shows that the SC-CO₂ is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO₂ across all three models at a 3 percent discount rate. It is included to represent lower probability but higher -impact outcomes from climate change, which are captured further out in the tail of the SC-CO₂ distribution, and while less likely than those reflected by the average SC-CO₂ estimates, would be much more harmful to society and therefore, are relevant to policy makers. The SC-CO₂ increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

A challenge particularly relevant to this analysis is that the IWG did not estimate the social costs of non-CO₂ GHG emissions at the time the SC-CO₂ estimates were developed. One alternative approach to value methane impacts is to use the global warming potential (GWP) to convert the emissions to CO₂ equivalents which are then valued using the SC-CO₂ estimates.

The GWP measures the cumulative radiative forcing from a perturbation of a non-CO₂ GHG relative to a perturbation of CO₂ over a fixed time horizon, often 100 years. The GWP mainly reflects differences in the radiative efficiency of gases and differences in their atmospheric lifetimes. While the GWP is a simple, transparent, and well-established metric for

³³ The current version of the SC-CO₂ TSD is available at: <<https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-td-final-july-2015.pdf>>. The TSDs present SC-CO₂ in \$2007. The estimates were adjusted to 2012\$ using the GDP Implicit Price Deflator (1.0804). Also available at: <http://www.bea.gov/iTable/index_nipa.cfm>. The SC-CO₂ values have been rounded to two significant digits. Unrounded numbers from the 2013 SCC TSD were adjusted to 2012\$ and used to calculate the CO₂ benefits.

assessing the relative impacts of non-CO₂ emissions compared to CO₂ on a purely physical basis, there are several well-documented limitations in using it to value non-CO₂ GHG benefits, as discussed in the 2010 SC-CO₂ TSD and previous rulemakings (e.g., U.S. EPA 2012b, 2012d).³⁴ In particular, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases (Marten and Newbold, 2012; Marten et al. 2014; and Waldhoff et al. 2014). Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO₂ GHG emissions relative to CO₂ at a specific point along the pathway from emissions to monetized damages (depicted in Figure 4-1), and this point may differ across measures.



Source: Marten *et al.* 2014

Figure 4-1 Path from GHG Emissions to Monetized Damages

The GWP is not ideally suited for use in benefit-cost analyses to approximate the social cost of non-CO₂ GHGs because it ignores important nonlinear relationships beyond radiative forcing in the chain between emissions and damages. These can become relevant because gases have different lifetimes and the SC-CO₂ takes into account the fact that marginal damages from an increase in temperature are a function of existing temperature levels. Another limitation of gas comparison metrics for this purpose is that some environmental and socioeconomic impacts are not linked to all of the gases under consideration, or radiative forcing for that matter, and will therefore be incorrectly allocated. For example, the economic impacts associated with increased agricultural productivity due to higher atmospheric CO₂ concentrations included in the SC-CO₂ would be incorrectly allocated to methane emissions with the GWP-based valuation approach.

Also of concern is the fact that the assumptions made in estimating the GWP are not consistent with the assumptions underlying SC-CO₂ estimates in general, and the SC-CO₂ estimates developed by the IWG more specifically. For example, the 100-year time horizon usually used in estimating the GWP is less than the approximately 300-year horizon the IWG

³⁴ See also Reilly and Richards, 1993; Schmalensee, 1993; Fankhauser, 1994; Marten and Newbold, 2012.

used in developing the SC-CO₂ estimates. The GWP approach also treats all impacts within the time horizon equally, independent of the time at which they occur. This is inconsistent with the role of discounting in economic analysis, which accounts for a basic preference for earlier over later gains in utility and expectations regarding future levels of economic growth. In the case of methane, which has a relatively short lifetime compared to CO₂, the temporal independence of the GWP could lead the GWP approach to underestimate the SC-CH₄ with a larger downward bias under higher discount rates (Marten and Newbold, 2012).³⁵

The EPA sought public comments on the valuation of non-CO₂ GHG impacts in previous rulemakings (e.g., U.S. EPA 2012b, 2012d). In general, the commenters strongly encouraged the EPA to incorporate the monetized value of non-CO₂ GHG impacts into the benefit cost analysis, however they noted the challenges associated with the GWP-approach, as discussed above, and encouraged the use of directly-modeled estimates of the SC-CH₄ to overcome those challenges.

The EPA had cited several researchers that had directly estimated the social cost of non-CO₂ emissions using IAMs but noted that the number of such estimates was small compared to the large number of SC-CO₂ estimates available in the literature. The EPA found considerable variation among these published estimates in terms of the models and input assumptions they employ (U.S. EPA, 2012d)³⁶. These studies differed in the emissions perturbation year, employed a wide range of constant and variable discount rate specifications, and considered a range of baseline socioeconomic and emissions scenarios that have been developed over the last 20 years. Furthermore, at the time, none of the other published estimates of the social cost of non-CO₂ GHG were consistent with the SC-CO₂ estimates developed by the IWG, and most were likely underestimates due to changes in the underlying science since their publication.

Therefore, the EPA concluded in those rulemaking analyses that the GWP approach would serve as an interim method of analysis until directly modeled social cost estimates for non-CO₂ GHGs, consistent with the SC-CO₂ estimates developed by the IWG, were developed.

³⁵ We note that the truncation of the time period in the GWP calculation could lead to an overestimate of SC-CH₄ for near term perturbation years when the SC-CO₂ is based on a sufficiently low or steeply declining discount rate.

³⁶ The researchers cited U.S. EPA 2012d include: Fankhauser (1994); Kandlikar (1995); Hammitt et al. (1996); Tol et al. (2003); Tol (2004); and Hope and Newberry (2006).

The EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefit-cost analyses.³⁷

Since then, a paper by Marten *et al.* (2014) provided the first set of published SC-CH₄ estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO₂ estimates.³⁸ Specifically, the estimation approach Marten *et al.* used incorporated the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO₂ estimates. The aggregation method involved distilling the 45 distributions of the SC-CH₄ produced for each emissions year into four estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3 percent discount rate. Marten *et al.* also used the same rationale as the IWG to develop global estimates of the SC-CH₄, given that methane is a global pollutant.

In addition, the atmospheric lifetime and radiative efficacy of methane used by Marten *et al.* is based on the estimates reported by the IPCC in their Fourth Assessment Report (AR4, 2007), including an adjustment in the radiative efficacy of methane to account for its role as a precursor for tropospheric ozone and stratospheric water. These values represent the same ones used by the IPCC in AR4 for calculating GWPs. At the time Marten *et al.* developed their estimates of the SC-CH₄, AR4 was the latest assessment report by the IPCC. The IPCC updates GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest estimate of the methane GWP ranged from 28-36, compared to a GWP of 25 in AR4. The updated values reflect a number of changes: changes in the lifetime and radiative efficiency estimates for CO₂, changes in the lifetime estimate for methane, and changes in the correction

³⁷ For example, the 2012 New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry are expected to reduce methane emissions by 900,000 metric tons annually, see <<http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf>>. Additionally, the 2017-2025 Light-duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, promulgated jointly with the National Highway Traffic Safety Administration, is expected to reduce methane emissions by over 100,000 metric tons in 2025 increasing to nearly 500,000 metric tons in 2050, see <<http://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf>>.

³⁸ Marten *et al.* (2014) also provided the first set of SC-N₂O estimates that are consistent with the assumptions underlying the SC-CO₂ estimates.

factor applied to methane's GWP to reflect the effect of methane emissions on other climatically important substances such as tropospheric ozone and stratospheric water vapor. In addition, the range presented in the latest IPCC report reflects different choices regarding whether to account for climate feedbacks on the carbon cycle for both methane and CO₂ (rather than just for CO₂ as was done in AR4).^{39,40}

Marten *et al.* (2014) discuss these estimates, (SC-CH₄ estimates presented below in Table 4-3), and compare them with other recent estimates in the literature.⁴¹ The authors noted that a direct comparison of their estimates with all of the other published estimates is difficult, given the differences in the models and socioeconomic and emissions scenarios, but results from three relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and Newbold (2012), Waldhoff *et al.* (2014)). Marten *et al.* found that, in general, the SC-CH₄ estimates from their 2014 paper are higher than previous estimates. The higher SC-CH₄ estimates are partially driven by the higher effective radiative forcing due to the inclusion of indirect effects from methane emissions in their modeling. Marten *et al.*, similar to other recent studies, also find that their directly modeled SC-CH₄ estimates are higher than the GWP-weighted estimates. More detailed discussion of the SC-CH₄ estimation methodology, results and a comparison to other published estimates can be found in Marten *et al.*

³⁹ *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

⁴⁰ Note that this analysis uses a GWP value for methane of 25 for CO₂ equivalency calculations, consistent with the GHG emissions inventories and the IPCC Fourth Assessment Report (AR4).

⁴¹ Marten *et al.* (2014) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using National Income and Product Accounts Tables, Table 1.1.9, Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), <http://www.bea.gov/iTable/index_nipa.cfm> (1.0804) Accessed 3/3/15.

**Table 4-3 Social Cost of Methane (SC-CH₄), 2012 – 2050^a [in 2012\$ per metric ton]
(Source: Marten *et al.*, 2014^b)**

| Year | SC-CH ₄ | | | |
|------|--------------------|-------------------|---------------------|---------------------------|
| | 5 Percent Average | 3 Percent Average | 2.5 Percent Average | 3 Percent 95th percentile |
| 2012 | \$430 | \$1,000 | \$1,400 | \$2,800 |
| 2015 | \$490 | \$1,100 | \$1,500 | \$3,000 |
| 2020 | \$580 | \$1,300 | \$1,700 | \$3,500 |
| 2025 | \$700 | \$1,500 | \$1,900 | \$4,000 |
| 2030 | \$820 | \$1,700 | \$2,200 | \$4,500 |
| 2035 | \$970 | \$1,900 | \$2,500 | \$5,300 |
| 2040 | \$1,100 | \$2,200 | \$2,800 | \$5,900 |
| 2045 | \$1,300 | \$2,500 | \$3,000 | \$6,600 |
| 2050 | \$1,400 | \$2,700 | \$3,300 | \$7,200 |

^a The values are emissions-year specific and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

^b The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO₂ estimates described above. See Corrigendum to Marten *et al.* (2014) for more details
<<http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550>>.

The application of directly modeled estimates from Marten *et al.* (2014) to benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO₂ estimates. Specifically, the SC-CH₄ estimates in Table 4-3 are used to monetize the benefits of reductions in methane emissions expected as a result of the rulemaking. Forecasted changes in methane emissions in a given year, expected as a result of the regulatory action, are multiplied by the SC-CH₄ estimate for that year. To obtain a present value estimate, the monetized stream of future non-CO₂ benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-CO₂ GHG emission changes. In addition, the limitations for the SC-CO₂ estimates discussed above likewise apply to the SC-CH₄ estimates, given the consistency in the methodology.

In early 2015, the EPA conducted a peer review of the application of the Marten *et al.* (2014) non-CO₂ social cost estimates in regulatory analysis and received responses that supported this application.⁴² Three reviewers considered seven charge questions that covered

⁴² For a copy of the peer review responses, see Docket ID EPA-HQ-OAR-2010-0505-5016. Also available at <https://cfpub.epa.gov/si/si_public_pra_view.cfm?dirEntryID=291976> (see “SCCH4 EPA PEER REVIEW FILES.PDF”).

issues such as the EPA's interpretation of the Marten *et al.* estimates, the consistency of the estimates with the SC-CO₂ estimates, the EPA's characterization of the limits of the GWP-approach to value non-CO₂ GHG impacts, and the appropriateness of using the Marten *et al.* estimates in regulatory impact analyses. The reviewers agreed with the EPA's interpretation of Marten *et al.*'s estimates, generally found the estimates to be consistent with the SC-CO₂ estimates, and concurred with the limitations of the GWP approach, finding directly modeled estimates to be more appropriate. While outside of the scope of the review, the reviewers briefly considered the limitations in the SC-CO₂ methodology (e.g., those discussed earlier in this section) and noted that because the SC-CO₂ and SC-CH₄ methodologies are similar, the limitations also apply to the resulting SC-CH₄ estimates. Two of the reviewers concluded that use of the SC-CH₄ estimates developed by Marten *et al.* and published in the peer-reviewed literature is appropriate in RIAs, provided that the Agency discuss the limitations, similar to the discussion provided for SC-CO₂ and other economic analyses. All three reviewers encouraged continued improvements in the SC-CO₂ estimates and suggested that as those improvements are realized they should also be reflected in the SC-CH₄ estimates, with one reviewer suggesting the SC-CH₄ estimates lag this process. The EPA supports continued improvement in the SC-CO₂ estimates developed by the U.S. government and agrees that improvements in the SC-CO₂ estimates should also be reflected in the SC-CH₄ estimates. The fact that the reviewers agree that the SC-CH₄ estimates are generally consistent with the SC-CO₂ estimates that are recommended by OMB's guidance on valuing CO₂ emissions reductions, leads the EPA to conclude that use of the SC-CH₄ estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis.

The EPA also carefully considered the full range of public comments and associated technical issues on the Marten *et al.* SC-CH₄ estimates received through this rulemaking and determined that it would continue to use the estimates in the final rulemaking analysis. Based on the evaluation of the public comments on this rulemaking, the favorable peer review of the Marten *et al.* application, and past comments urging the EPA to value non-CO₂ GHG impacts in its rulemakings, the EPA concluded that the estimates represent the best scientific information on the impacts of climate change available in a form appropriate for incorporating the damages from incremental methane emissions changes into regulatory analysis. The Agency has valued the methane benefits expected from this rulemaking using the Marten *et al.* (2014) SC-CH₄ estimates

and has included those benefits in the main benefits analysis. Please see the Response to Comments document, section XIII-H-4, for EPA’s detailed responses to the comments on methane valuation.

The estimated methane benefits are presented in Table 4-4 below for years 2020 and 2025 across regulatory options. Applying this approach to the methane reductions estimated for the final NSPS option (Option 2), the 2020 methane benefits vary by discount rate and range from about \$160 million to approximately \$950 million; the mean SC-CH₄ at the 3 percent discount rate results in an estimate of about \$360 million in 2020. The methane benefits increase for Option 2 in 2025 and likewise vary by discount rate, ranging from about \$320 million to approximately \$1.8 billion in that year; the mean SC-CH₄ at the 3-percent discount rate results in an estimate of about \$690 million in 2025.

Table 4-4 Estimated Global Benefits of Methane Reductions* (in millions, 2012\$)

| Discount rate and statistic | Option 1 | | Option 2 (final) | | Option 3 | |
|--|----------|---------|------------------|---------|----------|---------|
| | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| Million metric tonnes of methane reduced | 0.23 | 0.36 | 0.28 | 0.46 | 0.32 | 0.55 |
| Million metric tonnes of CO ₂ Eq. | 5.6 | 8.9 | 6.9 | 11 | 8.0 | 14 |
| 5% (average) | \$130 | \$250 | \$160 | \$320 | \$190 | \$390 |
| 3% (average) | \$290 | \$540 | \$360 | \$690 | \$420 | \$840 |
| 2.5% (average) | \$390 | \$690 | \$480 | \$890 | \$560 | \$1,100 |
| 3% (95 th percentile) | \$780 | \$1,400 | \$950 | \$1,800 | \$1,100 | \$2,200 |

*The SC-CH₄ values are dollar-year and emissions-year specific. SC-CH₄ values represent only a partial accounting of climate impacts.

The vast majority of this rule’s climate-related benefits are associated with methane reductions, but some climate-related impacts are expected from the rule’s secondary air impacts. The secondary impacts are discussed in Section 4.7.

Methane is also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2013). Approximately 40 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (HTAP, 2010). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (HTAP, 2010). Unlike NO_x and VOCs, which affect ozone concentrations regionally and at time scales of hours to days, methane emissions

affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime (HTAP, 2010). Reducing methane emissions, therefore, can reduce global background ozone concentrations, human exposure to ozone, and the incidence of ozone-related health effects (West *et al.*, 2006, Anenberg *et al.*, 2009). These benefits are global and occur in both urban and rural areas. Reductions in background ozone concentrations can also have benefits for agriculture and ecosystems (UNEP/WMO, 2011). Studies show that controlling methane emissions can reduce global ozone concentrations and climate change simultaneously. But, controlling other shorter-lived ozone precursors such as NO_x, carbon monoxide, or non-methane VOCs have larger local health benefits from greater reductions in local ozone concentrations (West and Fiore, 2005; West *et al.*, 2006; Fiore *et al.*, 2008; Dentener *et al.*, 2005; Shindell *et al.*, 2005, 2012; UNEP/WMO, 2011). The health, welfare, and climate effects associated with ozone are described in the preceding sections.

A paper was published in the peer-reviewed scientific literature that presented a range of estimates of the monetized ozone-related mortality benefits of reducing methane emissions (Sarofim *et al.* 2015). For example, under their base case assumptions using a 3% discount rate, Sarofim *et al.* find global ozone-related mortality benefits of methane emissions reductions to be \$790 per tonne of methane in 2020, with 10.6%, or \$80, of this amount resulting from mortality reductions in the United States. The methodology used in this study is consistent in some (but not all) aspects with the modeling underlying the SC-CO₂ and SC-CH₄ estimates discussed above, and required a number of additional assumptions such as baseline mortality rates and mortality response to ozone concentrations. The proposal requested comment on the application of the Sarofim *et al.* (2015) for this benefits analysis as an approach to estimating the ozone related mortality benefits resulting from the methane reductions expected from this rulemaking. Some commenters objected to the inclusion of these benefits because they argue that methane is not a VOC, whereas one commenter agreed that there is a connection between methane emissions, higher ozone levels, and therefore human mortality. While the EPA does consider the methane impacts on ozone to be important, there remain unresolved questions regarding several methodological choices involved in applying the Sarofim *et al.* (2015) approach in the context of an EPA benefits analysis, and therefore the EPA is not including a quantitative analysis of this effect in this rule at this time.

4.4 VOC as a PM_{2.5} Precursor

This rulemaking would reduce emissions of VOC, which are a precursor to PM_{2.5}. Most VOC emitted are oxidized to CO₂ rather than to PM, but a portion of VOC emission contributes to ambient PM_{2.5} levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce PM_{2.5} formation, human exposure to PM_{2.5}, and the incidence of PM_{2.5}-related health effects. However, we have not quantified the PM_{2.5}-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory, it is unlikely this sector has a large contribution to ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 µg/m³.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform the air quality modeling needed to quantify PM_{2.5} benefits associated with reducing VOC emissions for this rule. Due to the high degree of variability in the responsiveness of PM_{2.5} formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient PM_{2.5} levels without air quality modeling. However, we provide the discussion below for context regarding findings from previous modeling.

4.4.1 PM_{2.5} Health Effects and Valuation

Reducing VOC emissions would reduce PM_{2.5} formation, human exposure, and the incidence of PM_{2.5}-related health effects. Reducing exposure to PM_{2.5} is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated PM_{2.5}- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, the EPA generally quantifies several health effects associated with

exposure to PM_{2.5} (e.g., U.S. EPA (2011g)). These health effects include premature mortality for adults and infants; cardiovascular morbidity, such as heart attacks; respiratory morbidity, such as asthma attacks and acute and chronic bronchitis; which result in hospital and ER visits, lost work days, restricted activity days, and respiratory symptoms. Although the EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to PM_{2.5} is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

When the EPA quantifies PM_{2.5}-related benefits, the agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of PM_{2.5} in the underlying epidemiology studies.

Fann, Fulcher, and Hubbell (2009) examined how the monetized benefit-per-ton estimates of reducing ambient PM_{2.5} varies by the location of the emission reduction, the type of source emitting the precursor, and the specific precursor controlled. This study employed a reduced form air quality model to estimate changes in ambient PM_{2.5} from reducing 12 different combinations of precursor emissions and emission sources, including reducing directly emitted carbonaceous particles, nitrogen oxides, sulfur oxides, ammonia, and VOCs for nine urban areas and nationwide. For each precursor/source combination in each location, the study authors then estimated the total monetized health benefits associated with the PM_{2.5} change and divided these benefits by the corresponding emissions changes to generate benefit-per-ton estimates. The estimates from this study can provide general context for the unquantified VOC benefits in this rulemaking. Specifically, Fann, Fulcher, and Hubbell (2009) found that the monetized benefit-per-ton of reducing VOC emissions ranged from \$560 in Seattle, WA to \$5,700 in San Joaquin, CA, with a national average of \$2,400. These estimates assume a 50 percent reduction in VOC, from the Laden *et al.* (2006) mortality function (based on the Harvard Six Cities study, a large cohort epidemiology study in the Eastern U.S., an analysis year of 2015, a 3 percent discount

rate, and 2006\$). Additional benefit-per-ton estimates are available from this dataset using alternate assumptions regarding the relationship between PM_{2.5} exposure and premature mortality from empirical studies and those supplied by experts (e.g., Pope *et al.*, 2002; Laden *et al.*, 2006; Roman *et al.*, 2008). The EPA generally presents a range of benefits estimates derived from the American Cancer Society cohort (e.g., Pope *et al.*, 2002; Krewski *et al.*, 2009) to the Harvard Six Cities cohort (e.g., Laden *et al.*, 2006; Lepuele *et al.*, 2012) because the studies are both well-designed and extensively peer reviewed. The EPA provides the benefit estimates derived from expert opinions in Roman *et al.* (2008) as a characterization of uncertainty. As shown in Table 4-5, the range of VOC benefits that reflect the range of epidemiology studies and the range of the urban areas is \$300 to \$7,500 per ton of VOC reduced (2012\$).⁴³ Since these estimates were presented in the 2012 Oil and Gas NSPS RIA (U.S. EPA, 2012b), we updated our methods to apply more recent epidemiological studies for these cohorts (i.e., Krewski *et al.*, 2009; Lepuele *et al.*, 2012) as well as additional updates to the morbidity studies and population data.⁴⁴ Because these updates would not lead to significant changes in the benefit-per-ton estimates for VOC, we have not updated them here.

While these ranges of benefit-per-ton estimates provide general context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and PM_{2.5}, these factors lead the EPA to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of this rule, even as a bounding exercise.

⁴³ We also converted the estimates from Fann, Fulcher, and Hubbell (2009) to 2012\$ and applied EPA's current value of a statistical life (VSL) estimate. For more information regarding EPA's current VSL estimate, please see Section 5.6.5.1 of the RIA for the PM NAAQS RIA (U.S. EPA, 2012c). EPA continues to work to update its guidance on valuing mortality risk reductions.

⁴⁴ For more information regarding these updates, please see Section 5.3 of the RIA for the final PM NAAQS (U.S. EPA, 2012c).

Table 4-5 Monetized Benefits-per-Ton Estimates for VOC in 9 Urban Areas and Nationwide based on Fann, Fulcher, and Hubbell (2009) in (2012\$)

| Area | Pope <i>et al.</i> (2002) | Laden <i>et al.</i> (2006) | Expert A | Expert B | Expert C | Expert D | Expert E | Expert F | Expert G | Expert H | Expert I | Expert J | Expert K | Expert L |
|-------------------------|------------------------------|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|--------------|----------------|
| Atlanta | \$660 | \$1,600 | \$1,700 | \$1,300 | \$1,300 | \$920 | \$2,100 | \$1,200 | \$780 | \$980 | \$1,300 | \$1,000 | \$260 | \$1,000 |
| Chicago | \$1,600 | \$4,000 | \$4,200 | \$3,300 | \$3,200 | \$2,300 | \$5,300 | \$3,000 | \$1,900 | \$2,400 | \$3,200 | \$2,600 | \$640 | \$2,500 |
| Dallas | \$320 | \$790 | \$830 | \$650 | \$630 | \$450 | \$1,000 | \$580 | \$380 | \$480 | \$630 | \$510 | \$130 | \$490 |
| Denver | \$770 | \$1,900 | \$2,000 | \$1,500 | \$1,500 | \$1,100 | \$2,400 | \$1,400 | \$910 | \$1,100 | \$1,500 | \$1,200 | \$300 | \$910 |
| NYC/ Philadelphia | \$2,300 | \$5,600 | \$5,900 | \$4,600 | \$4,500 | \$3,200 | \$7,300 | \$4,100 | \$2,700 | \$3,400 | \$4,500 | \$3,600 | \$890 | \$3,300 |
| Phoenix | \$1,100 | \$2,700 | \$2,800 | \$2,200 | \$2,100 | \$1,500 | \$3,500 | \$2,000 | \$1,300 | \$1,600 | \$2,100 | \$1,700 | \$420 | \$1,600 |
| Salt Lake | \$1,400 | \$3,300 | \$3,500 | \$2,700 | \$2,700 | \$1,900 | \$4,400 | \$2,500 | \$1,600 | \$2,000 | \$2,700 | \$2,200 | \$570 | \$2,100 |
| San Joaquin | \$3,100 | \$7,500 | \$7,900 | \$6,100 | \$6,000 | \$4,300 | \$9,700 | \$5,500 | \$3,600 | \$4,500 | \$6,000 | \$4,900 | \$1,400 | \$4,600 |
| Seattle | \$300 | \$730 | \$770 | \$570 | \$590 | \$420 | \$950 | \$540 | \$350 | \$440 | \$580 | \$470 | \$120 | \$350 |
| National average | \$1,300 | \$3,200 | \$3,400 | \$2,600 | \$2,600 | \$1,800 | \$4,200 | \$2,300 | \$1,500 | \$1,900 | \$2,500 | \$2,100 | \$520 | \$1,900 |

* The estimates in this table provide general context regarding the potential magnitude of monetized benefits from reducing VOC emissions, but these urban areas were not chosen based on the locations of VOC emissions from the oil and gas sector. Coupled with other uncertainties, these VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of this rule. These estimates assumed a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been adjusted from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and the EPA's current VSL estimate. However, these estimates have not been updated to reflect recent epidemiological studies for mortality studies, morbidity studies, or population data. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the VOC benefit-per-ton estimates by approximately 13 percent. Assuming a 25 percent reduction in VOC emissions would decrease the VOC benefit-per-ton estimates by 13 percent. The EPA generally presents a range of benefits estimates derived from the expert functions from Roman *et al.* (2008) as a characterization of uncertainty.

4.4.2 *Organic PM Welfare Effects*

According to the previous residual risk assessment for this sector (U.S. EPA, 2012a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a). This summary is from section 6.6.1 of the 2012 PM NAAQS RIA (U.S. EPA, 2012c).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers *et al.*, 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the

original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.4.3 *Visibility Effects*

Reducing secondary formation of PM_{2.5} from VOC emissions would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2011a; U.S. EPA, 2011g; U.S. EPA, 2012c) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.5 VOC as an Ozone Precursor

This rulemaking would reduce emissions of VOC, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NO_x), react in the presence of sunlight. In urban areas, compounds representing all classes of VOC are important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a, 2014b). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a

benefit-per-ton estimate, particularly for sectors with substantial new growth. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOC. Rural areas and downwind suburban areas are often NO_x-limited, which means that ozone concentrations are most effectively reduced by lowering NO_x emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NO_x and VOC.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform air quality modeling for this rule needed to quantify the ozone benefits associated with reducing VOC emissions. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions and data limitations regarding the location of new and modified wellsites, we are unable to estimate the effect that reducing VOC will have on ambient ozone concentrations without air quality modeling.

4.5.1 Ozone Health Effects and Valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2013). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. The scientific literature is also suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOC from industrial boilers resulted in \$3.6 to \$15 million (2008\$) of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).⁴⁵ After updating the currency year to 2012\$, this implies a

⁴⁵ While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NO_x emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

benefit-per-ton for ozone of \$260 to \$1,100 per ton of VOC reduced. Since EPA conducted the analysis of industrial boilers, EPA published the *Integrated Science Assessment for Ozone* (U.S. EPA, 2013), the *Health Risk and Exposure Assessment for Ozone* (U.S. EPA, 2014a), and the RIA for the proposed Ozone NAAQS (U.S. EPA, 2014b). Therefore, the ozone mortality studies applied in the boiler analysis, while current at that time, do not reflect the most updated literature available. The selection of ozone mortality studies used to estimate benefits in RIAs was revisited in the RIA for the proposed Ozone NAAQS. Applying the more recent studies would lead to benefit-per-ton estimates for ozone within the range shown here. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those estimates to provide useful estimates of the monetized benefits of this rule, even as a bounding exercise.

4.5.2 Ozone Vegetation Effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

4.5.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing greenhouse gas (GHG) (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun’s harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming

levels of increased tropospheric ozone concentrations resulting from human methane, NO_x, and VOC emissions was 0.5 W/m², or about 30 percent as large a warming influence as elevated CO₂ concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

4.6 Hazardous Air Pollutant (HAP) Benefits

When looking at exposures from all air toxic sources of outdoor origin across the U.S., we see that emissions declined by approximately 60 percent since 1990. However, despite this decline, the 2011 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2015).⁴⁶ The levels of air toxics to which people are exposed vary depending on where they live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, the EPA conducts the NATA.⁴⁷ The most recent NATA was conducted for calendar year 2011 and was released in December 2015. NATA includes four steps:

- 1) Compiling a national emissions inventory of air toxics emissions from outdoor sources
- 2) Estimating ambient concentrations of air toxics across the U.S. utilizing dispersion models
- 3) Estimating population exposures across the U.S. utilizing exposure models
- 4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2011 NATA, the EPA estimates that less than 1 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 40 in a million. Nationwide, the key pollutants that contribute most to the overall

⁴⁶ The 2011 NATA is available on the Internet at <http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment>.

⁴⁷ The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2011 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2015) 2011 National-Scale Air Toxics Assessment. <<http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment>>.

cancer risks are formaldehyde and benzene.^{48,49} Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile, biogenics, and background sources contribute lesser amounts to the remaining cancer risk.

Noncancer health effects can result from chronic,⁵⁰ subchronic,⁵¹ or acute⁵² inhalation exposure to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2011 NATA, about 80 percent of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2011 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-2 and Figure 4-3 depict the 2011 NATA estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions were more than seventeen times acrolein emissions on a national basis in the EPA's 2011 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, this results in 2011 NATA estimates of nationwide chronic respiratory noncancer risks from acrolein being over three times that of

⁴⁸ Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2011 NATA risk estimates can be found at <<http://www.epa.gov/national-air-toxics-assessment/nata-limitations>>.

⁴⁹ Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at <<http://www.epa.gov/national-air-toxics-assessment/nata-limitations>>.

⁵⁰ Chronic exposure is defined in the glossary of the Integrated Risk Information System (IRIS) database (<<http://www.epa.gov/iris>>) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10 of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

⁵¹ Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10 of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

⁵² Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

acetaldehyde.⁵³ Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

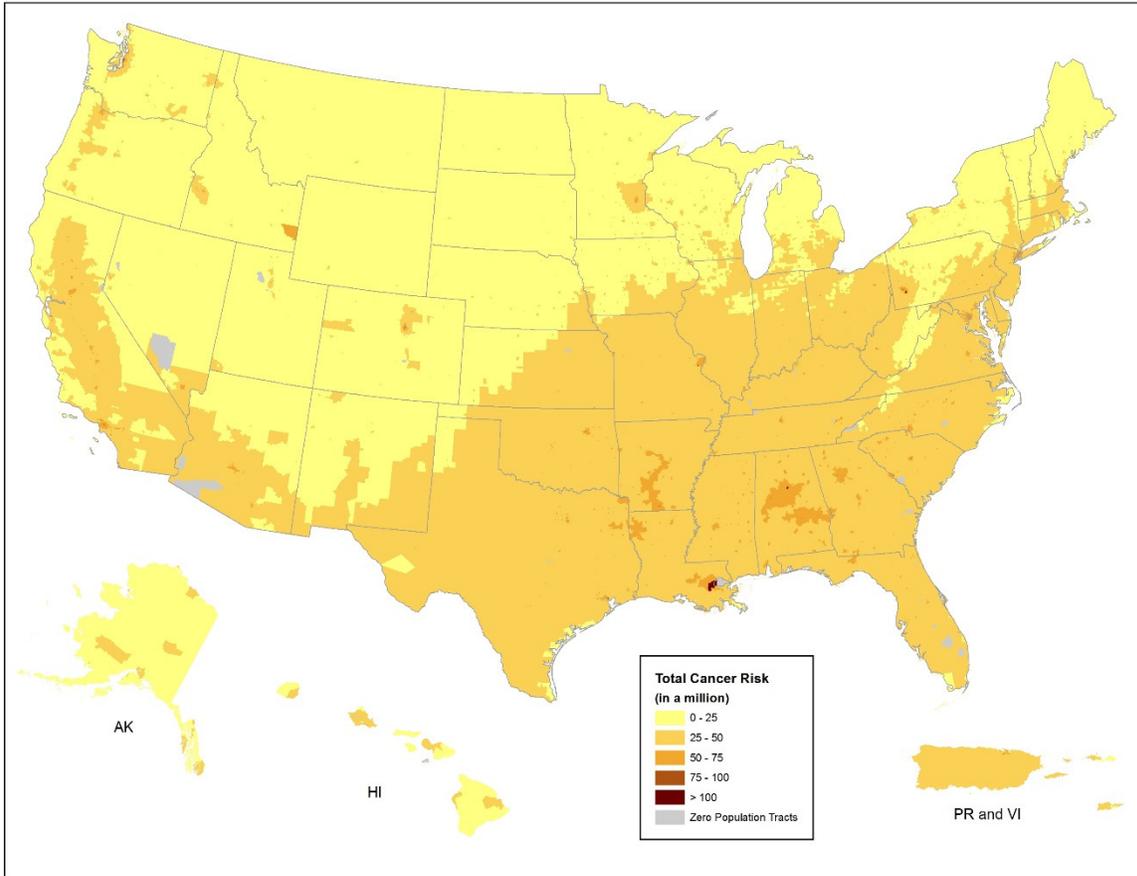


Figure 4-2 2011 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

⁵³ Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at <<http://www.epa.gov/iris>>.

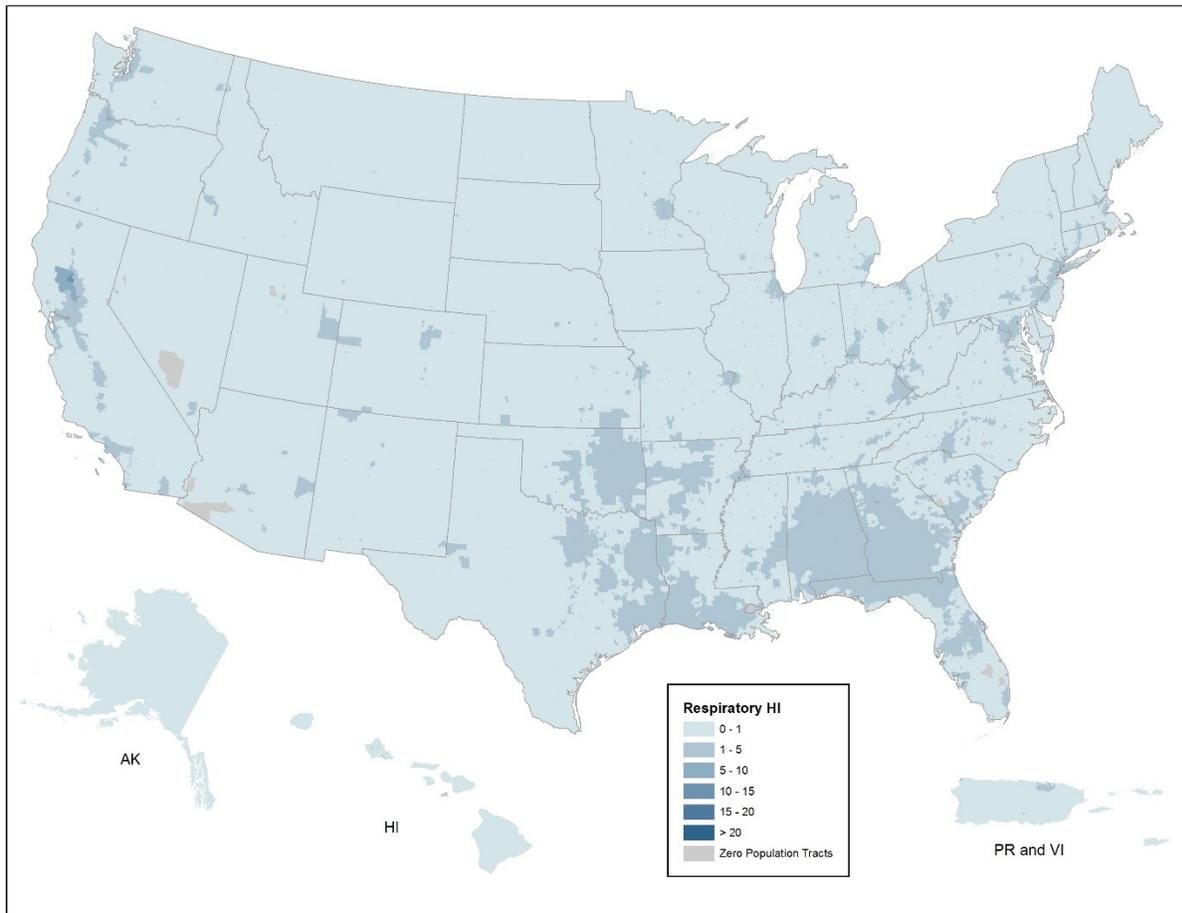


Figure 4-3 2011 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of this rule. In a few previous analyses of the benefits of reductions in HAP, EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) and reference concentrations (RfC) developed through risk assessment procedures. The URF is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu\text{g}/\text{m}^3$ of a pollutant. These URFs are designed to be conservative, and as such, are more likely to represent the high end of

the distribution of risk rather than a best or most likely estimate of risk. An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious noncancer health effects during a lifetime. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAP) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn *et al.*, 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by this rule. EPA remains committed to

improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2012a). In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. This rule is anticipated to avoid or reduce 3,400 tons of HAP in 2025. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

4.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.^{54,55,56} EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human

⁵⁴ U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <<http://www.epa.gov/iris/subst/0276.htm>>.

⁵⁵ International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

⁵⁶ Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

Services has characterized benzene as a known human carcinogen.^{57,58} A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.^{59,60}

4.6.2 Toluene⁶¹

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in

⁵⁷ International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

⁵⁸ U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: <<http://ntp.niehs.nih.gov/go/16183>>.

⁵⁹ Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. *Environ. Health Perspect.* 82: 193-197.

⁶⁰ Goldstein, B.D. (1988). Benzene toxicity. *Occupational medicine. State of the Art Reviews.* 3: 541-554.

⁶¹ All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <<http://www.epa.gov/iris/subst/0118.htm>>.

subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.6.3 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.⁶² No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.⁶³

4.6.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral

⁶² Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at <http://toxnet.nlm.nih.gov/>. Carbonyl health effects summary available at <http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1>.

⁶³ U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0617.htm>.

cavities in male and female rats exposed to ethylbenzene via the oral route.^{64,65} The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).^{66,67} The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.6.5 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.⁶⁸ Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.⁶⁹ Long-term inhalation exposure to xylenes in humans has been associated with a

⁶⁴ Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. *Am J Ind Med* 7:415-446.

⁶⁵ Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. *Annals NY Acad Sci* 837:15-52.

⁶⁶ International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

⁶⁷ National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

⁶⁸ U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <<http://www.epa.gov/iris/subst/0270.htm>>.

⁶⁹ Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <<http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>>.

number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.⁷⁰ EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.6.6 *n*-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of *n*-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of *n*-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to *n*-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for *n*-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.⁷¹

4.6.7 *Other Air Toxics*

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H₂S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.⁷²

4.7 Secondary Air Emissions Impacts

The control techniques to meet the standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. Table 4-6 shows the estimated secondary emissions associated with combustion of emissions as a result of the rule. In

⁷⁰ Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <<http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>>.

⁷¹ U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

⁷² U.S. EPA Integrated Risk Information System (IRIS) database is available at: <www.epa.gov/iris>.

particular, combustion-related emissions result from the control of oil well completions (i.e., exploratory and delineation wells and development wells where RECs are infeasible and pneumatic pumps and centrifugal compressors (because the requirement for these sources is to route to control). More details on the estimation of secondary impacts for each emissions category are presented in the TSD. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant increases is small.

Table 4-6 Increases in Secondary Air Pollutant Emissions (short tons per year)

| Emissions Category | 2020 | | | | |
|---|------------------|-----------------|----------------|----------------|----------------|
| | CO ₂ | NO _x | PM | CO | THC |
| Total Hydraulically Fractured and Re-fractured Oil Well Completions | 890,000 | 460 | 17 | 2,500 | 940 |
| Fugitive Emissions | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> |
| Pneumatic Pumps | 100,000 | 52 | 2 | 290 | 110 |
| Pneumatic Controllers | 3,900 | 2 | 0 | 11 | 4 |
| Compressors | 0 | 0 | 0 | 0 | 0 |
| Total 2020 | 1,000,000 | 510 | 19 | 2,800 | 1,100 |

| Emissions Category | 2025 | | | | |
|---|------------------|-----------------|----------------|----------------|----------------|
| | CO ₂ | NO _x | PM | CO | THC |
| Total Hydraulically Fractured and Re-fractured Oil Well Completions | 950,000 | 490 | 18 | 2,700 | 1,000 |
| Fugitive Emissions | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> | <i>minimal</i> |
| Pneumatic Pumps | 200,000 | 100 | 4 | 570 | 220 |
| Pneumatic Controllers | 7,800 | 4 | 0 | 22 | 8 |
| Compressors | 0 | 0 | 0 | 0 | 0 |
| Total in 2025 | 1,200,000 | 600 | 22 | 3,200 | 1,200 |

The secondary emission impacts for regulatory options are equal across the options. This result holds because the only requirements varied across the options is the frequency of survey and repair requirements. Moving from Option 1 to Option 3 increases the frequency of survey and repair under the fugitive emissions requirement, and secondary emissions from the fugitive emissions requirements are expected to be minimal.

The CO₂ impacts in Table 4-6 are the emissions that are expected to occur from natural gas emissions that are captured by emissions controls and combusted. However, because of the atmospheric chemistry associated with the natural gas emissions, most of the carbon in the VOCs

and CH₄ emissions expected in the absence of combustion-related emissions controls would have eventually oxidized forming CO₂ in the atmosphere and led to approximately the same long-run CO₂ concentrations as with controls.⁷³ Therefore, most of the impact of these CO₂ contribution to atmospheric concentrations from the flaring of CH₄ and VOC versus future oxidization is not additional to the impacts that otherwise would have occurred through the oxidation process. However, there is a shift in the timing of the contribution of atmospheric CO₂ concentration under the policy case (in which case natural gas emissions that are captured by emissions controls are combusted). In the case of VOCs, the oxidization time in the atmosphere is relatively short, on the order of hours to months, so from a climate perspective the difference between emitting the carbon immediately as CO₂ during combustion or as VOCs is expected to be negligible. In the case of CH₄, the oxidization time is on the order of a decade, so the timing of the contribution to atmospheric CO₂ concentration will differ between the baseline and policy case. Because the growth rate of the SC-CO₂ estimates are lower than their associated discount rates, the estimated impact of CO₂ produced in the future via oxidized methane from these fossil-based emissions may be less than the estimated impact of CO₂ released immediately from combusting emissions, which would imply a small disbenefit associated with the earlier release of CO₂ during combustion of the CH₄ emissions.

In the proposal RIA, the EPA solicited comment on the appropriateness of monetizing the impact of the earlier release of CO₂ due to combusting methane and VOC emissions from oil and gas sites and a new potential approach for approximating this value using the SC-CO₂. This illustrative analysis provides a method for evaluating the estimated emissions outcomes associated with destroying one metric ton of methane by combusting fossil-based emissions at oil and gas sites (flaring) and releasing the CO₂ emissions immediately versus releasing them in the future via the methane oxidation process. This illustrative analysis as provided in the proposal demonstrated that the potential disbenefits of flaring—i.e., an earlier contribution of CO₂ emissions to atmospheric concentrations—are minor compared to the benefits of flaring—i.e., avoiding the release of and associated climate impacts from CH₄ emissions. EPA did not receive any comments regarding the appropriate methodology for conducting such an analysis,

⁷³ The social cost of methane (SC-CH₄) used previously in this chapter to monetize the benefits of the CH₄ emissions reductions does not include the impact of the carbon in CH₄ emissions after it oxidizes to CO₂.

but did receive one comment letter that voiced general support for monetizing the secondary impacts.

In consideration of this comment while recognizing the challenges and uncertainties related to estimation of these secondary emissions impacts for this rulemaking, EPA has continued to examine this issue in the context of this regulatory analysis—i.e, the combusting of fossil-based CH₄ at oil and gas sites—and explored ways to improve this illustrative analysis. Specifically, EPA has modified the illustrative analysis by updating the oxidization process of CH₄ to be dynamic and consistent with the modeling that underlies the SC-CH₄ estimates. Also for this illustrative analysis, EPA assumed an average methane oxidation period of 12 years, consistent with the perturbation lifetime-folding time used in IPCC AR4. The estimated disbenefits associated with destroying one metric ton of methane through combustion of emissions at oil and gas sites and releasing the CO₂ emissions in 2020 instead of being released in the future via the methane oxidation process are found to be small relative to the benefits of flaring. Specifically, the disbenefit is estimated to be about \$15 per metric ton CH₄ (based on average SC-CO₂ at 3 percent) or roughly one percent of the SC-CH₄ estimate per metric ton for 2020. The analogous estimate for 2025 is \$18 per metric ton CH₄ or about one percent of the SC-CH₄ estimates per metric ton for 2025.^{74,75}

⁷⁴ To calculate the CO₂ related impacts associated the complete destruction of a ton of CH₄ emissions through flaring for this illustrative application, EPA took the difference between the SC-CO₂ at the time of the flaring and the discounted value of the CO₂ impacts assuming a geometric decay of CH₄ via the oxidation process with a 12 year e-folding time using the same discount rate as used to estimate the SC-CO₂. This value was then scaled by 44/16 to account for the relative mass of carbon contained in a ton of CH₄ versus a ton of CO₂. More specifically, the impacts of shifting the CO₂ impacts are calculated as

$$(44/16) \left[SC-CO_2_\tau - \sum_{t=\tau}^T e^{-1/12(t-\tau)} (1 - e^{-1/12}) \left(\frac{1}{1+r} \right)^{t-\tau} SC-CO_2_t \right],$$

where τ is the year the CH₄ is destroyed, r is the discount rate, and T is the time horizon of the analysis. Ideally the time horizon, T, would be sufficiently long to capture the period in which nearly all of the CH₄ is expected to have been oxidized. In this analysis we use the 2100 as the time horizon, making the assumption that the SC-CO₂ remains constant after 2050, the last year for which the IWG provides estimates. This methodology improves upon the one presented at proposal by updating the oxidization process of CH₄ to be dynamic and consistent with the modeling that underlies the SC-CH₄ estimates.

⁷⁵ The EPA also calculated these estimates using additional SC-CO₂ values, specifically the average SC-CO₂ at discount rates of 5 and 2.5 percent and the 95th percentile at 3 percent. Applying these values, the estimates of the disbenefit of releasing CO₂ emissions in 2020 instead of in the future via methane oxidation ranges from \$7 to \$40 per metric ton CH₄. The corresponding estimates for 2025 range from \$9 to \$51 per metric ton CH₄.

It is important to note that there are challenges and uncertainties related to this illustrative method and estimates, which was developed to analyze secondary fossil-based emissions from combustion. For example, these dollar per ton CH₄ estimates cannot readily be applied to the total CH₄ emissions reductions presented in section 3 without additional information about the downstream outcomes associated with the recovered gas that is not flared – e.g., whether some of that captured gas going to be burned or leaked somewhere down the line.

The EPA will continue to study this issue and assess the complexities involved in estimating the net emissions effects associated with secondary fossil-based emissions, including differences in the timing of contributions to atmospheric CO₂ concentrations. Given the uncertainties related to estimating net secondary emissions effects and that the EPA has not yet received appropriate input and review on some aspects of these calculations, the EPA is not including monetized estimates of the impacts of small changes in the timing of atmospheric CO₂ concentration increases in the final benefits estimates in this RIA. The EPA will continue to follow the scientific literature on this topic and update its methodologies as warranted.

Table 4-7 provides a summary of the direct and secondary emissions changes. Based on the summary and analysis above, the net impact of both the direct and secondary impacts of this final rule would be an improvement in ambient air quality, which would reduce potency of greenhouse gas emissions, reduce exposure to various harmful pollutants, improve visibility impairment, and reduce vegetation damage.

Table 4-7 Summary of Emissions Changes (short tons per year, except where noted)

| | Pollutant | Option 1 | | Option 2 (final) | | Option 3 | |
|-----------------------------------|-----------------|-----------|-----------|------------------|-----------|-----------|-----------|
| | | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| Change in Direct Emissions | Methane | -250,000 | -390,000 | -300,000 | -510,000 | -350,000 | -610,000 |
| | VOC | -130,000 | -170,000 | -150,000 | -210,000 | -160,000 | -230,000 |
| | HAP | -1,300 | -2,700 | -1,900 | -3,900 | -2,400 | -5,000 |
| Secondary Emissions | CO ₂ | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 |
| | NO _x | 510 | 600 | 510 | 600 | 510 | 600 |
| | PM | 19 | 22 | 19 | 22 | 19 | 22 |
| | CO | 2,800 | 3,200 | 2,800 | 3,200 | 2,800 | 3,200 |
| | THC | 1,100 | 1,200 | 1,100 | 1,200 | 1,100 | 1,200 |

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5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs across Regulatory Options

Tables 5-1 through Table 5-3 present the summary of the benefits, costs, and net benefits for the NSPS across regulatory options. Table 5-4 provides a summary of the direct and secondary emissions changes for each regulatory option.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|---|---|
| Total Monetized Benefits ¹ | \$290 million | \$540 million |
| Total Costs ² | \$240 million | \$360 million |
| Net Benefits ³ | \$54 million | \$180 million |
| | Non-monetized climate benefits | Non-monetized climate benefits |
| Non-monetized Benefits | Health effects of PM2.5 and ozone exposure from 130,000 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 170,000 tons of VOC reduced |
| | Health effects of HAP exposure from 1,300 tons of HAP reduced | Health effects of HAP exposure from 2,700 tons of HAP reduced |
| | Health effects of ozone exposure from 250,000 tons of methane | Health effects of ozone exposure from 390,000 tons of methane |
| | Visibility impairment | Visibility impairment |
| | Vegetation effects | Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$130 million to \$780 million in 2020 and \$250 million to \$1.4 billion in 2025 for Option 1, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 5.6 million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

Table 5-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Selected Option 2 in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|---|---|
| Total Monetized Benefits ¹ | \$360 million | \$690 million |
| Total Costs ² | \$320 million | \$530 million |
| Net Benefits ³ | \$35 million | \$170 million |
| Non-monetized Benefits | Non-monetized climate benefits | Non-monetized climate benefits |
| | Health effects of PM2.5 and ozone exposure from 150,000 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 210,000 tons of VOC reduced |
| | Health effects of HAP exposure from 1,900 tons of HAP reduced | Health effects of HAP exposure from 3,900 tons of HAP reduced |
| | Health effects of ozone exposure from 300,000 tons of methane | Health effects of ozone exposure from 510,000 tons of methane |
| | Visibility impairment | Visibility impairment |
| | Vegetation effects | Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$160 million to \$950 million in 2020 and \$320 million to \$1.8 billion in 2025 for Option 2, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

Table 5-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$)

| | 2020 | 2025 |
|---------------------------------------|---|--|
| Total Monetized Benefits ¹ | \$420 million | \$840 million |
| Total Costs ² | \$490 million | \$880 million |
| Net Benefits ³ | -\$75 million | -\$38 million |
| Non-monetized Benefits | Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 160,00 tons of VOC reduced Health effects of HAP exposure from 2,400 tons of HAP reduced Health effects of ozone exposure from 350,000 tons of methane Visibility impairment Vegetation effects | Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 230,000 tons of VOC reduced Health effects of HAP exposure from 5,000 tons of HAP reduced Health effects of ozone exposure from 610,000 tons of methane Visibility impairment Vegetation effects |

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$190 million to \$1.1 billion in 2020 and \$390 million to \$2.2 billion in 2025 for this more stringent option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 8 million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.

³ Estimates may not sum due to independent rounding.

A break-even analysis answers the question: “What would the benefits need to be for the benefits to exceed the costs?” While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits. For Options 1 and 2 (final selected option), the monetized climate benefits from methane emission reductions already exceed the costs, which renders a break-even analysis for these options unnecessary. For Option 3, the monetized net benefits are estimated to be -\$73 million and -\$37 million and the estimated VOC emission reductions are 160,000 and 230,000 tons for 2020 and 2025, respectively. Thus, a break-even analysis suggests that the VOC emissions would need to be valued at \$460 per ton in 2020 and \$160 per ton in 2025 for the total monetized benefits of Option 3 to exceed costs, assuming that

the health benefits from HAP emission reductions and the ozone health benefits from methane emission reductions are zero. Previous assessments have shown that the PM_{2.5} health benefits associated with reducing VOC emissions were valued at \$300 to \$7,500 per ton of VOC emissions reduced in specific urban areas and ozone health benefits from reducing VOC emissions were valued at \$260 to \$1,100 per ton of VOC emissions reduced. These break-even estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even point is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and PM_{2.5} formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

Table 5-4 Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted)

| | Pollutant | Option 1 | | Option 2 (final) | | Option 3 | |
|--------------------------------------|-----------------|-----------|-----------|------------------|-----------|-----------|-----------|
| | | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| Reduction in Direct Emissions | Methane | -250,000 | -390,000 | -300,000 | -510,000 | -350,000 | -610,000 |
| | VOC | -130,000 | -170,000 | -150,000 | -210,000 | -160,000 | -230,000 |
| | HAP | -1,300 | -2,700 | -1,900 | -3,900 | -2,400 | -5,000 |
| Secondary Emissions | CO ₂ | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 |
| | NO _x | 510 | 600 | 510 | 600 | 510 | 600 |
| | PM | 19 | 22 | 19 | 22 | 19 | 22 |
| | CO | 2,800 | 3,200 | 2,800 | 3,200 | 2,800 | 3,200 |
| | THC | 1,100 | 1,200 | 1,100 | 1,200 | 1,100 | 1,200 |

5.2 Uncertainties and Limitations

Throughout the RIA, we considered a number of sources of uncertainty, both quantitatively and qualitatively, regarding emissions reductions, benefits, and costs of the rule. We summarize the key elements of our discussions of uncertainty here:

- **Projection methods and assumptions:** As discussed in Section 3.4.2, over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS

accumulates. The large majority of impacts of the rule (completion requirements at hydraulically fractured oil well completions and fugitive emissions requirements at wellsites) are based on projections and growth rates consistent with the drilling activity in the 2015 Annual Energy Outlook. To the extent actual drilling activities diverge from the Annual Energy Outlook projections, the projected regulatory impacts estimated in this document will diverge.

- **Years of analysis:** The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period, as discussed in Section 3.4.2. While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.
- **State regulations in baseline:** In preparing the impacts analysis, the EPA reviewed state regulations and permitting requirements, as discussed in Section 3.4.2. Applicable facilities in these states with similar requirements to the final NSPS are not included in the estimates of incrementally affected facilities presented in the RIA. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements are not reflected in this RIA.
- **Wellhead natural gas prices used to estimate revenues from natural gas recovery:** The annualized compliance cost estimates presented in this RIA include revenue from natural gas recovery resulting from emissions reductions. As a result, national compliance costs depend the price of natural gas. The sensitivity of national compliance costs to assumptions about wellhead natural gas prices are examined in Section 3.5.2.
- **Monetized methane-related climate benefits:** The EPA considered the uncertainty associated with the social cost of methane (SC-CH₄) estimates, which were used to calculate the global social benefits of methane emissions reductions expected from the NSPS. The modeling underlying the development of the SC-CH₄ estimates, which is consistent with the modeling assumptions underlying the interagency working group's SC-CO₂ estimates, addressed uncertainty in several ways. For example, the analysis addressed uncertainty in following areas: differences in model structure through an

ensemble of three integrated assessment models; sensitivity of the SC-CH₄ estimates to key exogenous projections by using five different socioeconomic and emissions forecasts; and three discount rates to reflect some uncertainty about how interest rates may change over time and the possibility that climate damages are positively correlated with uncertain future economic activity. The application of four point estimates also helps reflect uncertainty. Chapter 4 of this RIA provides a comprehensive discussion about the methodology and application of the SC-CH₄ as well as consideration of several types of secondary emissions impacts, which may partially offset the direct benefits of this rule.

- **Non-monetized benefits:** Numerous categories of health, welfare, and climate benefits are not quantified and monetized in this RIA. These unquantified benefits, including benefits from reducing emissions of methane, VOCs and HAP, are described in detail in Chapter 4.

6 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

6.1 Introduction

This section includes three sets of analyses for the final NSPS:

- Energy Markets Impacts
- Final Regulatory Flexibility Analysis
- Employment Impacts

6.2 Energy Markets Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS on U.S. energy markets. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas.

A brief conceptual discussion about our energy markets impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and presenting results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain in production at the producer level for a given cost. For example, the analysis for the rule shows that performing reduced emissions completions on hydraulically-fractured oil wells would account for about 36 percent of the natural gas captured by emissions controls in 2020 and about 23 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to account for about 62 percent of the natural gas captured by emissions controls in 2020 and about 75 percent of captured natural gas in 2025. The assumed \$4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production.

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts

accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

6.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of the U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy (DOE). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. DOE first developed NEMS in the 1980s, and the model has undergone frequent updates and significant expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

The EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at the website: <http://www.eia.gov/forecasts/aeo/>.

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel *et al.* 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next module after establishing an updated provisional solution.

NEMS provides what EIA refers to as “mid-term” projections to the year 2040. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2015.⁷⁶ The RIA baseline is consistent with that of the Annual Energy Outlook 2015, which is used extensively in Section 2 in the Industry Profile.

6.2.2 *Inputs to National Energy Modeling System*

To model potential impacts associated with the final rule, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore and Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2014). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern findings and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the NSPS. We are able to target additional expenditures for environmental controls required by the NSPS on new exploratory and developmental oil and gas production activities. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the rule.

⁷⁶ Assumptions for the 2015 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/>.

While the oil production simulated by the OGSM is sent to the refining module (the Liquid Fuels Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and “negotiates” supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas is transported through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

6.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Regulatory costs associated with reduced emission completions for hydraulically fractured oil well completions are added to the drilling and completion costs of oil wells in the OGSM. Other regulatory costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The additional expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells or natural gas wells. We base the per well cost estimates on the engineering costs. Because we model natural gas recovery, we do not include revenues from additional product recovery in these costs. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

In general, the cost of capital in the model will implicitly capture potential barriers to obtaining additional capital financing for the industry on average. However, the model may not fully capture heterogeneity in the cost of capital across the industry, and therefore, may not fully capture distributional impacts across the industry as a result of firm specific characteristics that cause them to have varying access to additional capital. An additional caveat to this analysis is that the modeling does not attempt to represent potential constraints on the supply of specific capital equipment, which may or may not be binding in practice.

Table 6-1 shows the incremental compliance that accrue to new drilling projects as a result of producers having to comply with the NSPS, across sources anticipated in 2020 and

2025. We estimate those costs as a function of new wells anticipated to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify whether costs will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells.

We divide the estimated compliance costs for the given emissions point by the appropriate number of expected new crude oil and natural gas wells in the year of analysis. The result yields an approximation of per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Hydraulically fractured oil well completions and fugitives at oil and natural gas well sites differ slightly from this approach. Drilling and completion costs of new hydraulically fractured oil wells are incremented by the weighted average of the cost of performing a REC with completion combustion and completion combustion alone. The resulting cost is itself weighted by the proportion of new hydraulically fractured oil wells estimated to be affected by the regulation. Meanwhile, assuming there is an average of two wells per wells site (see TSD for more details), new oil and gas wells face an increased annual cost of one-half of implementing the well site fugitive emission requirements.

Table 6-1 Per Well Costs for Environmental Controls Entered into NEMS (2012\$)

| Emissions Sources/Points | Wells Applied To in NEMS | Annualized Cost per Unit (2012\$) | Per Well Costs Applied in NEMS (2012\$) | Natural Gas Recovery per Unit (Mcf) | Per Well Natural Gas Recovery Applied in NEMS (Mcf) |
|--|---------------------------------------|--|--|--|--|
| Well Completions | | | | | |
| Hydraulically Fractured Oil Well Completions | New Hydraulically Fractured Oil Wells | Varies ^a | \$4,590 | 0 | 0 |
| Fugitive Emissions | | | | | |
| Oil Production Well Sites | New Oil Wells | \$2,285 | \$905 | 191 ^c | 38 |
| Natural Gas Production Well Sites | New Gas Wells | \$2,285 | \$1,101 | 73 | 18 |
| Gathering and Boosting Stations | New Gas Wells | \$25,050 | \$284 | 1,629 | 18 |
| Transmission Stations | New Gas Wells | \$27,370 | \$13 | 1,673 | 1 |
| Storage Facilities | New Gas Wells | \$42,093 | \$25 | 5,899 | 3 |
| Reciprocating Compressors | | | | | |
| Transmission Stations | New Gas Wells | \$1,748 | \$3 | 1,122 | 2 |
| Storage Facilities | New Gas Wells | \$2,077 | \$4 | 1,130 | 2 |
| Centrifugal Compressors | | | | | |
| Storage Facilities | New Gas Wells | \$114,146 | \$0 | 0 | 0 |
| Pneumatic Controllers - | | | | | |
| Transmission and Storage Stations | New Gas Wells | \$25 | \$0 | 144 | 2 |
| Pneumatic Pumps | | | | | |
| Well Sites | New Wells | \$774 | \$15 | 0 | 0 |
| Reporting and Recordkeeping | New Wells | \$6,200,000 ^b | \$154 | 0 | 0 |

^a Since compliance costs vary across hydraulically fractured oil well completions, this table uses the weighted average costs by completion cost type.

^b Reporting and recordkeeping costs are assumed to be equally allocated across all new wells.

^c Natural gas recovery at oil well sites is the weighted average of the recovery expected from oil well sites and oil well (associated gas) sites. See TSD for detailed description of these model well sites.

6.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A result of controlling methane and VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of

implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right in an increment consistent with the technically achievable emissions transferred into the production stream as a result of the final NSPS. We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 6-1).

6.2.3 *Energy Markets Impacts*

We estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas. In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the final rule. We also present impacts over the 2020 to 2025 period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because offshore production is not affected by the NSPS and the bulk of the rule's impacts are expected to be in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 6-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

Table 6-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

| | 2012 | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|---|---------------|------------------|---------------|------------------|---------------|---------------------|----------------|
| | | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Successful Wells Drilled | | | | | | | |
| Natural Gas | 10,490 | 10,501 | 10,481 | 12,200 | 12,145 | 65,896 | 65,785 |
| Crude Oil | 28,496 | 27,455 | 27,463 | 29,244 | 29,231 | 168,768 | 168,736 |
| Total | 38,986 | 37,956 | 37,944 | 41,444 | 41,376 | 234,664 | 234,521 |
| % Change in Successful Wells Drilled from Baseline | | | | | | | |
| Natural Gas | | | 0.19% | | -0.45% | | -0.17% |
| Crude Oil | | | 0.03% | | -0.04% | | -0.02% |
| Total | | | 0.03% | | -0.16% | | -0.06% |

Results show that the final NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, with very slight increases both oil and natural gas wells, relative to the baseline. Meanwhile, drilling of both natural gas and crude oil wells decreases slightly in 2025, relative to the baseline. The small increase in drilling in 2020 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple periods. Crude oil drilling over the 2020 to 2025 period decreases overall but by about 30 wells total, or about 0.02 percent, relative to the baseline. Natural gas drilling, over the same period remains declines by about 110 wells total, or about 0.17 percent, relative to the baseline.

Table 6-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS.

Table 6-3 Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

| | 2012 | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|---|--------|------------------|--------|------------------|--------|---------------------|---------|
| | | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Domestic Production | | | | | | | |
| Natural Gas (trillion cubic feet) | 22.158 | 26.544 | 26.537 | 28.172 | 28.163 | 164.130 | 164.086 |
| Crude Oil (million bbls/day) | 4.597 | 8.031 | 8.031 | 8.027 | 8.028 | 48.084 | 48.086 |
| % Change in Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States) | | | | | | | |
| Natural Gas | | | -0.03% | | -0.03% | | -0.03% |
| Crude Oil | | | 0.00% | | 0.01% | | 0.00% |

As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Crude oil production remains essentially unchanged in 2020 and 2025 (with changes around or less than 0.01 percent in both years), relative to the baseline. While slightly increasing over the time horizon, the overall change in crude oil production is less than 0.01 percent, relative to the baseline. Natural gas production is estimated to decrease slightly during the 2020-25 period, by around 0.03 percent, relative to the baseline.

Note this analysis estimates very little change in domestic natural gas production, despite some environmental controls anticipated in response to the rule capture natural gas that would otherwise be emitted (about 16 bcf in 2020 and 27 bcf in 2025). NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 6-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 6-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012\$)

| | 2012 | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|--|--------|------------------|--------|------------------|--------|---------------------|--------|
| | | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Lower 48 Average Wellhead Price | | | | | | | |
| Natural Gas (2012\$ per Mcf) | 2.566 | 4.428 | 4.441 | 5.184 | 5.190 | 4.880 | 4.890 |
| Crude Oil (2012\$ per barrel) | 94.835 | 73.920 | 73.918 | 85.219 | 85.218 | 79.530 | 79.527 |
| % Change in Lower 48 Average Wellhead Price from Baseline | | | | | | | |
| Natural Gas | | | 0.29% | | 0.12% | | 0.20% |
| Crude Oil | | | 0.00% | | 0.00% | | -0.01% |

Wellhead crude oil prices for onshore lower 48 production are not estimated to change meaningfully in 2020 or 2025, or over the 2020-25 period, relative to the baseline. The production-weighted average price for wellhead crude oil over the 2020 to 2025 period is not estimated to change more than 0.01 percent, relative to the baseline. Meanwhile, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly in response

to the rule in 2020 by about 0.29 percent and by about 0.12 percent in 2025, relative to the baseline. The production-weighted average price for wellhead natural gas over the 2020 to 2025 period is estimated to increase by around 0.2 percent, relative to the baseline.

Table 6-5 Net Imports of Natural Gas and Crude Oil

| | 2012 | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|-----------------------------------|-------|------------------|--------|------------------|--------|---------------------|---------|
| | | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Net Imports | | | | | | | |
| Natural Gas (trillion cubic feet) | 1.519 | -2.557 | -2.554 | -3.502 | -3.498 | -18.959 | -18.939 |
| Crude Oil (million barrels/day) | 8.459 | 5.513 | 5.513 | 6.073 | 6.072 | 5.857 | 5.857 |
| % Change in Net Imports | | | | | | | |
| Natural Gas | | | 0.12% | | 0.11% | | 0.11% |
| Crude Oil | | | 0.00% | | -0.02% | | 0.00% |

Meanwhile, as shown in Table 6-5, net imports of natural gas are estimated to increase slightly in 2020 and 2025 relative to the baseline (by about 0.12 percent and 0.11 percent, respectively) relative to the baseline. Net imports of natural gas are also expected to increase by about 0.11 percent across the 2020 to 2025 period under the rule. Crude oil imports are not estimated to change in 2020 and to decrease slightly in 2025 by about 0.02 percent relative to the baseline. Over the 2020 to 2025 period, net imports of crude oil are not estimated to change in response to the rule.

6.3 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that whenever an agency publishes a final rule after a general notice of proposed rulemaking is made, it must prepare and make available a final regulatory flexibility analysis (FRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. A FRFA describes the economic impact of the rule on small entities and any significant alternatives to the rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 604 of the RFA, the EPA prepared a final regulatory flexibility

analysis (FRFA) that examines the impact of the final rule on small entities along with regulatory alternatives that could minimize that impact.

Prior to publication of the proposed rule, the EPA prepared an initial regulatory flexibility analysis (IRFA) and convened a Small Business Advocacy Review (SBAR) Panel consisting of the Director of the Sector Policies & Programs Division of the EPA Office of Air Quality Planning & Standards, the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget, and the Chief Counsel for Advocacy of the Small Business Administration. The IRFA and Final SBAR Panel Report can be found in the docket to this rulemaking at EPA-HQ-OAR-2010-0505.

6.3.1 Reasons why the Action is Being Considered

The EPA is finalizing amendments to subpart OOOO due to reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator, which include implementation improvements. The EPA is also finalizing a new subpart, 40 CFR 60, subpart OOOOa, which includes: standards for greenhouse gas (GHG) emissions (in the form of limitations on methane) from certain facilities that are covered by current VOC standards in the oil and natural gas source category, and standards for GHG and VOC emissions from facilities across the source category that are currently unregulated, including hydraulically fractured oil well completions; fugitive emissions from well sites and compressor stations; pneumatic pumps; and centrifugal compressors, reciprocating compressors and pneumatic controllers in the transmission and storage segment. The EPA is including requirements for methane emissions in subpart OOOOa because methane is a GHG, and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.⁷⁷

6.3.2 Significant Issues Raised

The EPA received comments on the proposed standards related to the potential impacts on small entities and requests for comments that were included based on the SBAR Panel

⁷⁷ “Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,” 74 FR 66496 (Dec. 15, 2009) (“2009 Endangerment Finding”).

Recommendations. See sections VI and VIII of the preamble to the final rule and the RTC Document in Docket ID EPA-HQ-OAR-2010-0505 for more detailed responses.

Low production wells: Several commenters supported the proposed exemption of low production well sites from the fugitive monitoring requirements. Commenters noted that marginal wells generate relatively low revenue and these wells are often drilled and operated by small companies.

Response: While these commenters did provide support for the proposed low production well exemption, other commenters indicated that low production well sites have the potential to emit substantial amounts of fugitive emissions, and that a significant number of wells would be excluded from fugitive emissions monitoring based on this exemption. We did not receive data showing that low production well sites have lower emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring.

REC costs: Commenters stated that small operators have higher well completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. However, commenters did not provide specific cost information.

Response: The BSER analysis is based on the averages of nationwide data. It is possible for a small operator to have higher than the nationwide average completion costs, however, the daily completion cost provided by the commenters is not significantly different than the EPA's estimate. Therefore, we do not believe that the cost of RECs disfavor small businesses.

Phase-in period for RECs: Commenters stated that the EPA should create a compliance phase-in period of at least 6 months for the REC requirements, to accommodate small operators. Commenters stated that REC equipment is in short supply, and this will drive up REC costs.

Commenters stated that small entities lack the purchasing power of larger operators, which makes it difficult to obtain the needed equipment before the compliance period begins.

Response: We agree that compliance with the REC requirements in the final rule could be burdensome for some in the near term due to the unavailability of REC equipment. As discussed in section VI of the preamble, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplied in the near term.

Alternatives to OGI technology: Several commenters indicated that the EPA should allow alternatives to OGI technology as the cost is excessive for small operators.

Response: In the final rule, the EPA is allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We believe this alternative will alleviate some of the burden on small entities.

Basing monitoring frequency on the percentage of leaking components: Commenters indicated that using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities since a small site will have fewer fugitive emission components than a larger site. Commenters stated that smaller entities are much more likely to operate these smaller sites, and thus are more likely to have a higher frequency survey requirements under the percentage-based system.

Response: The EPA agrees that imposing a performance based monitoring schedule would require operators to develop a program that would require extensive administration to ensure compliance. We believe that the potential for a performance-based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed monitoring frequency instead of performance based monitoring.

Timing of initial fugitive monitoring periods: Commenters stated that the requirement to conduct surveys for affected facilities using OGI technology within 30 days of the well completion or within 30 days of modification is overly restrictive. Additionally, commenters stated that small operators may not be able to find vendors available to survey a small number of

wells within the required timeframe. One commenter stated that contractors will be in high demand and may give scheduling preference to larger clients versus small business entities.

Response: EPA considered these and other comments and concluded that the proposed time of 30 days within a well completion or modification is not enough time to complete the necessary preparations for the initial monitoring survey. In addition, other commenters pointed out that first date of production should be the trigger, rather than the date of well completion. Therefore, for the collection of fugitive emissions components at a new or modified well site, we are finalizing that the initial monitoring survey must take place within **[insert date 1 year after publication of the final rule in the Federal Register]** or within 60 days of the startup of production, whichever is later. We believe this extended timeframe for compliance will alleviate some of the burden on smaller operators.

Third party compliance: Commenters believe that requiring third party compliance audits will be a significant burden on small entities. One commenter said that a third-party audit requirement will dramatically increase the costs of the program and have a negative competitive impact on smaller, less funded operators.

Response: While the EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance, we have explored alternatives to the independent third party verification. Specifically, the “qualified professional engineer” model was assessed to focus on the element of engineering design. The final rule requires a professional engineer certification of technical infeasibility of connecting a pneumatic pump to an existing control device, and a professional engineer design of closed vent systems. These certifications will ensure that the owner or operator has effectively assessed appropriate factors before making a claim of infeasibility and that the closed vent system is properly designed to verify that all emissions from the unit being controlled in fact reach the control device and allow for proper control. We believe this simplified approach will reduce the burden imposed on all affected facilities, including those owned by small businesses.

6.3.3 *Small Business Administration Comments*

The Chief Counsel for Advocacy of the Small Business Administration (SBA) did not file any comments in response to the proposed rule.

6.3.4 *Description and Estimate of Affected Small Entities*

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The EPA conducted this regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities.⁷⁸ The EPA identified the size of ultimate parent entities by using the SBA size threshold guidelines.⁷⁹ The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as can be seen in Table 6-6.

Table 6-6 SBA Size Standards by NAICS Code

| NAICS Codes | NAICS Industry Description | Size Standards (in millions of dollars) | Size Standards (in no. of employees) |
|-------------|---|--|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | - | 1,250 |
| 211112 | Natural Gas Liquid Extraction | - | 750 |
| 213111 | Drilling Oil and Gas Wells | - | 1,000 |
| 213112 | Support Activities for Oil and Gas Operations | \$38.5 | - |
| 486110 | Pipeline Transportation of Crude Oil | - | 1,500 |
| 486210 | Pipeline Transportation of Natural Gas | \$27.5 | - |

Sources: U.S. Census Bureau, Statistics of U.S. Businesses, 2012. <<http://www.census.gov/econ/subb/>>. SBA Size Standards, 13 CFR 121. 201

We have projections of future potentially affected activities at an aggregate level, but identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. Because of these limitations, we based the analysis in this FRFA on impacts estimates for the final requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. We are able to do this because the base year activity counts for the impacts estimates (as described in the TSD)

⁷⁸ See Section 2.6 of this RIA for more information on oil and natural gas industry firm characteristics and a breakdown of firms by size at the national level.

⁷⁹ U.S. Small Business Administration (SBA). 2016. Small Business Size Standards. Effective as of February 26, 2016. See: <https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf>.

for this rule were based on detailed information for 2012 in a dataset of U.S. wells. The proprietary DrillingInfo dataset contains a variety of information including oil, condensate, and natural gas production levels, geographic locations, as well as basin and formation information, and information about owners/operators of wells, among other data fields.⁸⁰ As described in the TSD sections on hydraulically fractured and re-fractured oil well completions and fugitive emissions, we used the DrillingInfo dataset to identify and estimate all wells that were completed in 2012, as well as completions of hydraulically fracture or re-fractured oil wells.⁸¹ We used the field called “common operator” to identify the owner/operator of all wells in this set of new or modified 2012 wells.

While the FRFA does not incorporate potential impacts from other provisions of the final NSPS, the completions and fugitive emissions provisions represent about 98 percent of the estimated compliance costs of the final NSPS in 2020 and 2025 (Table 6-7). Not incorporating impacts from other provisions in this analysis is a limitation, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the rule in its entirety.

Table 6-7 Distribution of Estimated Compliance Costs Across Sources

| | Annualized Costs (With Product Recovery, 2012\$) | | | |
|---|--|----------|---------------|----------|
| | 2020 | 2020 (%) | 2025 | 2025 (%) |
| Hydraulically-fractured and Re-fractured Oil Well Completions and Recompletions | \$130,000,000 | 39% | \$130,000,000 | 25% |
| Fugitive Emissions at Well Sites | \$190,000,000 | 59% | \$380,000,000 | 73% |
| Other Sources | \$8,000,000 | 2% | \$11,000,000 | 2% |
| Total Annualized Costs of Proposed NSPS | \$320,000,000 | 100% | \$530,000,000 | 100% |

Note: sums may not total due to independent rounding.

To identify potentially affected entities under the NSPS, the EPA combined ownership information from the DrillingInfo dataset with information drawn from the Hoover’s Inc. online

⁸⁰ DrillingInfo is a private company that provides information and analysis to the energy sector. More information is available at: <http://info.drillinginfo.com>.

⁸¹ The TSD for this proposed rule provides information on this dataset of U.S. wells. Additional details on the development of this dataset can also be found in the following docketed memo: Memorandum to Mark de Figueiredo, EPA, from Casey MacQueen and Jessica Gray, ERG. “DrillingInfo Processing Methodology”. August 27, 2014.

platform, which includes information about companies, such as NAICS codes, employee counts, and sales information.⁸² Note that this analysis assumes that the firms performing potentially affected activities are also the firms performing activities in the future under the NSPS. While likely true for many firms, this will not be the case for all firms.

The EPA matched owner/operators from the DrillingInfo dataset to companies in a database developed from a download of oil and gas companies in Hoover’s online database. The EPA matched as many records as possible. In the instances where the DrillingInfo owner/operator was not the highest level or company ownership, we recorded the highest level of owner as was identifiable in Hoovers. Linking these two datasets yields information on the NAICS, employee levels, and revenues of the owner/operators shown in the DrillingInfo dataset to have new or modified wells in 2012.

The EPA then used the NAICS codes associated with the matched owner/operators to determine which owner/operators should be considered to be small entities for this analysis, based on the SBA size standards above. That said, many DrillingInfo owner/operators had no match in Hoovers. Additionally, some Hoovers records lacked the information (employees or revenues, depending on the NAICS) needed to make a size determination. We initially classified these as an “unknown” size. See Table 6-8 for a summary of results of this matching exercise.

Table 6-8 No. of Completions in 2012 by Preliminary Firm Size

| Firm Size Performing | Well Completions | No. of Firms | Number of Completions, 2012 | |
|----------------------|------------------|--------------|---|-----------------|
| | | | Hydraulically Fractured or Re-fractured Oil Wells | All Completions |
| Small | | 951 | 2,998 | 10,360 |
| Not Small | | 150 | 10,674 | 22,866 |
| Unknown | | 1,118 | 676 | 5,762 |
| Total | | 2,219 | 14,348 | 38,988 |

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

⁸² The Hoover’s Inc. online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: <<http://www.hoovers.com>>.

Upon analysis of the firms of unknown size, the EPA observed that, on average, the firms of unknown size perform fewer well completions. For this reason, we made the observation that the firms of unknown size are more likely to be small than not small. To proceed with the analysis, we reclassified these firms as small, resulting in the distribution presented in the first two columns of Table 6-9.

Table 6-9 No. of Completions in 2012 by Firm Size

| Firm Size Performing Well Completions | | No. of Completions, 2012 | |
|---------------------------------------|--------------|---|-----------------|
| | | Hydraulically Fractured or Re-fractured Oil Wells | All Completions |
| Small | 2,069 | 3,674 | 16,122 |
| Not Small | 150 | 10,674 | 22,866 |
| Total | 2,219 | 14,348 | 38,988 |

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

6.3.5 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by **state, local, tribal or the Federal** government. All facilities are privately owned for-profit businesses. The requirements in this

action result in an industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and training personnel to be able to respond to the collection of information. The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual average cost of \$3,361,074. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

6.3.5.1 Methodology for Estimating Compliance Cost Impacts on Small Entities

This section describes how we project the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels, how we estimate costs at the firm level from these activity estimates, and how we estimated sales for small entities when available data on sales are incomplete.

New and modified hydraulically fractured oil well completions and well sites in this FRFA are based on the same growth rates used to project future activities as described in the TSD and are consistent with other analyses in this RIA. These growth rates are consistent with the drilling activity in the 2015 Annual Energy Outlook. These growth rates are applied to the 2012 base year estimates for each firm in the database.

Table 6-10 presents future year estimates of incrementally affected new and modified sources.

Table 6-10 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size

| Firm Size Performing Well Completions | No. of Incrementally Affected Sources, 2020 | | | No. of Incrementally Affected Sources, 2025 | | |
|---------------------------------------|---|----------------|----------------|---|----------------|----------------|
| | Hydraulically Fractured or Re-fractured Oil Wells | Gas Well Sites | Oil Well Sites | Hydraulically Fractured or Re-fractured Oil Wells | Gas Well Sites | Oil Well Sites |
| Small | 3,500 | 5,600 | 33,000 | 3,800 | 11,000 | 68,000 |
| Not Small | 10,000 | 11,000 | 44,000 | 11,000 | 24,000 | 86,000 |
| Total | 14,000 | 17,000 | 77,000 | 15,000 | 35,000 | 160,000 |

Note: Sums may not total due to independent rounding. Assumes well sites have two wells apiece.

This approach assumes that no other firms perform potentially affected activities and firms performing these activities in 2012 will continue to do so in 2020 and 2025. Again, the analysis in this FRFA is meant to be illustrative of impacts on small entities. Exact predictions of future activities at the firm level is not possible.

Once the future year activities were estimated we allocated compliance costs across small entities based upon the costs estimated in the TSD and consistently with other analyses in this RIA. These cost estimates include estimates of revenue from natural gas recovery at the assumed value of \$4/Mcf in 2012 dollars, again consistent with other analyses in this RIA. For hydraulically fractured and re-fractured oil well completions, we assumed each small entity is required to perform RECs and combustion in the same proportions assumed in the TSD and RIA. We also assumed the same proportion would be exploratory or delineation wells as the TSD and RIA. Table 6-11 shows the distribution of compliance costs estimates across firm size and year.

Table 6-11 Distribution of Estimated Compliance Costs¹ across Firm Size Classes

| Firm Size | Annualized Compliance Costs (2012\$) | | |
|--------------|--------------------------------------|--------------------|--------------------|
| | No. of Firms | 2020 | 2025 |
| Small | 2,069 | 110,000,000 | 190,000,000 |
| Not Small | 150 | 200,000,000 | 320,000,000 |
| Total | 2,219 | 310,000,000 | 510,000,000 |

¹ Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. As described in Section 6.1.3, these provisions account for the large majority of the rule's potential impact in 2020 and 2025.

Note: sums may not total due to independent rounding.

In order to estimate the cost-to-sales ratio, we again combined information from Hoovers and the DrillingInfo databases. The Hoovers database has sales information for some, but not all, small entities estimated in this FRFA analysis to have impacts. To supplement the sales information, we estimated 2012 sales by multiplying 2012 oil and natural gas production levels reported in the DrillingInfo database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the same \$4/Mcf for natural gas.⁸³ For oil prices, we estimated revenues using two alternative prices, \$70/bbl and \$50/bbl. In the results, we call the case using \$70/bbl the “primary scenario” and the case using the \$50/bbl as the “low oil price scenario”.⁸⁴ In the instances where the 2012 production-derived revenues exceeded the Hoovers revenues, we replaced the Hoovers estimate with the production-derived estimate as more likely to be an accurate estimate of sales for 2012.

6.3.5.2 *Compliance Cost Impact Estimate Results*

This section presents results of the cost-to-sales ratio analysis for both the primary scenario and the low oil price scenario. The percent of small entities with cost-to-sales ratios exceeding 1 percent and 3 percent in 2020 and 2025 are greater under the low oil price scenario, as would be expected due to lower estimated sales revenues from a lower oil price. Also, as expected, the entities with cost-to-sales ratios greater than 1 percent and greater than 3 percent increase from 2020 to 2025 in both the main case and the low oil price scenario as affected sources accumulate under the NSPS.

⁸³ The U.S. Energy Information Administration’s 2015 Annual Energy Outlook projects 2020 Henry Hub natural gas prices to be \$4.88/MMBtu in its reference case and \$4.30/MMBtu in its “low oil” price case in 2013 dollars. Available at: <<http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>>. After adjusting to \$/Mcf (using the conversion of 1 MMBtu = 1.208 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are \$4.80/Mcf in the reference case and \$4.323/Mcf in the low oil price case. Rounding down to \$4/Mcf likely under-estimates sales.

⁸⁴ The 2015 Annual Energy Outlook projects wellhead oil prices to be \$75.16/bbl in its reference case and \$54.10/bbl in its “low oil” price case in 2013 dollars. Available at: <<http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>>. After adjusting to 2012 dollars (using the GDP-Implicit Price Deflator), these prices are \$74.00/bbl in the reference case and \$53.27/bbl in the low oil price case.

Table 6-12 Compliance Costs-to-Sales¹ Ratios across Firm Size Classes for Primary Scenario and Low Oil Price Scenario²

| | 2020 (Main Case) | | 2020 (Low Oil Price Case) | |
|------------------------|-----------------------|---------------------|---------------------------|---------------------|
| | No. of Small Entities | % of Small Entities | No. of Small Entities | % of Small Entities |
| No. of Small Entities | 2,031 | - | 2,043 | - |
| Greater than 1 percent | 564 | 28% | 648 | 32% |
| Greater than 3 percent | 289 | 14% | 344 | 17% |

| | 2025 (Main Case) | | 2025 (Low Oil Price Case) | |
|------------------------|-----------------------|---------------------|---------------------------|---------------------|
| | No. of Small Entities | % of Small Entities | No. of Small Entities | % of Small Entities |
| No. of Small Entities | 2,031 | - | 2,043 | - |
| Greater than 1 percent | 824 | 41% | 924 | 45% |
| Greater than 3 percent | 419 | 21% | 502 | 25% |

¹ Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. These provisions account for the large majority of the rule's potential impact in 2020 and 2025.

² In the main case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$70/bbl for crude oil. In the low oil price case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$50/bbl for crude oil.

6.3.5.3 Caveats and Limitations

The analysis above is subject to a number of caveats and limitations, many of which we discussed in the presentation of methods and results. It is useful, however, to present a complete list of the caveats and limitations here.

- Because of data limitations, the analysis presented in the FRFA only examines impacts on requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While impacts from these requirements constitute a large proportion of the estimated impacts from the final NSPS, the omission of the estimated costs of other requirements leads to a relative under-estimation of the impacts on small entities. Also, the impacts from other requirements may affect firms that are not drilling wells, such as pipeline transmission firms.
- Not all owner/operators listed in the DrillingInfo database could be identified in the Hoovers database. These owner/operators tend to have developed relatively few new or modified wells in 2012. As a result, we assumed these were small entities, whereas these entities may actually be subsidiaries of larger enterprises. While the impacts estimates are not affected in the aggregate by this assumption, the assumption likely leads to an over-estimate of the impact on small entities for the provisions examined.
- The analysis assumes the same population of entities completing wells in 2012 are also completing wells in 2020 and 2025, according to growth rates developed for the entire

sector. In the future, many of these firms will complete fewer or more wells, and other firms will complete wells. All of these firms combined may complete new or modified wells at higher or lower rates depending on economics and technological factors that are largely unpredictable.

- The approach used to estimate sales for the cost-to-sales ratio might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced in 2020 and 2025.

6.3.6 *Regulatory Flexibility Alternatives*

The EPA considered three major options for this final rule. The option EPA is finalizing contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. This option requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Additionally this option requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

The other options considered differ from the finalized option with respect to the requirements for fugitive emissions. One option exempted low production well sites from the well site fugitive requirements. This less stringent option was analyzed as an alternative to reduce burden on small entities. However, it was rejected because we believe that low production well sites have the same type of equipment and components as production well sites with production greater than 15 boe per day. Since we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. Additionally, we did not receive data showing that low production well sites have lower methane or VOC emissions than well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with industry stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of

equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable, and low production well sites were included in the selected option.

Lastly, the more stringent option required quarterly monitoring for all sites under the fugitive emissions program. This option lead to greater emission reductions, however it was not selected because it increased costs, resulting in a net effect of lower net benefits compared to the finalized option.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available on the World Wide Web approximately 60 days after promulgation of the rule, at <https://www3.epa.gov/airquality/oilandgas/implement.html>.

The EPA notes that the IRFA includes numerous recommendations made by the SBAR Panel⁸⁵. The EPA considered these recommendations during the development of the proposal and final rule. The rationale for the EPA's acceptance or rejection of each recommendation can be found in the relevant discussion of each emission source throughout the preamble to the proposal, final rule, and RTC. Though all comments were seriously considered, the EPA is unable to incorporate all suggestions without compromising the effectiveness of the final regulation. Changes to the rule from proposal that may benefit small entities due to comments received include allowing both OGI and Method 21 as acceptable monitoring technology, replacing a performance based monitoring schedule with a fixed frequency, lengthening the time of initial fugitive monitoring from within 30 days to the later of either **[insert date 1 year after publication of the final rule in the Federal Register]** or with 60 days of the startup of production, and simplified the third party verification of technical infeasibility requirements. Though these are not monetized, we believe the flexibility and simplifications these changes have added to the rule result in a reduced burden on small entities.

⁸⁵ The final SBAR Panel report is found at <<https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4959>>.

6.4 Employment Impact Analysis

In addition to addressing the costs and benefits of the final rule, the EPA has analyzed the impacts of this rulemaking on employment, which are presented in this section.⁸⁶ While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule. Executive Order 13563, states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation.”⁸⁷ A discussion of compliance costs, including reporting and recordkeeping requirements, is included in Section 3 of this RIA. This analysis uses detailed engineering information on labor requirements for each of the control strategies identified in this final rule in order to estimate partial employment impacts for affected entities in the oil and gas industry. These bottom-up, engineering-based estimates represent only one portion of potential employment impacts within the regulated industry, and do not represent estimates of the *net* employment impacts of this rule. First, this section presents an overview of the various ways that environmental regulation can affect employment. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is valid and informative. The section concludes with partial employment impact estimates that rely on engineering-based information for labor requirements for each of the control strategies identified by the rule.

6.4.1 Employment Impacts of Environmental Regulation

From an economic perspective labor is an input into producing goods and services; if a regulation requires that more labor be used to produce a given amount of output, that additional labor is reflected in an increase in the cost of production. Moreover, when the economy is at full employment, we would not expect an environmental regulation to have a net impact on overall employment because labor is being shifted from one sector to another. On the other hand, in

⁸⁶ The employment analysis in this RIA is part of the EPA’s ongoing effort to “conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]” pursuant to CAA section 321(a).

⁸⁷ Executive Order 13563 (January 21, 2011). *Improving Regulation and Regulatory Review. Section 1. General Principles of Regulation*, Federal Register, Vol. 76, Nr. 14, p. 3821.

periods of high unemployment, net employment effects (both positive and negative) are possible.

For example, an increase in labor demand due to regulation may result in a short-term net increase in overall employment as workers are hired by the regulated sector to help meet new requirements (e.g., to install new equipment) or by the environmental protection sector to produce new abatement capital resulting in hiring previously unemployed workers. When significant numbers of workers are unemployed, the opportunity costs associated with displacing jobs in other sectors are likely to be higher. And, in general, if a regulation imposes high costs and does not increase the demand for labor, it may lead to a decrease in employment. The responsiveness of industry labor demand depends on how these forces all interact. Economic theory indicates that the responsiveness of industry labor demand depends on a number of factors: price elasticity of demand for the product, substitutability of other factors of production, elasticity of supply of other factors of production, and labor's share of total production costs. Berman and Bui (2001) put this theory in the context of environmental regulation, and suggest that, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all.

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing environmental regulations. When a regulation is promulgated, one typical response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. On the other hand, the closure of plants that choose not to comply – and any changes in production levels at plants choosing to comply and remain in operation - occur after the compliance date, or earlier in anticipation of the compliance obligation. Environmental regulation may increase revenue and employment in the environmental technology industry. While these increases represent gains for that industry, they translate into costs to the regulated industries required to install the equipment.

Environmental regulations support employment in many basic industries. Regulated firms either hire workers to design and build pollution controls directly or purchase pollution control devices from a third party for installation. Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment—much like they hire workers to produce more output. In addition to the increase in employment in the environmental

protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment.

Berman and Bui (2001) demonstrate using standard neoclassical microeconomics that environmental regulations have an ambiguous effect on employment in the regulated sector. The theoretical results imply that the effect of environmental regulation on employment in the regulated sector is an empirical question. Berman and Bui (2001) developed an innovative approach to examine how an increase in local air quality regulation that reduces nitrogen oxides (NO_x) emissions affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which incorporates Los Angeles and its suburbs. During the time frame of their study, 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in the regulated industries.⁸⁸ The authors find that "while regulations do impose large costs, they have a limited effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).⁸⁹

While there is an extensive empirical, peer-reviewed literature analyzing the effect of environmental regulations on various economic outcomes including productivity, investment, competitiveness as well as environmental performance, there are only a few papers that examine the impact of environmental regulation on employment, but this area of the literature has been growing. As stated previously in this RIA section, empirical results from Berman and Bui (2001) suggest that new or more stringent environmental regulations do not have a substantial impact on net employment (either negative or positive) in the regulated sector. Similarly, Ferris, Shadbegian, and Wolverton (2014) also find that regulation-induced net employment impacts are

⁸⁸ Berman and Bui include over 40 4-digit SIC industries in their sample.

⁸⁹ Including the employment effect of exiting plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.

close to zero in the regulated sector. Furthermore, Gray et al (2014) find that pulp mills that had to comply with both the air and water regulations in the EPA's 1998 "Cluster Rule" experienced relatively small and not always statistically significant, decreases in employment. Nevertheless, other empirical research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). However, the methodology used in these two studies cannot estimate whether aggregate employment is lower or higher due to more stringent environmental regulation, it can only imply that relative employment growth in some sectors differs between more and less regulated areas. List *et al.* (2003) find some evidence that this type of geographic relocation, from more regulated areas to less regulated areas may be occurring. Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

While the theoretical framework laid out by Berman and Bui (2001) still holds for the industries affected under these emission guidelines, important differences in the markets and regulatory settings analyzed in their study and the setting presented here lead us to conclude that it is inappropriate to utilize their quantitative estimates to estimate the net employment impacts from this final regulation. In particular, the industries used in these two studies as well as the timeframe (late 1970's to early 1990's) are quite different than those in this final NSPS. Furthermore, the control strategies analyzed for this RIA include implementing RECs, reducing fugitive emissions, and reducing emissions from pneumatic controllers, pumps, and reciprocating and centrifugal compressors, which are very different than the control strategies examined by Berman and Bui.⁹⁰ For these reasons we conclude there are too many uncertainties as to the transferability of the quantitative estimates from Berman and Bui to apply their estimates to quantify the net employment impacts within the regulated sectors for this regulation, though these studies have usefulness for qualitative assessment of employment impacts.

The preceding sections have outlined the challenges associated with estimating net employment effects in the regulated sector and in the environmental protection sector. These challenges make it very difficult to accurately produce net employment estimates for the whole

⁹⁰ More detail on how emission reductions expected from compliance with this rule can be found in Section 3 of this RIA.

economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Given the difficulty with estimating national impacts of regulations, the EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the evaluation of costs, benefits, and economic impacts associated with environmental regulation, the EPA has formed a panel of experts as part of the EPA's Science Advisory Board (SAB) to advise the EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.⁹¹ Once the EPA receives guidance from this panel it will carefully consider this input and then decide if and how to proceed on economy-wide modeling of net employment impacts of its regulations.

6.4.2 Labor Estimates Associated with Final Requirements

Section 2 of the RIA, in Table 2-17 and Table 2-18, presents background information on employment and wages in the oil and natural gas industry. As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in six oil and natural gas-related NAICS codes from 1990 to 2014.⁹² The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry. From 1990 to 2014, average wages for the oil and natural gas industry increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry.

The focus of this part of the analysis is on labor requirements related to the compliance actions for the final rule of the affected entities within the oil and natural gas sector. We do not estimate any potential changes in labor outside of the affected sector, and due to data and

⁹¹ For further information see:

<http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument>

⁹² NAICS 211111, 21112, 213111, 213112, 486110, and 486210.

methodology limitations we do not estimate net employment impacts for the affected sector, apart from the partial estimate of the labor requirements related to control strategies. This analysis estimates the labor required to the install, operate, and maintain control equipment and activities, as well as to perform new reporting and recordkeeping requirements.

It is important to highlight that, unlike the typical case where a firm often has to reduce production in order to reduce output of negative production externalities (i.e., emissions), many of the emission controls required by the final NSPS will simultaneously increase production and reduce negative externalities. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. Therefore, new labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions. However, these rules may require unprofitable investments for some operators, and there is a possibility that these producers decrease output in response and create downward pressure on labor demand, both in the regulated sector and on those sectors using natural gas as an input. This RIA does not include quantified estimates of these potential adverse effects on the labor market due to data limitations and theoretical challenges, as described above.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because the EPA does not currently have this information. The labor requirements analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in Chapter 3 of this RIA includes estimates of the labor requirements associated with implementing the regulations. Each of these labor changes may be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of employees involved or whether new jobs are created for new employees.

The results of this employment analysis of the NSPS are presented in Table 6-13 through

Table 6-16 for 2020 and 2025 for individual sources regulated under this rule. Table 6-17 presents summary-level labor impacts for all sources. The tables break down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. The labor information is based upon the cost analysis presented in the TSD that supports this rule, based upon analysis presented in the RIA developed for the 2012 NSPS and NESHAP Amendments for the Oil and Natural Gas Sector (U.S. EPA, 2012). In addition, for the final NSPS, reporting and recordkeeping requirements were estimated for the entire rule rather than by anticipated control requirements. The reporting and recordkeeping estimates are consistent with estimates the EPA submitted as part of its Information Collection Request (ICR), the estimated costs which are included in the cost estimates presented in Chapter 3.

Table 6-13 presents estimates of labor requirements for hydraulically fractured oil well completions. The REC and completion combustion requirements are associated with certain new and existing oil well completions. While individual well completions take place over a short period of time (days to a few weeks), the overall industry completes new wells and re-completes some existing wells every year. Because of the continuing nature of new and existing well completions, annually, at the industry level, we report the REC-related labor requirements in annual units.

The per-unit estimates of one-time labor requirements associated with implementing RECs and completion combustion are drawn from the labor requirements estimated for implementing RECs on hydraulically fractured well completions in EPA (2012). However, the labor requirements in that report were based upon a completion that is assumed to last seven days (218 hours per completion for a REC or 22 hours labor per completion for completion combustion). In this analysis, completion events for hydraulically fractured oil wells are assumed to last three days, so we multiply the seven-day requirements by $3/7$ (93 hours per completion for a REC or 9 hours labor per completion for completion combustion).

Table 6-13 Estimates of Labor Required to Comply with NSPS for Hydraulically Fractured Oil Well Completions, 2020 and 2025

| Emissions Source/Control | Projected No. of Incrementally Affected Units (2020) | Per Unit One-time Labor Estimate (hours) | Per Unit Annual Labor Estimate (hours) | Total One-Time Labor Estimate (hours) | Total Annual Labor Estimate (hours) | One-time FTE | Annual FTE |
|---|---|---|---|--|--|---------------------|-------------------|
| 2020 | | | | | | | |
| Hydraulically Fractured Oil Well Completions and Recompletions | | | | | | | |
| Completions where REC and completion combustion is required | 7,500 | 0 | 93 | 0 | 700,000 | 0 | 340 |
| Completions where completion combustion is required | 5,600 | 0 | 9 | 0 | 53,000 | 0 | 25 |
| Total | 13,000 | N/A | N/A | 0 | 760,000 | 0 | 360 |
| 2025 | | | | | | | |
| Hydraulically Fractured Oil Well Completions and Recompletions | | | | | | | |
| Completions where REC and completion combustion is required | 8,000 | 0 | 93 | 0 | 750,000 | 0 | 360 |
| Completions where completion combustion is required | 6,000 | 0 | 9 | 0 | 57,000 | 0 | 27 |
| Total | 14,000 | N/A | N/A | 0 | 800,000 | 0 | 390 |

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per-unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-14 presents estimates of labor requirements for fugitive emissions. Consistent with the cost estimates for fugitive emissions presented in Section 5 of the TSD, we estimate labor associated with company-level activities and activities at field sites. Company-level activities include one-time activities such as planning the company’s fugitive emissions program and annual requirements such as reporting and recordkeeping. Field-level activities include semiannual inspection and repair of leaks. It is important to note, however, that the compliance costs estimates for leak inspection were based upon an estimate of the costs to hire a contractor to provide the inspection service, but the source providing this information does not have a breakdown of the labor component of the rental cost. As a result, the labor requirements for the fugitives program remain uncertain.

Table 6-14 Estimates of Labor Required to Comply with NSPS for Fugitive Emissions, 2020 and 2025

| Emissions Source | Emissions Control | Projected No. of Incrementally Affected Units (2020) | Per Unit One-time Labor Estimate (hours) | Per Unit Annual Labor Estimate (hours) | Total One-Time Labor Estimate (hours) | Total Annual Labor Estimate (hours) | One-time FTE | Annual FTE |
|---|----------------------------|--|--|--|---------------------------------------|-------------------------------------|--------------|--------------|
| 2020 | | | | | | | | |
| Well Sites | | | | | | | | |
| Company-level | Planning | 4,300 | 120 | 0.0 | 500,000 | 0 | 240 | 0 |
| Site-level | Monitoring and Maintenance | 94,000 | 0.0 | 14 | 0 | 1,300,000 | 0 | 640 |
| Gathering and Boosting Stations | | | | | | | | |
| Company-level | Planning | 480 | 120 | 0.0 | 57,000 | 0 | 27 | 0 |
| Site-level | Monitoring and Maintenance | 480 | 0.0 | 110 | 0 | 52,000 | 0 | 25 |
| Transmission Compressor Stations | | | | | | | | |
| Company-level | Planning | 20 | 120 | 0.0 | 2,400 | 0 | 1 | 0 |
| Site-level | Monitoring and Maintenance | 20 | 0.0 | 110 | 0 | 2,100 | 0 | 1 |
| Storage Compressor Stations | | | | | | | | |
| Company-level | Planning | 25 | 120 | 0.0 | 3,000 | 0 | 1 | 0 |
| Site-level | Monitoring and Maintenance | 25 | 0.0 | 210 | 0 | 5,300 | 0 | 3 |
| Total | | 94,000 | N/A | N/A | 560,000 | 1,400,000 | 270 | 660 |
| 2025 | | | | | | | | |
| Well Sites | | | | | | | | |
| Company-level | Planning | 4,300 | 120 | 0.0 | 500,000 | 0 | 240 | 0 |
| Site-level | Monitoring and Maintenance | 190,000 | 5.4 | 14 | 0 | 2,700,000 | 0 | 1,300 |
| Gathering and Boosting Stations | | | | | | | | |
| Company-level | Planning | 480 | 120 | 0.0 | 57,000 | 0 | 27 | 0 |
| Site-level | Monitoring and Maintenance | 960 | 0.0 | 110 | 0 | 100,000 | 0 | 50 |
| Transmission Compressor Stations | | | | | | | | |
| Company-level | Planning | 20 | 120 | 0.0 | 2,400 | 0 | 1 | 0 |
| Site-level | Monitoring and Maintenance | 40 | 0.0 | 110 | 0 | 4,300 | 0 | 2 |
| Storage Compressor Stations | | | | | | | | |
| Company-level | Planning | 25 | 120 | 0.0 | 3,000 | 0 | 1 | 0 |
| Site-level | Monitoring and Maintenance | 50 | 0.0 | 210 | 0 | 11,000 | 0 | 5 |
| Total | | 190,000 | N/A | N/A | 560,000 | 2,800,000 | 270 | 1,400 |

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Most labor required for fugitive emissions is needed at well sites in the field, which number in the thousands. Note that the labor requirements estimates increase from 2020 to 2025 as the number of sites regulated under the final NSPS accumulates.

Table 6-15 presents labor requirement estimates for monitoring and maintenance requirements for reciprocating compressors and routing emissions to a control device for centrifugal compressors. Like the estimates for completions, the per unit labor estimates were based on EPA (2012). As relatively little labor is required for reciprocating compressors and relatively few affected centrifugal compressors are expected in the future, the estimates of both one-time and on-going labor requirements for compressor requirements are minimal.

Table 6-15 Estimates of Labor Required to Comply with NSPS for Reciprocating and Centrifugal Compressors, 2020 and 2025

| Emissions Source | Emissions Control | Projected No. of Incr. Affected Units | Per-unit | Per-unit | Total | Total | One-time FTE | Annual FTE |
|--------------------|----------------------------|---------------------------------------|---------------------------|-------------------------|-------------------------------|-----------------------------|--------------|------------|
| | | | One-time Labor Est. (hrs) | Annual Labor Est. (hrs) | One-Time Labor Estimate (hrs) | Annual Labor Estimate (hrs) | | |
| 2020 | | | | | | | | |
| Compressors | | | | | | | | |
| Reciprocating | Monitoring and Maintenance | 160 | 1 | 1 | 160 | 160 | 0 | 0 |
| Centrifugal | Route to Control | 5 | 360 | 0 | 1,800 | 0 | 1 | 0 |
| Total | | 170 | N/A | N/A | 2,000 | 160 | 1 | 0 |
| 2025 | | | | | | | | |
| Compressors | | | | | | | | |
| Reciprocating | Monitoring and Maintenance | 320 | 1 | 1 | 160 | 320 | 0 | 0 |
| Centrifugal | Route to Control | 10 | 360 | 0 | 1,800 | 0 | 1 | 0 |
| Total | | 330 | N/A | N/A | 2,000 | 320 | 1 | 0 |

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-16 presents the labor requirement estimates for requirements applying to pneumatic controllers and pneumatic pumps. Note that pneumatic controllers have no one-time or continuing labor requirements. While the controls do require labor for installation, operation,

and maintenance, the required labor is less than that of the controllers that would be used absent the regulation (U.S. EPA, 2012). In this instance, we assume the incremental labor requirements are zero. Meanwhile, we are currently unable to estimate the labor associated with pneumatic pump control activities.

Table 6-16 Estimates of Labor Required to Comply with NSPS for Pneumatic Controllers and Pumps, 2020 and 2025

| Emissions Source | Emissions Control | Projected No. of Incr. Affected Units | Per-unit One-time Labor Est. (hrs) | Per-unit Annual Labor Est. (hrs) | Total One-Time Labor Estimate (hrs) | Total Annual Labor Estimate (hrs) | One-time FTE | Annual FTE |
|-----------------------|-------------------|---------------------------------------|------------------------------------|----------------------------------|-------------------------------------|-----------------------------------|--------------|------------|
| 2020 | | | | | | | | |
| Pneumatic Controllers | Emissions Limit | 480 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pneumatic Pumps | Route to Control | 3,900 | N/A | N/A | N/A | N/A | N/A | N/A |
| 2025 | | | | | | | | |
| Pneumatic Controllers | Emissions Limit | 960 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pneumatic Pumps | Route to Control | 7,900 | N/A | N/A | N/A | N/A | N/A | N/A |

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-17 presents the labor estimates across all emissions sources. Two main categories contain the majority of the labor requirements for the final NSPS: implementing reduced emissions completions (REC) at hydraulically fracture oil well completions and fugitive emissions detection and repair at well sites. The up-front labor requirement to comply with the final NSPS is estimated at 270 FTEs in 2020 and in 2025. The annual labor requirement to comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 6-17 Estimates of Labor Required to Comply with NSPS, 2020 and 2025

| Emissions Source | Projected No. of Incrementally Affected Units (2020) | Total One-Time Labor Estimate (hours) | Total Annual Labor Estimate (hours) | One-time FTE | Annual FTE |
|---|--|---------------------------------------|-------------------------------------|--------------|--------------|
| 2020 | | | | | |
| Hydraulically Fractured and Re-fractured Oil Well Completions | 13,000 | 0 | 760,000 | 0 | 360 |
| Fugitive Emissions | 94,000 | 560,000 | 1,400,000 | 270 | 660 |
| Pneumatic Controllers | 480 | 0 | 0 | 0 | 0 |
| Pneumatic Pumps | 3,900 | N/A | N/A | N/A | N/A |
| Reciprocating Compressors | 160 | 160 | 160 | 0 | 0 |
| Centrifugal Compressors | 5 | 1,800 | 0 | 1 | 0 |
| Reporting and Recordkeeping Requirements | All | 0 | 180,000 | 0 | 88 |
| Total | 110,000 | 570,000 | 2,300,000 | 270 | 1,100 |
| 2025 | | | | | |
| Hydraulically Fractured and Re-fractured Oil Well Completions | 14,000 | 0 | 800,000 | 0 | 390 |
| Fugitive Emissions | 190,000 | 560,000 | 2,800,000 | 270 | 1,400 |
| Pneumatic Controllers | 960 | 0 | 0 | 0 | 0 |
| Pneumatic Pumps | 7,900 | N/A | N/A | N/A | N/A |
| Reciprocating Compressors | 320 | 160 | 320 | 0 | 0 |
| Centrifugal Compressors | 10 | 1,800 | 0 | 1 | 0 |
| Reporting and Recordkeeping Requirements | All | 0 | 180,000 | 0 | 88 |
| Total | 220,000 | 570,000 | 3,800,000 | 270 | 1,800 |

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Rounded to two significant digits. Totals may not sum due to independent rounding.

6.5 References

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COST-BENEFIT ANALYSIS
SUBMITTED PER § 24-4-103(2.5), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 3 (5 CCR 1001-5) and
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

The Colorado Air Pollution Control Division (Division) submits the following Cost-Benefit Analysis in conjunction with its proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9).

The proposed revisions collectively expand the air emission control requirements on oil and gas facilities in Colorado. They were developed after an extensive, year-long stakeholder process including input from diverse industry, environmental and governmental stakeholders. The proposal has received the support of several industry and environmental leaders. The Division estimates that the proposed strategies will result in substantial reductions of hydrocarbon emissions from the oil and gas industry. More specifically, the Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be \$42.4 million per year. This translates to approximately \$453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado AQCC and the U.S. Environmental Protection Agency (EPA). In prehearing submittals to the AQCC, the supporters of the proposal have concluded that the Division's costs estimates are reasonable. Some opponents of the proposal have asserted that the costs may be much higher. The AQCC will consider the Division's proposal and any alternate proposals at the rulemaking hearing commencing February 19, 2014.

The proposed changes to Regulation Number 3 simplify certain air quality reporting and permitting requirements. They remove the requirements for sources with emissions below state reporting and permitting thresholds but subject to either a federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP") to file an Air Pollutant Emission Notice ("APEN") and obtain a minor source permit ("catch-all provisions"). The Regulation Number 3 revisions also simplify reporting requirements for non-criteria reportable pollutant sources, and remove the permitting exemption for crude oil storage tanks.

The Regulation Number 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. These proposed revisions consist of the following:

- 1) Enhancing the existing control program for petroleum storage tanks by:

- a. Lowering the control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;
 - b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
 - c. Expanding non-attainment area requirements for tank controls during the first 90 days of production to the rest of the state;
- 2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
 - 3) Establishing leak detection and repair requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
 - 4) Expanding the existing non-attainment area requirements for auto-igniters on flare devices to the rest of the state;
 - 5) Expanding the existing ozone non-attainment area requirements for low bleed pneumatic devices to the rest of the state, and where feasible requiring no-bleed pneumatic devices; and
 - 6) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production.
 - 7) Lowering the existing control requirement threshold for existing glycol dehydrators to 6 tons per year of uncontrolled actual VOC emissions and 2 tons per year of uncontrolled actual VOC emissions for dehydrators located within 1,320 feet of a building, and establishing a 2 ton per year control threshold for all new glycol dehydrators; and
 - 8) Establishing requirements for the use of best management practices both to minimize the need for downhole well maintenance and liquids unloading and to minimize emissions during well maintenance and liquids unloading events.

If adopted, these proposed revisions will result in substantial reduction of hydrocarbon emissions including volatile organic compounds (VOCs) and methane.

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the AQCC to consider. Some of these proposals request that the AQCC adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the AQCC limit aspects of the Division's proposed revisions. Copies of each of these proposals along with any economic impact analysis that the parties submitted identifying the projected costs and benefits of their particular proposals are attached to this Cost-Benefit Analysis as exhibits.

As set forth in § 24-4-103(2.5), C.R.S. this Cost-Benefit analysis shall include the following:

- (I) The reason for the rule or amendment;

Cost Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7

- (II) The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;
- (III) The anticipated costs of the rule or amendment, which shall include the direct costs to the government to administer the rule or amendment and the direct and indirect costs to businesses and other entities required to comply with the rule or amendment;
- (IV) Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and
- (V) At least two alternatives to the proposed rule or amendment that can be identified by the submitting agency or member of the public, including the costs and benefits of pursuing each of the alternatives identified.

In connection with this Cost- Benefit Analysis, the Division has assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division has sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

II. THE REASON FOR THE RULE OR AMENDMENT

The Division is proposing revisions to AQCC Regulation Number 3 in order to improve the efficiency of Colorado's air quality reporting and permitting system. Under current regulation, when Colorado adopts certain federal air quality standards, all sources that are subject to these standards must report their emissions to the Division and obtain a permit. This requirement can result in the imposition of reporting and permitting burdens for very small sources of emissions. The proposed change would allow the state to adopt these federal requirements, but only require reporting and permitting for sources with emissions above established de minimis levels. The proposed revisions would also simplify reporting of non-criteria reportable pollutants, and provide that crude oil tanks must be permitted if their emissions are over the established de minimis levels. It appears that all parties to the AQCC rulemaking support the proposed revisions to Regulation Number 3.

The Division is proposing revisions to AQCC Regulation Number 7 in an effort to enhance the effectiveness of Colorado's air quality requirements for the oil and gas exploration and production sector. During the past ten years, Colorado has been a leader in developing and implementing requirements to reduce air emissions from the oil and gas sector. As a result of these efforts, Colorado now has in place a series of cost-effective requirements that significantly reduce air emissions from Colorado oil and gas facilities. Despite this success, however, the tremendous growth of oil and gas production in Colorado continues to threaten the air quality gains that we have achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. While this growth has provided important economic benefits for Colorado, increased air emissions can have a negative impact on Colorado's public health and environment.

Specifically, VOC emissions contribute to the formation of ground level ozone. Ozone (O₃) is photochemical oxidant and known respiratory irritant. Ground level ozone is a secondary pollutant produced through the reaction of VOCs, nitrogen oxides and sunlight. Elevated levels of ground level ozone have been linked to a variety of adverse health effects including decreased lung function, increased respiratory symptoms, serious indicators of respiratory morbidity including emergency visits and hospital admissions, as well as total non-accidental and cardio-respiratory mortality. The U.S. EPA has set the current National Ambient Air Quality Standards for ground level ozone at 75 parts per billion (ppb) averaged over an 8-hour period. Based on a review of the then current health literature the Clean Air Scientific Advisory Committee concluded in 2008 that the 75 ppb standard was not sufficiently protective of public health, and recommended that the standard be set at between 60 ppb and 70 ppb. EPA is in the process of considering whether to lower the ozone standard.

Currently, the Denver Metro/North Front Range area is out of attainment with federal health-based ground level ozone standards. This includes much of the Denver/Julesberg oil field. Other areas of the state have also experienced elevated ozone levels recently, with one monitor in Western Colorado showing concentrations above 75 ppb and a number of other monitors showing levels between 60 ppb and 75 ppb.

Addressing oil and gas emissions is a critical component of Colorado's efforts to lower ozone levels since this sector represents the largest source of VOC emissions in the state. Based on the most recent inventory (2011), 54% of the anthropogenic VOC emissions in the state come from the oil and gas sector, which is roughly triple the amount of emissions from the next largest source. Moreover, because of the ongoing growth in the oil and gas industry and the projected decline in VOC emissions from other sectors, the share of VOC emissions attributable to the oil and gas sector will likely increase over the foreseeable future. The proposed emission reduction strategies will further enhance existing public health and environment protections on both a local and regional scale.

In addition to VOC emissions, oil and gas operations are a large source of methane. Methane is a potent greenhouse gas, which contributes to global climate change. In addition to reducing VOCs that contribute to regional ozone pollution, the Division's proposed strategies will reduce methane, and thereby play a role in Colorado's overall efforts to reduce greenhouse gas emissions. Methane is also a valuable natural resource (natural gas), and reducing leaks will benefit Colorado's environment and economy.

III. ANTICIPATED ECONOMIC BENEFITS

The proposed changes to Regulation Number 7 are projected to result in substantial reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. For VOCs, the Division has calculated that based on 2013 emissions, the proposed strategies will reduce VOC emissions from the oil and gas sector by approximately 93,500 tons per year or 257 tons per day. To put this in context, 257 tons per day represents approximately 45% of the total oil and gas related VOC emissions in 2011 and nearly 25% of the total 2011 VOC emissions

from all anthropogenic sources in Colorado. Additionally, the proposed strategies are projected to reduce methane/ethane emissions by approximately 64,000 tons per year.

These VOC reductions will aid Colorado's efforts to bring the Denver Metro/North Front Range area (DMA/NFR) into compliance with the current ozone NAAQS, as well as serve as a proactive step in addressing future lower ozone standards. As noted above, ground level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. According to EPA, attaining the current ozone standard throughout the nation will result in between \$6.9 billion and \$18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieving a 70 ppb standard will result in between \$13 billion and \$37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between \$22 billion and \$61 billion per year. EPA does not report these health benefits by state, but since the population of the DMA/NFR accounts for approximately 2.5% of the total national population living in areas that are in violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

In addition to impacting human health, elevated levels of ozone can have a negative impact on crop production. For example, EPA's analysis indicates that reducing ozone levels to 70 ppb will increase winter wheat yields in a number of Front Range counties, including an increase of between 1% and 2% in Weld County.

Separate from the beneficial impacts of reducing ozone, the proposed rules will also produce substantial benefits associated with reducing greenhouse gases. As part of this rulemaking the Environmental Defense Fund (EDF) has engaged an expert to estimate the benefits of the rulemaking based on the social cost of carbon. Based on this analysis, EDF projects that the total annual benefit from the projected methane reductions is between \$104 million and \$318 million in 2016 and between \$132 million and \$404 million in 2025.¹

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form of increased product capture and the creation of new jobs associated with the implementation of the new requirements. As discussed more fully in Section IV below, the proposed rules are expected to result in the capture of approximately \$16.8 million dollars worth of natural gas each year that would otherwise be lost to the atmosphere. Additionally, a significant portion of the overall costs associated with the proposed rules is for additional inspections of oil and gas facilities by company employees or contractors. Based on the total calculated inspection time, the proposed requirements will necessitate the hiring of approximately 150 additional employees or contractors to conduct inspections. The remaining costs of the proposal are associated with the purchase, installation and maintenance of equipment along with supervisory oversight and required recordkeeping and reporting. These expenditures will likely result in additional job creation, but the actual number of these jobs has not been calculated.

IV. ANTICIPATED COSTS

¹ A copy of the analysis is attached hereto as Exhibit O.

As set forth below, the Division has assessed the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7. These costs are set forth in Sections A through H below and include equipment costs, labor costs, maintenance costs, supervision costs, travel costs, and costs associated with recordkeeping and reporting. Section I discusses the costs to government associated with administering the proposed Regulation Number 7 revisions. Finally, Section J details the costs to the regulated community and government administration costs associated with the proposed revisions to Regulation Number 3.

As detailed below, the Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately \$59.2 million. In addition, as discussed in Section III above, the proposed strategies are expected to result in the capture of additional product worth approximately \$16.8 million, for a total net cost of \$42.4 million per year. In addition to these direct costs, implementation of the proposed strategies could potentially result in the shut-in of a few marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.² An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.³ This information will be considered by the AQCC as part of the rulemaking hearing.

A. Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the AQCC has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in the non-attainment area must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the AQCC's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity of 40 degrees or greater." While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities

² See discussion in Section V below.

³ See Attached Exhibit B.

continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the non-attainment area be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 1 below. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 2-4 below.

1. General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study⁴ adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter⁵ is about \$6,287.⁶

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|---------------------|--------------------------|--------------------------------|-----------------------|------------------------|
| Flare | \$18,169 | | | |
| Freight/Engineering | | \$1,648 | | |
| Flare Installation | | \$6,980 | | |
| Auto Igniter | \$1,648 | | | |
| Pilot Fuel** | | | \$768 | |
| Maintenance | | | \$2,197 | |
| Subtotal Costs | \$19,817 | \$8,628 | \$2,965 | |
| Annualized Costs*** | \$2,747 | \$575 | \$2,965 | |

*Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.⁷

⁴ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process. For reference or background purposes the Division has cited herein certain information that has been submitted to the AQCC as part of the rulemaking; however, it is not necessarily included with this Cost-Benefit Analysis as an exhibit.

⁵ Currently only flares in the non-attainment area are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section D.

⁶ Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA’s cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA’s analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

** Pilot fuel costs \$3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

2. Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the non-attainment area (NAA) and the remaining 192 are within the current non-attainment area.

| Tank Battery Type | Ozone NAA [count] | Outside NAA [count] | Cancelled Tanks [count] | Total Statewide Tanks [count] |
|------------------------------------|-------------------|---------------------|-------------------------|-------------------------------|
| Controlled Tanks | 4,971 | 490 | | 5,461 |
| Uncontrolled Tanks | 1,451 | 1,132 | 36 | 2,619 |
| All Tanks | 6,422 | 1,622 | 36 | 8,080 |
| | | | | |
| Uncontrolled Tanks (≥ 6 tpy) | 192 | 396 | | 588 |

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,⁸ and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|--|--|--------------------------------------|------------------------------------|
| NAA Uncontrolled Tanks (≥ 6 tpy) | 2,355 | 677* | 1,678 |
| Outside NAA Uncontrolled Tanks (≥ 6 tpy) | 4,890 | 1,406* | 3,484 |
| Totals: | 7,245 | 2,083 | 5,162 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

⁷ It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.

⁸ The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section B.

The annualized cost of installing 588 flare control devices is about \$3.7 million dollars with an average cost effectiveness of about \$716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

| Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|---------------------------|-------------------------------|---------------------------|------------------------------|---------------------------|
| 588 | \$6,286.8 | \$3,696,638 | 5,162 | \$716 |

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or \$1,884 per ton of methane/ethane reduced.

3. Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the AQCC adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division’s APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

| Tank Battery Type | Total Statewide Water Tanks |
|---------------------------|-----------------------------|
| Controlled Water Tanks: | 338 |
| Uncontrolled Water Tanks: | 530 |
| Total: | 868 |

| Tank Battery Type | Total Statewide Water Tanks |
|------------------------------------|-----------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 52 |

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|------------------------------------|--|--------------------------------------|------------------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 641.4 | 184.4* | 457 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 52 flare control devices is about \$327,000, with an average cost effectiveness of about \$715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

| Tank Size | Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------------|------------------------|----------------------------|------------------------|---------------------------|------------------------|
| ≥ 6 tpy | 52 | \$6,286.8 | \$326,914 | 457 | \$715 |

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),⁹ it appears likely that the Division’s APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.¹⁰

⁹ Based on an analysis of 2010 COGCC data.

¹⁰ Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

| Tank Battery Type | Total Statewide Crude Oil Tanks |
|------------------------------------|---------------------------------|
| Controlled Crude Oil Tanks | 36 |
| Uncontrolled Crude Oil Tanks | 29 |
| Total: | 65 |
| Uncontrolled Tanks (≥ 6 tpy) | 8 |

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|------------------------------------|--|--------------------------------------|------------------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 165.2 | 47.5* | 117.7 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing eight flare control devices is about \$50,294 dollars with an average cost effectiveness of about \$427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

| Tank Size | Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$ /ton] |
|--------------|------------------------|----------------------------|------------------------|---------------------------|-------------------------|
| ≥ 6 tpy | 8 | \$6,286.8 | \$50,294.4 | 117.7 | \$427 |

4. Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the non-attainment area have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this issue in the non-attainment area, the AQCC mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the non-attainment area based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,¹¹ total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (see Section B below) the flare control efficiency is 95%, and thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the non-attainment area will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the non-attainment area each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or \$1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be \$6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional \$3,000 in annual relocation costs, for a total annualized cost of about \$9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is \$176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

| Storage Tank Threshold [tpy] | Number of New Storage Tanks | Number of New Flares | Annualized Cost Each Flare | Total Flare Cost | Total VOC Reduction [tons/year] | VOC Control Cost [\$ /ton] |
|------------------------------|-----------------------------|----------------------|----------------------------|------------------|---------------------------------|----------------------------|
| <6 | 57 | 19 | \$9,286.8 | \$176,449.2 | 44.7 | \$3,947 |
| ≥6 | 84 | 84 | \$1,571.7 | \$132,022.8 | 1,705.7 | \$77 |
| | 141 | | | \$308,472 | 1,750.4 | \$176 |

Using the methodology discussed in subsection A.2 above the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or \$464 per ton of methane/ethane reduced.

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's

¹¹ Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using infra-red (IR) cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division’s proposal requires that owners and operators of controlled storage tanks implement a Storage Tank Emission Management (STEM) plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division’s STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly¹² auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using EPA Reference Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections

| Tank Uncontrolled Actual VOC Emissions | Inspection Frequency |
|--|----------------------|
| ≥ 6 tpy to ≤ 12 tpy | Annually |
| > 12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division’s proposal discussed in Section A above. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division’s proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division assumed that buffer bottle

¹² There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

technology would be installed on each of the subject tanks.¹³ The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.¹⁴

Table 13: Annualized Cost Analysis for Buffer Bottle

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|-------------------|--------------------------|--------------------------------|-----------------------|------------------------|
| Buffer Bottle | \$11,500 | | | |
| Freight/Engr | | \$600 | | |
| Installation | | \$2,280 | | |
| Maintenance | | | \$2,500 | |
| Subtotal Costs | \$11,500 | \$2,880 | \$2,500 | |
| Annualized Costs* | \$1,593.8 | \$192 | \$2,500 | \$4,285.8 |

* Annualized over 15 years at 5% ROR

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.¹⁵

Assuming that each inspection takes two hours and utilizing a \$103/hour¹⁶ in-house inspection cost and a \$134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is \$5,392,010, which equates to \$1,015.4 per year for each tank that will be subject to STEM.

¹³ Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

¹⁴ For this Cost-Benefit Analysis the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.

¹⁵ In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.

¹⁶ The hourly inspection cost is discussed below in Table 20.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering

| Tank Uncontrolled Actual VOC Emissions | Inspection Type/Hourly Rate | Number of Tanks | Inspection Frequency | Number of Inspections | STEM Inspection Costs |
|--|-----------------------------|-----------------|----------------------|-----------------------|-----------------------|
| >6 tpy to ≤ 12 tpy | In-House/\$103 | 1,085 | Annually | 1,085 | \$223,510 |
| >12 tpy to ≤ 50 tpy | In-House/\$103 | 2,595 | Quarterly | 10,380 | \$2,138,280 |
| > 50 tpy | In-House/\$103 | 745 | Monthly | 8,940 | \$1,841,640 |
| Subtotal: | | 4,425 | | 20,405 | \$4,203,430 |
| >6 tpy to ≤ 12 tpy | Contractor/\$134 | 323 | Annually | 323 | \$86,564 |
| >12 tpy to ≤ 50 tpy | Contractor/\$134 | 329 | Quarterly | 1,316 | \$352,688 |
| > 50 tpy | Contractor/\$134 | 233 | Monthly | 2,796 | \$749,328 |
| Subtotal: | | 885 | | 4,435 | \$1,188,580 |
| Total: | | 5,310 | | 24,840 | \$5,392,010 |

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.¹⁷ Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is \$5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

$$\text{Emission reduction} = [\text{uncontrolled VOC} * (1 - (0.75 * 0.95))] - [\text{uncontrolled VOC} * (1 - 0.95)],$$

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

¹⁷ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008, at pg. 8.

Table 15: STEM Emission Control Analysis (Statewide)

| Number of Tanks ≥ 6 tpy | Uncontrolled VOC [tons/year] | Controlled VOC (@ 71.25% Control) [tons/year] | Controlled VOC (@ 95% Control) [tons/year] | VOC Reduction [tons/year] |
|------------------------------|------------------------------|---|--|---------------------------|
| 5,269 | 221,569 | 63,701 | 11,078 | 52,623 |
| 41 | 3,213 | 924 | 161 | 763 |
| 5,310 | 224,782 | 64,625 | 11,239 | 53,386 |

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is \$527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)

| Type of Technology | Number of Tanks | Each Device Annualized Costs [\$ /year] | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$ /ton] |
|--------------------|-----------------|---|------------------------|---------------------------|-------------------------|
| Buffer Bottle | 5,310 | \$5,301.2 | \$28,149,372 | 53,386 | \$527.3 |

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to \$1,388 per ton of methane/ethane reduced.

During the Division stakeholder process leading up the AQCC rulemaking hearing, certain parties raised questions about the Division’s assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be \$264/ton VOC¹⁸. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be \$2,636/ton VOC¹⁹.

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure

¹⁸ This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.

¹⁹ This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about \$19,341.

Table 17: Annualized Cost Analysis for HLP Separator

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|----------------------|-----------------------------|-----------------------------------|--------------------------|---------------------------|
| HLP/VRU | \$90,000 | | | |
| Freight/Engr | | \$1,648 | | |
| HLP/VRU Installation | | \$11,154 | | |
| Maintenance | | | \$9,396 | |
| VRU Recovered NG * | | | \$(3,382) | |
| Subtotal Costs | \$90,000 | \$12,802 | \$6,014 | |
| Annualized Costs** | \$12,474 | \$853 | \$6,014 | \$19,341 |

* Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥6 tpy (uncontrolled VOC).

** Annualized over 15 years at 5% ROR

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the \$6,286.8 annual cost of a flare and annual instrument based monitoring costs of \$1,015.4 per tank, the total annual control costs for a new tank will be \$26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of \$444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is \$4,674 per ton VOC. For methane ethane the cost per ton is \$1,168 per ton reduced on average.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct

periodic inspections using EPA Reference Method 21²⁰ and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.²¹ To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an infrared (IR) camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations

| Component Leak Uncontrolled Actual VOC Emissions | Inspection Frequency |
|--|----------------------|
| ≤ 12 tpy | Annually |
| >12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements discussed in Section B above.²²

²⁰ While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

²¹ Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

²² Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this Cost-Benefit Analysis, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the

| Tank Uncontrolled Actual VOC Emissions | Inspection Frequency |
|--|----------------------------|
| < 6 tpy | One Time (and Monthly AVO) |
| ≥ 6 tpy to ≤ 12 tpy | Annually |
| >12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.²³ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be \$193,629, which equates to an hourly inspection rate of \$103.

| Item | Capital Costs (one time) | Annual Costs | Annualized Total Costs |
|--------------------------------|--------------------------|------------------------|------------------------|
| FLIR Camera | \$122,000 | | |
| FLIR Camera Maintenance/Repair | | \$7,500 | |
| Photo Ionization Detector | \$5,000 | | |
| Vehicle (4x4 Truck) | \$22,000 | | |
| Inspection Staff | | \$75,000 | |
| Supervision (@ 20%) | | \$15,000 | |
| Overhead (@10%) | | \$7,500 | |
| Travel (@15%) | | \$11,250 | |
| Recordkeeping (@10%) | | \$7,500 | |
| Reporting (@10%) | | \$7,500 | |
| Fringe (@30%) | | \$22,500 | |
| Subtotal Costs | \$149,000 | \$153,750 | |
| Annualized Costs* | \$39,879 | \$153,750 | \$193,629 |
| *over 5 years at 6% ROR | | Annualized Hourly Rate | \$103 |

The Division initially assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller companies that cannot fully utilize an IR camera, however, conducting inspections in-house may

same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

²³ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

not be the most cost effective option. To account for this in the Cost-Benefit Analysis the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection (\$134 per hour).

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.²⁴

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

Table 21: Calculated Inspection Time Compressor Station Leak Inspections

| Component Leak Uncontrolled Actual VOC Emissions | Method 21 Inspection | IR Camera/ Hybrid Inspection |
|--|----------------------|------------------------------|
| ≤ 12 tpy | 21.2 hours | 10.6 hours |
| >12 tpy to ≤ 50 tpy | 56.2 hours | 28.1 hours |
| > 50 tpy* | | |

* there are currently no compressor stations in Colorado with calculated leaks at this level

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the non-attainment area and well production facilities outside the non-attainment area. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections

| Area | Method 21 Inspection | IR Camera/ Hybrid |
|------|----------------------|-------------------|
|------|----------------------|-------------------|

²⁴ Based on the Division’s own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division’s assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

| | | Inspection |
|---------------------|------------|------------|
| Non-Attainment Area | 12.2 hours | 6.1 hours |
| Rest of the State | 6.8 hours | 3.4 hours |

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 20, for the purposes of this Cost-Benefit Analysis the Division also assumed an additional three hours in travel time for each inspection outside the non-attainment area. This assumption reflects the fact that certain well sites in basins outside the non-attainment area may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.²⁵ Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the stakeholder process it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial Economic Impact Analysis to the AQCC, the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement to the AQCC, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A to CG-PHS, Testimony of David McCabe at pg. 8. Nevertheless, for this Cost-Benefit Analysis, the Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a \$66.24 hourly rate to repair components, and an average repair time of between 0.17

²⁵ Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.

hours and 16 hours, depending on the both type of component and the complexity of the repair.²⁶ To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking component rate for facilities subject to annual inspections.²⁷ To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of \$3.50/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Annual Inspection Frequency | Time per IR Camera Inspection [hours] | Total Annual Inspection Time [hours] | Total Annual Inspection Cost |
|--|-------------------------------|-----------------------------|---------------------------------------|--------------------------------------|------------------------------|
| ≤ 12 tpy | 147 | 1 | 10.6 | 1,558.2 | \$208,799 |
| >12 to ≤ 50 tpy | 53 | 4 | 28.1 | 5,957.2 | \$798,265 |
| ≥ 50 tpy | 0 | 12 | | | |
| Total: | 200 | | | 7,515.4 | \$1,007,064 |

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Leak Repair Rate [\$/hr] | Number of Leaks per Compressor Station | Total Leak Repair Time per CS [hours] | Total Annual Repair Cost |
|--|-------------------------------|--------------------------|--|---------------------------------------|--------------------------|
| ≤ 12 tpy | 147 | \$66.24 | 30.1 | 23.0 | \$223,957.4 |

²⁶ See “Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards,” Bradley Nelson and Heather Brown, April 17, 2012; “Analysis of Emissions Reduction Techniques for Equipment Leaks,” Cindy Hancy, December 21, 2011.

²⁷ This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry’s Proposed Revisions to Colorado’s Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 26).

Table 24: Compressor Station Leak Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Leak Repair Rate [\$/hr] | Number of Leaks per Compressor Station | Total Leak Repair Time per CS [hours] | Total Annual Repair Cost |
|--|-------------------------------|--------------------------|--|---------------------------------------|--------------------------|
| >12 to ≤ 50 tpy | 53 | \$66.24 | 119.4 | 85.2 | \$299,113.3 |
| ≥ 50 tpy | 0 | \$66.24 | - | - | - |
| Total: | 200 | | | | \$523,071 |

Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Total Recovered Natural Gas per CS [tons/year] | Value of Natural Gas [\$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
|--|-------------------------------|--|-------------------------------|-----------------------------|---|
| ≤ 12 tpy | 147 | 10.2 | \$3.5 | 35.8 | \$187,875 |
| >12 to ≤ 50 tpy | 53 | 36.4 | \$3.5 | 35.8 | \$241,729 |
| ≥ 50 tpy | 0 | | \$3.5 | 35.8 | - |
| Total: | 200 | | | | \$429,604 |

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Total Annual Inspection Cost | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
|--|-------------------------------|------------------------------|--------------------------|---|---|
| ≤ 12 tpy | 147 | \$208,799 | \$223,957.4 | \$187,875 | \$244,882 |
| >12 to ≤ 50 tpy | 53 | \$798,265 | \$299,113.3 | \$241,729 | \$855,650 |
| ≥ 50 tpy | 0 | | - | - | - |
| Total: | 200 | \$1,007,064 | \$523,071 | \$429,604 | \$1,100,531 |

For well production facilities the estimated annual inspection costs are set forth in Table 27.

Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

| Uncontrolled | O&G | Number | Annual | Total | Inspection | Total Annual |
|--------------|-----|--------|--------|-------|------------|--------------|
|--------------|-----|--------|--------|-------|------------|--------------|

| VOC at Storage Tank Battery Tier [tpy] | Basin* | of Facilities | Inspection Frequency | Number of Inspections | Time Per Inspection [hours] | Inspection Cost |
|--|--------|---------------|----------------------|-----------------------|-----------------------------|---------------------|
| In-House Inspections at \$103/hour | | | | | | |
| > 6 to ≤12 | DJ/NAA | 945 | 1 | 945 | 6.1 | \$593,744 |
| > 12 to ≤ 50 | DJ/NAA | 2,447 | 4 | 9,788 | 6.1 | \$6,149,800 |
| > 50 | DJ/NAA | 693 | 12 | 8,316 | 6.1 | \$5,224,943 |
| Subtotal: | | 4,085 | | 19,049 | | \$11,968,487 |
| In-House Inspections at \$103/hour | | | | | | |
| > 6 to ≤12 | ROS | 173 | 1 | 173 | 6.4** | \$114,042 |
| > 12 to ≤ 50 | ROS | 176 | 4 | 704 | 6.4 | \$464,077 |
| > 50 | ROS | 115 | 12 | 1,380 | 6.4 | \$909,696 |
| Subtotal: | | 464 | | 2,257 | | \$1,487,815 |
| Contract Inspections at \$134/hour | | | | | | |
| > 6 to ≤12 | DJ/NAA | 150 | 1 | 150 | 6.1 | \$122,610 |
| > 12 to ≤ 50 | DJ/NAA | 153 | 4 | 612 | 6.1 | \$500,249 |
| > 50 | DJ/NAA | 118 | 12 | 1,416 | 6.1 | \$1,157,438 |
| Subtotal: | | 421 | | 2,178 | | \$1,780,297 |
| Contractor Inspections at \$134/hour | | | | | | |
| > 6 to ≤12 | ROS | 140 | 1 | 140 | 6.4** | \$120,064 |
| > 12 to ≤ 50 | ROS | 148 | 4 | 592 | 6.4 | \$507,699 |
| > 50 | ROS | 52 | 12 | 624 | 6.4 | \$535,142 |
| Subtotal: | | 340 | | 1,356 | | \$1,162,905 |
| Total: | | 5,310 | | 24,840 | | \$16,399,504 |

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

Table 28: Well Production Facility Leak Repair Costs

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities | Number of Leaks per Tank | Total Leak Repair Time per Tank [hours] | Total Annual Repair Cost |
|---|-----------|----------------------|--------------------------|---|--------------------------|
| > 6 to ≤12 | DJ/NAA | 1,095 | 17.0 | 11.8 | \$855,887 |
| > 12 to ≤ 50 | DJ/NAA | 2,600 | 25.5 | 17.7 | \$3,048,365 |
| > 50 | DJ/NAA | 811 | 34.1 | 23.6 | \$1,267,807 |
| Subtotal: | | 4,506 | | | \$5,172,059 |
| > 6 to ≤12 | ROS | 313 | 9.7 | 7.7 | \$159,645 |
| > 12 to ≤ 50 | ROS | 324 | 14.5 | 11.6 | \$248,956 |
| > 50 | ROS | 167 | 19.4 | 15.4 | \$170,356 |
| Subtotal: | | 804 | | | \$578,957 |
| Total: | | 5,310 | | | \$5,751,016 |

Table 29: Well Production Facility Recovered Natural Gas Value from Leak Repairs

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities | Total Recovered Natural Gas per tank [tons/year] | Value of Natural Gas [\$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
|---|-----------|----------------------|--|-------------------------------|-----------------------------|---|
| > 6 to ≤12 | DJ/NAA | 1,095 | 4.6 | \$3.5 | 35.8 | \$631,136 |
| > 12 to ≤ 50 | DJ/NAA | 2,600 | 7.0 | \$3.5 | 35.8 | \$2,280,460 |
| > 50 | DJ/NAA | 811 | 9.3 | \$3.5 | 35.8 | \$945,050 |
| Subtotal: | | 4,506 | | | | \$3,856,646 |
| > 6 to ≤12 | ROS | 313 | 4.6 | \$3.5 | 35.8 | \$180,407 |
| > 12 to ≤ 50 | ROS | 324 | 6.8 | \$3.5 | 35.8 | \$276,061 |
| > 50 | ROS | 167 | 9.1 | \$3.5 | 35.8 | \$190,418 |
| Subtotal: | | 804 | | | | \$646,886 |
| Total: | | 5,310 | | | | \$4,503,532 |

The total net costs for well production facility station LDAR are set forth in Table 30.

Table 30: Well Production Facility –Net Leak Inspection and Repair Costs

| Uncont. VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Total Annual Inspection Cost | | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
|--|-----------|------------------------------|--------------------|--------------------------|---|---|
| | | In-House | Contractor | | | |
| > 6 to ≤12 | DJ/NAA | \$593,744 | \$122,610 | \$855,887 | \$631,136 | \$941,105 |
| > 12 to ≤ 50 | DJ/NAA | \$6,149,800 | \$500,249 | \$3,048,365 | \$2,280,460 | \$7,417,954 |
| > 50 | DJ/NAA | \$5,224,943 | \$1,157,438 | \$1,267,807 | \$945,050 | \$6,705,138 |
| Subtotal: | | \$11,968,487 | \$1,780,297 | \$5,172,059 | \$3,856,646 | \$15,064,197 |
| > 6 to ≤12 | ROS | \$114,042 | \$120,064 | \$159,645 | \$180,407 | \$213,344 |
| > 12 to ≤ 50 | ROS | \$464,077 | \$507,699 | \$248,956 | \$276,061 | \$944,671 |
| > 50 | ROS | \$909,696 | \$535,142 | \$170,356 | \$190,418 | \$1,424,776 |
| Subtotal: | | \$1,487,815 | \$1,162,905 | \$578,957 | \$646,886 | \$2,582,791 |
| Total: | | \$13,456,302 | \$2,943,202 | \$5,751,016 | \$4,503,532 | \$17,646,988 |

Additionally, based on information in the Division’s APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be \$1,639,239.²⁸

Table 31: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities and Inspections | Inspection Time Per Inspection [hours] | Inspection Type/Hourly Rate | Total Annual Inspection Cost |
|---|-----------|--------------------------------------|--|-----------------------------|------------------------------|
| ≤ 6 | DJ/NAA | 1,598 | 6.1 | In-House/\$103 | \$1,004,023 |
| ≤ 6 | ROS | 500 | 3.4 | In-House/\$103 | \$175,100 |
| Subtotal: | | 2,098 | | | \$1,179,123 |
| ≤ 6 | DJ/NAA | 389 | 6.1 | Contractor/\$134 | \$317,969 |
| ≤ 6 | ROS | 312 | 3.4 | Contractor/\$134 | \$142,147 |
| Subtotal: | | 701 | | | \$460,116 |

²⁸ To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the non-attainment area based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

Total: 2,799**\$1,639,239**

The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections, the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

Table 32: Compressor Station Leak Inspection Emission Reductions

| Comp. Station Fugitive VOC Tier [tpy] | Number of Comp Stations | LDAR Program Reduction % | Fugitive VOC Emissions for each CS tier [tpy] | Total VOC Reduction [tpy] | Fugitive Methane-Ethane Emissions for each CS tier [tpy] | Total Methane-Ethane Reduction [tpy] |
|---------------------------------------|-------------------------|--------------------------|---|---------------------------|--|--------------------------------------|
| ≤ 12 | 147 | 40% | 10.1 | 588.0 | 15.5 | 911.4 |
| > 12 to ≤ 50 | 53 | 60% | 16.4 | 519.4 | 44.3 | 1,409.8 |
| > 50 | | 80% | | | | |
| | 200 | | | 1,107.4 | | 2,321.1 |

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be \$994/ton VOC and \$474/ton methane/ethane.

Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21

| Comp. Station Fugitive VOC Tier [tpy] | Number of Comp Stations | Total Net Annual Inspection & Repair Cost | LDAR Program Reduction % | Total VOC Reduction [tpy] | VOC Control Cost [\$/ton] | Total Methane-Ethane Reduction [tpy] | Methane-Ethane Control Cost [\$/ton] |
|---------------------------------------|-------------------------|---|--------------------------|---------------------------|---------------------------|--------------------------------------|--------------------------------------|
| ≤ 12 | 147 | \$244,882 | 40% | 588.0 | \$416 | 911.4 | \$269 |
| > 12 to ≤ 50 | 53 | \$855,650 | 60% | 519.4 | \$1,647 | 1,409.8 | \$607 |
| > 50 | | | 80% | | | | |
| | 200 | \$1,100,531 | | 1,107.4 | \$994 | 2,321.2 | \$474 |

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions

| Uncontrolled VOC at Tank Battery Tier [tpy] | Number of Facilities | LDAR Program Reduction % | Fugitive VOC Emissions for each Tank Battery [tpy] | Total VOC Reduction [tpy] | Fugitive Methane-Ethane Emissions for each Tank Battery [tpy] | Total Methane-Ethane Reduction [tpy] |
|---|----------------------|--------------------------|--|---------------------------|---|--------------------------------------|
| DJ/NAA | | | | | | |
| > 6 to ≤ 12 | 1,095 | 40% | 4.6 | 1,971.0 | 7.0 | 3,066.0 |
| > 12 to ≤ 50 | 2,600 | 60% | 4.6 | 7,280.0 | 7.0 | 10,920.0 |
| > 50 | 811 | 80% | 4.6 | 3,000.7 | 7.0 | 4,541.6 |
| Subtotal: | 4,506 | | | 12,251.7 | | 18,527.6 |
| Remainder of State | | | | | | |
| > 6 to ≤ 12 | 313 | 40% | 3.9 | 500.8 | 7.5 | 939.0 |
| > 12 to ≤ 50 | 324 | 60% | 3.9 | 745.2 | 7.5 | 1,458.0 |
| > 50 | 167 | 80% | 3.9 | 517.7 | 7.5 | 1,002.0 |
| Subtotal: | 804 | | | 1,763.7 | | 3,399.0 |
| Total: | 5,310 | | | 14,015.4 | | 21,926.6 |

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be \$1,259/ton VOC and \$805/ton methane/ethane.

Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

| Uncont. VOC at Tank | Number of Tanks | Total Net Annual Leak | LDAR Program | Total VOC | VOC Control | Total Methane- | Methane-Ethane |
|---------------------|-----------------|-----------------------|--------------|-----------|-------------|----------------|----------------|
|---------------------|-----------------|-----------------------|--------------|-----------|-------------|----------------|----------------|

| Battery Tier [tpy] | | Inspection & Repair Cost | Reduction % | Reduction [tpy] | Cost [\$/ton] | Ethane Reduction [tpy] | Control Cost [\$/ton] |
|--------------------|-------|--------------------------|-------------|-----------------|---------------|------------------------|-----------------------|
| DJ/NAA | | | | | | | |
| > 6 to ≤ 12 | 1,095 | \$941,105 | 40% | 1,971.0 | \$477 | 3,066.0 | \$307 |
| > 12 to ≤ 50 | 2,600 | \$7,417,954 | 60% | 7,280.0 | \$1,019 | 10,920.0 | \$679 |
| > 50 | 811 | \$6,705,138 | 80% | 3,000.7 | \$2,235 | 4,541.6 | \$1,476 |
| Subtotal: | 4,506 | \$15,064,197 | | 12,251.7 | \$1,230 | 18,527.6 | \$813 |
| ROS | | | | | | | |
| > 6 to ≤ 12 | 313 | \$213,344 | 40% | 500.8 | \$426 | 939.0 | \$227 |
| > 12 to ≤ 50 | 324 | \$944,671 | 60% | 745.2 | \$1,268 | 1,458.0 | \$648 |
| > 50 | 167 | \$1,424,776 | 80% | 517.7 | \$2,752 | 1,002.0 | \$1,422 |
| Subtotal: | 804 | \$2,582,791 | | 1,763.7 | \$1,464 | 3,399.0 | \$760 |
| Total: | 5,310 | \$17,646,988 | | 14,015.4 | \$1,259 | 21,926.6 | \$805 |

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be \$409/ton VOC and \$249/ton methane/ethane.

In addition to the component leak detection and repair requirements for compressor stations and well production facilities, the Division's proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division's proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange, plug or second valve, it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this widespread prevalence in federal rules the Division believes that the proposal represents a simple

and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division’s proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of \$46,974.²⁹

With respect to reciprocating compressors, the Division’s proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of \$43 per ton of VOC reduced and \$12 per ton of methane reduced.³⁰

D. Auto Igniter Requirements on Existing Flare Control Devices Outside the Non-Attainment Area

Unlike the non-attainment area, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is \$475 based on information that the industry provided to the Division in 2008, adjusted for inflation.³¹

Table 36: Auto Igniter Control Device – Retrofit Cost Analysis

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|------|--------------------------|--------------------------------|-----------------------|------------------------|
|------|--------------------------|--------------------------------|-----------------------|------------------------|

²⁹ See APCD-PHS Ex. HHHH pp. 6-1—6-3

³⁰ See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.

³¹ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008.

| | | | | |
|---------------------|---------|--|--------|-------|
| Auto Igniter | \$1,648 | | | |
| Freight/Engineering | | | \$200 | |
| Flare Installation | | | \$500 | |
| Maintenance | | | | \$200 |
| Subtotal Costs | \$1,648 | | \$700 | \$200 |
| Annualized Costs* | \$228.4 | | \$46.7 | \$200 |
| | | | | \$475 |

* Annualized over 15 years at 5% ROR

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1 tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about \$378,100 the estimated cost effectiveness of this strategy is about \$302 per ton of VOC reduced.

Table 37: Auto Igniter Emission Reduction Estimates

| Source Type for Existing Flare Controls | Number of Auto Igniters | Uncontrolled VOC [tpy] | Uncontrolled VOC Using 3% Downtime [tpy] | Total VOC Reduction [tpy] |
|---|-------------------------|------------------------|--|---------------------------|
| Condensate Tanks | 490 | 31,170.6 | 935.1 | 666.3 |
| Dehydrators | 131 | 16,372.0 | 491.2 | 466.6 |
| Produced Water Tanks | 172 | 4,842.2 | 145.3 | 103.5 |
| Crude Oil Tanks | 3 | 716.3 | 21.5 | 15.3 |
| | 796 | 53,101.1 | 1,593.1 | 1251.7 |

* Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.

Table 38: Auto Igniter Control Cost Estimates (Outside NAA)

| Number | Each Auto-Igniter Annualized Costs | Total Annualized Costs | VOC Reduction* [tons/year] | Control Costs [\$/ton] |
|--------|------------------------------------|------------------------|----------------------------|------------------------|
| 796 | \$475 | \$378,100 | 1,251.7 | \$302 |

E. Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the AQCC adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the non-attainment area. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 Colorado Oil and Gas Conservation Commission (COGCC) well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the nonattainment area. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current non-attainment area low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study³² adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is \$169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be \$1,268 for each device replaced. As a result, the net annual gain is \$1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|----------------------|--------------------------|--------------------------------|-----------------------|------------------------|
| Low/No Bleed Device* | \$1,033 | | | |
| Labor | | \$387 | | |
| Value of NG Saved** | | | \$(1,268) | |
| Maintenance | | | \$16 | |
| Subtotal Costs | \$1,033 | \$387 | \$(1,253) | |

³² See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008.

| | | | | |
|---------------------|-------|------|-----------|-----------|
| Annualized Costs*** | \$143 | \$26 | \$(1,253) | \$(1,084) |
|---------------------|-------|------|-----------|-----------|

* Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.

** Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

Assuming 9,384 total devices replaced, adoption of this strategy will result in \$10,169,441 in annual cost savings.

| Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA) | | | | |
|---|------------------------------|------------------------|---------------------------|------------------------|
| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
| 9,384 | \$(1,084) | \$(10,169,441) | 14,921 | NA |

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

F. Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to A Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

G. Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division’s proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is \$6,286.80 per unit. See Section IV.A.1. above.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of \$786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be \$3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------|------------------------------|------------------------|---------------------------|------------------------|
| 217 | \$6,286.8 | \$1,364,236 | 1,736 | \$786 |

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of \$632/ton VOC.

Table 42: Dehydrator Control Cost Estimates (6 TPY Control Threshold)

| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------|------------------------------|------------------------|---------------------------|------------------------|
| 148 | \$6,286.8 | \$930,446 | 1,472 | \$632 |

H. Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.³³ For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division’s proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA’s Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division’s proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the

³³ See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

I. Division Regulation Number 7 Implementation Costs

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of 9 full time inspectors and 4 term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from 6 inspectors to 9. In 2013, the legislature appropriated additional funds to hire 4 term limited inspectors to conduct infra-red camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the AQCC chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is \$1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

J. Regulation Number 3 Costs

The proposed revisions to Regulation remove the requirement for sources subject to either a NSPS or NESHAP/MACT adopted into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether their emissions exceed the reporting or permitting thresholds ("catch-all provisions"). They also simplify the non-criteria reportable pollutant de minimis determination to 250 pounds per year of any individual non-criteria reportable pollutant; and remove the crude oil storage tank permitting exemptions. There is little to no economic impact to the regulated community due to these revisions.

Catch-all Provisions

Removal of the catchall provisions will reduce permitting, reporting and associated cost burdens for the regulated community. By reducing permitting and reporting, the proposed revision will also reduce costs to the Division associated with these activities. There are no anticipated costs to either the regulated community or the government associated with this proposed revision.

Non-Criteria Reportable Pollutants

Revision of the threshold for non-criteria reportable pollutants could result in either cost savings or additional costs to the regulated community depending on the source. Sources that are required to report non-criteria reportable pollutants must pay an emission fee of \$152.90 per ton. Currently Regulation Number 3 contains a complex reporting formula involving multiple and different thresholds, some of which are above and some of which are below the proposed 250 pound threshold. Accordingly, changing the threshold will reduce costs for some sources, while increasing costs for other sources. Based on an analysis of reported emissions, the proposed threshold change will reduce industry fees paid to the Division by \$47,702 per year. Because the emissions from sources that are not currently reporting is unknown it is not possible to calculate the additional costs to sources that will be required to report for the first time under the new proposed threshold.

Additionally, beyond the actual emission fees, the current reporting system is very complex resulting in numerous hours being spent by both the regulated community and Division staff in determining whether reporting is required. Simplifying the reporting system will eliminate the costs associated with this analysis.

Crude Oil Storage Tanks

There are minimal direct costs projected for the affected businesses and industrial sector associated with the removal of the crude oil storage tank permitting exemption. Stationary sources with crude oil storage tanks whose uncontrolled actual emissions exceed the minor source or operating permit thresholds would be required to obtain a permit. In 2008, the Commission removed the reporting exemption for crude oil storage tanks to improve the inventory of uncontrolled actual emissions. Based on the reported data, removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately \$19,500. Additionally, permitting these sources will result in some costs to the Division. Given the small number of these sources and the fact that permitting fees offset most of the costs associated with drafting permits, the anticipated cost to the Division is minimal.

V. ADVERSE EFFECTS ON THE ECONOMY

The oil and gas industry plays an important role in Colorado's economy. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total VOC emissions both in the non-attainment area and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division's proposal is projected to result in a net annual cost to the industry of approximately \$42.4 million. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal. In 2012, for example, oil and gas producers in Colorado sold 48,450,717 barrels of oil and 1,661,073,176 MCF of natural gas. Based on the current price of oil, \$96 per barrel, and assuming a price for natural gas of \$3.5/MCF³⁴, annual revenue from the sale of oil and gas in Colorado based on 2012 production levels is approximately \$10.5 billion. Accordingly, the net cost of the Division's proposal is approximately 0.4% of the annual revenues. Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions. Collectively, the Division estimates that these companies will bear approximately 75% of the total annual cost of the proposed rules.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately \$712 .

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful negative impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

VI. ALTERNATIVE PROPOSALS

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the AQCC to consider. Some of these proposals request that the AQCC adopt additional requirements that go beyond the Division's proposal, while other

³⁴ The Division assumed a price per MCF of \$3.50 throughout its analysis; however, natural gas prices are currently around \$5 per MCF, suggesting that the Division has underestimated the value of gas saved by the proposal.

alternatives request that the AQCC limit aspects of the Division's proposed revisions. In some cases, the parties submitting the proposals included analyses estimating the costs and benefits associated with their proposals. The section below identifies each of the submitted proposals, discusses how the proposals differ from the Division's proposal, and addresses the projected costs and benefits of each proposal.³⁵

Joint Industry Work Group

A collection of oil and gas companies and industry trade groups have submitted an alternative proposal seeking to limit the requirements set forth in the Division's proposal.³⁶ Specifically, the Joint Industry Work Group request that the AQCC limit the Division's proposal in the following respects: 1) restrict all proposed requirements to the front range ozone non-attainment area; 2) reduce the required frequency proposed for leak inspection and repair; 3) eliminate the proposed requirements for dehydrators; 4) limit proposed requirements for compressor seals and open-ended lines to compressor stations; and 5) eliminate proposed requirements related to well maintenance and liquids unloading. In addition to these proposed limitations, the Joint Industry Work Group have proposed a number of additional changes, which could have some minimal additional impacts on the costs and benefits of the proposal.

Since the Joint Industry Group did not submit an economic analysis detailing the projected costs and benefits of their alternative proposal,³⁷ the Division has conducted an analysis of the Joint Industry Work Group alternative proposal utilizing the same methodologies and assumptions detailed in Section IV above. Based on this analysis, the Division estimates that the Joint Industry Work Group alternative proposal would have a net cost³⁸ to the regulated community of approximately \$32.2 million, and would reduce emissions of VOCs by 56,525 tons per year and methane/ethane by 33,058 tons per year. The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new

³⁵ In instances where a party submitted an analysis of the costs and benefits associated with their proposal, such analysis is attached. Where parties submitted proposal without an analysis of their own proposal, the Division has endeavored to analyze the costs and benefits of these proposals using the same methodologies used to analyze the costs and benefits of the Division's proposal.

³⁶ A copy of this alternative proposal is attached to this Cost Benefit Analysis as Exhibit A.

³⁷ The group did submit an analysis of the Division's proposal showing substantially higher costs than reflected in the Division's analysis. A copy of this analysis is attached hereto as Exhibit B. It should be noted that while the Joint Industry Work Group predicts much higher costs from the Division's proposals, Anadarko Petroleum Corporation, Noble Energy, Inc. and Encana Oil and Gas USA have submitted information during the rulemaking supporting the reasonableness of the Division's cost and benefit calculations. Submissions from these companies can be found at the following link.

<ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20%26%20ALT%20PROPOSAL%20REVISIONS/>

³⁸ Net cost reflects the cost of implementing the proposed strategy less the value of the additional product captured as a result of the proposed strategies.

inspector jobs attributable to the proposal. Finally, because the Joint Industry Work Group proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section III above would be reduced.

WPX Energy

WPX is the largest natural gas producer in the state. In the current rulemaking WPX has offered an alternative proposal that would decrease the total number of leak inspections by allowing well production facilities with low leak rates during two consecutive inspections to reduce inspection frequency from monthly to quarterly, or from quarterly to annually depending on the size of the facility.³⁹ While it is difficult to predict in advance how many facilities would be able to take advantage of this reduced inspection rate, for the purposes of this Cost Benefit Analysis the Division assumes that one half of the facilities would be able to utilize the reduced frequency. Based on this assumption, adoption of WPX's alternative proposal would reduce the total net annual cost of the proposed revisions from approximately \$42.4 million to approximately \$36.8 million. This change would also decrease the amount of emission reductions from the Division's proposal by 1,845 tons per year of VOC and 2,757 tons per year of methane/ethane.

The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. Given the relatively small difference in net costs between the two proposals, any positive impact should be fairly small. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Based on the number of inspection hours for each proposal, the number of new inspector jobs would decrease. Finally, because the WPX proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section III above would be reduced.

Conservation Groups

As part of the rulemaking a number of conservation groups have submitted an alternative proposal requiring additional leak detection inspections for well production facilities and compressor stations relative to the Division's proposal. In addition, the Conservation Groups' alternative proposal increases the number of pneumatic devices that would need to be retrofitted. A copy of the Conservation Groups' alternative proposal is attached as Exhibit D. Additionally, their analysis of the costs and benefits associated with their alternative proposal is attached as Exhibit E.

³⁹ In addition to this change, WPX has proposed a limited number of additional changes and clarifications that do not impact the cost and benefit calculations conducted for the Division's proposal. A copy of WPX's alternative proposal is attached as Exhibit C.

Local Community Organizations

A group of local community organizations have submitted an alternative proposal aimed at increasing the stringency of the Division's proposal for facilities that are located within 1,320 feet of a building unit or designated outdoor activity area. Specifically, for such facilities the Local Community Organizations' alternative proposal would decrease the threshold for controls from petroleum storage tanks from 6 tons per year (as proposed by the Division) to two tons per year. Additionally, facilities located within 1,320 feet of these designated areas would be subject to a more stringent leak inspection schedule. Copies of the Local Community Organizations' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits F and G.

Local Government Coalition

The Local Government Coalition consists of a number of county and city governments including Adams County, Boulder County, La Plata County, Pitkin County and San Miguel County, Fort Collins, the City of Boulder, and the City and County of Denver. In their alternative proposal, the Local Government Coalition seeks to increase the number of leak detection inspections for compressor stations and well production facilities relative to the Division's proposal. The Local Government Coalition also seeks to require that well production facilities be tied in to a gas gathering line within 90 days after the date of first production, unless the Division approves an extension of this deadline. Copies of the Local Government Coalition's alternative proposal and documents assessing the costs and benefits of that proposal are attached hereto as Exhibits H through L.

Worldwide Liquid Solutions, LLC

Worldwide Liquid Solutions (WLS) is a manufacturer of emission reduction technology designed to control VOC emissions from petroleum storage tanks. According to WLS, their emission reduction technology cannot control methane and ethane and therefore cannot meet the control standards for tanks reflected in the Division proposal. To address this, WLS has submitted an alternative proposal that would only require reductions of VOCs from tanks and not methane/ethane. As an alternative to their alternative, WLS has proposed rejecting all of the proposed changes to Regulation No. 7 set forth in the Division's proposal. Copies of WLS' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits M and N.

Conclusion

The Division has in good faith developed this comprehensive Cost-Benefit Analysis that complies with all requirements of 24-4-103(2.5.), C.R.S. The Division believes that the proposal before the AQCC reflects a balanced approach that includes proven and cost effective strategies to reduce emissions from the oil and gas sector, while enabling the sector to continue to grow in

a responsible and protective manner. The Division looks forward to the AQCC's consideration of its proposal and alternate proposals of other parties at the February 2014 hearing.

FINAL
ECONOMIC IMPACT ANALYSIS
PER § 25-7-110.5(4), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

The Colorado Air Pollution Control Division (Division) submits the following Final Economic Impact Analysis in conjunction with its proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 7 (5 CCR 1001-9). The Regulation Number 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. Among other things, the Division proposes to: increase control requirements and improve capture efficiency requirements for oil and gas storage tanks; minimize fugitive emissions of hydrocarbons (including volatile organic compounds, methane and ethane) from leaking components at compressor stations and well production facilities; expand control requirements for pneumatic devices, increase control requirements for glycol dehydrators; and minimize venting at oil and gas production facilities.

In this Final Economic Impact Analysis, the Division has assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division has sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

II. REQUIREMENTS FOR A FINAL ECONOMIC IMPACT ANALYSIS

Section 25-7-110.5(4), C.R.S. requires the proponent to submit a final economic impact analysis for any proposed rule. Section 25-7-110.5(4)(a), C.R.S. The statute further provides that:

The proponent and the division shall select one or more of the following economic impact analyses. The commission may ask affected industry to submit information with regard to the cost of compliance with the proposed rule, and, if it is not provided, it shall not be considered reasonably available. The economic impact analysis required by this subsection (4) shall be based upon reasonably available data

Section 25-7-110.5(4)(c), C.R.S.. For the purposes of this Final Economic Impact Analysis, the Division has chosen to utilize the methodology set forth in § 25-7-110.5(4)(c)(I), C.R.S., which requires the following:

(I) Cost-effectiveness analyses for air pollution control that identify:

(A) The cumulative cost including but not limited to the total capital, operation, and maintenance costs of any proposed controls for affected business entity or industry to comply with the provisions of the proposal;

(B) Any direct costs to be incurred by the general public to comply with the provisions of the proposal;

(C) Air pollution reductions caused by the proposal;

(D) The cost per unit of air pollution reductions caused by the proposal;

(E) The cost for the division to implement the provisions of the proposal;

III. OVERVIEW OF PROPOSED REGULATORY CHANGES

The Division is proposing revisions to AQCC Regulation Number 7 in an effort to enhance the effectiveness of Colorado's air quality requirements for the oil and gas exploration and production sector. These proposed revisions consist of the following:

- 1) Enhancing the existing control program for petroleum storage tanks by:
 - a. Lowering the existing control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;
 - b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
 - c. Expanding non-attainment area requirements for tank controls during the first 90 days of production to the rest of the state;
- 2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
- 3) Establishing leak detection and repair requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
- 4) Expanding the existing non-attainment area requirements for auto-igniters on flare devices to the rest of the state;
- 5) Expanding the existing non-attainment area requirements for low bleed pneumatic devices to the rest of the state and where feasible requiring no-bleed pneumatic devices;
- 6) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production;

- 7) Lowering the existing control requirement threshold for existing glycol dehydrators to 6 tons per year of uncontrolled actual VOC emissions and 2 tons per year of uncontrolled actual VOC emissions for dehydrators located within 1,320 feet of a building, and establishing a 2 ton per year control threshold for all new glycol dehydrators; and
- 8) Establishing requirements for the use of best management practices both to minimize the need for downhole well maintenance and liquids unloading and to minimize emissions during well maintenance and liquids unloading events.

IV. COST/BENEFIT ANALYSIS:

The Division's assessment of the costs and benefits for the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements beyond current expenditures. Currently the Division has 12 inspectors dedicated to inspecting oil and gas facilities. If the proposed rules are adopted, the Division intends to utilize these existing resources to ensure compliance with these rules. The costs associated with these inspectors are detailed below.

A. Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the Air Quality Control Commission has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in non-attainment areas must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the AQCC's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity of 40 degrees or greater." While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities continue to be the most significant source of VOC emissions from this sector. To address this

emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the non-attainment area be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 1 below. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 2-4 below.

1. General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study¹ adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter² is about \$6,287.³

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|---------------------|-----------------------------|-----------------------------------|--------------------------|---------------------------|
| Flare | \$18,169 | | | |
| Freight/Engineering | | \$1,648 | | |
| Flare Installation | | \$6,980 | | |
| Auto Igniter | \$1,648 | | | |
| Pilot Fuel** | | | \$768 | |
| Maintenance | | | \$2,197 | |
| Subtotal Costs | \$19,817 | \$8,628 | \$2,965 | |
| Annualized Costs*** | \$2,747 | \$575 | \$2,965 | |

*Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.⁴

¹ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process.

² Currently only flares in the non-attainment area are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section D.

³ Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA’s cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA’s analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

⁴ It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment

** Pilot fuel costs \$3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

2. Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the non-attainment area and the remaining 192 are within the current non-attainment area.

Table 2: Condensate Tank Battery Analysis

| Tank Battery Type | Ozone NAA [count] | Outside NAA [count] | Cancelled Tanks [count] | Total Statewide Tanks [count] |
|------------------------------------|-------------------|---------------------|-------------------------|-------------------------------|
| Controlled Tanks | 4,971 | 490 | | 5,461 |
| Uncontrolled Tanks | 1,451 | 1,132 | 36 | 2,619 |
| All Tanks | 6,422 | 1,622 | 36 | 8,080 |
| | | | | |
| Uncontrolled Tanks (≥ 6 tpy) | 192 | 396 | | 588 |

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,⁵ and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|--|--|--------------------------------------|------------------------------------|
| NAA Uncontrolled Tanks (≥ 6 tpy) | 2,355 | 677* | 1,678 |
| Outside NAA Uncontrolled Tanks (≥ 6 tpy) | 4,890 | 1,406* | 3,484 |
| Totals: | 7,245 | 2,083 | 5,162 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 588 flare control devices is about \$3.7 million dollars with an average cost effectiveness of about \$716 per ton of VOC reduced. For the smallest individual

sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.

⁵ The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section B.

tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices

| Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|---------------------------|-------------------------------|---------------------------|------------------------------|---------------------------|
| 588 | \$6,286.8 | \$3,696,638 | 5,162 | \$716 |

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or \$1,884 per ton of methane/ethane reduced.

3. Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the AQCC adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division’s APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

Table 5: Produced Water Tank Battery Analysis

| Tank Battery Type | Total Statewide Water Tanks |
|---------------------------|-----------------------------|
| Controlled Water Tanks: | 338 |
| Uncontrolled Water Tanks: | 530 |
| Total: | 868 |

| Tank Battery Type | Total Statewide Water Tanks |
|------------------------------------|-----------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 52 |

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|------------------------------------|--|--------------------------------------|------------------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 641.4 | 184.4* | 457 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 52 flare control devices is about \$327,000, with an average cost effectiveness of about \$715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

| Tank Size | Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------------|------------------------|----------------------------|------------------------|---------------------------|------------------------|
| ≥ 6 tpy | 52 | \$6,286.8 | \$326,914 | 457 | \$715 |

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),⁶ it appears likely that the Division’s APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.⁷

⁶ Based on an analysis of 2010 COGCC data.

⁷ Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

| Tank Battery Type | Total Statewide Crude Oil Tanks |
|------------------------------------|---------------------------------|
| Controlled Crude Oil Tanks | 36 |
| Uncontrolled Crude Oil Tanks | 29 |
| Total: | 65 |
| Uncontrolled Tanks (≥ 6 tpy) | 8 |

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

| Tank Battery Type | Uncontrolled VOC Emissions [tons/year] | Controlled VOC Emissions [tons/year] | VOC Emission Reduction [tons/year] |
|------------------------------------|--|--------------------------------------|------------------------------------|
| Uncontrolled Tanks (≥ 6 tpy) | 165.2 | 47.5* | 117.7 |

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing eight flare control devices is about \$50,294 dollars with an average cost effectiveness of about \$427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

| Tank Size | Affected Tanks [count] | Each Flare Annualized Cost | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$ /ton] |
|--------------|------------------------|----------------------------|------------------------|---------------------------|-------------------------|
| ≥ 6 tpy | 8 | \$6,286.8 | \$50,294.4 | 117.7 | \$427 |

4. Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the non-attainment area have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this issue in the non-attainment area, the AQCC mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the non-attainment area based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,⁸ total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (See Section B) the flare control efficiency is 95%, thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the non-attainment area will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the non-attainment area each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or \$1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be \$6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional \$3,000 in annual relocation costs, for a total annualized cost of about \$9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is \$176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

| Storage Tank Threshold [tpy] | Number of New Storage Tanks | Number of New Flares | Annualized Cost Each Flare | Total Flare Cost | Total VOC Reduction [tons/year] | VOC Control Cost [\$ /ton] |
|------------------------------|-----------------------------|----------------------|----------------------------|------------------|---------------------------------|----------------------------|
| <6 | 57 | 19 | \$9,286.8 | \$176,449.2 | 44.7 | \$3,947 |
| ≥6 | 84 | 84 | \$1,571.7 | \$132,022.8 | 1,705.7 | \$77 |
| | 141 | | | \$308,472 | 1,750.4 | \$176 |

Using the methodology discussed in subsection A.2 above the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or \$464 per ton of methane/ethane reduced.

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

⁸ Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using infra-red (IR) cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a Storage Tank Emission Management (STEM) plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly⁹ auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

| <i>Table 12: Proposed Tiering for Instrument Based Tank Inspections</i> | |
|--|-----------------------------|
| Tank Uncontrolled Actual VOC Emissions | Inspection Frequency |
| ≥ 6 tpy to ≤ 12 tpy | Annually |
| > 12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division's proposal discussed in Section A above. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division's proposal does not specify the type of technology or operational practices that

⁹ There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

operators will use, for the purposes of this analysis the Division assumed that buffer bottle technology would be installed on each of the subject tanks.¹⁰ The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.¹¹

Table 13: Annualized Cost Analysis for Buffer Bottle

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|-------------------|--------------------------|--------------------------------|-----------------------|------------------------|
| Buffer Bottle | \$11,500 | | | |
| Freight/Engr | | \$600 | | |
| Installation | | \$2,280 | | |
| Maintenance | | | \$2,500 | |
| Subtotal Costs | \$11,500 | \$2,880 | \$2,500 | |
| Annualized Costs* | \$1,593.8 | \$192 | \$2,500 | \$4,285.8 |

* Annualized over 15 years at 5% ROR

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.¹²

Assuming that each inspection takes two hours and utilizing a \$103/hour¹³ in-house inspection cost and a \$134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is \$5,392,010, which equates to \$1,015.4 per year for each tank that will be subject to STEM.

¹⁰ Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

¹¹ For this Final EIA the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.

¹² In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.

¹³ The hourly inspection cost is discussed below in Table 20.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering

| Tank Uncontrolled Actual VOC Emissions | Inspection Type/Hourly Rate | Number of Tanks | Inspection Frequency | Number of Inspections | STEM Inspection Costs |
|--|-----------------------------|-----------------|----------------------|-----------------------|-----------------------|
| >6 tpy to ≤ 12 tpy | In-House/\$103 | 1,085 | Annually | 1,085 | \$223,510 |
| >12 tpy to ≤ 50 tpy | In-House/\$103 | 2,595 | Quarterly | 10,380 | \$2,138,280 |
| > 50 tpy | In-House/\$103 | 745 | Monthly | 8,940 | \$1,841,640 |
| Subtotal: | | 4,425 | | 20,405 | \$4,203,430 |
| >6 tpy to ≤ 12 tpy | Contractor/\$134 | 323 | Annually | 323 | \$86,564 |
| >12 tpy to ≤ 50 tpy | Contractor/\$134 | 329 | Quarterly | 1,316 | \$352,688 |
| > 50 tpy | Contractor/\$134 | 233 | Monthly | 2,796 | \$749,328 |
| Subtotal: | | 885 | | 4,435 | \$1,188,580 |
| Total: | | 5,310 | | 24,840 | \$5,392,010 |

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.¹⁴ Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is \$5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

$$\text{Emission reduction} = [\text{uncontrolled VOC} * (1 - (0.75 * 0.95))] - [\text{uncontrolled VOC} * (1 - 0.95)],$$

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

¹⁴ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008, at pg. 8.

Table 15: STEM Emission Control Analysis (Statewide)

| Number of Tanks ≥ 6 tpy | Uncontrolled VOC [tons/year] | Controlled VOC (@ 71.25% Control) [tons/year] | Controlled VOC (@ 95% Control) [tons/year] | VOC Reduction [tons/year] |
|------------------------------|------------------------------|---|--|---------------------------|
| 5,269 | 221,569 | 63,701 | 11,078 | 52,623 |
| 41 | 3,213 | 924 | 161 | 763 |
| 5,310 | 224,782 | 64,625 | 11,239 | 53,386 |

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is \$527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)

| Type of Technology | Number of Tanks | Each Device Annualized Costs [\$/year] | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------------------|-----------------|--|------------------------|---------------------------|------------------------|
| Buffer Bottle | 5,310 | \$5,301.2 | \$28,149,372 | 53,386 | \$527.3 |

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to \$1,388 per ton of methane/ethane reduced.

During the stakeholder process certain parties have raised questions about the Division’s assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be \$264/ton VOC¹⁵. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be \$2,636/ton VOC¹⁶.

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation,

¹⁵ This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.

¹⁶ This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about \$19,341.

Table 17: Annualized Cost Analysis for HLP Separator

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|----------------------|-----------------------------|-----------------------------------|--------------------------|---------------------------|
| HLP/VRU | \$90,000 | | | |
| Freight/Engr | | \$1,648 | | |
| HLP/VRU Installation | | \$11,154 | | |
| Maintenance | | | \$9,396 | |
| VRU Recovered NG * | | | \$(3,382) | |
| Subtotal Costs | \$90,000 | \$12,802 | \$6,014 | |
| Annualized Costs** | \$12,474 | \$853 | \$6,014 | \$19,341 |

* Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥ 6 tpy (uncontrolled VOC).

** Annualized over 15 years at 5% ROR

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the \$6,286.8 annual cost of a flare and annual instrument based monitoring costs of \$1,015.4 per tank, the total annual control costs for a new tank will be \$26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of \$444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is \$4,674 per ton VOC. For methane ethane the cost per ton is \$1,168 per ton reduced on average.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct

periodic inspections using EPA Reference Method 21¹⁷ and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.¹⁸ To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations

| Component Leak Uncontrolled Actual VOC Emissions | Inspection Frequency |
|--|----------------------|
| ≤ 12 tpy | Annually |
| >12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements discussed in Section B above.¹⁹

¹⁷ While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

¹⁸ Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

¹⁹ Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this EIA, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate,

| Tank Uncontrolled Actual VOC Emissions | Inspection Frequency |
|--|----------------------------|
| < 6 tpy | One Time (and Monthly AVO) |
| ≥ 6 tpy to ≤ 12 tpy | Annually |
| >12 tpy to ≤ 50 tpy | Quarterly |
| > 50 tpy | Monthly |

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.²⁰ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be \$193,629, which equates to an hourly inspection rate of \$103.

| Item | Capital Costs (one time) | Annual Costs | Annualized Total Costs |
|-----------------------------------|-----------------------------|------------------------|---------------------------|
| FLIR Camera | \$122,000 | | |
| FLIR Camera Maintenance/Repair | | \$7,500 | |
| Photo Ionization Detector | \$5,000 | | |
| Vehicle (4x4 Truck) | \$22,000 | | |
| Inspection Staff | | \$75,000 | |
| Supervision (@ 20%) | | \$15,000 | |
| Overhead (@10%) | | \$7,500 | |
| Travel (@15%) | | \$11,250 | |
| Recordkeeping (@10%) | | \$7,500 | |
| Reporting (@10%) | | \$7,500 | |
| Fringe (@30%) | | \$22,500 | |
| Subtotal Costs | \$149,000 | \$153,750 | |
| Annualized Costs* | \$39,879 | \$153,750 | \$193,629 |
| *over 5 years at 6% ROR | | Annualized Hourly Rate | \$103 |

In the Initial EIA the Division assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller

the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

²⁰ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

companies that cannot fully utilize an IR camera, however, conducting inspections in-house may not be the most cost effective option. To account for this in the Final EIA the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection (\$134 per hour).

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.²¹

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

| Table 21: Calculated Inspection Time Compressor Station Leak Inspections | | |
|---|----------------------|------------------------------|
| Component Leak Uncontrolled Actual VOC Emissions | Method 21 Inspection | IR Camera/ Hybrid Inspection |
| ≤ 12 tpy | 21.2 hours | 10.6 hours |
| >12 tpy to ≤ 50 tpy | 56.2 hours | 28.1 hours |
| > 50 tpy* | | |

* there are currently no compressor stations in Colorado with calculated leaks at this level

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the non-attainment area and well production facilities outside the non-attainment area. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections

²¹ Based on the Division’s own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division’s assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

| Area | Method 21 Inspection | IR Camera/ Hybrid Inspection |
|---------------------|----------------------|------------------------------|
| Non-Attainment Area | 12.2 hours | 6.1 hours |
| Rest of the State | 6.8 hours | 3.4 hours |

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 20, for the purposes of this Final EIA the Division also assumed an additional three hours in travel time for each inspection outside the non-attainment area. This assumption reflects the fact that certain well sites in basins outside the non-attainment area may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.²² Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the stakeholder process it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial EIA the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A, Testimony of David McCabe at pg. 8. Nevertheless, for this Final EIA, the Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a \$66.24 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity

²² Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.

of the repair.²³ To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking component rate for facilities subject to annual inspections.²⁴ To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of \$3.50/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Annual Inspection Frequency | Time per IR Camera Inspection [hours] | Total Annual Inspection Time [hours] | Total Annual Inspection Cost |
|--|-------------------------------|-----------------------------|---------------------------------------|--------------------------------------|------------------------------|
| ≤ 12 tpy | 147 | 1 | 10.6 | 1,558.2 | \$208,799 |
| >12 to ≤ 50 tpy | 53 | 4 | 28.1 | 5,957.2 | \$798,265 |
| ≥ 50 tpy | 0 | 12 | | | |
| Total: | 200 | | | 7,515.4 | \$1,007,064 |

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Leak Repair Rate [\$/hr] | Number of Leaks per Compressor Station | Total Leak Repair Time per CS [hours] | Total Annual Repair Cost |
|--|-------------------------------|--------------------------|--|---------------------------------------|--------------------------|
| ≤ 12 tpy | 147 | \$66.24 | 30.1 | 23.0 | \$223,957.4 |

²³ See “Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards,” Bradley Nelson and Heather Brown, April 17, 2012; “Analysis of Emissions Reduction Techniques for Equipment Leaks,” Cindy Hancy, December 21, 2011.

²⁴ This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry’s Proposed Revisions to Colorado’s Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 22).

Table 24: Compressor Station Leak Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Leak Repair Rate [\$/hr] | Number of Leaks per Compressor Station | Total Leak Repair Time per CS [hours] | Total Annual Repair Cost |
|--|-------------------------------|--------------------------|--|---------------------------------------|--------------------------|
| >12 to ≤ 50 tpy | 53 | \$66.24 | 119.4 | 85.2 | \$299,113.3 |
| ≥ 50 tpy | 0 | \$66.24 | - | - | - |
| Total: | 200 | | | | \$523,071 |

Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Total Recovered Natural Gas per CS [tons/year] | Value of Natural Gas [\$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
|--|-------------------------------|--|-------------------------------|-----------------------------|---|
| ≤ 12 tpy | 147 | 10.2 | \$3.5 | 35.8 | \$187,875 |
| >12 to ≤ 50 tpy | 53 | 36.4 | \$3.5 | 35.8 | \$241,729 |
| ≥ 50 tpy | 0 | | \$3.5 | 35.8 | - |
| Total: | 200 | | | | \$429,604 |

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs

| Compressor Station Fugitive VOC Tier [tpy] | Number of Compressor Stations | Total Annual Inspection Cost | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
|--|-------------------------------|------------------------------|--------------------------|---|---|
| ≤ 12 tpy | 147 | \$208,799 | \$223,957.4 | \$187,875 | \$244,882 |
| >12 to ≤ 50 tpy | 53 | \$798,265 | \$299,113.3 | \$241,729 | \$855,650 |
| ≥ 50 tpy | 0 | | - | - | - |
| Total: | 200 | \$1,007,064 | \$523,071 | \$429,604 | \$1,100,531 |

For well production facilities the estimated annual inspection costs are set forth in Table 27.

Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin* | Number of Facilities | Annual Inspection Frequency | Total Number of Inspections | Inspection Time Per Inspection [hours] | Total Annual Inspection Cost |
|---|------------|----------------------|-----------------------------|-----------------------------|--|------------------------------|
| In-House Inspections at \$103/hour | | | | | | |
| > 6 to ≤12 | DJ/NAA | 945 | 1 | 945 | 6.1 | \$593,744 |
| > 12 to ≤ 50 | DJ/NAA | 2,447 | 4 | 9,788 | 6.1 | \$6,149,800 |
| > 50 | DJ/NAA | 693 | 12 | 8,316 | 6.1 | \$5,224,943 |
| Subtotal: | | 4,085 | | 19,049 | | \$11,968,487 |
| In-House Inspections at \$103/hour | | | | | | |
| > 6 to ≤12 | ROS | 173 | 1 | 173 | 6.4** | \$114,042 |
| > 12 to ≤ 50 | ROS | 176 | 4 | 704 | 6.4 | \$464,077 |
| > 50 | ROS | 115 | 12 | 1,380 | 6.4 | \$909,696 |
| Subtotal: | | 464 | | 2,257 | | \$1,487,815 |
| Contract Inspections at \$134/hour | | | | | | |
| > 6 to ≤12 | DJ/NAA | 150 | 1 | 150 | 6.1 | \$122,610 |
| > 12 to ≤ 50 | DJ/NAA | 153 | 4 | 612 | 6.1 | \$500,249 |
| > 50 | DJ/NAA | 118 | 12 | 1,416 | 6.1 | \$1,157,438 |
| Subtotal: | | 421 | | 2,178 | | \$1,780,297 |
| Contractor Inspections at \$134/hour | | | | | | |
| > 6 to ≤12 | ROS | 140 | 1 | 140 | 6.4** | \$120,064 |
| > 12 to ≤ 50 | ROS | 148 | 4 | 592 | 6.4 | \$507,699 |
| > 50 | ROS | 52 | 12 | 624 | 6.4 | \$535,142 |
| Subtotal: | | 340 | | 1,356 | | \$1,162,905 |
| Total: | | 5,310 | | 24,840 | | \$16,399,504 |

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

Table 28: Well Production Facility Leak Repair Costs

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities | Number of Leaks per Tank | Total Leak Repair Time per Tank [hours] | Total Annual Repair Cost |
|---|-----------|----------------------|--------------------------|---|--------------------------|
| > 6 to ≤12 | DJ/NAA | 1,095 | 17.0 | 11.8 | \$855,887 |
| > 12 to ≤ 50 | DJ/NAA | 2,600 | 25.5 | 17.7 | \$3,048,365 |
| > 50 | DJ/NAA | 811 | 34.1 | 23.6 | \$1,267,807 |
| Subtotal: | | 4,506 | | | \$5,172,059 |
| > 6 to ≤12 | ROS | 313 | 9.7 | 7.7 | \$159,645 |
| > 12 to ≤ 50 | ROS | 324 | 14.5 | 11.6 | \$248,956 |
| > 50 | ROS | 167 | 19.4 | 15.4 | \$170,356 |
| Subtotal: | | 804 | | | \$578,957 |
| Total: | | 5,310 | | | \$5,751,016 |

Table 29: Well Production Facility Recovered Natural Gas Value from Leak Repairs

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities | Total Recovered Natural Gas per tank [tons/year] | Value of Natural Gas [\$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
|---|-----------|----------------------|--|-------------------------------|-----------------------------|---|
| > 6 to ≤12 | DJ/NAA | 1,095 | 4.6 | \$3.5 | 35.8 | \$631,136 |
| > 12 to ≤ 50 | DJ/NAA | 2,600 | 7.0 | \$3.5 | 35.8 | \$2,280,460 |
| > 50 | DJ/NAA | 811 | 9.3 | \$3.5 | 35.8 | \$945,050 |
| Subtotal: | | 4,506 | | | | \$3,856,646 |
| > 6 to ≤12 | ROS | 313 | 4.6 | \$3.5 | 35.8 | \$180,407 |
| > 12 to ≤ 50 | ROS | 324 | 6.8 | \$3.5 | 35.8 | \$276,061 |
| > 50 | ROS | 167 | 9.1 | \$3.5 | 35.8 | \$190,418 |
| Subtotal: | | 804 | | | | \$646,886 |
| Total: | | 5,310 | | | | \$4,503,532 |

The total net costs for well production facility station LDAR are set forth in Table 30.

| Uncont. VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Total Annual Inspection Cost | | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
|--|-----------|------------------------------|--------------------|--------------------------|---|---|
| | | In-House | Contractor | | | |
| > 6 to ≤12 | DJ/NAA | \$593,744 | \$122,610 | \$855,887 | \$631,136 | \$941,105 |
| > 12 to ≤ 50 | DJ/NAA | \$6,149,800 | \$500,249 | \$3,048,365 | \$2,280,460 | \$7,417,954 |
| > 50 | DJ/NAA | \$5,224,943 | \$1,157,438 | \$1,267,807 | \$945,050 | \$6,705,138 |
| Subtotal: | | \$11,968,487 | \$1,780,297 | \$5,172,059 | \$3,856,646 | \$15,064,197 |
| > 6 to ≤12 | ROS | \$114,042 | \$120,064 | \$159,645 | \$180,407 | \$213,344 |
| > 12 to ≤ 50 | ROS | \$464,077 | \$507,699 | \$248,956 | \$276,061 | \$944,671 |
| > 50 | ROS | \$909,696 | \$535,142 | \$170,356 | \$190,418 | \$1,424,776 |
| Subtotal: | | \$1,487,815 | \$1,162,905 | \$578,957 | \$646,886 | \$2,582,791 |
| Total: | | \$13,456,302 | \$2,943,202 | \$5,751,016 | \$4,503,532 | \$17,646,988 |

Additionally, based on information in the Division’s APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be \$1,639,239.²⁵

| Uncontrolled VOC at Storage Tank Battery Tier [tpy] | O&G Basin | Number of Facilities and Inspections | Inspection Time Per Inspection [hours] | Inspection Type/Hourly Rate | Total Annual Inspection Cost |
|---|-----------|--------------------------------------|--|-----------------------------|------------------------------|
| ≤ 6 | DJ/NAA | 1,598 | 6.1 | In-House/\$103 | \$1,004,023 |
| ≤ 6 | ROS | 500 | 3.4 | In-House/\$103 | \$175,100 |
| Subtotal: | | 2,098 | | | \$1,179,123 |

²⁵ To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the non-attainment area based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

| | | | | | |
|---------------|--------|--------------|-----|------------------|--------------------|
| ≤ 6 | DJ/NAA | 389 | 6.1 | Contractor/\$134 | \$317,969 |
| ≤ 6 | ROS | 312 | 3.4 | Contractor/\$134 | \$142,147 |
| Subtotal: | | 701 | | | \$460,116 |
| Total: | | 2,799 | | | \$1,639,239 |

The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

| Comp. Station Fugitive VOC Tier [tpy] | Number of Comp Stations | LDAR Program Reduction % | Fugitive VOC Emissions for each CS tier [tpy] | Total VOC Reduction [tpy] | Fugitive Methane-Ethane Emissions for each CS tier [tpy] | Total Methane-Ethane Reduction [tpy] |
|---------------------------------------|-------------------------|--------------------------|---|---------------------------|--|--------------------------------------|
| ≤ 12 | 147 | 40% | 10.1 | 588.0 | 15.5 | 911.4 |
| > 12 to ≤ 50 | 53 | 60% | 16.4 | 519.4 | 44.3 | 1,409.8 |
| > 50 | | 80% | | | | |
| | 200 | | | 1,107.4 | | 2,321.1 |

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be \$994/ton VOC and \$474/ton methane/ethane.

Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21

| Comp. Station Fugitive VOC Tier [tpy] | Number of Comp Stations | Total Net Annual Inspection & Repair Cost | LDAR Program Reduction % | Total VOC Reduction [tpy] | VOC Control Cost [\$ /ton] | Total Methane-Ethane Reduction [tpy] | Methane-Ethane Control Cost [\$ /ton] |
|---------------------------------------|-------------------------|---|--------------------------|---------------------------|----------------------------|--------------------------------------|---------------------------------------|
| ≤ 12 | 147 | \$244,882 | 40% | 588.0 | \$416 | 911.4 | \$269 |
| > 12 to ≤ 50 | 53 | \$855,650 | 60% | 519.4 | \$1,647 | 1,409.8 | \$607 |
| > 50 | | | 80% | | | | |
| | 200 | \$1,100,531 | | 1,107.4 | \$994 | 2,321.2 | \$474 |

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions

| Uncontrolled VOC at Tank Battery Tier [tpy] | Number of Facilities | LDAR Program Reduction % | Fugitive VOC Emissions for each Tank Battery [tpy] | Total VOC Reduction [tpy] | Fugitive Methane-Ethane Emissions for each Tank Battery [tpy] | Total Methane-Ethane Reduction [tpy] |
|---|----------------------|--------------------------|--|---------------------------|---|--------------------------------------|
| DJ/NAA | | | | | | |
| > 6 to ≤ 12 | 1,095 | 40% | 4.6 | 1,971.0 | 7.0 | 3,066.0 |
| > 12 to ≤ 50 | 2,600 | 60% | 4.6 | 7,280.0 | 7.0 | 10,920.0 |
| > 50 | 811 | 80% | 4.6 | 3,000.7 | 7.0 | 4,541.6 |
| Subtotal: | 4,506 | | | 12,251.7 | | 18,527.6 |
| Remainder of State | | | | | | |
| > 6 to ≤ 12 | 313 | 40% | 3.9 | 500.8 | 7.5 | 939.0 |
| > 12 to ≤ 50 | 324 | 60% | 3.9 | 745.2 | 7.5 | 1,458.0 |
| > 50 | 167 | 80% | 3.9 | 517.7 | 7.5 | 1,002.0 |
| Subtotal: | 804 | | | 1,763.7 | | 3,399.0 |
| Total: | 5,310 | | | 14,015.4 | | 21,926.6 |

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be \$1,259/ton VOC and \$805/ton methane/ethane.

Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

| Uncont. VOC at Tank Battery Tier [tpy] | Number of Tanks | Total Net Annual Leak Inspection & Repair Cost | LDAR Program Reduction % | Total VOC Reduction [tpy] | VOC Control Cost [\$/ton] | Total Methane-Ethane Reduction [tpy] | Methane-Ethane Control Cost [\$/ton] |
|--|-----------------|--|--------------------------|---------------------------|---------------------------|--------------------------------------|--------------------------------------|
| DJ/NAA | | | | | | | |
| > 6 to ≤ 12 | 1,095 | \$941,105 | 40% | 1,971.0 | \$477 | 3,066.0 | \$307 |
| > 12 to ≤ 50 | 2,600 | \$7,417,954 | 60% | 7,280.0 | \$1,019 | 10,920.0 | \$679 |
| > 50 | 811 | \$6,705,138 | 80% | 3,000.7 | \$2,235 | 4,541.6 | \$1,476 |
| Subtotal: | 4,506 | \$15,064,197 | | 12,251.7 | \$1,230 | 18,527.6 | \$813 |
| ROS | | | | | | | |
| > 6 to ≤ 12 | 313 | \$213,344 | 40% | 500.8 | \$426 | 939.0 | \$227 |
| > 12 to ≤ 50 | 324 | \$944,671 | 60% | 745.2 | \$1,268 | 1,458.0 | \$648 |
| > 50 | 167 | \$1,424,776 | 80% | 517.7 | \$2,752 | 1,002.0 | \$1,422 |
| Subtotal: | 804 | \$2,582,791 | | 1,763.7 | \$1,464 | 3,399.0 | \$760 |
| Total: | 5,310 | \$17,646,988 | | 14,015.4 | \$1,259 | 21,926.6 | \$805 |

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be \$409/ton VOC and \$249/ton methane/ethane.

In addition to the component leak detection and repair requirements for compressor stations and well production facilities, the Division’s proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division’s proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange,

plug or second valve it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this widespread prevalence in federal rules the Division believes that the proposal represents a simple and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division's proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of \$46,974.²⁶

With respect to reciprocating compressors, the Division's proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of \$43 per ton of VOC reduced and \$12 per ton of methane reduced.²⁷

D. Auto Igniter Requirements on Existing Flare Control Devices Outside the Non-Attainment Area

Unlike the non-attainment area, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is \$475 based on information that the industry provided to the Division in 2008, adjusted for inflation.²⁸

²⁶ See APCD-PHS Ex. HHHH pp. 6-1—6-3

²⁷ See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.

²⁸ See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|---------------------|-----------------------------|-----------------------------------|--------------------------|---------------------------|
| Auto Igniter | \$1,648 | | | |
| Freight/Engineering | | \$200 | | |
| Flare Installation | | \$500 | | |
| Maintenance | | | \$200 | |
| Subtotal Costs | \$1,648 | \$700 | \$200 | |
| Annualized Costs* | \$228.4 | \$46.7 | \$200 | \$475 |

* Annualized over 15 years at 5% ROR

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1 tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about \$378,100 the estimated cost effectiveness of this strategy is about \$302 per ton of VOC reduced.

| Source Type for Existing Flare Controls | Number of Auto Igniters | Uncontrolled VOC [tpy] | Uncontrolled VOC Using 3% Downtime [tpy] | Total VOC Reduction [tpy] |
|--|-------------------------------|---------------------------|--|---------------------------------|
| Condensate Tanks | 490 | 31,170.6 | 935.1 | 666.3 |
| Dehydrators | 131 | 16,372.0 | 491.2 | 466.6 |
| Produced Water Tanks | 172 | 4,842.2 | 145.3 | 103.5 |
| Crude Oil Tanks | 3 | 716.3 | 21.5 | 15.3 |
| | 796 | 53,101.1 | 1,593.1 | 1251.7 |

* Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.

| Number | Each Auto-Igniter Annualized Costs | Total Annualized Costs | VOC Reduction* [tons/year] | Control Costs [\$/ton] |
|--------|---------------------------------------|---------------------------|-------------------------------|---------------------------|
| 796 | \$475 | \$378,100 | 1,251.7 | \$302 |

E. Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the AQCC adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the non-attainment area. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 Colorado Oil and Gas Conservation Commission (COGCC) well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the nonattainment area. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current non-attainment area low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study²⁹ adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is \$169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be \$1,268 for each device replaced. As a result, the net annual gain is \$1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

| Item | Capital Costs (one time) | Non-Recurring Costs (one time) | O&M Costs (recurring) | Annualized Total Costs |
|----------------------|--------------------------|--------------------------------|-----------------------|------------------------|
| Low/No Bleed Device* | \$1,033 | | | |
| Labor | | \$387 | | |
| Value of NG Saved** | | | \$(1,268) | |
| Maintenance | | | \$16 | |

²⁹ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008.

| | | | | |
|---------------------|---------|-------|-----------|-----------|
| Subtotal Costs | \$1,033 | \$387 | \$(1,253) | |
| Annualized Costs*** | \$143 | \$26 | \$(1,253) | \$(1,084) |

* Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.

** Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

Assuming 9,384 total devices replaced, adoption of this strategy will result in \$10,169,441 in annual cost savings.

| Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA) | | | | |
|---|------------------------------|------------------------|---------------------------|------------------------|
| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
| 9,384 | \$(1,084) | \$(10,169,441) | 14,921 | NA |

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

F. Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to A Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

G. Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division’s proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is \$6,286.80 per unit. See Section IV.A.1. above.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of \$786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be \$3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------|------------------------------|------------------------|---------------------------|------------------------|
| 217 | \$6,286.8 | \$1,364,236 | 1,736 | \$786 |

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of \$632/ton VOC.

| Number | Each Device Annualized Costs | Total Annualized Costs | VOC Reduction [tons/year] | Control Costs [\$/ton] |
|--------|------------------------------|------------------------|---------------------------|------------------------|
| 148 | \$6,286.8 | \$930,446 | 1,472 | \$632 |

H. Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.³⁰ For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division’s proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA’s Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division’s proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in

³⁰ See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

I. Division Implementation Costs

The Division will implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of 9 full time inspectors and 4 term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature increased the size of the inspection team from 6 inspectors to 9. In 2013, the legislature appropriated additional funds to hire 4 additional term limited inspectors to conduct infra-red camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will allow the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is \$1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

V. CONCLUSION

The Division projects that the proposal will reduce VOC emissions in Colorado by approximately 93,500 tons per year and methane/ethane emissions by approximately 65,000 per year at a cost of approximately \$42.5 million per year. Another portion of the proposal requires one-time leak detection and repair on well production facilities <6 tons/year, which will reduce VOC emissions by about 4,900 tons, methane emissions by about 8,000 tons and cost approximately \$2 million dollars. The calculated cost per ton of VOC reduced ranges from between \$176 and \$1,259 per ton. The overall cost effectiveness for the entire package is approximately \$453 per ton of VOC reduced.

The Division prepared this Final Economic Impact Analysis in accordance with the requirements of Section 25-7-110.5(4), C.R.S. Specifically, the Division utilized the methodology identified in § 25-7-110.5(4)(c)(I), C.R.S. In completing this analysis, the Division assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in the analysis. To the extent that other parties to the rulemaking provide additional data regarding the costs and benefits of the proposed strategies, the Commission should consider such data in assessing the cost-effectiveness of the proposed strategies.



REBELLION PHOTONICS

As a solutions provider with proven technology to help reduce methane emissions from the oil and gas sector, Rebellion Photonics would like to provide comments on EPA's draft rule in order to ensure it reflects the current state of methane science and technology to address this issue.

Oil and gas companies emit 7 million tons of methane from their operations every year. Methane escaping from the oil and gas industry has the same 20-year climate impact as 160 coal-fired power plants, and represents enough wasted natural gas to heat over 5 million homes. These emissions are currently projected to increase 25 percent over the next decade. Methane emissions are a significant climate and energy-waste problem that's only going to grow.

We believe there are ways the draft rule could be improved and our technology could help solve this problem. Gas Cloud Imaging technology such as Rebellion Photonics camera is an available, cost effective, and proven solution for detection and reduction of methane and other VOC's from the installation of new equipment, upgrades, and modified sources in the oil and gas industry.

While we credit the EPA with their initial proposal for bi-annual leak detection inspections, the step up and down provisions based on the number of leaking components is based on faulty logic. Studies have shown that leaks by nature are random and thus make comprehensive and frequent LDAR critical. Emerging data show that a disproportionate share of fugitive emissions can come from a relatively small percentage of leaks that can appear almost anywhere, anytime – at new and old facilities, and big and small ones. A well site that looks good today might be a big problem tomorrow. . More frequent intervals such as monthly or quarterly inspections are what is needed and still just as cost effective. Stepping up the frequency of inspections allows for better identification and fixing of leaks which will greatly impact the overall reduction of methane.

Rebellion's Gas Cloud Imaging Camera employs advanced hyperspectral infrared imaging technology, engages advanced detection algorithms, and employs powerful data storage and transmittal technology. The GCI is different from other leak imagers because ***leak detection is automated, identification and quantification are possible, and wide areas can be monitored.*** With the ability to "see" the leak, operators can pinpoint the leak source to initiate repair on the spot. The GCI has the potential to catch leaks early and help operators avoid walking into a hazardous cloud. It will also aid operators when making process safety decisions to avoid leak escalation that can lead to "low-frequency, high-consequence" incidents.

We have seen in Colorado, where state regulations are the strictest in the country that significant reductions can be made cost-effectively. Our technology, which is an approved instrument monitoring method for Colorado Air Quality Control Commission Regulation No 7 STEM and LDAR, is cost effective at just \$250 per site for inspections.....This is affordable even for the low producing well sites. We believe these Colorado regulations could be a model for the nation. Customers there are complying with the law, reducing emissions



REBELLION

PHOTONICS

in a cost-effective manner. With some customers, we can cover in upwards of 25 sites per day and have monitored over 1,100 pieces of overall equipment in one week. Our camera allows for speedy, efficient leak detection and with the ability to quickly scan sites, it enables companies to perform inspections more often. It also supports our customers' ability to prioritize maintenance and repair of sites which thus reduces spent labor, time, and gas losses. When putting all of these factors together in dollars and cents, it more than pays for the service operation of the camera.

Well site inspections in Colorado have also offered to us numerous examples of the importance of more frequent LDAR inspections. A simple thief hatch proves to be quite the culprit in a large percentage of the leaks we find.....This leak at times can be traced back to something as simple as a dirty seal.....A dirty seal that may have shown not to be leaking one month ago or even one day ago. Again, leaks are random in nature. So, inspecting a piece of equipment such as a thief hatch proves to be something that is more effective on an increased basis versus a decreased basis if we're working to cut methane emissions.

The importance of follow up surveys after repair is just as critical to ensure correct maintenance/repair of the emitting equipment and also that correcting one leaking component does not create a new one. Again, this is where Colorado leads the nation in how they approach their regulations....They have companies keep logs of inspections, leaks, 1st or 2nd or 3rd attempt of leak repair, and then finally inspection of the fixed equipment. Rebellion creates a turnkey approach to this for our customers by providing a web portal included in our \$250 per site that can store well site inspection videos, both of leaks and then post leak repair, and the required maintenance logs.

EPA's proposed rule covers new and modified sources. We would encourage EPA to take an expansive approach to how it treats modified sources, particularly when it comes to the application of LDAR for modified sources. As we've discussed, much of what drives fugitive emissions is human error. When equipment is modified, we've very often seen it done incorrectly, leading to large leaks. The only way to know confidently whether equipment that has been modified is working correctly is by conducting LDAR on it.

In the end, we are finding the forward charge of the EPA and the thought of potentially stricter methane regulations have made companies take note and begin to implement actions with their sites by utilizing our proven technology in an attempt to capture fugitive emissions and reduce lost product. In the end, lower methane emissions are good for companies, good for the industry as a whole, and good for the environment.



Leak Detection and Repair Cost-Effectiveness Analysis

Prepared for Environmental Defense Fund



December 4, 2015



Project Outline

- Motivation for the Analysis
- Objective of the Stochastic LDAR Analysis
- Modeling Concept
- Limitations of Analysis
- Segment Specific Data Sources
- Segment Specific Scenarios and Assumptions
- Segment Specific Results



Motivation for the Analysis

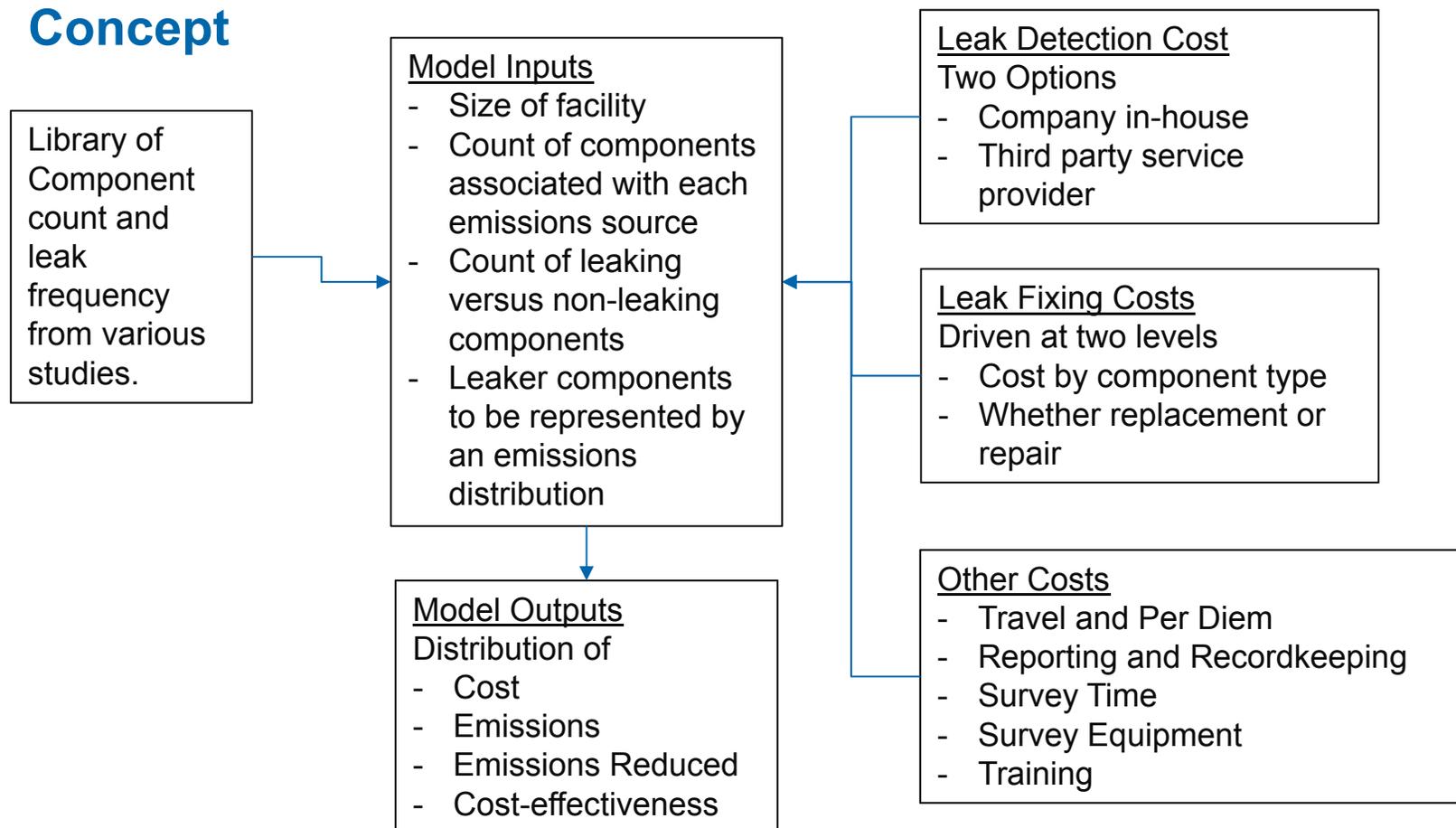
- Much of current LDAR costs and emissions reduction analysis based on average values
 - However, there is a wide variation in the size of the facilities and types of equipment at each facility
 - Average values do not take into account the variation in emissions rate (and therefore reductions), specifically from super-emitters
 - Difficult to analyze multiple scenarios when using average values
- Propose a LDAR stochastic modeling approach



Objective of Stochastic LDAR Analysis

- Develop facility models that replicate the real world and capture variations in facility size and characteristics
- Use Monte Carlo simulation to analyze facility emissions, reductions, and costs
 - Model includes inter-relationships between different factors, such as leak frequency and time required to conduct LDAR
 - Includes correlations between activity data, count of reciprocating and centrifugal compressors at compressor stations are correlated with each other and the total count of compressor at the station
 - Emissions rate and activity represented by statistical distributions
 - Use data from multiple publications and studies as appropriate
 - Ability to develop multiple scenarios, including impact of changing frequency of LDAR
- Evaluate LDAR cost-effectiveness from the following segments – production well-pads, gathering and boosting stations, processing plants, transmission compressor stations, and storage stations

LDAR Modelling Concept





Model Concept - Inputs

- Emission sources include –
 - Fugitive sources - valves, connectors, pressure relief valves (PRV), compressor PRVs, open-ended lines (OEL), compressor starter OELs, compressor blowdown valves, pressure regulators, orifice meters
- Statistical distributions assigned to each emission source activity factor and emissions rate
- Leak frequency identifying percentage of components leaking
 - Range of leak frequencies based on data on number of leaking components from field studies that provide raw data that allows for distribution fitting
- Economic Factors
 - Gas Price, Labor Cost, Time to Survey Equipment, Repair/Maintenance Cost, Survey Equipment Costs, Other Costs
- GWP=25

Model Concept - Simulation

- The simulation is run for 10,000 iterations with each iteration representing a unique and random combination of;
 - Facility characteristics, such as size, type of equipment, count of emissions source
 - Number of leakers for each emissions source
 - Leak rate of each leaking unit of leakers for each emissions source
- General simulation model steps
 - Step 1 – Select random facility characteristic, example – well-pad with specific number of wells and equipment
 - Step 2 – Determine the count of associated components (emissions sources)
 - Step 3 – Determine the survey time and associated costs based on component count
 - Step 4 – Randomly select the percentage of each components that are leaking
 - Step 5 – Randomly assign leak rates to each leaking component
 - Step 6 – Determine if each leak has to be repaired or replaced; assign costs accordingly
 - Step 7 – Determine reductions achieved from repair or replacement
 - Step 8 – Calculate output statistics



Model Concept - Output

- Distribution of emissions per facility
- Distribution of costs associated with conducting LDAR at various frequencies – annual, semi-annual, and quarterly
- Trends in LDAR cost-effectiveness, i.e. \$/Mcf-reduced, over time
- The \$/Mcf-reduced metric is the ratio of the total cost to conduct an LDAR survey to the difference in Mcf of emissions from the baseline each year where the baseline is assumed to be the uncontrolled emissions in the first year



Limitations of Analysis

- Model results are driven by data inputs
 - The representativeness of results to national, state, company, or facility level is limited by representativeness of the data
- Limited time series data is available on the impact of different LDAR frequencies on reduction in leak frequencies in each subsequent survey
 - Assumption in this study is based on best available data from Colorado
- Costs to repair or replace can vary depending on location and complexity of leak
 - This study uses best available data from Gas STAR published documents and expert judgement where no data was available

Production Segment Assumptions and Results



Production Model Data Sources

- Data Sources used to model facility
 - Subpart W
 - EPA/ GRI
 - City of Fort Worth Natural Gas Air Quality Study
 - UT Study - Methane Emissions in the Natural Gas Supply Chain: Production
 - UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers
 - Jonah Energy LLC WCCA Spring Meeting Presentation

Component Replacement and Maintenance Costs



| Emission Source | Default Replacement Cost | Default Maintenance Cost |
|----------------------------------|--------------------------|--------------------------|
| Valve | \$112.00 | \$41.67 |
| Connection | \$226.67 | \$20.00 |
| Pressure Relief Valve | \$500.00 | \$100.00 |
| Compressor Pressure Relief Valve | \$1,000.00 | \$200.00 |
| Open-Ended Line | \$150.00 | \$45.00 |
| Starter Open Ended Line | \$500.00 | \$250.00 |
| Pressure Regulators | \$300.00 | \$200.00 |
| Orifice Meters | \$775.00 | \$200.00 |



Time to Measure Individual Components

| Emission Source | Estimated Time to Survey in Minutes |
|----------------------------------|-------------------------------------|
| Valve | 0.1 |
| Connection | 0.1 |
| Pressure Relief Valve | 0.5 |
| Compressor Pressure Relief Valve | 0.5 |
| Open-Ended Line | 0.5 |
| Starter Open Ended Line | 0.5 |
| Pressure Regulators | 0.1 |
| Orifice Meters | 0.1 |

Survey Equipment Costs Default



| Component | Default Costs |
|---------------------|---------------|
| IR Camera | \$115,000 |
| Hi Flow Sampler | \$20,000 |
| Calibrated Bag | \$500 |
| Vehicle (4x4 Truck) | \$22,000 |

Other Costs



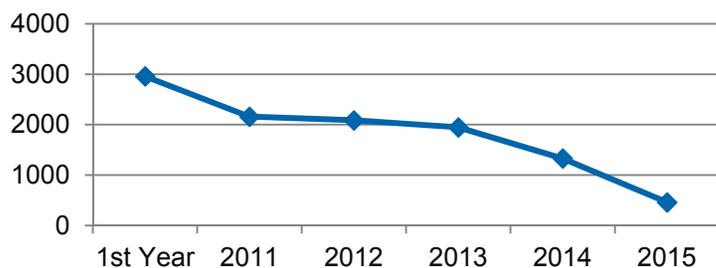
| Emission Source | Estimated Time to Survey in Minutes |
|---|-------------------------------------|
| Prep Time per 4 hours or Working (Hours) | 0.25 |
| Percentage of Year Contractor Utilizes Equipment | 75% |
| Contractor Scalar | 30% |
| Years Contractors Recoup Survey Equipment Costs | 3 |
| Profit Percentage for Contractors on Survey Equipment | 25% |
| Hours of Training for In-House Operations | 80 |
| Lodging and Per Diem | 250 |
| Supervision (Inhouse) | \$31,200 |
| Fringe (Inhouse) | \$46,800 |
| Training for Contractor | \$15,600 |
| Reporting and Record Keeping | \$100 |

Leak Frequency and Emission Truncation Over Future Surveys

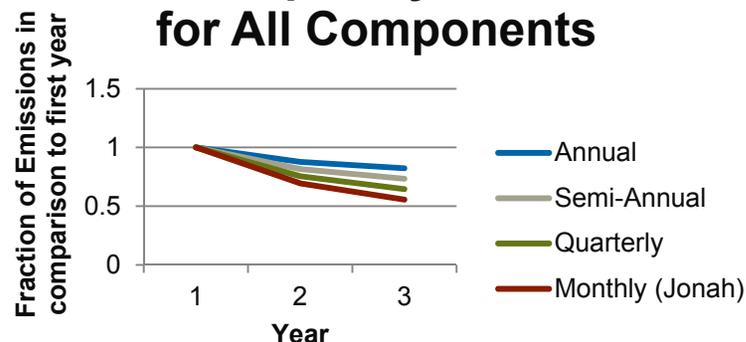


- Leaks occur less frequently over subsequent LDAR surveys
- Reduction in leak frequency was designed based on data from Colorado monthly survey results
- Annual, semi-annual and quarterly surveys assumed to experience slower reductions in leak frequencies

Leaks Identified Per Year Raw Data



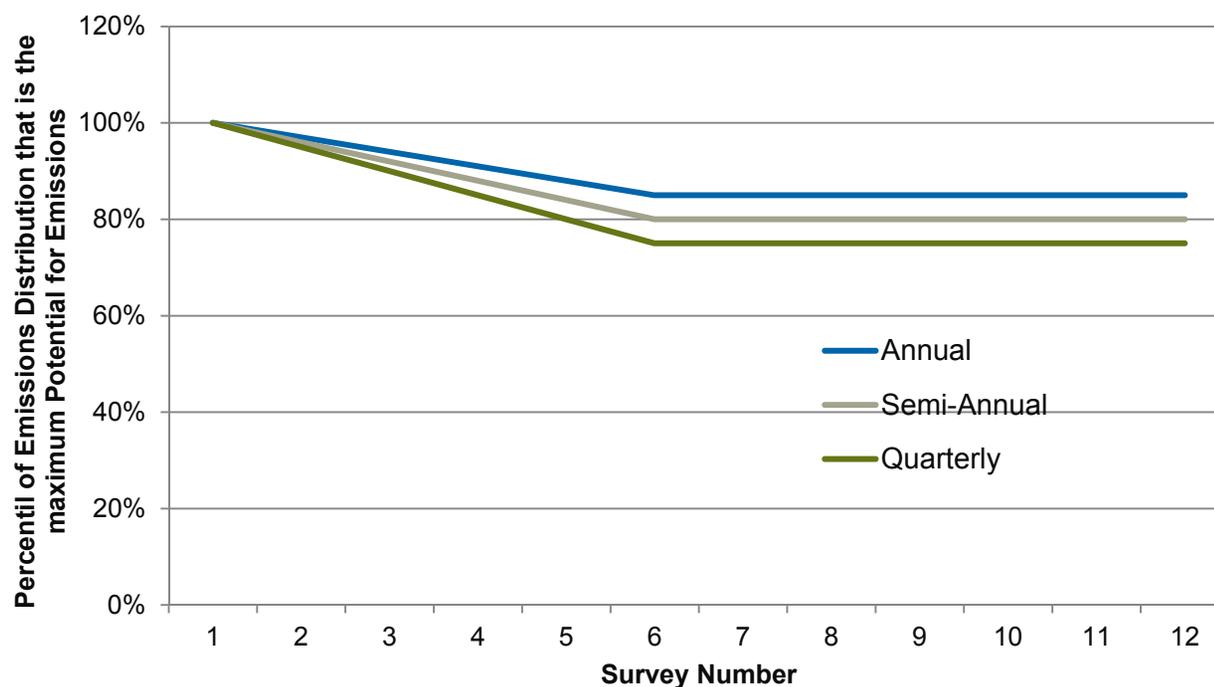
Leak Frequency Over Time for All Components



Emission Truncation Over Future Surveys

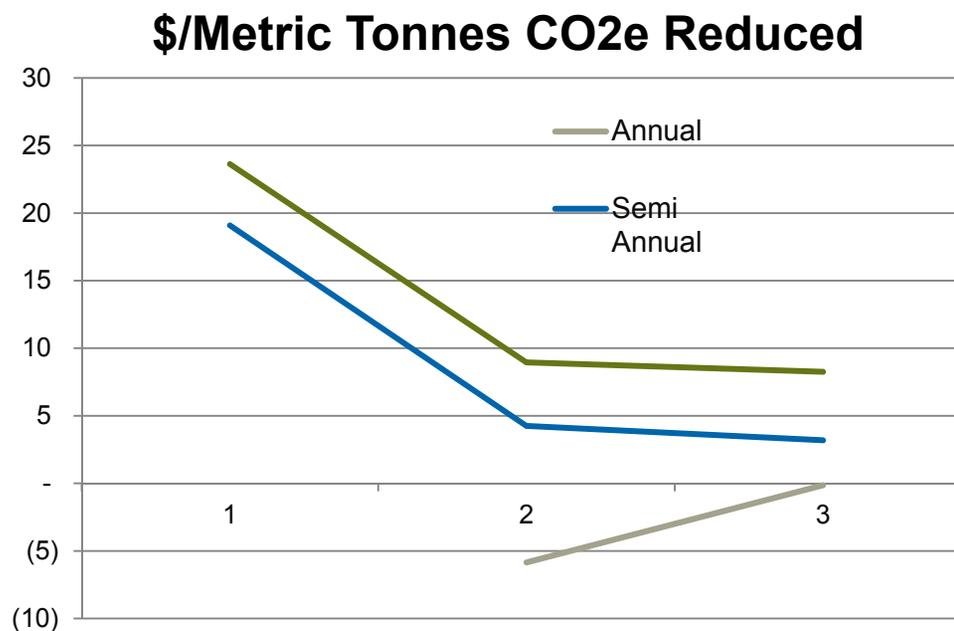
- Fewer high emitting leaks are identified from subsequent LDAR surveys
- Trend has been captured by truncating the right tail of emissions rate distributions

Emission Truncation Percentiles



Fugitive Sources Case 1

- Case 1 Parameters:
 - Gas price: \$3 dollars/Mcf
 - Evaluates fugitive sources
 - Assumes two contractors are hired

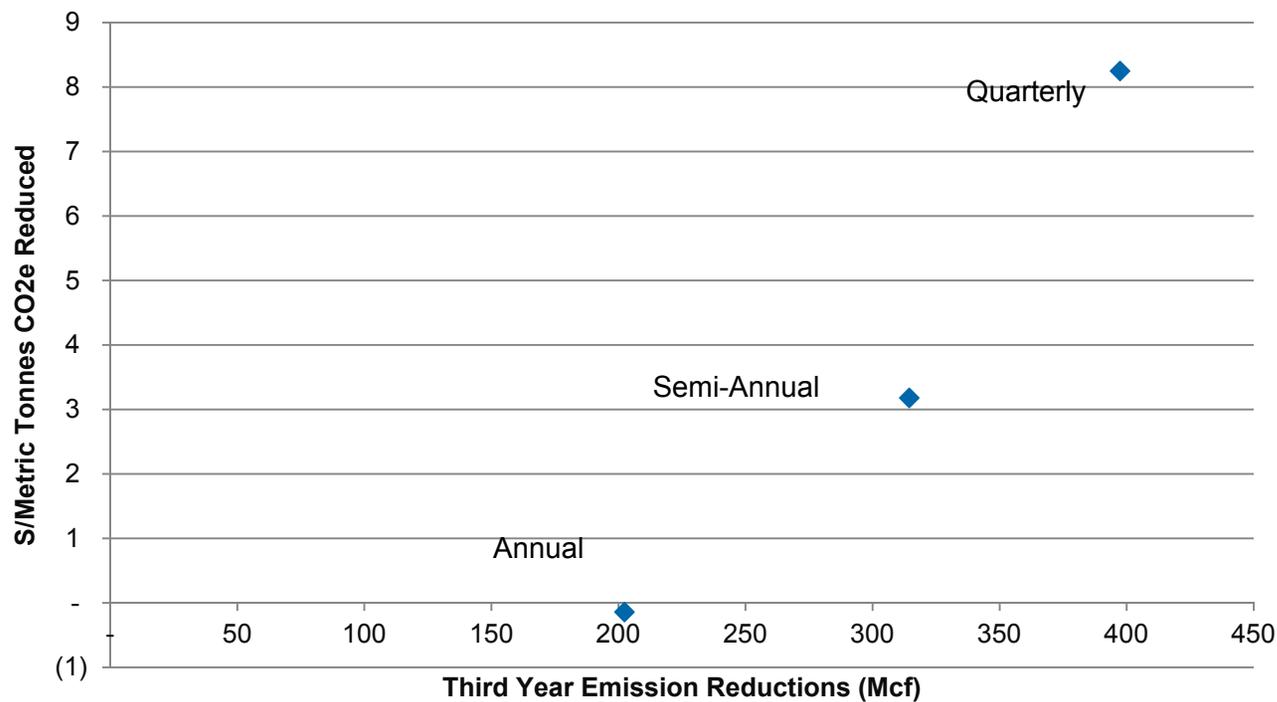


Fugitive Sources Case 1



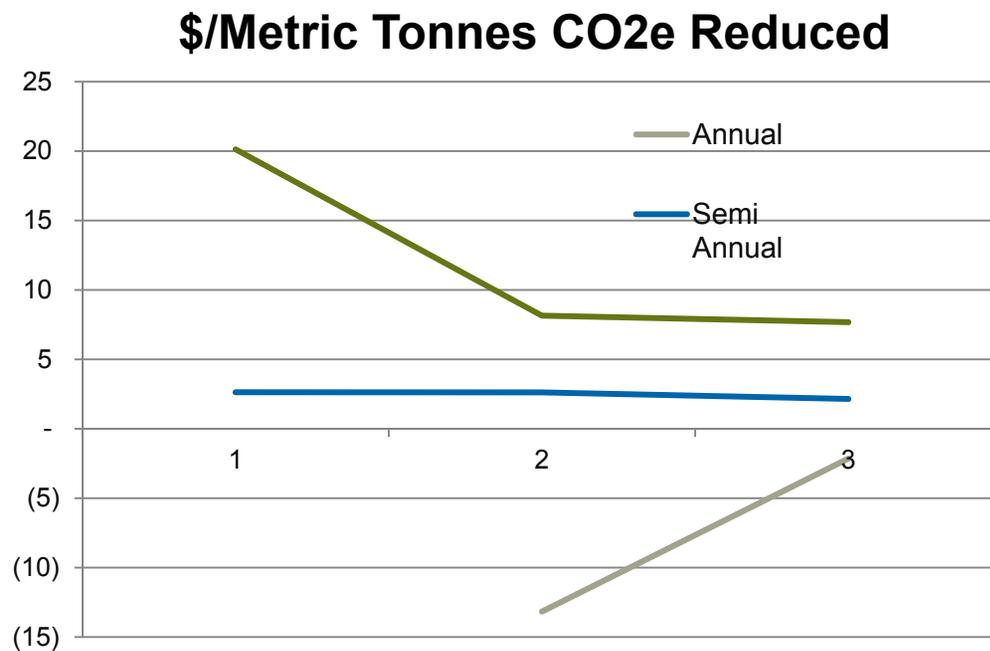
- Total emissions reduced in year three plotted against average cost effectiveness of reductions in year 3.

Third Year Emission Reductions vs. Cost Effectiveness



Fugitive Sources Case 2

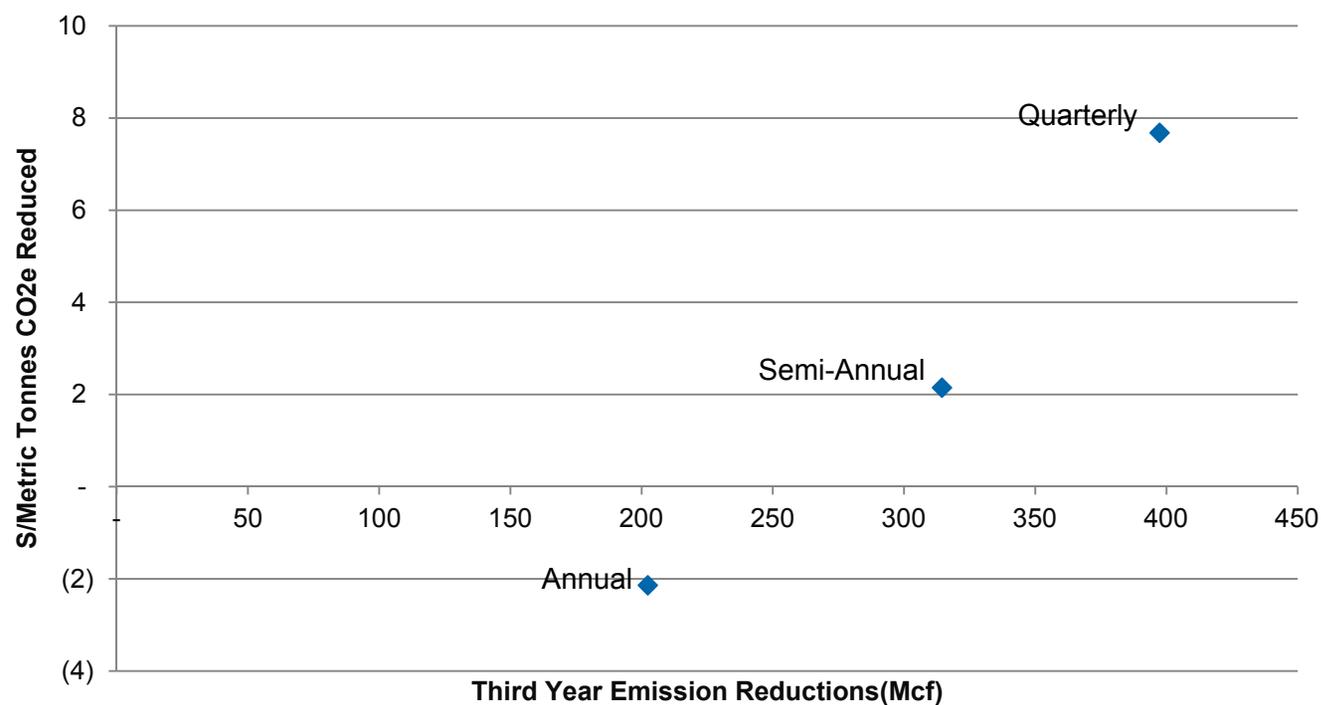
- Case 2 Parameters
 - Gas price: \$4 dollars/Mcf
 - Evaluates fugitive sources
 - Assumes two contractors are hired



Fugitive Sources Case 2

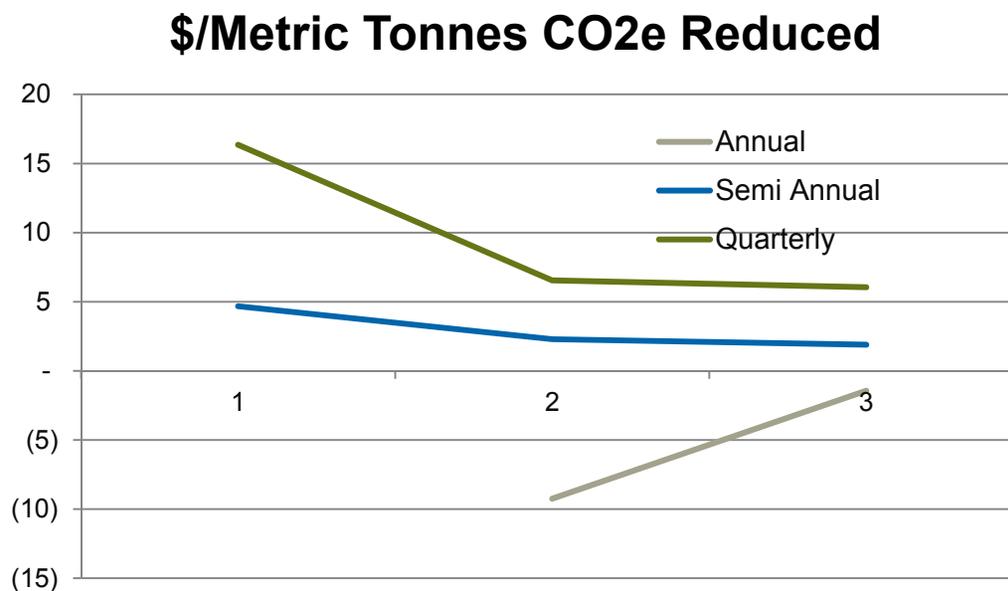
- Total emissions reduced in year three plotted against average cost effectiveness of reductions in year 3.

Third Year Emission Reductions vs. Cost Effectiveness



Fugitive Sources Case 3

- Case 3 Parameters:
 - Gas price: \$3 dollars/Mcf
 - Evaluates fugitive sources
 - Assumes one contractor is hired

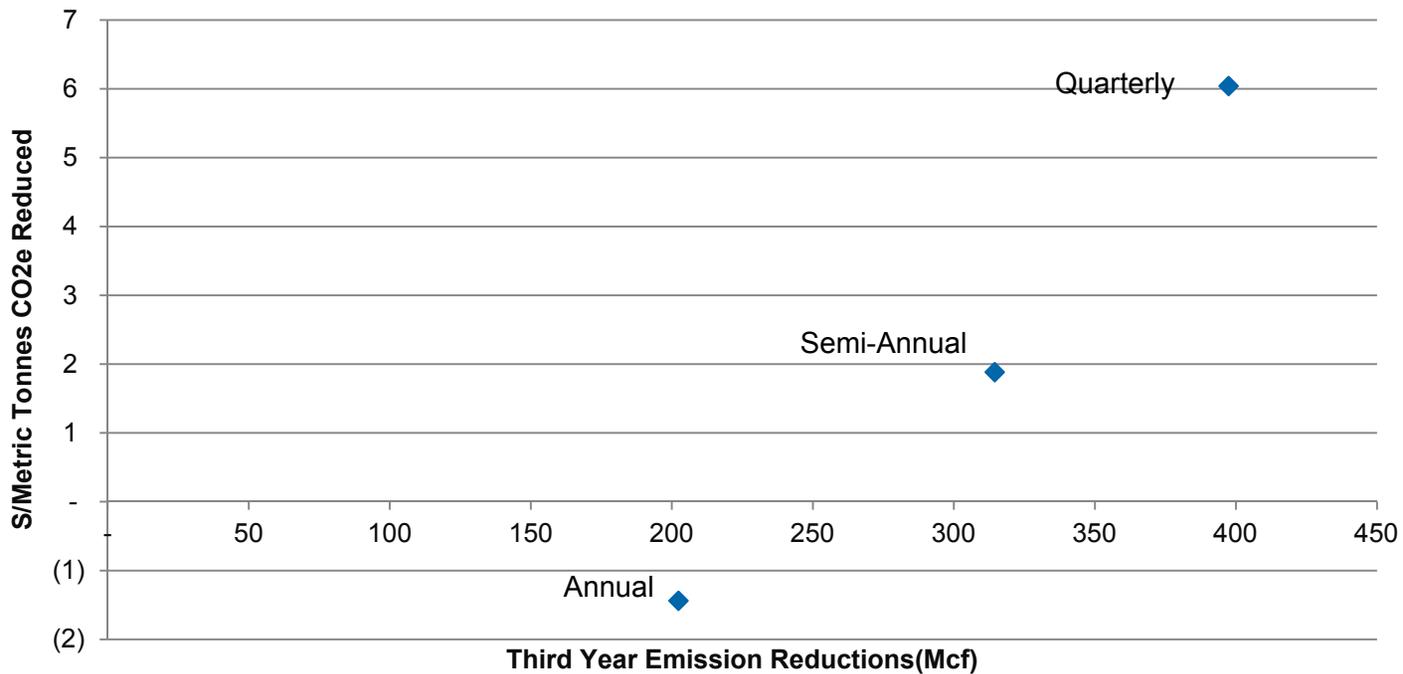


Fugitive Sources Case 3



- Total emissions reduced in year three plotted against average cost effectiveness of reductions in year 3.

Third Year Emission Reductions vs. Cost Effectiveness





Total Three Year Production Mean Fugitive Results

| | \$/Metric Tonnes CO2e Reduced | | |
|-------------|-------------------------------|---------|------------------------|
| | \$3/Mcf | \$4/Mcf | \$3/Mcf One Contractor |
| Annual | -4.76 | -11.19 | -7.86 |
| Semi-annual | 4.94 | 2.39 | 2.29 |
| Quarterly | 11.56 | 10.32 | 8.27 |

GWP=25

**WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
STANDARDS AND REGULATIONS**

Nonattainment Area Regulations

CHAPTER 8

Section 1. Introduction to nonattainment area regulations.

(a) Chapter 8 establishes regulations specific to areas not attaining the National Ambient Air Quality Standards. Section 2 applies exclusively to Sweetwater County, Wyoming particulate matter regulations. Section 3 applies to general federal actions, excluding those covered under Section 4, within any federally designated nonattainment area of the state. Section 4 applies to specific transportation projects within any federally designated nonattainment area of the state. Section 5 establishes requirements for the submittal of emission inventories from facilities or sources located in an ozone nonattainment area(s) pursuant to the requirements of the Clean Air Act, Section 182. Section 6 establishes requirements for all PAD and single-well oil and gas production facilities or sources, and all compressor stations, located in the Upper Green River Basin (UGRB) ozone nonattainment area that were existing as of January 1, 2014. Sections 7 through 9 are reserved. Section 10 incorporates by reference all Code of Federal Regulations (CFRs) cited in this chapter, including their Appendices.

Section 2. Sweetwater County particulate matter regulations.

(a) Notwithstanding other provisions in these regulations concerning the emission of particulate matter or required fugitive dust control measures, the requirements and emission limitations set forth in Chapter 8, Section 2(b) and (c) for the specific sources and activities enumerated are applicable. Sources and/or activities which cause particulate matter to be emitted into the air and which are not addressed in this section are subject to the requirements of other sections.

(b) Point Source Particulate Matter Emission Rate Allowables:

The following tables specify the maximum allowable particulate matter emission rate for each of the listed sources. The emission of particulate matter is measured as specified in Chapter 3, Section 2(h)(iv) of these regulations.

(i) Stauffer Chemical Company of Wyoming, Green River Soda Ash Plant.

| <u>Source Description</u> | <u>Allowable Emission Rate lb/hr</u> |
|---------------------------|--|
| #1 Boiler | 3.00 |

| | |
|-----------|------|
| #2 Boiler | 3.00 |
| #3 Boiler | N.A. |
| #4 Boiler | 7.50 |

(i) Stauffer Chemical Company of Wyoming, Green River Soda Ash Plant (Continued).

| | |
|-----------|------|
| #5 Boiler | 8.62 |
| #6 Boiler | 7.50 |
| ES-1 | 30.6 |
| 2ES-1 | 27.3 |
| 3ES-1 | 29.2 |

| <u>Source Description</u> | <u>Allowable Emission Rate lb/hr</u> |
|---------------------------|--|
| 3ES-2 | 34.5 |
| 4SC-2 | 51.6 |
| 4SC-3 | 5.2 |
| 4SC-4 | 52.6 |
| 4ES-201 | 23.1 |
| Phase II Dryer-Cooler | 12.0 |

(ii) Allied Chemical Corporation, Green River Works

| <u>Source Description</u> | | <u>Allowable Emission Rate lb/hr</u> |
|---------------------------|-----------|--|
| Crusher Building | GR-I-A | 3.0 |
| Prod. Loading | GR-I-B(1) | 3.0 |
| Prod. Loading | GR-I-B(2) | 3.0 |
| Calciner #1 | GR-I-C | 20.0 |
| Calciner #2 | GR-I-D | 25.0 |
| Calciner #3 | GR-I-E | 20.0 |
| Dryer #1 | GR-I-F | 4.0 |
| Dryer #2 | GR-I-G | 4.0 |
| Dryer #3 | GR-I-H | 4.0 |
| Housekeeping (North) | GR-I-J(1) | 2.0 |
| Housekeeping (South) | GR-I-J(2) | 2.0 |
| Product Cooler | GR-I-K | 2.0 |
| Coal Handling Tunnel | CH-1 | 1.7 |
| Coal Handling Gallery | CH-2 | 1.0 |
| Ore Bin Gallery | GR-II-A | 3.0 |
| Product Storage | GR-II-B | 4.0 |
| Calciner #4 | GR-II-C | 20.0 |
| Calciner #5 | GR-II-D | 20.0 |
| Dissolver #1 | GR-II-E-1 | 3.0 |

| | | |
|--------------|-----------|-----|
| Dissolver #2 | GR-II-E-2 | 3.0 |
| Dryer #4 | GR-II-F | 4.0 |
| Dryer #5 | GR-II-G | 4.0 |

(ii) Allied Chemical Corporation, Green River Works (Continued)

| | | |
|--------------------|---------|------|
| Dryer #6 | GR-II-H | 4.0 |
| Housekeeping | GR-II-J | 10.0 |
| Product Cooler | GR-II-K | 3.0 |
| Lime Storage | GR-II-O | 0.1 |
| Reclaim Ore System | RO-1 | 1.4 |

| <u>Source Description</u> | | <u>Allowable Emission Rate</u> <u>lb/hr</u> |
|---------------------------|----------|--|
| Crusher | GR-III-A | 3.0 |
| Ore Conveyor | GR-III-B | 1.0 |
| Ore Gallery | GR-III-C | 1.0 |
| Calciner #1 | GR-III-D | 37.9 |
| Calciner #2 | GR-III-E | 37.9 |
| Dissolver #1 (East) | GR-III-F | 2.0 |
| Dissolver #2 (West) | GR-III-G | 2.0 |
| Filter Aid | GR-III-H | NIL |
| Dryer #1 | GR-III-K | 1.5 |
| Dryer #2 | GR-III-L | 1.5 |
| Dryer #3 | GR-III-M | 1.5 |
| Dryer #4 | GR-III-N | 1.5 |
| Dryer #5 | GR-III-P | 1.5 |
| Dryer Vent | GR-III-R | 2.0 |
| Prod. Cooler #1 | GR-III-S | 1.0 |
| Prod. Cooler #2 | GR-III-T | 1.0 |
| Housekeeping #1 | GR-III-U | 3.0 |
| Housekeeping #2 | GR-III-V | 3.0 |
| Crusher | A-305 | 2.0 |
| Crusher | A-309 | 2.0 |
| “C” Boiler | GR-II-L | 50.0 |
| “D” Boiler | GR-III-W | 80.0 |

(iii) FMC Corporation, Green River

| <u>Source Description</u> | | <u>Allowable Emission Rate</u> <u>lb/hr</u> |
|---------------------------|------------|--|
| Crusher | PA-4; PA-5 | 2.5 |
| Dissolver | PA-6 | 1.0 |
| Dissolver | PA-7 | 1.0 |
| Dissolver | PA-8 | 1.0 |

| | | |
|----------------|------|------|
| Dissolver | PA-9 | 1.0 |
| Sesqui Dryer | RA-1 | 10.0 |
| Dust Collector | RA-2 | 2.0 |

(iii) FMC Corporation, Green River (Continued)

| | | |
|-------------------|-------|------|
| Calciner | RA-13 | 8.0 |
| Calciner | RA-14 | 4.0 |
| Calciner | RA-15 | 4.0 |
| Calciner | RA-16 | 4.0 |
| Calciner Scrubber | RA-22 | 35.0 |

| <u>Source Description</u> | | <u>Allowable Emission Rate</u> <u>lb/hr</u> |
|---------------------------|--------|--|
| Calciner Scrubber | RA-23 | 35.0 |
| Calciner Scrubber | RA-24 | 45.0 |
| Fluid Bed Calciner | RA-25 | 26.5 |
| Dust Collector | RA-27 | 3.0 |
| Dust Collector | RA-33 | 3.0 |
| Phosphorus Furnace | PP-12 | 15.0 |
| Spray Dryer | PP-21 | 28.0 |
| Dust Collector | PP-24 | 4.0 |
| Calciner | PP-25 | 15.0 |
| Dust Collector | PP-26 | 2.0 |
| Dust Collector | PP-27 | 2.0 |
| Trona Calciner | NA-2 | 3.0 |
| Dust Collection | NA-3 | 10.0 |
| Cooler | NA-5 | 6.0 |
| Dust Collection | Mono 2 | 2.6 |
| Dust Collection | Mono 3 | 1.3 |
| Dust Collection | Mono 4 | 2.0 |
| Calciner | Mono 5 | 53.0 |
| Dryer | Mono 6 | 20.0 |
| Dust Collection | Mono 7 | 2.0 |
| Dust Collection | Mono 8 | 1.9 |
| Dust Collection | NS-2 | 0.5 |
| Calciner | NS-3 | 41.0 |
| Crusher | NS-4 | 1.0 |
| Dissolver | NS-5 | 2.7 |
| Dryer | NS-6 | 20.0 |
| Coal Dust Collection | NS-7 | 0.5 |
| Coal Dust Collection | NS-8 | 0.5 |
| Coal Dust Collection | NS-9 | 0.5 |
| Gas/Oil Boiler | PH-1 | 8.4 |
| Gas/Oil Boiler | PH-2 | 4.2 |
| Gas/Oil Boiler | PH-3 | 8.4 |

| | | |
|----------------|--------|------|
| Gas/Oil Boiler | Mono I | 7.5 |
| Coal Boiler | NS-1A | 45.0 |
| Coal Boiler | NS-1B | 45.0 |

(iv) Church and Dwight Company

| <u>Source Description</u> | | <u>Allowable Emission Rate</u> <u>lb/hr</u> |
|---------------------------|------|--|
| Soda Ash Unloading | SA | 3.0 |
| Throwing Box Scrubber | TB | 2.0 |
| Jeffrey Dryer Scrubber | JD | 3.0 |
| #1 Process Dryer | 1PD | 2.0 |
| #2 Process Dryer | 2PD | 5.0 |
| #3 Process Dryer | 3PD | 2.0 |
| #1 House Dust System | 1HDS | 2.0 |
| #2 House Dust System | 2HDS | 2.0 |
| #3 House Dust System | 3HDS | 2.0 |

(c) Fugitive Dust Controls. The following subparagraphs specify fugitive dust control measures required for the delineated activities and sources and the schedules for completion of such measures. If, at any time, the Administrator is satisfied that the applicable suspended particulate matter standards have been attained and will be maintained, uncompleted programs may be completed at the option of the owner of the facility if failure to complete same will not in the opinion of the Administrator adversely affect such attainment status.

(i) Allied Chemical, Green River

Unpaved Roads – Pave all roads in facility area that encounter frequent traffic and maintain such roads in a clean condition through the use of a vacuum sweeper as required. Complete: November 30, 1980.

Distressed Area – Reclaim the distressed area outside the east fence or apply suitable soil binders. Complete: December 1, 1981.

Coal Stockpile – The active coal stockpile is to be enclosed or a dust suppression system installed and used during periods of activity. Complete: December 31, 1982.

Equipment Movement – Equipment movement around the periphery of the trona stockpile should be further reduced. Complete: June 1, 1979.

(ii) FMC Corporation

Stockpile – Installation and effective operation of the following abatement program elements is required to control excessive fugitive emissions from the coal

handling facilities.

(A) Dust collectors with pick-ups at the transfer points.

(B) A dust suppression spray system to apply wetting agents to coal being unloaded, transferred, reclaimed, crushed and handled.

(C) Rapid unloading railroad cars.

(D) Use of counter weighted hood-type doors on the coal stacker.

Ore Stockpile – Install variable height booms so that the free fall distance of the ore is held to a minimum and install shroud (wind shield) to contain the ore as much as possible after it drops from the end of the boom. Complete: Sesqui Areas – January 1, 1981; Mono Areas – April 1, 1981.

Loadout Facilities – The mono loadout facilities are to be equipped with hoods around product chutes of adequate size to cap hatches of slot top or hatch top rail cars. The resultant dust generated due to displacement shall be aspirated to adequate dust collectors. The above requirements also apply to any truck bulk product loadout facilities. Complete: July 1, 1982.

Unpaved Roads – All unpaved roads that encounter frequent traffic in the facility area shall be paved and maintained in a clean condition through the use of a vacuum sweeper as required. Infrequently traveled roads are to be treated with oil or other suitable dust suppressants. Complete: October 1, 1980.

Overflow Chutes – Overflow or spillover chutes which discharge in the open, are to be eliminated or emptied into closed containers. Chutes for housekeeping purposes are to be eliminated and replaced with a vacuum dust system that utilizes a dust collector. Complete: October 1, 1980.

(iii) Stauffer Chemical, Green River

Ore Stockpile – Install and utilize a variable height boom so that the free fall distance of the ore is held to a minimum. A shroud (wind shield) to contain the ore as much as possible after it drops from the end of the boom is to be installed and utilized. Complete: July 1981.

Product Loadout – Rail loadout facilities are to be equipped with hoods around product chutes of adequate size to cap hatches of slot and portal top rail cars. The resultant dust generated due to displacement should be aspirated to adequate dust collectors. The above requirements will also apply to any truck bulk product loadout facilities. Maintenance or redesigning of existing baghouse collectors will also be necessary at these facilities. Complete: September 1982.

Product Handling and Storage – Product silo vents are to be equipped with dust collectors. Proper maintenance and/or redesign of existing dust collectors is also required in this area. Complete: September 1982.

Crusher Area – The removing of accumulated dust from crusher building by sweeping or dumping the material outside the building is to be eliminated. Housekeeping chores in this area as well as other areas are to be accomplished by the use of a vacuum system and dust collector. Existing baghouse collectors are to be properly maintained and if necessary other control measures installed and utilized at all transfer points in and around the crusher area. Complete: September 1982.

Overflow Chutes – Overflow or spillover chutes which discharge in the open are to be eliminated or emptied into closed containers. Complete: March 1979.

Unpaved Roads – All roads within the facility area that encounter frequent traffic are to be paved and maintained in a clean condition through the use of a vacuum sweeper as required. All other less frequently used roads are to be treated with oil or other suitable dust suppressants. Complete: September 1982.

Distressed Areas – Distressed areas to the south of the facility which contain distressed product piles and tailing pond dredgings are to be reclaimed and treated with dust suppressants. Complete: September 1979.

Section 3. Conformity of general federal actions to state implementation plans.

(a) Prohibition.

(i) No department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to an applicable implementation plan.

(ii) A Federal agency must make a determination that a Federal action conforms to the applicable implementation plan in accordance with the requirements of this section before the action is taken.

(iii) [Reserved]

(iv) Notwithstanding any provision of this section, a determination that an action is in conformance with the applicable implementation plan does not exempt the action from any other requirements of the applicable implementation plan, the National Environmental Policy Act (NEPA), or the CAA.

(v) If an action would result in emissions originating in more than one nonattainment or maintenance area, the conformity must be evaluated for each area separately.

(b) Definitions. Terms used but not defined in this section shall have the meaning given them by the CAA and EPA's regulations (40 CFR Chapter I), in that order of priority.

“Affected Federal land manager” means the Federal agency or the Federal official charged with direct responsibility for management of an area designated Class I under the CAA (42 U.S.C. 7472) that is located within 100 km of the proposed Federal action.

“Applicability analysis” is the process of determining if your Federal action must be supported by a conformity determination.

“Applicable implementation plan or applicable SIP” means the portion (or portions) of the SIP or most recent revision thereof, which has been approved under section 110(k) of the CAA, or promulgated under section 110(c) of the CAA (Federal implementation plan), or a plan promulgated or approved pursuant to section 301(d) of the CAA (Tribal implementation plan or TIP) and which implements the relevant requirements of the CAA.

“Areawide air quality modeling analysis” means an assessment on a scale that includes the entire nonattainment or maintenance area which uses an air quality dispersion model or photochemical grid model to determine the effects of emissions on air quality, for example, an assessment using EPA's community multi-scale air quality (CMAQ) modeling system.

“CAA” means the Clean Air Act, as amended.

“Cause or contribute to a new violation” means a Federal action that:

(i) Causes a new violation of a national ambient air quality standard (NAAQS) at a location in a nonattainment or maintenance area which would otherwise not be in violation of the standard during the future period in question if the Federal action were not taken; or

(ii) Contributes, in conjunction with other reasonably foreseeable actions, to a new violation of a NAAQS at a location in a nonattainment or maintenance area in a manner that would increase the frequency or severity of the new violation.

“Caused by”, as used in the terms “direct emissions” and “indirect emissions,” means emissions that would not otherwise occur in the absence of the Federal action.

“Confidential business information (CBI)” means information that has been determined by a Federal agency, in accordance with its applicable regulations, to be a trade secret, or commercial or financial information obtained from a person and privileged or confidential and is exempt from required disclosure under the Freedom of

Information Act (5 U.S.C. 552(b)(4)).

“Conformity determination” is the evaluation (made after an applicability analysis is completed) that a Federal action conforms to the applicable implementation plan and meets the requirements of this section.

“Conformity evaluation” is the entire process from the applicability analysis through the conformity determination that is used to demonstrate that the Federal action conforms to the requirements of this section.

“Continuing program responsibility” means a Federal agency has responsibility for emissions caused by:

(i) Actions it takes itself; or

(ii) Actions of non-Federal entities that the Federal agency, in exercising its normal programs and authorities, approves, funds, licenses or permits, provided the agency can impose conditions on any portion of the action that could affect the emissions.

“Continuous program to implement” means that the Federal agency has started the action identified in the plan and does not stop the actions for more than an 18-month period, unless it can demonstrate that such a stoppage was included in the original plan.

“Criteria pollutant or standard” means any pollutant for which there is established a NAAQS at 40 CFR part 50.

“Direct emissions” means those emissions of a criteria pollutant or its precursors that are caused or initiated by the Federal action and originate in a nonattainment or maintenance area and occur at the same time and place as the action and are reasonably foreseeable.

“Emergency” means a situation where extremely quick action on the part of the Federal agencies involved is needed and where the timing of such Federal activities makes it impractical to meet the requirements of this section, such as natural disasters like hurricanes or earthquakes, civil disturbances such as terrorist acts and military mobilizations.

“Emissions budgets” are those portions of the applicable SIP’s projected emission inventories that describe the levels of emissions (mobile, stationary, area, etc.) that provide for meeting reasonable further progress milestones, attainment, and/or maintenance for any criteria pollutant or its precursors.

“Emission inventory” means a listing of information on the location, type of source, type and quantity of pollutant emitted as well as other parameters of the emissions.

“Emissions offsets”, for purposes of Subsection (h), are emissions reductions which are quantifiable, consistent with the applicable SIP attainment and reasonable further progress demonstrations, surplus to reductions required by, and credited to, other applicable SIP provisions, enforceable at both the State and Federal levels, and permanent within the timeframe specified by the program.

“EPA” means the U.S. Environmental Protection Agency.

“Federal action” means any activity engaged in by a department, agency, or instrumentality of the Federal government, or any activity that a department, agency or instrumentality of the Federal government supports in any way, provides financial assistance for, licenses, permits, or approves, other than activities related to transportation plans, programs, and projects developed, funded, or approved under Title 23 U.S.C. or the Federal Transit Act (49 U.S.C. 1601 *et seq.*). Where the Federal action is a permit, license, or other approval for some aspect of a non-Federal undertaking, the relevant activity is the part, portion, or phase of the non-Federal undertaking that requires the Federal permit, license, or approval.

“Federal agency” means, for purposes of this section, a Federal department, agency, or instrumentality of the Federal government.

“Increase the frequency or severity of any existing violation of any standard in any area” means to cause a nonattainment area to exceed a standard more often or to cause a violation at a greater concentration than previously existed and/or would otherwise exist during the future period in question, if the project were not implemented.

“Indirect emissions” means those emissions of a criteria pollutant or its precursors:

- (i) That are caused or initiated by the Federal action and originate in the same nonattainment or maintenance area but occur at a different time or place as the action;
- (ii) That are reasonably foreseeable;
- (iii) That the Federal agency can practically control; and
- (iv) For which the Federal agency has continuing program responsibility.

For the purposes of this definition, even if a Federal licensing, rulemaking or other approving action is a required initial step for a subsequent activity that causes emissions, such initial steps do not mean that a Federal agency can practically control any resulting emissions.

“Local air quality modeling analysis” means an assessment of localized impacts

on a scale smaller than the entire nonattainment or maintenance area, including, for example, congested roadways on a Federal facility, which uses an air quality dispersion model (e.g., Industrial Source Complex Model or Emission and Dispersion Model System) to determine the effects of emissions on air quality.

“Maintenance area” means an area that was designated as nonattainment and has been re-designated in 40 CFR part 81 to attainment, meeting the provisions of section 107(d)(3)(E) of the CAA and has a maintenance plan approved under section 175A of the CAA.

“Maintenance plan” means a revision to the applicable SIP, meeting the requirements of section 175A of the CAA.

“Metropolitan Planning Organization (MPO)” means the policy board of an organization created as a result of the designation process in 23 U.S.C. 134(d).

“Milestone” has the meaning given in sections 182(g)(1) and 189(c)(1) of the CAA.

“Mitigation measure” means any method of reducing emissions of the pollutant or its precursor taken at the location of the Federal action and used to reduce the impact of the emissions of that pollutant caused by the action.

“National ambient air quality standards (NAAQS)” are those standards established pursuant to section 109 of the CAA and include standards for carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO₂), ozone, particulate matter (PM₁₀ and PM_{2.5}), and sulfur dioxide (SO₂).

“NEPA” is the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 et seq.).

“Nonattainment area (NAA)” means an area designated as nonattainment under section 107 of the CAA and described in 40 CFR part 81.

“Precursors of a criteria pollutant” are:

(i) For ozone, nitrogen oxides (NO_x), unless an area is exempted from NO_x requirements under section 182(f) of the CAA, and volatile organic compounds (VOC).

(ii) For PM₁₀, those pollutants described in the PM₁₀ nonattainment area applicable SIP as significant contributors to the PM₁₀ levels.

(iii) For PM_{2.5}:

(A) Sulfur dioxide (SO₂) in all PM_{2.5} nonattainment and

maintenance areas,

(B) Nitrogen oxides in all PM_{2.5} nonattainment and maintenance areas unless both the State and EPA determine that it is not a significant precursor, and

(C) Volatile organic compounds (VOC) and ammonia (NH₃) only in PM_{2.5} nonattainment or maintenance areas where either the State or EPA determines that they are significant precursors.

“Reasonably foreseeable emissions” are projected future direct and indirect emissions that are identified at the time the conformity determination is made; the location of such emissions is known and the emissions are quantifiable as described and documented by the Federal agency based on its own information and after reviewing any information presented to the Federal agency.

“Regional water and/or wastewater projects” include construction, operation, and maintenance of water or wastewater conveyances, water or wastewater treatment facilities, and water storage reservoirs which affect a large portion of a nonattainment or maintenance area.

“Restricted information” is information that is privileged or that is otherwise protected from disclosure pursuant to applicable statutes, Executive Orders, or regulations. Such information includes, but is not limited to: Classified national security information, protected critical infrastructure information, sensitive security information, and proprietary business information.

“Take or start the Federal action” means the date that the Federal agency signs or approves the permit, license, grant or contract or otherwise physically begins the Federal action that requires a conformity evaluation under this section.

“Total of direct and indirect emissions” means the sum of direct and indirect emissions increases and decreases caused by the Federal action; i.e., the “net” emissions considering all direct and indirect emissions. The portion of emissions which are exempt or presumed to conform under Subsections (c)(iii), (iv), (v), or (vi) are not included in the “total of direct and indirect emissions.” The “total of direct and indirect emissions” includes emissions of criteria pollutants and emissions of precursors of criteria pollutants.

(c) Applicability.

(i) Conformity determinations for Federal actions related to transportation plans, programs, and projects developed, funded, or approved under Title 23 U.S.C. or the Federal Transit Act (49 U.S.C. 1601 et seq.) must meet the procedures and criteria of Chapter 8, Section 4, in lieu of the procedures set forth in this section.

(ii) For Federal actions not covered by paragraph (i) of this subsection, a conformity determination is required for each criteria pollutant or precursor where the

total of direct and indirect emissions of the criteria pollutant or precursor in a nonattainment or maintenance area caused by a Federal action would equal or exceed any of the rates in paragraphs (ii)(A) or (B) of this subsection.

(A) For purposes of paragraph (ii) of this subsection, the following rates apply in nonattainment areas (NAAs):

| | <u>Tons/Year</u> |
|--|------------------|
| Ozone (VOCs or NO _x): | |
| Serious NAAs | 50 |
| Severe NAAs | 25 |
| Extreme NAAs | 10 |
| Other ozone NAAs outside an ozone transport region | 100 |
| Other ozone NAAs inside an ozone transport region: | |
| VOC | 50 |
| NO _x | 100 |
| Carbon monoxide: | |
| All NAAs | 100 |
| SO ₂ or NO ₂ : | |
| All NAAs | 100 |
| PM ₁₀ : | |
| Moderate NAAs | 100 |
| Serious NAAs | 70 |
| PM _{2.5} : | |
| Direct emissions | 100 |
| SO ₂ | 100 |
| NO _x (unless determined not to be significant precursors) | 100 |
| VOC or ammonia (if determined to be significant precursors) | 100 |
| Pb: | |
| All NAAs | 25 |

(B) For purposes of paragraph (ii) of this subsection, the following rates apply in maintenance areas:

| | <u>Tons/Year</u> |
|--|------------------|
| Ozone (NO _x , SO ₂ or NO ₂): | |
| All Maintenance Areas | 100 |
| Ozone (VOCs): | |
| Maintenance areas inside an ozone transport region | 50 |
| Maintenance areas outside an ozone transport region | 100 |

| | | |
|---------------------|--|-----|
| Carbon monoxide: | | |
| | All maintenance areas | 100 |
| PM ₁₀ : | | |
| | All maintenance areas | 100 |
| PM _{2.5} : | | |
| | Direct emissions | 100 |
| | SO ₂ | 100 |
| | NO _x (unless determined not to be significant precursors) | 100 |
| | VOC or ammonia (if determined to be significant precursors) | 100 |
| Pb: | | |
| | All maintenance areas | 25 |

(iii) The requirements of this section shall not apply to the following Federal actions:

(A) Actions where the total of direct and indirect emissions are below the emissions levels specified in paragraph (ii) of this subsection.

(B) Actions which would result in no emissions increase or an increase in emissions that is clearly de minimus:

(I) Judicial and legislative proceedings.

(II) Continuing and recurring activities such as permit renewals where activities conducted will be similar in scope and operation to activities currently being conducted.

(III) Rulemaking and policy development and issuance.

(IV) Routine maintenance and repair activities, including repair and maintenance of administrative sites, roads, trails, and facilities.

(V) Civil and criminal enforcement activities, such as investigations, audits, inspections, examinations, prosecutions, and the training of law enforcement personnel.

(VI) Administrative actions such as personnel actions, organization changes, debt management or collection, cash management, internal agency audits, program budget proposals, and matters relating to the administration and collection of taxes, duties and fees.

(VII) The routine, recurring transportation of material and personnel.

(VIII) Routine movement of mobile assets, such as ships and aircraft, in home port reassignments and stations (when no new support facilities or personnel are required) to perform as operational groups and/or for repair or overhaul.

(IX) Maintenance dredging and debris disposal where no new depths are required, applicable permits are secured, and disposal will be at an approved disposal site.

(X) Actions, such as the following, with respect to existing structures, properties, facilities and lands where future activities conducted will be similar in scope and operation to activities currently being conducted at the existing structures, properties, facilities, and lands; for example, relocation of personnel, disposition of federally-owned existing structures, properties, facilities, and lands, rent subsidies, operation and maintenance cost subsidies, the exercise of receivership or conservatorship authority, assistance in purchasing structures, and the production of coins and currency.

(XI) The granting of leases, licenses such as for exports and trade, permits, and easements where activities conducted will be similar in scope and operation to activities currently being conducted.

(XII) Planning, studies, and provision of technical assistance.

(XIII) Routine operation of facilities, mobile assets and equipment.

(XIV) Transfers of ownership, interests, and titles in land, facilities, and real and personal properties, regardless of the form or method of the transfer.

(XV) The designation of empowerment zones, enterprise communities, or viticultural areas.

(XVI) Actions by any of the Federal banking agencies or the Federal Reserve Banks, including actions regarding charters, applications, notices, licenses, the supervision or examination of depository institutions or depository institution holding companies, access to the discount window, or the provision of financial services to banking organizations or to any department, agency or instrumentality of the United States.

(XVII) Actions by the Board of Governors of the Federal Reserve System or any Federal Reserve Bank necessary to effect monetary or exchange rate policy.

(XVIII) Actions that implement a foreign affairs function of the United States.

(XIX) Actions (or portions thereof) associated with transfers of land, facilities, title, and real properties through an enforceable contract or lease agreement where the delivery of the deed is required to occur promptly after a specific, reasonable condition is met, such as promptly after the land is certified as meeting the requirements of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and where the Federal agency does not retain continuing authority to control emissions associated with the lands, facilities, title, or real properties.

(XX) Transfers of real property, including land, facilities, and related personal property from a Federal entity to another Federal entity and assignments of real property, including land, facilities, and related personal property from a Federal entity to another Federal entity for subsequent deeding to eligible applicants.

(XXI) Actions by the Department of the Treasury to effect fiscal policy and to exercise the borrowing authority of the United States.

(XXII) Air traffic control activities and adopting approach, departure, and enroute procedures for aircraft operations above the mixing height specified in the applicable SIP. Where the applicable SIP does not specify a mixing height, the Federal agency can use the 3,000 feet above ground level as a default mixing height, unless the agency demonstrates that use of a different mixing height is appropriate because the change in emissions at and above that height caused by the Federal action is *de minimis*.

(C) Actions where the emissions are not reasonably foreseeable, such as the following:

(I) Initial Outer Continental Shelf lease sales which are made on a broad scale and are followed by exploration and development plans on a project level.

(II) Electric power marketing activities that involve the acquisition, sale and transmission of electric energy.

(D) Actions which implement a decision to conduct or carry out a conforming program such as prescribed burning actions which are consistent with a conforming land management plan.

(iv) Notwithstanding the other requirements of this section, a conformity determination is not required for the following Federal actions (or portion thereof):

(A) The portion of an action that includes major or minor new or modified stationary sources that require a permit under the new source review (NSR)

program (Section 110(a)(2)(C) and section 173 of the CAA) or the prevention of significant deterioration (PSD) program (Title I, part C of the CAA);

(B) Actions in response to emergencies which are typically commenced on the order of hours or days after the emergency and, if applicable, which meet the requirements of paragraph (v) of this subsection;

(C) Research, investigations, studies, demonstrations, or training (other than those exempted under paragraph (iii)(B) of this subsection), where no environmental detriment is incurred and/or, the particular action furthers air quality research, as determined by the State agency primarily responsible for the applicable SIP;

(D) Alteration and additions of existing structures as specifically required by new or existing applicable environmental legislation or environmental regulations (e.g., hush houses for aircraft engines and scrubbers for air emissions);

(E) Direct emissions from remedial and removal actions carried out under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and associated regulations to the extent such emissions either comply with the substantive requirements of the PSD/NSR permitting program or are exempted from other environmental regulation under the provisions of CERCLA and applicable regulations issued under CERCLA.

(v) Federal actions which are part of a continuing response to an emergency or disaster under paragraph (iv)(B) of this subsection and which are to be taken more than 6 months after the commencement of the response to the emergency or disaster under paragraph (iv)(B) of this subsection are exempt from the requirements of this section only if:

(A) The Federal agency taking the actions makes a written determination that, for a specified period not to exceed an additional 6 months, it is impractical to prepare the conformity analyses which would otherwise be required and the actions cannot be delayed due to overriding concerns for public health and welfare, national security interests and foreign policy commitments; or

(B) For actions which are to be taken after those actions covered by paragraph (v)(A) of this subsection, the Federal agency makes a new determination as provided in paragraph (v)(A) of this subsection and:

(I) Provides a draft copy of the written determinations required to affected EPA Regional office(s), the affected State(s) and/or air pollution control agencies, and any Federal recognized Indian tribal government in the nonattainment or maintenance area. Those organizations must be allowed 15 days from the beginning of the extension period to comment on the draft determination; and

(II) Within 30 days after making the determination, publish a notice of the determination by placing a prominent advertisement in a daily newspaper of general circulation in the area affected by the action.

(C) If additional actions are necessary in response to an emergency or disaster under paragraph (iv)(B) of this subsection beyond the specified time period in paragraph (v)(B) of this subsection, a Federal agency can make a new written determination as described in (v)(B) of this subsection for as many 6-month periods as needed, but in no case shall this exemption extend beyond three 6-month periods except where an agency:

(I) Provides information to EPA and the State stating that the conditions that gave rise to the emergency exemption continue to exist and how such conditions effectively prevent the agency from conducting a conformity evaluation.

(vi) Notwithstanding other requirements of this section, actions specified by individual Federal agencies that have met the criteria set forth in either paragraphs (vii)(A), (vii)(B), or (vii)(C) of this subsection and the procedures set forth in paragraph (viii) of this subsection are “presumed to conform”, except as provided in paragraph (x) of this subsection. Actions specified by individual Federal agencies as “presumed to conform” may not be used in combination with one another when the total direct and indirect emissions from the combination of actions would equal or exceed any of the rates specified in paragraphs (ii)(A) or (ii)(B) of this subsection.

(vii) The Federal agency must meet the criteria for establishing activities that are presumed to conform by fulfilling the requirements set forth in either paragraphs (vii)(A), (vii)(B), or (vii)(C) of this subsection:

(A) The Federal agency must clearly demonstrate using methods consistent with this section that the total of direct and indirect emissions from the type of activities which would be presumed to conform would not:

(I) Cause or contribute to any new violation of any standard in any area;

(II) Interfere with provisions in the applicable SIP for maintenance of any standard;

(III) Increase the frequency or severity of any existing violation of any standard in any area; or

(IV) Delay timely attainment of any standard or any required interim emission reductions or other milestones in any area including, where applicable, emission levels specified in the applicable SIP for purposes of:

progress;

(1.) A demonstration of reasonable further

(2.) A demonstration of attainment;

(3.) A maintenance plan; or

(B) The Federal agency must provide documentation that the total of direct and indirect emissions from such future actions would be below the emission rates for a conformity determination that are established in paragraph (ii) of this subsection, based, for example, on similar actions taken over recent years.

(C) The Federal agency must clearly demonstrate that the emissions from the type or category of actions and the amount of emissions from the action are included in the applicable SIP and the State, local, or tribal air quality agencies responsible for the SIP(s) provide written concurrence that the emissions from the actions along with all other expected emissions in the area will not exceed the emission budget in the SIP.

(viii) In addition to meeting the criteria for establishing exemptions set forth in paragraphs (vii)(A), (vii)(B), or (vii)(C) of this subsection, the following procedures must also be complied with to presume that activities will conform:

(A) The Federal agency must identify through publication in the Federal Register its list of proposed activities that are “presumed to conform” and the basis for the presumptions. The notice must clearly identify the type and size of the action that would be “presumed to conform” and provide criteria for determining if the type and size of action qualifies it for the presumption;

(B) The Federal agency must notify the appropriate EPA Regional Office(s), State and local air quality agencies and, where applicable, the agency designated under §174 of the CAA and the MPO and provide at least 30 days for the public to comment on the list of proposed activities “presumed to conform”. If the “presumed to conform” action has regional or national application (e.g., the action will cause emission increases in excess of the *de minimis* levels identified in paragraph (ii) of this subsection in more than one of EPA’s Regions), the Federal agency, as an alternative to sending it to EPA Regional Offices, can send the draft conformity determination to U.S. EPA, Office of Air Quality Planning and Standards;

(C) The Federal Agency must document its response to all the comments received and make the comments, response, and final list of activities available to the public upon request; and

(D) The Federal agency must publish the final list of such activities in the Federal Register.

(ix) Emissions from the following actions are “presumed to conform”:

(A) Actions at installations with facility-wide emission budgets meeting the requirements in Subsection (k) provided that the State has included the emission budget in the EPA-approved SIP and the emissions from the action along with all other emissions from the installation will not exceed the facility-wide emission budget.

(B) Prescribed fires conducted in accordance with a smoke management program (SMP) which meets the requirements of EPA’s Interim Air Quality Policy on Wildland and Prescribed Fires or an equivalent replacement EPA policy.

(C) Emissions for actions that the State identifies in the EPA-approved SIP as “presumed to conform”.

(x) Even though an action would otherwise be “presumed to conform” under paragraphs (vi) or (ix) of this subsection, an action shall not be “presumed to conform” and the requirements of Subsection (a), 40 CFR 93.151, Subsections (d) through (j) and Subsections (l) through (n) shall apply to the action if EPA or a third party shows that the action would:

(A) Cause or contribute to any new violation of any standard in any area;

(B) Interfere with provisions in the applicable SIP for maintenance of any standard;

(C) Increase the frequency or severity of any existing violation of any standard in any area; or

(D) Delay timely attainment of any standard or any required interim emissions reductions or other milestones in any area including, where applicable, emission levels specified in the applicable SIP for purposes of:

(I) A demonstration of reasonable further progress;

(II) A demonstration of attainment; or

(III) A maintenance plan.

(xi) The provisions of this section shall apply in all nonattainment and maintenance areas except conformity requirements for newly designated nonattainment areas are not applicable until 1 year after the effective date of the final nonattainment designation for each NAAQS and pollutant in accordance with section 176(c)(6) of the CAA.

(d) Federal Agency Conformity Responsibility. Any department, agency, or instrumentality of the Federal government taking an action subject to this section must make its own conformity determination consistent with the requirements of this section. In making its conformity determination, a Federal agency must follow the requirements in Subsections (e) through (j) and Subsections (l) through (o) and must consider comments from any interested parties. Where multiple Federal agencies have jurisdiction for various aspects of a project, a Federal agency may choose to adopt the analysis of another Federal agency or develop its own analysis in order to make its conformity determination.

(e) Reporting Requirements.

(i) A Federal agency making a conformity determination under Subsections (d) through (j) and Subsections (l) through (n) must provide to the appropriate EPA Regional Office(s), State and local air quality agencies, any federally-recognized Indian tribal government in the nonattainment or maintenance area, and, where applicable, affected Federal Land Managers, the agency designated under section 174 of the CAA and the MPO, a 30-day notice which describes the proposed action and the Federal agency's draft conformity determination on the action. If the action has multi-regional or national impacts (e.g., the action will cause emission increases in excess of the *de minimis* levels identified in Subsection (c)(ii) in three or more of EPA's Regions), the Federal agency, as an alternative to sending it to EPA Regional Offices, can provide the notice to EPA's Office of Air Quality Planning and Standards.

(ii) A Federal agency must notify the appropriate EPA Regional Office(s), State and local air quality agencies, any federally-recognized Indian tribal government in the nonattainment or maintenance area, and, where applicable, affected Federal Land Managers, the agency designated under section 174 of the Clean Air Act and the MPO, within 30 days after making a final conformity determination under this section.

(iii) The draft and final conformity determination shall exclude any restricted information or confidential business information. The disclosure of restricted information and confidential business information shall be controlled by the applicable laws, regulations, security manuals, or executive orders concerning the use, access, and release of such materials. Subject to applicable procedures to protect restricted information from public disclosure, any information or materials excluded from the draft or final conformity determination or supporting materials may be made available in a restricted information annex to the determination for review by Federal and State representatives who have received appropriate clearances to review the information.

(f) Public Participation.

(i) Upon request by any person regarding a specific Federal action, a Federal agency must make available, subject to the limitation in paragraph (v) of this section, for review its draft conformity determination under Subsection (d) with

supporting materials which describe the analytical methods and conclusions relied upon in making the applicability analysis and draft conformity determination.

(ii) A Federal agency must make public its draft conformity determination under Subsection (d) by placing a notice by prominent advertisement in a daily newspaper of general circulation in the area affected by the action and by providing 30 days for written public comment prior to taking any formal action on the draft determination. This comment period may be concurrent with any other public involvement, such as occurs in the NEPA process. If the action has multi-regional or national impacts (e.g., the action will cause emission increases in excess of the *de minimis* levels identified in Subsection (c)(ii) in three or more of EPA's Regions), the Federal agency, as an alternative to publishing separate notices, can publish a notice in the Federal Register.

(iii) A Federal agency must document its response to all the comments received on its draft conformity determination under Subsection (d) and make the comments and responses available, subject to the limitation in paragraph (v) of this subsection, upon request by any person regarding a specific Federal action, within 30 days of the final conformity determination.

(iv) A Federal agency must make public its final conformity determination under Subsection (d) for a federal action by placing a notice by prominent advertisement in a daily newspaper of general circulation in the area affected by the action within 30 days of the final conformity determination. If the action would have multi-regional or national impacts, the Federal agency, as an alternative, can publish the notice in the Federal Register.

(v) The draft and final conformity determination shall exclude any restricted information or confidential business information. The disclosure of restricted information and confidential business information shall be controlled by the applicable laws, regulations or executive orders concerning the release of such materials.

(g) Reevaluation of Conformity.

(i) Once a conformity determination is completed by a Federal agency, that determination is not required to be reevaluated if the agency has maintained a continuous program to implement the action; the determination has not lapsed as specified in paragraph (ii) of this subsection; or any modification to the action does not result in an increase in emissions above the levels specified in Subsection (c)(ii). If a conformity determination is not required for the action at the time the NEPA analysis is completed, the date of the finding of no significant impact (FONSI) for an Environmental Assessment, a record of decision (ROD) for an Environmental Impact Statement, or a categorical exclusion determination can be used as a substitute date for the conformity determination date.

(ii) The conformity status of a Federal action automatically lapses 5 years from the date a final conformity determination is reported under Subsection (e), unless the Federal action has been completed or a continuous program to implement the Federal action has commenced.

(iii) Ongoing Federal activities at a given site showing continuous progress are not new actions and do not require periodic redeterminations so long as such activities are within the scope of the final conformity determination reported under Section (e).

(iv) If the Federal agency originally determined through the applicability analysis that a conformity determination was not necessary because the emissions for the action were below the limits in Subsection (c)(ii) and changes to the action would result in the total emissions from the action being above the limits in Subsection (c)(ii), then the Federal agency must make a conformity determination.

(h) Criteria for Determining Conformity of General Federal Actions.

(i) An action required under Subsection (c) to have a conformity determination for a specific pollutant, will be determined to conform to the applicable SIP if, for each pollutant that exceeds the rates in Subsection (c)(ii), or otherwise requires a conformity determination due to the total of direct and indirect emissions from the action, the action meets the requirements of paragraph (iii) of this subsection, and meets any of the following requirements:

(A) For any criteria pollutant or precursor, the total of direct and indirect emissions from the action are specifically identified and accounted for in the applicable SIP's attainment or maintenance demonstration or reasonable further progress milestone or in a facility-wide emission budget included in a SIP in accordance with Subsection (k);

(B) For precursors of ozone, nitrogen dioxide, or PM, the total of direct and indirect emissions from the action are fully offset within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violations in the past, in the area with the Federal action) through a revision to the applicable SIP or a similarly enforceable measure that effects emissions reductions so that there is no net increase in emissions of that pollutant;

(C) For any directly-emitted criteria pollutant, the total of direct and indirect emissions from the action meets the requirements:

(I) Specified in paragraph (ii) of this subsection, based on areawide air quality modeling analysis and local air quality modeling analysis; or

(II) Meet the requirements of paragraph (i)(E) of this subsection and, for local air quality modeling analysis, the requirement of paragraph (ii) of this subsection;

(D) For CO or directly emitted PM₁₀:

(I) Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (ii) of this subsection, based on local air quality modeling analysis; or

(II) Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is appropriate and that a local air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (ii) of this subsection, based on areawide modeling, or meet the requirements of paragraph (i)(E) of this subsection; or

(E) For ozone or nitrogen dioxide, and for purposes of paragraphs (i)(C)(II) and (i)(D)(II) of this subsection, each portion of the action or the action as a whole meets any of the following requirements:

(I) Where EPA has approved a revision to the applicable implementation plan after the area was designated as nonattainment and the State makes a determination as provided in paragraph (i)(E)(I)(1.) of this subsection or where the State makes a commitment as provided in paragraph (i)(E)(I)(2.) of this subsection:

(1.) The total of direct and indirect emissions from the action (or portion thereof) is determined and documented by the State agency primarily responsible for the applicable SIP to result in a level of emissions which, together with all other emissions in the nonattainment (or maintenance) area, would not exceed the emissions budgets specified in the applicable SIP.

(2.) The total of direct and indirect emissions from the action (or portion thereof) is determined by the State agency responsible for the applicable SIP to result in a level of emissions which, together with all other emissions in the nonattainment (or maintenance) area, would exceed an emissions budget specified in the applicable SIP and the State Governor or the Governor's designee for SIP actions makes a written commitment to EPA which includes the following:

a. A specific schedule for adoption and submittal of a revision to the SIP which would achieve the needed emission reductions prior to the time emissions from the Federal action would occur;

b. Identification of specific measures for incorporation into the SIP which would result in a level of emissions which, together with

all other emissions in the nonattainment or maintenance area, would not exceed any emissions budget specified in the applicable SIP;

c. A demonstration that all existing applicable SIP requirements are being implemented in the area for the pollutants affected by the Federal action, and that local authority to implement additional requirements has been fully pursued;

d. A determination that the responsible Federal agencies have required all reasonable mitigation measures associated with their action; and

e. Written documentation including all air quality analyses supporting the conformity determination.

(3.) Where a Federal agency made a conformity determination based on a State's commitment under paragraph (i)(E)(I)(2.) of this subsection and the State has submitted a SIP to EPA covering the time period during which the emissions will occur or is scheduled to submit such a SIP within 18 months of the conformity determination, the State commitment is automatically deemed a call for a SIP revision by EPA under section 110(k)(5) of the CAA, effective on the date of the Federal conformity determination and requiring response within 18 months or any shorter time within which the State commits to revise the applicable SIP;

(4.) Where a Federal agency made a conformity determination based on a State commitment under paragraph (i)(E)(I)(2.) of this subsection and the State has not submitted a SIP covering the time period when the emissions will occur or is not scheduled to submit such a SIP within 18 months of the conformity determination, the State must, within 18 months, submit to EPA a revision to the existing SIP committing to include the emissions in the future SIP revision.

(II) The action (or portion thereof), as determined by the MPO, is specifically included in a current transportation plan and transportation improvement program which have been found to conform to the applicable SIP under Chapter 8, Section 4, or 40 CFR part 93, Subpart A;

(III) The action (or portion thereof) fully offsets its emissions within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violations in the past, in the area with the Federal action) through a revision to the applicable SIP or an equally enforceable measure that effects emissions reductions equal to or greater than the total of direct and indirect emissions from the action so that there is no net increase in emissions of that pollutant;

(IV) Where EPA has not approved a revision to the relevant SIP since the area was redesignated or reclassified, the total of direct and indirect

emissions from the action for the future years (described in Subsection (i)(iv)) do not increase emissions with respect to the baseline emissions:

(1.) The baseline emissions reflect the historical activity levels that occurred in the geographic area affected by the proposed Federal action during:

a. The most current calendar year with a complete emission inventory available before an area is designated unless EPA sets another year; or

b. The emission budget in the applicable SIP;

c. The year of the baseline inventory in the PM₁₀ applicable SIP;

(2.) The baseline emissions are the total of direct and indirect emissions calculated for the future years (described in Subsection (i)(iv)) using the historic activity levels (described in paragraph (i)(E)(IV)(1.) of this subsection) and appropriate emission factors for the future years; or

(V) Where the action involves regional water and/or wastewater projects, such projects are sized to meet only the needs of population projections that are in the applicable SIP.

(ii) The areawide and/or local air quality modeling analyses must:

(A) Meet the requirements in Subsection (i); and

(B) Show that the action does not:

(I) Cause or contribute to any new violation of any standard in any area; or

(II) Increase the frequency or severity of any existing violation of any standard in any area.

(iii) Notwithstanding any other requirements of this subsection, an action subject to this section may not be determined to conform to the applicable SIP unless the total of direct and indirect emissions from the action is in compliance or consistent with all relevant requirements and milestones contained in the applicable SIP, such as elements identified as part of the reasonable further progress schedules, assumptions specified in the attainment or maintenance demonstration, prohibitions, numerical emission limits, and work practice requirements.

(iv) Any analyses required under this subsection must be completed, and any mitigation requirements necessary for a finding of conformity must be identified before the determination of conformity is made.

(i) Procedures for Conformity Determinations of General Federal Actions.

(i) The analyses required under this section must be based on the latest planning assumptions.

(A) All planning assumptions must be derived from the estimates of population, employment, travel, and congestion most recently approved by the MPO, or other agency authorized to make such estimates, where available.

(B) Any revisions to these estimates used as part of the conformity determination, including projected shifts in geographic location or level of population, employment, travel, and congestion, must be approved by the MPO or other agency authorized to make such estimates for the urban area.

(ii) The analyses required under this section must be based on the latest and most accurate emission estimation techniques available as described below, unless such techniques are inappropriate. If such techniques are inappropriate, the Federal agency may obtain written approval from the appropriate EPA Regional Administrator for modification or substitution, of another technique on a case-by-case basis or, where appropriate, on a generic basis for a specific Federal agency program.

(A) For motor vehicle emissions, the most current version of the motor vehicle emissions model specified by EPA and available for use in the preparation or revision of SIPs in that State must be used for the conformity analysis as specified in paragraphs (ii)(A)(I) and (II) of this subsection:

(I) The EPA must publish in the Federal Register a notice of availability of any new motor vehicle emissions model; and

(II) A grace period of three months shall apply during which the motor vehicle emissions model previously specified by EPA as the most current version may be used unless EPA announces a longer grace period in the Federal Register. Conformity analyses for which the analysis was begun during the grace period or no more than 3 months before the Federal Register notice of availability of the latest emission model may continue to use the previous version of the model specified by EPA.

(B) For non-motor vehicle sources, including stationary and area source emissions, the latest emission factors specified by EPA in the “Compilation of Air Pollutant Emission Factors” (AP-42) must be used for the conformity analysis unless more accurate emission data are available, such as actual stack test data from stationary sources which are part of the conformity analysis.

(iii) The air quality modeling analyses required under this section must be based on the applicable air quality models, databases, and other requirements specified in the most recent version of the “Guideline on Air Quality Models” (Appendix W to 40 CFR part 51), unless:

(A) The guideline techniques are inappropriate, in which case the model may be modified or another model substituted on a case-by-case basis or, where appropriate, on a generic basis for a specific Federal agency program; and

(B) Written approval of the EPA Regional Administrator is obtained for any modification or substitution.

(iv) The analyses required under this section must be based on the total of direct and indirect emissions from the action and must reflect emission scenarios that are expected to occur under each of the following cases:

(A) The attainment year specified in the SIP, or if the SIP does not specify an attainment year, the latest attainment year possible under the CAA; or

(B) The last year for which emissions are projected in the maintenance plan;

(C) The year during which the total of direct and indirect emissions from the action is expected to be the greatest on an annual basis; and

(D) Any year for which the applicable SIP specifies an emissions budget.

(j) Mitigation of Air Quality Impacts.

(i) Any measures that are intended to mitigate air quality impacts must be identified and the process for implementation and enforcement of such measures must be described, including an implementation schedule containing explicit timelines for implementation.

(ii) Prior to determining that a Federal action is in conformity, the Federal agency making the conformity determination must obtain written commitments from the appropriate persons or agencies to implement any mitigation measures which are identified as conditions for making conformity determinations.

(iii) Persons or agencies voluntarily committing to mitigation measures to facilitate positive conformity determinations must comply with the obligations of such commitments.

(iv) In instances where the Federal agency is licensing, permitting or otherwise approving the action of another governmental or private entity, approval by the

Federal agency must be conditioned on the other entity meeting the mitigation measures set forth in the conformity determination.

(v) When necessary because of changed circumstances, mitigation measures may be modified so long as the new mitigation measures continue to support the conformity determination. Any proposed change in the mitigation measures is subject to the reporting requirements of Subsection (e) and the public participation requirements of Subsection (f).

(vi) Written commitments to mitigation measures must be obtained prior to a positive conformity determination and that such commitments must be fulfilled.

(vii) After a State revises its SIP and EPA approves that SIP revision, any agreements, including mitigation measures, necessary for a conformity determination will be both State and federally enforceable. Enforceability through the applicable SIP will apply to all persons who agree to mitigate direct and indirect emissions associated with a Federal action for a conformity determination.

(k) Conformity Evaluation for Federal Installations With Facility-Wide Emission Budgets.

(i) The State or local agency responsible for implementing and enforcing the SIP can in cooperation with Federal agencies or third parties authorized by the agency that operate installations subject to Federal oversight develop and adopt a facility-wide emission budget to be used for demonstrating conformity under Subsection (h)(i)(A). The facility-wide budget must meet the following criteria:

(A) Be for a set time period;

(B) Cover the pollutants or precursors of the pollutants for which the area is designated nonattainment or maintenance;

(C) Include specific quantities allowed to be emitted on an annual or seasonal basis;

(D) The emissions from the facility along with all other emissions in the area will not exceed the emission budget for the area;

(E) Include specific measures to ensure compliance with the budget, such as periodic reporting requirements or compliance demonstration, when the Federal agency is taking an action that would otherwise require a conformity determination;

(F) Be submitted to EPA as a SIP revision;

(G) The SIP revision must be approved by EPA.

(ii) The facility-wide budget developed and adopted in accordance with paragraph (i) of this subsection can be revised by following the requirements in paragraph (i) of this subsection.

(iii) Total direct and indirect emissions from Federal actions in conjunction with all other emissions subject to General Conformity from the facility that do not exceed the facility budget adopted pursuant to paragraph (i) of this subsection are “presumed to conform” to the SIP and do not require a conformity analysis.

(iv) If the total direct and indirect emissions from the Federal actions in conjunction with the other emissions subject to General Conformity from the facility exceed the budget adopted pursuant to paragraph (i) of this subsection, the action must be evaluated for conformity. A Federal agency can use the compliance with the facility-wide emissions budget as part of the demonstration of conformity, i.e., the agency would have to mitigate or offset the emissions that exceed the emission budget.

(v) If the SIP for the area includes a category for construction emissions, the negotiated budget can exempt construction emissions from further conformity analysis.

(l) Emissions Beyond the Time Period Covered by the SIP. If a Federal action would result in total direct and indirect emissions above the applicable thresholds which would be emitted beyond the time period covered by the SIP, the Federal agency can:

(i) Demonstrate conformity with the last emission budget in the SIP; or

(ii) Request the State to adopt an emissions budget for the action for inclusion in the SIP. The State must submit a SIP revision to EPA within 18 months either including the emissions in the existing SIP or establishing an enforceable commitment to include the emissions in future SIP revisions based on the latest planning assumptions at the time of the SIP revision. No such commitment by a State shall restrict a State’s ability to require RACT, RACM or any other control measures within the State’s authority to ensure timely attainment of the NAAQS.

(m) Timing of Offsets and Mitigation Measures.

(i) The emissions reductions from an offset or mitigation measure used to demonstrate conformity must occur during the same calendar year as the emission increases from the action except, as provided in paragraph (ii) of this subsection.

(ii) The State may approve emissions reductions in other years provided:

(A) The reductions are greater than the emission increases by the following ratios:

- (I) Extreme nonattainment areas 1.5:1
- (II) Severe nonattainment areas 1.3:1
- (III) Serious nonattainment areas 1.2:1
- (IV) Moderate nonattainment areas 1.15:1
- (V) All other areas 1.1:1

(B) The time period for completing the emissions reductions must not exceed twice the period of the emissions.

(C) The offset or mitigation measure with emissions reductions in another year will not:

(I) Cause or contribute to a new violation of any air quality standard;

(II) Increase the frequency or severity of any existing violation of any air quality standard; or

(III) Delay the timely attainment of any standard or any interim emissions reductions or other milestones in any area.

(iii) The approval by the State of an offset or mitigation measure with emissions reductions in another year does not relieve the State of any obligation to meet any SIP or CAA milestone or deadline. The approval of an alternate schedule for mitigation measures is at the discretion of the State, and they are not required to approve an alternate schedule.

(n) Inter-precursor Mitigation Measures and Offsets. Federal agencies must reduce the same type of pollutant as being increased by the Federal action except the State may approve offsets or mitigation measures of different precursors of the same criteria pollutant, if such trades are allowed by a State in a SIP approved NSR regulation, is technically justified, and has a demonstrated environmental benefit.

(o) Early Emission Reduction Credit Programs at Federal Facilities and Installation Subject to Federal Oversight.

(i) Federal facilities and installations subject to Federal oversight can, with the approval of the State agency responsible for the SIP in that area, create an early emissions reductions credit program. The Federal agency can create the emission reduction credits in accordance with the requirements in paragraph (ii) of this subsection and can use them in accordance with paragraph (iii) of this subsection.

(ii) Creation of Emission Reduction Credits.

(A) Emissions reductions must be quantifiable through the use of standard emission factors or measurement techniques. If non-standard factors or techniques to quantify the emissions reductions are used, the Federal agency must receive approval from the State agency responsible for the implementation of the SIP and from EPA's Regional Office. The emission reduction credits do not have to be quantified before the reduction strategy is implemented, but must be quantified before the credits are used in the General Conformity evaluation.

(B) The emission reduction methods must be consistent with the applicable SIP attainment and reasonable further progress demonstrations.

(C) The emissions reductions cannot be required by or credited to other applicable SIP provisions.

(D) Both the State and Federal air quality agencies must be able to take legal action to ensure continued implementation of the emission reduction strategy. In addition, private citizens must also be able to initiate action to ensure compliance with the control requirement.

(E) The emissions reductions must be permanent or the timeframe for the reductions must be specified.

(F) The Federal agency must document the emissions reductions and provide a copy of the document to the State air quality agency and the EPA Regional Office for review. The documentation must include a detailed description of the emission reduction strategy and a discussion of how it meets the requirements of paragraphs (ii)(A) through (E) of this subsection.

(iii) Use of Emission Reduction Credits. The emission reduction credits created in accordance with paragraph (ii) of this subsection can be used, subject to the following limitations, to reduce the emissions increase from a Federal action at the facility for the conformity evaluation.

(A) If the technique used to create the emission reduction is implemented at the same facility as the Federal action and could have occurred in conjunction with the Federal action, then the credits can be used to reduce the total direct and indirect emissions used to determine the applicability of the regulation as required in Subsection (c) and as offsets or mitigation measures required by Subsection (h).

(B) If the technique used to create the emission reduction is not implemented at the same facility as the Federal action or could not have occurred in conjunction with the Federal action, then the credits cannot be used to reduce the total direct and indirect emissions used to determine the applicability of the regulation as

required in Subsection (c), but can be used to offset or mitigate the emissions as required by Subsection (h).

(C) Emissions reductions credits must be used in the same year in which they are generated.

(D) Once the emission reduction credits are used, they cannot be used as credits for another conformity evaluation. However, unused credits from a strategy used for one conformity evaluation can be used for another conformity evaluation as long as the reduction credits are not double counted.

(E) Federal agencies must notify the State air quality agency responsible for the implementation of the SIP and EPA Regional Office when the emission reduction credits are being used.

Section 4. **Transportation conformity.**

(a) Definitions. Terms used but not defined in this subpart shall have the meaning given them by the CAA, titles 23 and 49 U.S.C., other Environmental Protection Agency (EPA) regulations, or other DOT regulations, in that order of priority.

“Applicable implementation plan” is defined in §302(q) of the CAA and means the portion (or portions) of the implementation plan, or most recent revision thereof, which has been approved under §110, or promulgated under §110(c), or promulgated or approved pursuant to regulations promulgated under §301(d) and which implements the relevant requirements of the CAA.

“CAA” means the Clean Air Act, as amended.

“Cause or contribute to a new violation” for a project means:

(A) To cause or contribute to a new violation of a standard in the area substantially affected by the project or over a region which would otherwise not be in violation of the standard during the future period in question, if the project were not implemented, or

(B) To contribute to a new violation in a manner that would increase the frequency or severity of a new violation of a standard in such area.

“Control strategy implementation plan revision” is the applicable implementation plan which contains specific strategies for controlling the emissions of and reducing ambient levels of pollutants in order to satisfy CAA requirements for demonstrations of reasonable further progress and attainment (CAA §§182(b)(1), 182(c)(2)(A), 182(c)(2)(B), 187(a)(7), 189(a)(1)(B), and 189(b)(1)(A); and §§192(a) and 192(b), for nitrogen dioxide).

“Control strategy period” with respect to particulate matter less than 10 microns in diameter (PM₁₀), carbon monoxide (CO), nitrogen dioxide (NO₂), and/or ozone precursors (volatile organic compounds and oxides of nitrogen), means that period of time after EPA approves control strategy implementation plan revisions containing strategies for controlling PM₁₀, NO₂, CO, and/or ozone, as appropriate. This period ends when a State submits and EPA approves a request under §107(d) of the CAA for redesignation to an attainment area.

“Design concept” means the type of facility identified by the project, e.g., freeway, expressway, arterial highway, grade-separated highway, reserved right-of-way rail transit, mixed-traffic rail transit, exclusive busway, etc.

“Design scope” means the design aspects which will affect the proposed facility’s impact on regional emissions, usually as they relate to vehicle or person carrying capacity and control, e.g., number of lanes or tracks to be constructed or added, length of project, signalization, access control including approximate number and location of interchanges, preferential treatment for high-occupancy vehicles, etc.

“Division” means the Air Quality Division of the Department of Environmental Quality.

“DOT” means the United States Department of Transportation.

“EPA” means the Environmental Protection Agency.

“FHWA” means the Federal Highway Administration of DOT.

“FHWA/FTA project” for the purpose of this subpart, is any highway or transit project which is proposed to receive funding assistance and approval through the Federal-Aid Highway program or the Federal mass transit program, or requires Federal Highway Administration (FHWA) or Federal Transit Administration (FTA) approval for some aspect of the project, such as connection to an interstate highway or deviation from applicable design standards on the interstate system.

“FTA” means the Federal Transit Administration of DOT.

“Forecast period” with respect to a transportation plan is the period covered by the transportation plan pursuant to 23 CFR part 450.

“Highway project” is an undertaking to implement or modify a highway facility or highway-related program. Such an undertaking consists of all required phases necessary for implementation. For analytical purposes, it must be defined sufficiently to:

(A) Connect logical termini and be of sufficient length to address environmental matters on a broad scope;

(B) Have independent utility or significance, i.e., be usable and be a reasonable expenditure even if no additional transportation improvements in the area are made; and

(C) Not restrict consideration of alternatives for other reasonably foreseeable transportation improvements.

“Horizon year” is a year for which the transportation plan describes the envisioned transportation system according to Chapter 8, Section 4(f).

“Hot-spot analysis” is an estimation of likely future localized CO and PM₁₀ pollutant concentrations and a comparison of those concentrations to the national ambient air quality standards. Pollutant concentrations to be estimated should be based on the total emissions burden which may result from the implementation of a single, specific project, summed together with future background concentrations (which can be estimated using the ratio of future to current traffic multiplied by the ratio of future to current emission factors) expected in the area. The total concentration must be estimated and analyzed at appropriate receptor locations in the area substantially affected by the project. Hot-spot analysis assesses impacts on a scale smaller than the entire nonattainment or maintenance area, including, for example, congested roadway intersections and highways or transit terminals, and uses an air quality dispersion model to determine the effects of emissions on air quality.

“Incomplete data area” means any ozone nonattainment area which EPA has classified, in 40 CFR part 81, as an incomplete data area.

“Increase the frequency or severity” means to cause a location or region to exceed a standard more often or to cause a violation at a greater concentration than previously existed and/or would otherwise exist during the future period in question, if the project were not implemented.

“ISTEA” means the Intermodal Surface Transportation Efficiency Act of 1991.

“Maintenance area” means any geographic region of the United States previously designated nonattainment pursuant to the CAA Amendments of 1990 and subsequently redesignated to attainment subject to the requirement to develop a maintenance plan under §175A of the CAA, as amended.

“Maintenance period” with respect to a pollutant or pollutant precursor means that period of time beginning when a State submits and EPA approves a request under §107(d) of the CAA for redesignation to an attainment area, and lasting for 20 years, unless the applicable implementation plan specifies that the maintenance period shall last for more than 20 years.

“Metropolitan planning organization (MPO)” is that organization designated as being responsible, together with the State, for conducting the continuing, cooperative,

and comprehensive planning process under 23 U.S.C. 134 and 49 U.S.C. 1607. It is the forum for cooperative transportation decision-making.

“Milestone” has the meaning given in §182(g)(1) and §189(c) of the CAA. A milestone consists of an emissions level and the date on which it is required to be achieved.

“Motor vehicle emissions budget” is that portion of the total allowable emissions defined in a revision to the applicable implementation plan (or in an implementation plan revision which was endorsed by the Governor or his or her designee, subject to a public hearing, and submitted to EPA, but not yet approved by EPA) for a certain date for the purpose of meeting reasonable further progress milestones or attainment or maintenance demonstrations, for any criteria pollutant or its precursors, allocated by the applicable implementation plan to highway and transit vehicles. The applicable implementation plan for an ozone nonattainment area may also designate a motor vehicle emissions budget for oxides of nitrogen (NO_x) for a reasonable further progress milestone year if the applicable implementation plan demonstrates that this NO_x budget will be achieved with measures in the implementation plan (as an implementation plan must do for VOC milestone requirements). The applicable implementation plan for an ozone nonattainment area includes a NO_x budget if NO_x reductions are being substituted for reductions in volatile organic compounds in milestone years required for reasonable further progress.

“National ambient air quality standards (NAAQS)” are those standards established pursuant to §109 of the CAA.

“NEPA” means the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 et seq.).

“NEPA process completion”, for the purposes of this subpart, with respect to FHWA or FTA, means the point at which there is a specific action to make a determination that a project is categorically excluded, to make a Finding of No Significant Impact, or to issue a record of decision on a Final Environmental Impact Statement under NEPA.

“Nonattainment area” means any geographic region of the United States which has been designated as nonattainment under §107 of the CAA for any pollutant for which a national ambient air quality standard exists.

“Not classified area” means any carbon monoxide nonattainment area which EPA has not classified as either moderate or serious.

“Phase II of the interim period” with respect to a pollutant or pollutant precursor, means that period of time after the effective date of this rule, lasting until the earlier of the following:

(A) Submission to EPA of the relevant control strategy implementation plan revisions which have been endorsed by the Governor (or his or her designee) and have been subject to a public hearing, or

(B) The date that the Clean Air Act requires relevant control strategy implementation plans to be submitted to EPA, provided EPA has made a finding of the State's failure to submit any such plans and the State, MPO, and DOT have received notice of such finding of the State's failure to submit any such plans. The precise end of Phase II of the interim period is defined in Chapter 8, Section 4(bb).

“Project” means a highway project or transit project.

“Recipient of funds designated under Title 23 U.S.C. or the Federal Transit Act” means any agency at any level of State, county, city, or regional government that routinely receives Title 23 U.S.C. or Federal Transit Act funds to construct FHWA/FTA projects, operate FHWA/FTA projects or equipment, purchase equipment, or undertake other services or operations via contracts or agreements. This definition does not include private landowners or developers, or contractors or entities that are only paid for services or products created by their own employees.

“Regionally significant project” means a transportation project (other than an exempt project) that is on a facility which serves regional transportation needs (such as access to and from the area outside of the region, major activity centers in the region, major planned developments such as new retail malls, sports complexes, etc., or transportation terminals as well as most terminals themselves) and would normally be included in the modeling of a metropolitan area's transportation network, including at a minimum all principal arterial highways, all fixed guideway transit facilities that offer an alternative to regional highway travel and any project that the Division identifies as having the potential to affect air quality on a regional basis, after consultation in accordance with Chapter 8, Section 4(e).

“Rural transport ozone nonattainment area” means an ozone nonattainment area that does not include, and is not adjacent to, any part of a Metropolitan Statistical Area, or, where one exists, a Consolidated Metropolitan Statistical Area (as defined by the United States Bureau of the Census) and is classified under Clean Air Act §182(h) as a rural transport area.

“Standard” means a national ambient air quality standard.

“Submarginal area” means any ozone nonattainment area which EPA has classified as submarginal in 40 CFR part 81.

“Title 23 U.S.C.” means Title 23 of the United States Code.

“Transit” is mass transportation by bus, rail, or other conveyance which provides general or special service to the public on a regular and continuing basis. It does not include school buses or charter or sightseeing services.

“Transit project” is an undertaking to implement or modify a transit facility or transit-related program, purchase transit vehicles or equipment, or provide financial assistance for transit operations. It does not include actions that are solely within the jurisdiction of local transit agencies, such as changes in routes, schedules, or fares. It may consist of several phases. For analytical purposes, it must be defined inclusively enough to:

(A) Connect logical termini and be of sufficient length to address environmental matters on a broad scope;

(B) Have independent utility or independent significance, i.e., be a reasonable expenditure even if no additional transportation improvements in the area are made; and

(C) Not restrict consideration of alternatives for other reasonably foreseeable transportation improvements.

“Transitional area” means any ozone nonattainment area which EPA has classified as transitional in 40 CFR part 81.

“Transitional period” with respect to a pollutant or pollutant precursor means that period of time which begins after submission to EPA of the relevant control strategy implementation plan which has been endorsed by the Governor (or his or her designee) and has been subject to a public hearing. The transitional period lasts until EPA takes final approval or disapproval action on the control strategy implementation plan submission or finds it to be incomplete. The precise beginning and end of the transitional period is defined in Chapter 8, Section 4(bb).

“Transportation control measure (TCM)” is any measure that is specifically identified and committed to in the applicable implementation plan that is either one of the types listed in §108 of the CAA, or any other measure for the purpose of reducing emissions or concentrations of air pollutants from transportation sources by reducing vehicle use or changing traffic flow or congestion conditions. Notwithstanding the above, vehicle technology-based, fuel-based, and maintenance-based measures which control the emissions from vehicles under fixed traffic conditions are not TCMs for the purposes of this subpart.

“Transportation improvement program (TIP)” means a staged, multiyear, intermodal program of transportation projects covering a metropolitan planning area which is consistent with the metropolitan transportation plan, and developed pursuant to 23 CFR part 450.

“Transportation plan” means the official intermodal metropolitan transportation plan that is developed through the metropolitan planning process for the metropolitan planning area, developed pursuant to 23 CFR part 450.

“Transportation project” is a highway project or a transit project.

“WYDOT” means the Wyoming Department of Transportation.

(b) Applicability.

(i) Action Applicability.

(A) Except as provided for in paragraph (iii) of this section or Chapter 8, Section 4(hh), conformity determinations are required for:

(I) The adoption, acceptance, approval or support of transportation plans developed pursuant to 23 CFR part 450 or 49 CFR part 613 by an MPO or DOT;

(II) The adoption, acceptance, approval or support of TIPs developed pursuant to 23 CFR part 450 or 49 CFR part 613 by an MPO or DOT; and

(III) The approval, funding, or implementation of FHWA/FTA projects.

(B) Conformity determinations are not required under this rule for individual projects which are not FHWA/FTA projects. However, Chapter 8, Section 4(cc) applies to such projects if they are regionally significant.

(ii) Geographic Applicability.

(A) The provisions of this subpart shall apply in all nonattainment and maintenance areas for transportation-related criteria pollutants for which the area is designated nonattainment or has a maintenance plan.

(B) The provisions of this subpart apply with respect to emissions of the following criteria pollutants: ozone, carbon monoxide, nitrogen dioxide, and particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM₁₀).

(C) The provisions of this subpart apply with respect to emissions of the following precursor pollutants:

(I) Volatile organic compounds and nitrogen oxides in ozone areas (unless the Administrator determines under §182(f) of the CAA that additional reductions of NO_x would not contribute to attainment);

(II) Nitrogen oxides in nitrogen dioxide areas; and

(III) Volatile organic compounds, nitrogen oxides, and PM₁₀ in PM₁₀ areas if:

(1.) During the interim period, the EPA Regional Administrator or the Director of the State air agency has made a finding (including a finding as part of an applicable implementation plan or a submitted implementation revision) that transportation-related precursor emissions within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT; or

(2.) During the transitional, control strategy, and maintenance periods, the applicable implementation plan (or implementation plan submission) establishes a budget for such emissions as part of the reasonable further progress, attainment or maintenance strategy.

(iii) Limitations.

(A) Projects subject to this regulation for which the NEPA process and a conformity determination have been completed by FHWA or FTA may proceed toward implementation without further conformity determinations if one of the following major steps has occurred within the most recent three-year period: NEPA process completion; start of final design; acquisition of a significant portion of the right-of-way; or approval of the plans, specifications and estimates. All phases of such projects which were considered in the conformity determination are also included, if those phases were for the purpose of funding, final design, right-of-way acquisition, construction, or any combination of these phases.

(B) A new conformity determination for the project will be required if there is a significant change in project design concept and scope, if a supplemental environmental document for air quality purposes is initiated, or if no major steps to advance the project have occurred within the most recent three-year period.

(c) Priority. When assisting or approving any action with air quality-related consequences, FHWA and FTA shall give priority to the implementation of those transportation portions of an applicable implementation plan prepared to attain and maintain the NAAQS. This priority shall be consistent with statutory requirements for allocation of funds among States or other jurisdictions.

(d) Frequency of Conformity Determinations.

(i) Conformity determinations and conformity redeterminations for transportation plans, TIPS, and FHWA/FTA projects must be made according to the requirements of this section and the applicable implementation plan.

(ii) Transportation Plans.

(A) Each new transportation plan must be found to conform before the transportation plan is approved by the MPO or accepted by DOT.

(B) All transportation plan revisions must be found to conform before the transportation plan revisions are approved by MPO or accepted by DOT, unless the revision merely adds or deletes exempt projects listed in Chapter 8, Section 4(hh) and has been made in accordance with the notification process provisions of Chapter 8, Section 4(e)(iii)(A)(VII). The conformity determination must be based on the transportation plan and the revision taken as a whole.

(C) The existing conformity determination will lapse unless conformity of the existing transportation plans is redetermined:

(I) By May 1, 1995 (unless previously redetermined in accordance with 40 CFR part 51 Subpart T); or

(II) Within 18 months of EPA approval of an implementation plan revision which:

(1.) Establishes or revises a transportation-related emissions budget (as required by CAA §§175A(a), 182(b)(1), 182(c)(2)(A), 182(c)(2)(B), 187(a)(7), 189(a)(1)(B), and 189(b)(1)(A); and §§192(a) and 192(b), for nitrogen dioxide; or

(2.) Adds, deletes, or changes TCMs; and

(III) Within 18 months of EPA promulgation of an implementation plan which establishes or revises a transportation-related emissions budget or adds, deletes, or changes TCMs.

(D) In any case, conformity determinations must be made no less frequently than every three years, or the existing conformity determination will lapse.

(iii) Transportation Improvement Programs.

(A) A new TIP must be found to conform before the TIP is approved by the MPO or accepted by DOT.

(B) A TIP amendment requires a new conformity determination for the entire TIP before the amendment is approved by the MPO or accepted by DOT, unless the amendment merely adds or deletes exempt projects listed in Chapter 8, Section 4(hh) and has been made in accordance with the notification process provisions of Chapter 8, Section 4(e)(iii)(A)(VII).

(C) After an MPO adopts a new or revised transportation plan, conformity must be redetermined by the MPO and DOT within six months from the date of adoption of the plan, unless the new or revised plan merely adds or deletes exempt projects listed in Chapter 8, Section 4(hh) and has been made in accordance with the notification process provisions of Chapter 8, Section 4(e)(iii)(A)(VII). Otherwise, the existing conformity determination for the TIP will lapse.

(D) In any case, conformity determinations must be made no less frequently than every three years or the existing conformity determination will lapse.

(iv) Projects. FHWA/FTA projects must be found to conform before they are adopted, accepted, approved, or funded. Conformity must be redetermined for any FHWA/FTA project if none of the following major steps has occurred within the most recent three-year period: NEPA process completion; start of final design; acquisition of a significant portion of the right-of-way; or approval of the plans, specifications and estimates.

(e) Consultation.

(i) General. This rule provides procedures for interagency consultation (Federal, State, and local) and resolution of conflicts. Such consultation procedures shall be undertaken by the WYDOT, MPOs and the DOT with the Division and EPA before making conformity determinations, and by the Division and EPA with MPOs, the WYDOT and DOT in developing and revising applicable implementation plans.

(ii) Interagency Consultation Procedures: General Factors.

(A) Representatives of the MPOs, the Division and the WYDOT shall undertake an interagency consultation process in accordance with this section with each other, with representatives of appropriate cities, towns, and counties and with local or regional offices of EPA, FHWA, and FTA on the development of the implementation plan, the list of TCMs in the applicable implementation plan, the unified planning work program under 23 CFR §450.314, the transportation plan, the TIP, any revisions to the preceding documents, and all conformity determinations required by this rule.

(B) The agency with the responsibility for a transportation plan, program, project, or applicable implementation plan shall also be responsible for preparing the final document of decision subject to the interagency consultation process and shall be the lead agency. It shall be the affirmative responsibility of the lead agency to initiate the process by notifying other participants, to convene consultation meetings early in the process of decision on the final document, to appoint the conveners of technical meetings, and to assure that all relevant documents and information are supplied to all participants in the consultation process in a timely manner.

(C) Regular consultation on routine activities such as the selection of models or any determination of conformity on transportation projects shall include meetings at regular, scheduled quarterly intervals, if determined necessary by the lead agency and shall be on the agenda of at least one meeting attended by representatives at the policy level of each agency. In addition, technical meetings shall be convened as necessary.

(D) Each lead agency in the consultation process required under this section shall confer with all other agencies identified under paragraph (A) with an interest in the document to be developed, provide all information to those agencies needed for meaningful input, and, prior to taking any action, consider the views of each such agency and respond to those views in a timely, substantive written manner prior to any final decision on such document. Such views and written response shall be made part of the record of any decision or action, if any.

(iii) Interagency Consultation Procedures: Specific Processes.

(A) An interagency consultation process in accordance with Chapter 8, Section 4(e)(ii) involving the MPO, the Division, the WYDOT, EPA, and DOT shall be undertaken for the following:

(I) Evaluating and choosing each model (or models) and associated methods and assumptions to be used in hot-spot analyses and regional emissions analyses, including vehicle miles traveled (“VMT”) forecasting, to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(II) Determining which minor arterials and other transportation projects should be considered “regionally significant” for the purposes of regional emissions analysis (in addition to those functionally classified as principal arterial or higher or fixed guideway systems or extension that offer an alternative to regional highway travel), and which projects should be considered to have a significant change in design concept and scope from the transportation plan of TIP, to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(III) Evaluate whether projects otherwise exempted from meeting the requirements of this section should be treated as non-exempt in cases where potential adverse emissions impacts may exist for any reason, to be initiated by the Division and conducted in accordance with Chapter 8, Section 4(e)(ii).

(IV) Make a determination, as required by Chapter 8, Section 4(m)(iii)(A), whether past obstacles to implementation of TCMs which are behind the schedule established in the applicable implementation plan have been identified and are being overcome, and whether State and local agencies with influence over approvals or funding for TCMs are giving maximum priority to approval or funding for TCMs, to be initiated by the Division and conducted in accordance with Chapter 8, Section 4(e)(ii). This consultation process shall also consider whether delays in TCM

implementation necessitate revisions to the applicable implementation plan to remove TCMs or substitute TCMs or other emission reduction measures.

(V) Making a determination, as required by Chapter 8, Section 4(cc)(ii), whether the project is included in the regional emission analysis supporting the currently conforming TIP's conformity determination, even if the project is not strictly "included" in the TIP for the purposes of MPO project selection or endorsement, and whether the project's design concept and scope have not changed significantly from those which were included in the regional emissions analysis, or in a manner which would significantly impact use of the facility, to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(VI) Identify, as required by Chapter 8, Section 4(ee)(iv), projects located at sites in PM₁₀ nonattainment areas which have vehicle and roadway emission and dispersion characteristics which are essentially identical to those at sites which have violations verified by monitoring, and therefore require quantitative PM₁₀ hot-spot analysis, to be initiated by the Division and conducted in accordance with Chapter 8, Section 4(e)(ii).

(VII) Notification of transportation plan or TIP revisions or amendments which merely add or delete exempt projects listed in Chapter 8, Section 4(hh), to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(VIII) Determining what forecast of vehicle miles traveled (VMT) to use in establishing or tracking emissions budgets, developing transportation plans, TIPS, or applicable implementation plans, or making conformity determinations, to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(B) An interagency consultation process in accordance with Chapter 8, Section 4(e)(ii) involving the MPO, the Division and the WYDOT, shall be undertaken for the following:

(I) Evaluating events which will trigger new conformity determinations in addition to those triggering events established in Chapter 8, Section 4(d), to be initiated by the Division and conducted in accordance with Chapter 8, Section 4(e)(ii); and

(II) Consulting on emissions analysis for transportation activities which cross the borders of MPOs or nonattainment areas or air basins, to be initiated by the Division and conducted in accordance with Chapter 8, Section 4(e)(ii).

(C) Where any metropolitan planning area does not include an entire nonattainment or maintenance area, an interagency consultation process in accordance with Chapter 8, Section 4(e)(ii) involving the MPO and the WYDOT shall be

undertaken for cooperative planning and analysis purposes of determining conformity of all projects outside the metropolitan area and within the nonattainment or maintenance area, to be initiated by the WYDOT and conducted in accordance with Chapter 8, Section 4(e)(ii).

(D) (I) An interagency consultation process in accordance with Chapter 8, Section 4(e)(ii) involving the MPO, the Division, the WYDOT, and recipients of funds designated under Title 23 U.S.C. or the Federal Transit Act shall be undertaken to assure that plans for construction of regionally significant projects which are not FHWA/FTA projects (including projects for which alternative locations, design concept and scope, or the no-build option are still being considered), including those by recipients of funds designated under Title 23 U.S.C. or the Federal Transit Act, are disclosed to the MPO on a regular basis, and to assure that any changes to those plans are immediately disclosed.

(II) The sponsor of any such regionally significant project, and any agency that becomes aware of any such project through applications for approval, permitting or funding or otherwise, shall disclose such project to the MPO in a timely manner. Such disclosure shall be made not later than the first occasion on which any of the following actions are sought: any policy board action necessary for the project to proceed, the issuance of administrative permits for the facility or for construction of the facility, the execution of a contract to design or construct the facility, the execution of any indebtedness for the facility, any final action of a board, commission or administrator authorizing or directing employees to proceed with design, permitting or construction of the project, or the execution of any contract to design or construct or any approval needed for any facility that is dependent on the completion of a regionally significant project.

(III) In the case of any such regionally significant project that has not been disclosed to the MPO and other interested agencies participating in the consultation process in a timely manner, such regionally significant project shall be deemed not to be included in the regional emissions analysis supporting the currently conforming TIP's conformity determination and not to be consistent with the motor vehicle emissions budget in the applicable implementation plan, for the purposes of Chapter 8, Section 4(cc).

(IV) For the purposes of this section and Chapter 8, Section 4(cc), the phrase "adopt or approve of a regionally significant project" means the first time any action necessary to authorizing a project occurs, such as any policy board action necessary for the project to proceed, the issuance of administrative permits for the facility or for construction of the facility, the execution of a contract to construct the facility, any final action of a board, commission or administrator authorizing or directing employees to proceed with construction of the project, or any written decision or authorization from the MPO that the project may be adopted or approved.

(E) An interagency cooperation process in accordance with Chapter 8, Section 4(e)(ii) involving the MPO and any other recipients of funds

designated under Title 23 U.S.C. or the Federal Transit Act shall be undertaken for assuming the location and design concept and scope of projects which are disclosed to the MPO under Chapter 8, Section 4(e)(iii)(E) of this section but whose sponsors have not yet decided these features, in sufficient detail to perform the regional emissions analysis according to the requirements of Chapter 8, Section 4(dd), to be initiated by the MPO and conducted in accordance with Chapter 8, Section 4(e)(ii).

(F) An interagency consultation process in accordance with Chapter 8, Section 4(e)(ii) involving any MPO, the Division and the WYDOT shall be undertaken for the design, schedule, and funding of research and data collection efforts and regional transportation model development by the MPO (e.g., household/travel transportation surveys), to be initiated by the MPO and conducted in accordance with Chapter 8, Section 4(e)(ii).

(iv) Resolving Conflicts.

(A) Any conflict among State agencies or between State agencies and an MPO shall be escalated to the Governor if the conflict cannot be resolved by the heads of the involved agencies. In the first instance, such agencies shall make every effort to resolve any differences, including personal meetings between the heads of such agencies or their policy-level representatives, to the extent possible.

(B) The Division has 14 calendar days to appeal a proposed determination of conformity to the Governor after the WYDOT or MPO has notified the Division of the resolution of all comments on such proposed determination of conformity or policy decision. Such 14-day period shall commence when the MPO or the WYDOT has confirmed receipt by the Administrator of the Division of the resolution of the comments of the Division.

(C) The final conformity decision must have the concurrence of the Governor if the Division appeals a conformity decision. If there is no appeal by the Division, the MPO or the WYDOT may proceed with the final conformity determination.

(D) The Division must provide notice of any appeal under Chapter 8, Section 4(e)(iv)(B) to the WYDOT and MPO.

(E) The Governor may delegate his/her role in the appeal process to anyone except the head or staff of the Division, the WYDOT, the Wyoming Environmental Quality Council, the Wyoming Transportation Commission or an MPO.

(v) Public Participation.

(A) Affected agencies making conformity determinations on transportation plans, programs, and projects shall establish a proactive public involvement process which provides opportunity for public review and comment prior to taking formal action on a conformity determination for all transportation plans and TIPs,

consistent with the requirements of 23 CFR 450, including §§450.316(b)(1), 450.322(c), and 450.324(c) as in effect on the date of adoption of this rule. In addition, any such agency must specifically address in writing in all public comments that known plans for a regionally significant project which is not receiving FHWA or FTA funding or approval have not been properly reflected in the emissions analysis supporting a proposed conformity finding for a transportation plan or TIP. Any such agency shall also provide opportunity for public involvement in conformity determination for projects to the extent otherwise required by law.

(B) The opportunity for public involvement provided under this subsection shall include access to information, emissions data, analyses, models and modeling assumptions used to perform a conformity determination, and the obligation of any such agency to consider and respond to significant comments.

(C) No transportation plan, TIP, or project may be found to conform unless the determination of conformity has been subject to a public involvement process in accordance with this subsection, without regard to whether the DOT has certified any process under 23 CFR part 450.

(f) Content of Transportation Plans.

(i) Transportation Plans Adopted After January 1, 1995 in Serious, Severe, or Extreme Ozone Nonattainment Areas and in Serious Carbon Monoxide Nonattainment Areas. The transportation plan must specifically describe the transportation system envisioned for certain future years which shall be called horizon years.

(A) The agency or organization developing the transportation plan, after consultation in accordance with Chapter 8, Section 4(e), may choose any years to be horizon years, subject to the following restrictions:

(I) Horizon years may be no more than 10 years apart.

(II) The first horizon year may be no more than 10 years from the base year used to validate the transportation demand planning model.

(III) If the attainment year is in the time span of the transportation plan, the attainment year must be a horizon year.

(IV) The last horizon year must be the last year of the transportation plan's forecast period.

(B) For these horizon years:

(I) The transportation plan shall quantify and document the demographic and employment factors influencing expected transportation demand,

including land use forecasts, in accordance with implementation plan provisions and Chapter 8, Section 4(e).

(II) The highway and transit system shall be described in terms of the regionally significant additions or modifications to the existing transportation network which the transportation plan envisions to be operational in the horizon years. Additions and modifications to the highway network shall be sufficiently identified to indicate intersections with existing regionally significant facilities, and to determine their effect on route options between transportation analysis zones. Each added or modified highway segment shall also be sufficiently identified in terms of its design concept and design scope to allow modeling of travel times under various traffic volumes, consistent with the modeling methods for area-wide transportation analysis in use by the MPO. Transit facilities, equipment, and services envisioned for the future shall be identified in terms of design concept, design scope, and operating policies sufficiently to allow modeling of their transit ridership. The description of additions and modifications to the transportation network shall also be sufficiently specific to show that there is a reasonable relationship between expected land use and the envisioned transportation system; and

(III) Other future transportation policies, requirements, services, and activities, including intermodal activities, shall be described.

(ii) Moderate Areas Reclassified to Serious. Ozone or CO nonattainment areas which are reclassified from moderate to serious must meet the requirements of paragraph (i) of this section within two years from the date of reclassification.

(iii) Transportation Plans for Other Areas. Transportation plans for other areas must meet the requirements of paragraph (a) of this section at least to the extent it has been the previous practice of the MPO to prepare plans which meet those requirements. Otherwise, transportation plans must describe the transportation system envisioned for the future specifically enough to allow determination of conformity according to the criteria and procedures of Chapter 8, Section 4(i)-(aa).

(iv) Savings. The requirements of this section supplement other requirements of applicable law or regulation governing the format or content of transportation plans.

(g) Relationship of Transportation Plan and TIP Conformity With the NEPA Process. The degree of specificity required in the transportation plan and the specific travel network assumed for air quality modeling do not preclude the consideration of alternatives in the NEPA process or other project development studies. Should the NEPA process result in a project with design concept and scope significantly different from that in the transportation plan or TIP, the project must meet the criteria in Chapter 8, Section 4(i)-(aa) for projects not from a TIP before NEPA process completion.

(h) Fiscal Constraints for Transportation Plans and TIPS. Transportation plans and TIPS shall be fiscally constrained and meet the requirements of 23 CFR 450.332(b)(11) and 450.324(e) as in effect on the date of adoption of this section in order to be found in conformity. The determination that a transportation plan or TIP is fiscally constrained shall be subject to consultation in accordance with Chapter 8, Section 4(e).

(i) Criteria and Procedures for Determining Conformity of Transportation Plans, Programs, and Projects: General.

(i) In order to be found to conform, each transportation plan, program, and FHWA/FTA project must satisfy the applicable criteria and procedures in Chapter 8, Section 4(j)-(aa) as listed in Table 1 in paragraph (ii) of this section, and must comply with all applicable conformity requirements of implementation plans and of court orders for the area which pertain specifically to conformity determination requirements. The criteria for making conformity determinations differ based on the action under review (transportation plans, TIPS, and FHWA/FTA projects), the time period in which the conformity determination is made, and the relevant pollutant.

(ii) The following table indicates the criteria and procedures in Chapter 8, Section 4(j)-(aa) which apply for each action in each time period.

Table 1. Conformity Criteria

| DURING ALL PERIODS | |
|--|-------------------|
| Action | Criteria |
| Transportation Plan | j,k,l,m(ii). |
| TIP | j,k,l,m(iii). |
| Project (From a conforming plan and TIP) | j,k,l,n,o,p,q |
| Project (Not from a conforming plan and TIP) | j,k,l,m(iv),n,p,q |

Table 1. Conformity Criteria (continued)

PHASE II OF THE INTERIM PERIOD

| Action | Criteria |
|--|----------|
| Transportation Plan | v,y |
| TIP | w,z |
| Project (From a conforming plan and TIP) | u |
| Project (Not from a conforming plan and TIP) | u,x,aa |

TRANSITIONAL PERIOD

| Action | Criteria |
|--|----------|
| Transportation Plan | r,v,y |
| TIP | s,w,z |
| Project (From a conforming plan and TIP) | u |
| Project (Not from a conforming plan and TIP) | t,u,x,aa |

CONTROL STRATEGY AND MAINTENANCE PERIODS

| Action | Criteria |
|--|------------------------|
| Transportation Plan | r |
| TIP | s |
| Project (From a conforming plan and TIP) | No additional criteria |
| Project (Not from a conforming plan and TIP) | t |

- (j) The conformity determination must be based on the latest planning assumptions.
- (k) The conformity determination must be based on the latest emission estimation model available.
- (l) The MPO must make the conformity determination according to the consultation procedures of this rule and the implementation plan revision required by 40 CFR part 51, Subpart T.
- (m) The transportation plan, TIP, or FHWA/FTA project which is not from a conforming plan and TIP must provide for the timely implementation of TCMs from the applicable implementation plan.
- (n) There must be a currently conforming transportation plan and currently conforming TIP at the time of project approval.

- (o) The project must come from a conforming transportation plan and program.
- (p) The FHWA/FTA project must not cause or contribute to any new localized CO or PM₁₀ violations or increase the frequency or severity of any existing CO or PM₁₀ violations in CO and PM₁₀ nonattainment and maintenance areas.
- (q) The FHWA/FTA project must comply with PM₁₀ control measures in the applicable implementation plan.
- (r) The transportation plan must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan or implementation plan submission.
- (s) The TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan or implementation plan submission.
- (t) The project which is not from a conforming transportation plan and conforming TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan or implementation plan submission.
- (u) The FHWA/FTA project must eliminate or reduce the severity and number of localized CO violations in the area substantially affected by the project (in CO nonattainment areas).
- (v) The transportation plan must contribute to emissions reductions in ozone and CO nonattainment areas.
- (w) The TIP must contribute to emissions reductions in ozone and CO nonattainment areas.
- (x) The project which is not from a conforming transportation plan and TIP must contribute to emissions reductions in ozone and CO nonattainment areas.
- (y) The transportation plan must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas.
- (z) The TIP must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas.
- (aa) The project which is not from a conforming transportation plan and TIP must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas.

(j) Criteria and Procedures: Latest Planning Assumptions.

(i) During all periods the conformity determination, with respect to all other applicable criteria in Chapter 8, Sections 4(k)-(aa), must be based upon the most recent planning assumptions in force at the time of the conformity determination. This criterion applies during all periods. The conformity determination must satisfy the requirements of paragraphs (ii) through (vi) of this section.

(ii) Assumptions (including, but not limited to, vehicle miles traveled per capita or per household, trip generation per household, vehicle occupancy, household size, vehicle fleet mix, vehicle ownership, and the geographic distribution of population growth) must be derived from the estimates of current and future population, employment, travel, and congestion most recently developed by the MPO or other agency authorized to make such estimates and approved by the MPO. The conformity

determination must also be based on the latest assumptions about current and future background concentrations. Any revisions to these estimates used as part of the conformity determination, including projected shifts in geographic location or level of population, employment, travel, and congestion, must be approved by the MPO or other agency authorized to make such estimates for the area, after consultation with the Division.

(iii) The conformity determination for each transportation plan and TIP must discuss how transit operating policies (including fares and service levels) and assumed transit ridership have changed since the previous conformity determination.

(iv) The conformity determination must include reasonable assumptions about transit service and increases in transit fares and road and bridge tolls over time.

(v) The conformity determination must use the latest existing information regarding the effectiveness of the TCMs which have already been implemented.

(vi) Key assumptions shall be specified and included in the draft documents and supporting materials used for the interagency and public consultation required by Chapter 8, Section 4(e).

(k) Criteria and Procedures: Latest Emissions Model.

(i) During all periods the conformity determination shall be based on the latest emission estimation model available. This criterion is satisfied if the most current version of the motor vehicle emissions model specified by EPA for use in the preparation or revision of implementation plans in that State or area is used for the conformity analysis. Where EMFAC is the motor vehicle emissions model used in preparing or revising the applicable implementation plan, new versions must be approved by EPA before they are used in the conformity analysis.

(ii) EPA will consult with DOT to establish a grace period following the specification of any new model.

(A) The grace period will be no less than three months and no more than 24 months after notice of availability is published in the Federal Register.

(B) The length of the grace period will depend on the degree of change in the model and the scope of re-planning likely to be necessary by MPOs in order to assure conformity. If the grace period will be longer than three months, EPA will announce the appropriate grace period in the Federal Register.

(iii) Conformity analyses for which the emissions analysis was begun during the grace period or before the Federal Register notice of availability of the latest emission model may continue to use the previous version of the model for transportation plans and TIPs. The previous model may also be used for projects if the analysis was

begun during the grace period or before the Federal Register notice of availability, provided no more than three years have passed since the draft environmental document was issued.

(l) **Criteria and Procedures: Consultation.** All conformity determinations shall be made according to the consultation procedures in Chapter 8, Section 4(e), and according to the public involvement procedures established by the MPO in compliance with 23 CFR part 450. This criterion applies during all periods. Until the implementation plan revision required by 40 CFR part 51, Subpart T is approved by EPA, the conformity determination must be made according to the procedures in 40 CFR 51.402(a)(2) and 40 CFR 51.402(e). Once the implementation plan revision has been approved by EPA, this criterion is satisfied if the conformity determination is made consistent with the implementation plan's consultation requirements.

(m) **Criteria and Procedures: Timely Implementation of TCMs.**

(i) The transportation plan, TIP, or FHWA/FTA project which is not from a conforming plan and TIP must provide for the timely implementation of TCMs from the applicable implementation plan. This criterion applies during all periods.

(ii) For transportation plans, this criterion is satisfied if the following two conditions are met:

(A) The transportation plan, in describing the envisioned future transportation system, provides for the timely completion or implementation of all TCMs in the applicable implementation plan, including, but not limited to, those which are eligible for funding under Title 23 U.S.C. or the Federal Transit Act, consistent with schedules included in the applicable implementation plan.

(B) Nothing in the transportation plan interferes with the implementation of any TCM in the applicable implementation plan.

(iii) For TIPs, this criterion is satisfied if the following conditions are met:

(A) An examination of the specific steps and funding source(s) needed to fully implement each TCM indicates that TCMs, including, but not limited to, those which are eligible for funding under Title 23 U.S.C. or the Federal Transit Act are on or ahead of the schedule established in the applicable implementation plan, or, if such TCMs are behind the schedule established in the applicable implementation plan, the MPO and DOT have determined that past obstacles to implementation of the TCMs have been identified and have been or are being overcome, and that all State and local agencies with influence over approvals or funding for TCMs are giving maximum priority to approval or funding of TCMs over other projects within their control, including projects in locations outside the nonattainment or maintenance area. Maximum priority to approval or funding of TCMs includes demonstrations with respect to funding

acceleration, commitment of staff or other agency resources, diligent efforts to seek approvals, and similar actions.

(B) If TCMs in the applicable implementation plan have previously been programmed for Federal funding but the funds have not been obligated and the TCMs are behind the schedule in the implementation plan, then the TIP cannot be found to conform if the funds intended for those TCMs are reallocated to projects in the TIP other than TCMs, or if there are no other TCMs in the TIP, if the funds are reallocated to projects in the TIP other than projects which are eligible for Federal funding under ISTEA's Congestion Mitigation and Air Quality Improvement Program.

(C) Nothing in the TIP may interfere with the implementation of any TCM in the applicable implementation plan.

(iv) For FHWA/FTA projects which are not from a conforming transportation plan and TIP, this criterion is satisfied if the project does not interfere with the implementation of any TCM in the applicable implementation plan.

(n) Criteria and Procedures: Currently Conforming Transportation Plan and TIP. There must be a currently conforming transportation plan and currently conforming TIP at the time of project approval. This criterion applies during all periods. It is satisfied if the current transportation plan and TIP have been found to conform to the applicable implementation plan by the MPO and DOT according to the criteria and procedures of this subpart. Only one conforming transportation plan or TIP may exist in an area at any time; conformity determinations of a previous transportation plan or TIP expire once the current plan or TIP is found to conform by DOT. The conformity determination on a transportation plan or TIP will also lapse if conformity is not determined according to the frequency requirements of Chapter 8, Section 4(d).

(o) Criteria and Procedures: Projects From a Plan and TIP.

(i) The project must come from a conforming plan and program. This criterion applies during all periods. If this criterion is not satisfied, the project must satisfy all criteria in Table 1 for a project not from a conforming transportation plan and TIP. A project is considered to be from a conforming transportation plan if it meets the requirements of paragraph (ii) of this section and from a conforming program if it meets the requirements of paragraph (iii) of this section.

(ii) A project is considered to be from a conforming transportation plan if one of the following conditions applies:

(A) For projects which are required to be identified in the transportation plan in order to satisfy §51.404, the project is specifically included in the conforming transportation plan and the project's design concept and scope have not changed significantly from those which were described in the transportation plan, or in a manner which would significantly impact use of the facility; or

(B) For projects which are not required to be specifically identified in the transportation plan, the project is identified in the conforming transportation plan, or is consistent with the policies and purpose of the transportation plan and will not interfere with other projects specifically included in the transportation plan.

(iii) A project is considered to be from a conforming program if the following conditions are met:

(A) The project is included in the conforming TIP and the design concept and scope of the project were adequate at the time of the TIP conformity determination to determine its contribution to the TIP's regional emissions and have not changed significantly from those which were described in the TIP, or in a manner which would significantly impact use of the facility; and

(B) If the TIP describes a project design concept and scope which includes project-level emissions mitigation or control measures, enforceable written commitments to implement such measures must be obtained from the project sponsor and/or operator as required by Chapter 8, Section 4(gg)(i) in order for the project to be considered from a conforming program. Any change in these mitigation or control measures that would significantly reduce their effectiveness constitutes a change in the design concept and scope of the project.

(p) Criteria and Procedures: Localized CO and PM₁₀ Violations (Hotspots).

(i) The FHWA/FTA project must not cause or contribute to any new localized CO or PM₁₀ violations or increase the frequency or severity of any existing CO or PM₁₀ violations in CO and PM₁₀ nonattainment and maintenance areas. This criterion applies during all periods. This criterion is satisfied if it is demonstrated that no new local violations will be created and the severity or number of existing violations will not be increased as a result of the project.

(ii) The demonstration must be performed according to the requirements of Chapter 8, Sections 4(e) and (ee).

(iii) For projects which are not of the type identified by Chapter 8, Section 4(ee)(i) or Chapter 8, Section 4(ee)(iv), this criterion may be satisfied if consideration of local factors clearly demonstrates that no local violations presently exist and no new local violations will be created as a result of the project. Otherwise, in CO nonattainment and maintenance areas, a quantitative demonstration must be performed according to the requirements of Chapter 8, Section 4(ee)(ii).

(q) Criteria and Procedures: Compliance With PM₁₀ Control Measures. The FHWA/FTA project must comply with PM₁₀ control measures in the applicable implementation plan. This criterion applies during all periods. It is satisfied if control

measures (for the purpose of limiting PM₁₀ emissions from the construction activities and/or normal use and operation associated with the project) contained in the applicable implementation plan are included in the final plans, specifications, and estimates for the project.

(r) Criteria and Procedures: Motor Vehicle Emissions Budget (Transportation Plan).

(i) The transportation plan must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan (or implementation plan submission). This criterion applies during the transitional period and the control strategy and maintenance periods, except as provided in Chapter 8, Section 4(jj). This criterion may be satisfied if the requirements in paragraphs (ii) and (iii) of this section are met:

(ii) A regional emissions analysis shall be performed as follows:

(A) The regional analysis shall estimate emissions of any of the following pollutants and pollutant precursors for which the area is in nonattainment or maintenance and for which the applicable implementation plan (or implementation plan submission) establishes an emissions budget:

(I) VOC as an ozone precursor;

(II) NO_x as an ozone precursor, unless the Administrator determines that additional reductions of NO_x would not contribute to attainment;

(III) CO;

(IV) PM₁₀ (and its precursors VOC and/or NO_x if the applicable implementation plan or implementation plan submission identifies transportation-related precursor emissions within the nonattainment area as a significant contributor to the PM₁₀ nonattainment problem or establishes a budget for such emissions); or

(V) NO_x (in NO₂ nonattainment or maintenance areas);

(B) The regional emissions analysis shall estimate emissions from the entire transportation system, including all regionally significant projects contained in the transportation plan and all other regionally significant highway and transit projects expected in the nonattainment or maintenance area in the time frame of the transportation plan;

(C) The emissions analysis methodology shall meet the requirements of Chapter 8, Section 4(dd);

(D) For areas with a transportation plan that meets the content requirements of Chapter 8, Section 4(f)(i), the emissions analysis shall be performed for each horizon year. Emissions in milestone years which are between the horizon years may be determined by interpolation; and

(E) For areas with a transportation plan that does not meet the content requirements of Chapter 8, Section 4(f)(i), the emissions analysis shall be performed for any years in the time span of the transportation plan provided they are not more than ten years apart and provided the analysis is performed for the last year of the plan's forecast period. If the attainment year is in the time span of the transportation plan, the emissions analysis must also be performed for the attainment year. Emissions in milestone years which are between these analysis years may be determined by interpolation.

(iii) The regional emissions analysis shall demonstrate that for each of the applicable pollutants or pollutant precursors in paragraph (ii)(A) of this section the emissions are less than or equal to the motor vehicle emissions budget as established in the applicable implementation plan or implementation plan submission as follows:

(A) If the applicable implementation plan or implementation plans submission establishes emissions budgets for milestone years, emissions in each milestone year are less than or equal to the motor vehicle emissions budget established for that year;

(B) For nonattainment areas, emissions in the attainment year are less than or equal to the motor vehicle emissions budget established in the applicable implementation plan or implementation plan submission for that year;

(C) For nonattainment areas, emissions in each analysis or horizon year after the attainment year are less than or equal to the motor vehicle emissions budget established by the applicable implementation plan or implementation plan submission for the attainment year. If emissions budgets are established for years after the attainment year, emission in each analysis year or horizon year must be less than or equal to the motor vehicle emissions budget for that year, if any, or the motor vehicle emissions budget for the most recent budget year prior to the analysis year or horizon year; and

(D) For maintenance areas, emissions in each analysis or horizon year are less than or equal to the motor vehicle emissions budget established by the maintenance plan for that year, if any, or the emissions budget for the most recent budget year prior to the analysis or horizon year.

(s) Criteria and Procedures: Motor Vehicle Emissions Budget (TIP)

(i) The TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan (or implementation plan submission). This criterion applies during the transitional period and the control strategy and maintenance

periods, except as provided in Chapter 8, Section 4(jj). This criterion may be satisfied if the requirements in paragraphs (ii) and (iii) of this section are met:

(ii) For areas with a conforming transportation plan that fully meets the content requirements of Chapter 8, Section 4(f)(i), this criterion may be satisfied without additional regional analysis if:

(A) Each program year of the TIP is consistent with the Federal funding which may be reasonably expected for that year, and required State/local matching funds and funds for State/local funding-only projects are consistent with the revenue sources expected over the same period; and

(B) The TIP is consistent with the conforming transportation plan such that the regional emissions analysis already performed for the plan applies to the TIP also. This requires a demonstration that:

(I) The TIP contains all projects which must be started in the TIP's time frame in order to achieve the highway and transit system envisioned by the transportation plan in each of its horizon years;

(II) All TIP projects which are regionally significant are part of the specific highway or transit system envisioned in the transportation plan's horizon years; and

(III) The design concept and scope of each regionally significant project in the TIP is not significantly different from that described in the transportation plan.

(C) If the requirements in paragraphs (ii)(A) and (ii)(B) of this section are not met, then:

(I) The TIP may be modified to meet those requirements;

or

(II) The transportation plan must be revised so that the requirements in paragraphs (ii)(A) and (ii)(B) of this section are met. Once the revised plan has been found to conform, this criterion is met for the TIP with no additional analysis except a demonstration that the TIP meets the requirements of paragraphs (ii)(A) and (ii)(B) of this section.

(iii) For areas with a transportation plan that does not meet the content requirements of Chapter 8, Section 4(f)(i), a regional emissions analysis must meet all of the following requirements:

(A) The regional emissions analysis shall estimate emissions from the entire transportation system, including all projects contained in the proposed TIP, the

transportation plan, and all other regionally significant highway and transit projects expected in the nonattainment or maintenance area in the time frame of the transportation plan;

(B) The analysis methodology shall meet the requirements of Chapter 8, Section 4(dd)(iii); and

(C) The regional analysis shall satisfy the requirements of Chapter 8, Sections 4(r)(ii)(A), (r)(ii)(E), and (r)(iii).

(t) Criteria and Procedures: Motor Vehicle Emissions Budget (Project Not From a Plan and TIP).

(i) The project which is not from a conforming transportation plan and a conforming TIP must be consistent with the motor vehicle emissions budget(s) in the applicable implementation plan (or implementation plan submission). This criterion applies during the transitional period and the control strategy and maintenance periods, except as provided in Chapter 8, Section 4(jj). It is satisfied if emissions from the implementation of the project, when considered with the emissions from the projects in the conforming transportation plan and TIP and all other regionally significant projects expected in the area, do not exceed the motor vehicle emissions budget(s) in the applicable implementation plan (or implementation plan submission).

(ii) For areas with a conforming transportation plan that meets the content requirements of Chapter 8, Section 4(f)(i):

(A) This criterion may be satisfied without additional regional analysis if the project is included in the conforming transportation plan, even if it is not specifically included in the latest conforming TIP. This requires a demonstration that:

(I) Allocating funds to the project will not delay the implementation of projects in the transportation plan or TIP which are necessary to achieve the highway and transit system envisioned by the transportation plan in each of its horizon years;

(II) The project is not regionally significant or is part of the specific highway or transit system envisioned in the transportation plan's horizon years; and

(III) The design concept and scope of the project is not significantly different from that described in the transportation plan.

(B) If the requirements in paragraph (ii)(A) of this section are not met, a regional emissions analysis must be performed as follows:

(I) The analysis methodology shall meet the requirements of Chapter 8, Section 4(ee);

(II) The analysis shall estimate emissions from the transportation system, including the proposed project and all other regionally significant projects expected in the nonattainment or maintenance area in the time frame of the transportation plan. The analysis must include emissions from all previously approved projects which were not from a transportation plan and TIP; and

(III) The emissions analysis shall meet the requirements of Chapter 8, Sections 4(r)(ii)(A), (r)(ii)(D), and (r)(iii).

(iii) For areas with a transportation plan that does not meet the content requirements of Chapter 8, Section 4(f)(i), a regional emissions analysis must be performed for the project together with the conforming TIP and all other regionally significant projects expected in the nonattainment or maintenance area. This criterion may be satisfied if:

(A) The analysis methodology meets the requirements of Chapter 8, Section 4(dd)(iii);

(B) The analysis estimates emissions from the transportation system, including the proposed project, and all other regionally significant projects expected in the nonattainment or maintenance area in the time frame of the transportation plan; and

(C) The regional analysis satisfies the requirements of Chapter 8, Sections 4(r)(ii)(A), (r)(ii)(E), and (r)(iii).

(u) Criteria and Procedures: Localized CO Violations (Hot Spots) in the Interim Period.

(i) Each FHWA/FTA project must eliminate or reduce the severity and number of localized CO violations in the area substantially affected by the project (in CO nonattainment areas). This criterion applies during the interim and transitional periods only. This criterion is satisfied with respect to existing localized CO violations if it is demonstrated that existing localized CO violations will be eliminated or reduced in severity and number as a result of the project.

(ii) The demonstration must be performed according to the requirements of Chapter 8, Sections 4(e) and (ee).

(iii) For projects which are not of the type identified by Chapter 8, Section 4(ee)(i), this criterion may be satisfied if consideration of local factors clearly demonstrates that existing CO violations will be eliminated or reduced in severity and

number. Otherwise, a quantitative demonstration must be performed according to the requirements of Chapter 8, Section 4(ee)(ii).

(v) Criteria and Procedures: Interim Period Reductions in Ozone and CO Areas (Transportation Plan).

(i) A transportation plan must contribute to emissions reductions in ozone and CO Nonattainment areas. This criterion applies during the interim and transitional periods only, except as otherwise provided in Chapter 8, Section 4(jj). It applies to the net effect on emissions of all projects contained in a new or revised transportation plan. This criterion may be satisfied if a regional emissions analysis is performed as described in paragraphs (ii) through (vi) of this section.

(ii) Determine the analysis years for which emissions are to be estimated. Analysis years shall be no more than ten years apart. The first analysis year shall be no later than the first milestone year (1995 in CO nonattainment areas and 1996 in ozone nonattainment areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year. The last year of the transportation plan's forecast period shall also be an analysis year.

(iii) Define the 'Baseline' scenario for each of the analysis years to be the future transportation system that would result from current programs, composed of the following (except that projects listed in Chapter 8, Sections 4(hh) and (ii) need not be explicitly considered):

(A) All in-place regionally significant highway and transit facilities, services and activities;

(B) All ongoing travel demand management or transportation system management activities; and

(C) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition (except for hardship acquisition and protective buying); come from the first three years of the previously conforming transportation plan and/or TIP; or have completed the NEPA process. (For the first conformity determination on the transportation plan after November 24, 1993, a project may not be included in the 'Baseline' scenario if one of the following major steps has not occurred within the past three years: NEPA process completion; start of final design; acquisition of a significant portion of the right-of-way; or approval of the plans, specifications and estimates. Such a project must be included in the 'Action' scenario, as described in paragraph (iv) of this section.)

(iv) Define the 'Action' scenario for each of the analysis years as the transportation system that will result in that year from the implementation of the

proposed transportation plan, TIPs adopted under it, and other expected regionally significant projects in the nonattainment area. It will include the following (except that projects listed in Chapter 8, Sections 4(hh) and (ii) need not be explicitly considered):

(A) All facilities, services, and activities in the ‘Baseline’ scenario;

(B) Completion of all TCMs and regionally significant projects (including facilities, services, and activities) specifically identified in the proposed transportation plan which will be operational or in effect in the analysis year, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is identified in the applicable implementation plan;

(C) All travel demand management programs and transportation system management activities known to the MPO, but not included in the applicable implementation plan or utilizing any Federal funding or approval, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the transportation plan;

(D) The incremental effects of any travel demand management programs and transportation system management activities known to the MPO, but not included in the applicable implementation plan or utilizing any Federal funding or approval, which were adopted and/or funded prior to the date of the last conformity determination on the transportation plan, but which have been modified since then to be more stringent or effective;

(E) Completion of all expected regionally significant highway and transit projects which are not from a conforming transportation plan and TIP; and

(F) Completion of all expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading toward their implementation and completion by the analysis year.

(v) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the ‘Baseline’ and ‘Action’ scenarios and determine the difference in regional VOC and NO_x emissions (unless the Administrator determines that additional reductions of NO_x would not contribute to attainment) between the two scenarios for CO nonattainment areas. The analysis must be performed for each of the analysis years according to the requirements of Chapter 8, Section 4(dd). Emissions in milestone years which are between the analysis years may be determined by interpolation.

(vi) This criterion is met if the regional VOC and NO_x emissions (for ozone nonattainment areas) and CO emissions (for CO nonattainment areas) predicted in the ‘Action’ scenario are less than the emissions predicted from the ‘Baseline’ scenario in

each analysis year, and if this can reasonably be expected to be true in the periods between the first milestone year and the analysis years. The regional analysis must show that the 'Action' scenario contributes to a reduction in emissions from the 1990 emissions by any non-zero amount.

(w) Criteria and Procedures: Interim Period Reductions in Ozone and CO Areas (TIP).

(i) A TIP must contribute to emissions reductions in ozone and CO nonattainment areas. This criterion applies during the interim and transitional periods only, except as otherwise provided in Chapter 8, Section 4(jj). It applies to the net effect on emissions of all projects contained in a new or revised TIP. This criterion may be satisfied if a regional emissions analysis is performed as described in paragraphs (ii) through (vi) of this section.

(ii) Determine the analysis years for which emissions are to be estimated. The first analysis year shall be no later than the first milestone year (1995 in CO nonattainment areas and 1996 in ozone nonattainment areas). The analysis years shall be no more than ten years apart. The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year. The last year of the transportation plan's forecast period shall also be an analysis year.

(iii) Define the 'Baseline' scenario as the future transportation system that would result from current programs, composed of the following (except that projects listed in Chapter 8, Sections 4(hh) and (ii) need not be explicitly considered):

(A) All in-place regionally significant highway and transit facilities, services and activities;

(B) All ongoing travel demand management or transportation system management activities; and

(C) Completion of all regionally significant projects, regardless of funding source, which are currently under construction or are undergoing right-of-way acquisition (except for hardship acquisition and protective buying); come from the first three years of the previously conforming TIP; or have completed the NEPA process. (For the first conformity determination on the TIP after (November 24, 1993), a project may not be included in the 'Baseline' scenario if one of the following major steps has not occurred within the past three years: NEPA process completion; start of final design; acquisition of a significant portion of the right-of-way; or approval of the plans, specifications and estimates. Such a project must be included in the 'Action' scenario, as described in paragraph (d) of this section.)

(iv) Define the 'Action' scenario as the future transportation system that will result from the implementation of the proposed TIP and other expected regionally

significant projects in the nonattainment area in the time frame of the transportation plan. It will include the following (except that projects listed in Chapter 8, Sections 4(hh) and (ii) need not be explicitly considered):

(A) All facilities, services, and activities in the ‘Baseline’ scenario;

(B) Completion of all TCMs and regionally significant projects (including facilities, services, and activities) included in the proposed TIP, except that regulatory TCMs may not be assumed to begin at a future time unless the regulation is already adopted by the enforcing jurisdiction or the TCM is contained in the applicable implementation plan;

(C) All travel demand management programs and transportation system management activities known to the MPO, but not included in the applicable implementation plan or utilizing any Federal funding or approval, which have been fully adopted and/or funded by the enforcing jurisdiction or sponsoring agency since the last conformity determination on the TIP;

(D) The incremental effects of any travel demand management programs and transportation system management activities known to the MPO, but not included in the applicable implementation plan or utilizing any Federal funding or approval, which were adopted and/or funded prior to the date of the last conformity determination on the TIP, but which have been modified since then to be more stringent or effective;

(E) Completion of all expected regionally significant highway and transit projects which are not from a conforming transportation plan and TIP; and

(F) Completion of all expected regionally significant non-FHWA/FTA highway and transit projects that have clear funding sources and commitments leading toward their implementation and completion by the analysis year.

(v) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the ‘Baseline’ and ‘Action’ scenarios, and determine the difference in regional VOC and NO_x emissions (unless the Administrator determines that additional reductions of NO_x would not contribute to attainment) between the two scenarios for ozone nonattainment areas and the difference in CO emissions between the two scenarios for CO nonattainment areas. The analysis must be performed for each of the analysis years according to the requirements of Chapter 8, Section 4(dd). Emissions in milestone years which are between analysis years may be determined by interpolation.

(vi) This criterion is met if the regional VOC and NO_x emissions in ozone nonattainment areas and CO emissions in CO nonattainment areas predicted in the ‘Action’ scenario are less than the emissions predicted from the ‘Baseline’ scenario in

each analysis year, and if this can reasonably be expected to be true in the period between the analysis years. The regional analysis must show that the 'Action' scenario contributes to a reduction in emissions from the 1990 emissions by any non-zero amount.

(x) Criteria and Procedures: Interim Period Reductions for Ozone and CO Areas (Project Not From a Plan and TIP). A transportation project which is not from a conforming transportation plan and TIP must contribute to emissions reductions in ozone and CO nonattainment areas. This criterion applies during the interim and transitional periods only, except as otherwise provided in Chapter 8, Section 4(jj). This criterion is satisfied if a regional emissions analysis is performed which meets the requirements of Chapter 8, Section 4(v) and which includes the transportation plan and project in the 'Action' scenario. If the project which is not from a conforming transportation plan and TIP is a modification of a project currently in the plan or TIP, the 'Baseline' scenario must include the project with its original design concept and scope, and the 'Action' scenario must include the project with its new design concept and scope.

(y) Criteria and Procedures: Interim Period Reductions for PM₁₀ and NO₂ Areas (Transportation Plan).

(i) A transportation plan must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas. This criterion applies only during the interim and transitional periods. It applies to the net effect on emissions of all projects contained in a new or revised transportation plan. This criterion may be satisfied if the requirements of either paragraph (ii) or (iii) of this section are met.

(ii) Demonstrate that implementation of the plan and all other regionally significant projects expected in the nonattainment area will contribute to reductions in emissions of PM₁₀ in a PM₁₀ nonattainment area (and of each transportation-related precursor of PM₁₀ in PM₁₀ nonattainment areas if the EPA Regional Administrator or the Director of the State air agency has made a finding that such precursor emissions from within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT) and of NO_x in an NO₂ nonattainment area, by performing a regional emissions analysis as follows:

(A) Determine the analysis years for which emissions are to be estimated. Analysis years shall be no more than ten years apart. The first analysis year shall be no later than 1996 (for NO₂ areas) or four years and six months following the date of designation (for PM₁₀ areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year. The last year of the transportation plan's forecast period shall also be an analysis year.

(B) Define for each of the analysis years the 'Baseline' scenario, as defined in Chapter 8, Section 4(v)(iii), and the 'Action' scenario, as defined in Chapter 8, Section 4(v)(iv).

(C) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the 'Baseline' and 'Action' scenarios and determine the difference between the two scenarios in regional PM₁₀ emissions in a PM₁₀ nonattainment area (and transportation-related precursors of PM₁₀ in PM₁₀ nonattainment areas if the EPA Regional Administrator or the Director of the State air agency has made a finding that such precursor emissions from within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT) and in NO_x emissions in an NO₂ nonattainment area. The analysis must be performed for each of the analysis years according to the requirements of Chapter 8, Section 4(dd). The analysis must address the periods between the analysis years and the periods between 1990, the first milestone year (if any), and the first of the analysis years. Emissions in milestone years which are between the analysis years may be determined by interpolation.

(D) Demonstrate that the regional PM₁₀ emissions and PM₁₀ precursor emissions, where applicable, (for PM₁₀ nonattainment areas) and NO_x emissions (for NO₂ nonattainment areas) predicted in the 'Action' scenario are less than the emissions predicted from the 'Baseline' scenario in each analysis year, and that this can reasonably be expected to be true in the periods between the first milestone year (if any) and the analysis years.

(iii) Demonstrate that when the projects in the transportation plan and all other regionally significant projects expected in the nonattainment area are implemented, the transportation system's total highway and transit emissions of PM₁₀ in a PM₁₀ nonattainment area (and transportation-related precursors of PM₁₀ in PM₁₀ nonattainment areas if the EPA regional Administrator or the Director of the State air agency has made a finding that such precursor emissions from within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT) and of NO_x in an NO₂ nonattainment area will not be greater than baseline levels, by performing a regional emissions analysis as follows:

(A) Determine the baseline regional emissions of PM₁₀ and PM₁₀ precursors, where applicable (for PM₁₀ nonattainment areas) and NO_x (for NO₂ nonattainment areas) from highway and transit sources. Baseline emissions are those estimated to have occurred during calendar year 1990, unless the implementation plan revision required by 40 CFR part 51, Subpart T defines the baseline emissions for a PM₁₀ area to be those occurring in a different calendar year for which a baseline emissions inventory was developed for the purpose of developing a control strategy implementation plan.

(B) Estimate the emissions of the applicable pollutant(s) from the entire transportation system, including projects in the transportation plan and TIP and all other regionally significant projects in the nonattainment area, according to the requirements of Chapter 8, Section 4(dd). Emissions shall be estimated for analysis years which are no more than ten years apart. The first analysis year shall be no later than 1996

(for NO₂ areas) or four years and six months following the date of designation (for PM₁₀ areas). The second analysis year shall be either the attainment year for the area, or if the attainment year is the same as the first analysis year or earlier, the second analysis year shall be at least five years beyond the first analysis year. The last year of the transportation plan's forecast period shall also be an analysis year.

(C) Demonstrate that for each analysis year the emissions estimated in paragraph (iii)(B) of this section are no greater than baseline emissions of PM₁₀ and PM₁₀ precursors, where applicable (for PM₁₀ nonattainment areas) or NO_x (for NO₂ nonattainment areas) from highway and transit sources.

(z) Criteria and Procedures: Interim Period Reductions for PM₁₀ and NO₂ Areas (TIP).

(i) A TIP must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas. This criterion applies only during the interim and transitional periods. It applies to the net effect on emission of all projects contained in a new or revised TIP. This criterion may be satisfied if the requirements of either paragraph (ii) or paragraph (iii) of this section are met.

(ii) Demonstrate that implementation of the plan and TIP and all other regionally significant projects expected in the nonattainment area will contribute to reductions in emissions of PM₁₀ in a PM₁₀ nonattainment area (and transportation-related precursors of PM₁₀ in PM₁₀ nonattainment areas if the EPA Regional Administrator or the Director of the State air agency has made a finding that such precursor emissions from within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT) and of NO_x in an NO₂ nonattainment area, by performing a regional emissions analysis as follows:

(A) Determine the analysis years for which emissions are to be estimated, according to the requirements of Chapter 8, Section 4(y)(ii)(A).

(B) Define for each of the analysis years the 'Baseline' scenario, as defined in Chapter 8, Section 4(w)(iii), and the 'Action' scenario, as defined in Chapter 8, Section 4(w)(iv).

(C) Estimate the emissions predicted to result in each analysis year from travel on the transportation systems defined by the 'Baseline' and 'Action' scenarios as required by Chapter 8, Section 4(y)(ii)(C), and make the demonstration required by Chapter 8, Section 4(y)(ii)(D).

(iii) Demonstrate that when the projects in the transportation plan and TIP and all other regionally significant projects expected in the area are implemented, the transportation system's total highway and transit emissions of PM₁₀ in a PM₁₀ nonattainment area (and transportation-related precursors of PM₁₀ in PM₁₀ nonattainment areas if the EPA Regional Administrator or the Director of the State air agency has made

a finding that such precursor emissions from within the nonattainment area are a significant contributor to the PM₁₀ nonattainment problem and has so notified the MPO and DOT) and of NO_x in an NO₂ nonattainment area will not be greater than baseline levels, by performing a regional emissions analysis as required by Chapter 8, Sections 4(y)(iii)(A)-(C).

(aa) Criteria and Procedures: Interim Period Reductions for PM₁₀ and NO₂ Areas (Project Not From a Plan and TIP). A transportation project which is not from a conforming transportation plan and TIP must contribute to emission reductions or must not increase emissions in PM₁₀ and NO₂ nonattainment areas. This criterion applies during the interim and transitional periods only. This criterion is met if a regional emissions analysis is performed which meets the requirements of Chapter 8, Section 4(y) and which includes the transportation plan and project in the 'Action' scenario. If the project which is not from a conforming transportation plan and TIP is a modification of a project currently in the transportation plan or TIP, and Chapter 8, Section 4(y)(ii) is used to demonstrate satisfaction of this criterion, the 'Baseline' scenario must include the project with its original design concept and scope, and the 'Action' scenario must include the project with its new design concept and scope.

(bb) Transition From the Interim Period to the Control Strategy Period.

(i) Areas Which Submit a Control Strategy Implementation Plan Revision After November 24, 1993.

(A) The transportation plan and TIP must be demonstrated to conform according to transitional period criteria and procedures by one year from the date the Clean Air Act requires submission of such control strategy implementation plan revision. Otherwise, the conformity status of the transportation plan and TIP will lapse, and no new project-level conformity determinations may be made.

(I) The conformity of new transportation plans and TIPs may be demonstrated according to Phase II interim period criteria and procedures for 90 days following submission of the control strategy implementation plan revision, provided the conformity of such transportation plans and TIPs is redetermined according to transitional period criteria and procedures as required in paragraph (i)(A) of this section.

(II) Beginning 90 days after submission of the control strategy implementation plan revision, new transportation plans and TIPs shall demonstrate conformity according to transitional period criteria and procedures.

(B) If EPA disapproves the submitted control strategy implementation plan revision and so notifies the State, MPO, and DOT, which initiates the sanction process under Clean Air Act sections 179 or 110(m), the conformity status of the transportation plan and TIP shall lapse 120 days after EPA's disapproval, and no new project-level conformity determinations may be made. No new transportation plan, TIP, or project may be found to conform until another control strategy implementation plan

revision is submitted and conformity is demonstrated according to transitional period criteria and procedures.

(C) Notwithstanding paragraph (i)(B) of this section, if EPA disapproves the submitted control strategy implementation plan revision but determines that the control strategy contained in the revision would have been considered approvable with respect to requirements for emission reductions if all committed measures had been submitted in enforceable form as required by Clean Air Act §110(a)(2)(A), the provisions of paragraph (i)(A) of this section shall apply for 12 months following the date of disapproval. The conformity status of the transportation plan and TIP shall lapse 12 months following the date of disapproval unless another control strategy implementation plan revision is submitted to EPA and found to be complete.

(ii) Areas Which Have Not Submitted a Control Strategy Implementation Plan Revision.

(A) For areas whose Clean Air Act deadline for submission of the control strategy implementation plan revision is after November 24, 1993 and EPA has notified the State, MPO, and DOT of the State's failure to submit a control strategy implementation plan revision, which initiates the sanction process under Clean Air Act sections 179 or 110(m):

(I) No new transportation plans or TIPs may be found to conform beginning 120 days after the Clean Air Act deadline; and

(II) The conformity status of the transportation plan and TIP shall lapse one year after the Clean Air Act deadline, and no new project-level conformity determinations may be made.

(B) For areas whose Clean Air Act deadline for submission of the control strategy implementation plan was before November 24, 1993 and EPA has made a finding of failure to submit a control strategy implementation plan revision, which initiates the sanction process under Clean Air Act sections 179 or 110(m), the following apply unless the failure has been remedied and acknowledged by a letter from the EPA Regional Administrator:

(I) No new transportation plans or TIPs may be found to conform beginning March 24, 1994; and

(II) The conformity status of the transportation plan and TIP shall lapse November 25, 1994, and no new project-level conformity determinations may be made.

(III) Notwithstanding paragraphs (iii)(B)(I) and (II) of this section, if EPA notes in its incompleteness finding that the submittal would have been considered complete with respect to requirements for emission reductions if all

committed measures had been submitted in enforceable form as required by Clean Air Act §110(a)(2)(A), the provisions of paragraph (iv)(A) of this section shall apply for a period of 12 months following the date of the incompleteness determination. The conformity status of the transportation plan and TIP shall lapse 12 months following the date of the incompleteness determination unless another control strategy implementation plan revision is submitted to EPA and found to be complete.

(iv) Areas Which Submitted a Control Strategy Implementation Plan Before November 24, 1993.

(A) The transportation plan and TIP must be demonstrated to conform according to transitional period criteria and procedures by November 25, 1994. Otherwise, their conformity status will lapse, and no new project-level conformity determinations may be made.

(I) The conformity of new transportation plans and TIPs may be demonstrated according to Phase II interim period criteria and procedures until February 22, 1994, provided the conformity of such transportation plans and TIPs is redetermined according to transitional period criteria and procedures as required in paragraph (iv)(A) of this section.

(II) Beginning February 22, 1994, new transportation plans and TIPs shall demonstrate conformity according to transitional period criteria and procedures.

(B) If EPA has disapproved the most recent control strategy implementation plan submission, the conformity status of the transportation plan and TIP shall lapse March 24, 1994, and no new project-level conformity determinations may be made. No new transportation plans, TIPs, or projects may be found to conform until another control strategy implementation plan revision is submitted and conformity is demonstrated according to transitional period criteria and procedures.

(C) Notwithstanding paragraph (iv)(B) of this section, if EPA has disapproved the submitted control strategy implementation plan revision but determines that the control strategy contained in the revision would have been considered approvable with respect to requirements for emission reductions if all committed measures had been submitted in enforceable form as required by Clean Air Act §110(a)(2)(A), the provisions of paragraph (iv)(A) of this section shall apply for 12 months following November 24, 1993. The conformity status of the transportation plan and TIP shall lapse 12 months following November 24, 1993 unless another control strategy implementation plan revision is submitted to EPA and found to be complete.

(v) Projects. If the currently conforming transportation plan and TIP have not been demonstrated to conform according to transitional period criteria and procedures, the requirements of paragraphs (v)(A) and (B) of this section must be met.

(A) Before a FHWA/FTA project which is regionally significant and increases single-occupant vehicle capacity (a new general purpose highway on a new location or adding general purpose lanes) may be found to conform, the State air agency must be consulted on how the emissions which the existing transportation plan and TIPs conformity determination estimates for the 'Action' scenario (as required by Chapter 8, Sections 4(v)-(aa)) compare to the motor vehicle emissions budget in the implementation plan submission or the projected motor vehicle emissions budget in the implementation plan under development.

(B) In the event of unresolved disputes on such project-level conformity determinations, the State air agency may escalate the issue to the Governor consistent with the procedure in Chapter 8, Section 4(e), which applies for any State air agency comments on a conformity determination.

(vi) Redetermination of Conformity of the Existing Transportation Plan and TIP According to the Transitional Period Criteria and Procedures.

(A) The redetermination of the conformity of the existing transportation plan and TIP according to transitional period criteria and procedures (as required by paragraphs (i)(A) and (iv)(A) of this section) does not require new emissions analysis and does not have to satisfy the requirements of Chapter 8, Sections 4(j) and (k) if:

(I) The control strategy implementation plan revision submitted to EPA uses the MPO's modeling of the existing transportation plan and TIP for its projections of motor vehicle emissions; and

(II) The control strategy implementation plan does not include any transportation projects which are not included in the transportation plan and TIP.

(B) A redetermination of conformity as described in paragraph (vi)(A) of this section is not considered a conformity determination for the purposes of Chapter 8, Sections 4(d)(ii)(D) or (d)(iii)(D) regarding the maximum intervals between conformity determinations. Conformity must be determined according to all the applicable criteria and procedures of Chapter 8, Section 4(i) within three years of the last determination which did not rely on paragraph (vi)(A) of this section.

(vii) Ozone Nonattainment Areas.

(A) The requirements of paragraph (ii)(A) of this section apply if a serious or above ozone nonattainment area has not submitted the implementation plan revisions which Clean Air Act §§182(c)(2)(A) and 182(c)(2)(B) require to be submitted to EPA November 15, 1994, even if the area has submitted the implementation plan revision which Clean Air Act §182(b)(1) requires to be submitted to EPA November 15, 1993.

(B) The requirements of paragraph (ii)(A) of this section apply if a moderate ozone nonattainment area which is using photochemical dispersion modeling to demonstrate the “specific annual reductions as necessary to attain” required by Clean Air Act §182(b)(1), and which has permission from EPA to delay submission of such demonstration until November 15, 1994, does not submit such demonstration by that date. The requirements of paragraph (ii)(A) of this section apply in this case even if the area has submitted the 15% emission reduction demonstration required by Clean Air Act §182(b)(1).

(C) The requirements of paragraph (i) of this section apply when the implementation plan revisions required by Clean Air Act §§182(c)(2)(A) and 182(c)(2)(B) are submitted.

(viii) Nonattainment Areas Which Are Not Required to Demonstrate Reasonable Further Progress and Attainment. If an area listed in Chapter 8, Section 4(jj) submits a control strategy implementation plan revision, the requirements of paragraphs (i) and (v) of this section apply. Because the areas listed in Chapter 8, Section 4(jj) are not required to demonstrate reasonable further progress and attainment and therefore have no Clean Air Act deadline, the provisions of paragraph (ii) of this section do not apply to these areas at any time.

(ix) Maintenance Plans. If a control strategy implementation plan revision is not submitted to EPA but a maintenance plan required by Clean Air Act §175 is submitted to EPA, the requirements of paragraphs (i) or (iv) of this section apply, with the maintenance plan submission treated as a “control strategy implementation plan revision” for the purposes of those requirements.

(cc) Requirements for Adoption or Approval of Projects By Recipients of Funds Designated Under Title 23 U.S.C. or the Federal Transit Act. No recipient of Federal funds designated under Title 23 U.S.C. or the Federal Transit Act shall adopt or approve a regionally significant highway or transit project, regardless of funding source, unless there is a currently conforming transportation plan and TIP consistent with the requirements of Chapter 8, Section 4(n) and the requirements of one of the following paragraphs (i) through (v) are met:

(i) The project comes from a conforming plan and program consistent with the requirements of Chapter 8, Section 4(o);

(ii) The project is included in the regional emissions analysis supporting the currently conforming TIPs conformity determination, even if the project is not strictly “included” in the TIP for the purposes of MPO project selection or endorsement, and the project’s design concept and scope have not changed significantly from those which were included in the regional emissions analysis, or in a manner which would significantly impact use of the facility;

(iii) During the control strategy or maintenance period, the project is consistent with the motor vehicle emissions budget(s) in the applicable implementation plan consistent with the requirements of Chapter 8, Section 4(t);

(iv) During Phase II of the interim period, the project contributes to emissions reductions or does not increase emissions consistent with the requirements of Chapter 8, Section 4(x) (in ozone and CO nonattainment areas) or Chapter 8, Section 4(aa) (in PM₁₀ and NO₂ nonattainment areas); or

(v) During the transitional period, the project satisfies the requirements of both paragraphs (iii) and (iv) of this section.

(dd) Procedures for Determining Regional Transportation-Related Emissions.

(i) General Requirements.

(A) The regional emissions analysis for the transportation plan, TIP, or project not from a conforming plan and TIP shall include all regionally significant projects expected in the nonattainment or maintenance area, including FHWA/FTA projects proposed in the transportation plan and TIP and all other regionally significant projects which are disclosed to the MPO as required by Chapter 8, Section 4(e). Projects which are not regionally significant are not required to be explicitly modeled, but VMT from such projects must be estimated in accordance with reasonable professional practice. The effects of TCMs and similar projects that are not regionally significant may also be estimated in accordance with reasonable professional practice.

(B) The emissions analysis may not include for emissions reduction credit any TCMs which have been delayed beyond the scheduled date(s) until such time as implementation has been assured. If the TCM has been partially implemented and it can be demonstrated that it is providing quantifiable emission reduction benefits, the emissions analysis may include that emissions reduction credit.

(C) Emissions reduction credit from projects, programs, or activities which require a regulation in order to be implemented may not be included in the emissions analysis unless the regulation is already adopted by the enforcing jurisdiction. Adopted regulations are required for demand management strategies for reducing emissions which are not specifically identified in the applicable implementation plan, and for control programs which are external to the transportation system itself, such as tailpipe or evaporative emission standards, limits on gasoline volatility, inspection and maintenance programs, and oxygenated or reformulated gasoline or diesel fuel. A regulatory program may also be considered to be adopted if an opt-in to a Federally enforced program has been approved by EPA, if EPA has promulgated the program (if the control program is a Federal responsibility, such as tailpipe standards), or if the Clean Air Act requires the program without need for individual State action and without any discretionary authority for EPA to set its stringency, delay its effective date, or not implement the program.

(D) Notwithstanding paragraph (i)(C) of this section, during the transitional period, control measures or programs which are committed to in an implementation plan submission as described in Chapter 8, Sections 4(r)-(t), but which has not received final EPA action in the form of a finding of incompleteness, approval, or disapproval may be assumed for emission reduction credit for the purpose of demonstrating that the requirements of Chapter 8, Sections 4(r)-(t) are satisfied.

(E) A regional emissions analysis for the purpose of satisfying the requirements of Chapter 8, Sections 4(v)-(x) may account for the programs in paragraph (i)(D) of this section, but the same assumptions about these programs shall be used for both the 'Baseline' and 'Action' scenarios.

(ii) Serious, Severe, and Extreme Ozone Nonattainment Areas and Serious Carbon Monoxide Areas After January 1, 1995. Estimates of regional transportation-related emissions used to support conformity determinations must be made according to procedures which meet the requirements in paragraphs (ii)(A) through (E) of this section.

(A) A network-based transportation demand model or models relating travel demand and transportation system performance to land-use patterns, population demographics, employment, transportation infrastructure, and transportation policies must be used to estimate travel within the metropolitan planning area of the nonattainment area. Such a model shall possess the following attributes:

(I) The modeling methods and the functional relationships used in the model(s) shall in all respects be in accordance with acceptable professional practice, and reasonable for purposes of emission estimation;

(II) The network-based model(s) must be validated against ground counts for a base year that is not more than 10 years prior to the date of the conformity determination. Land use, population, and other inputs must be based on the best available information and appropriate to the validation base year;

(III) For peak-hour or peak-period traffic assignments, a capacity sensitive assignment methodology must be used;

(IV) Zone-to-zone travel times used to distribute trips between origin and destination pairs must be in reasonable agreement with the travel times which result from the process of assignment of trips to network links. Where use of transit currently is anticipated to be a significant factor in satisfying transportation demand, these times should also be used for modeling mode splits;

(V) Free-flow speeds on network links shall be based on empirical observations;

(VI) Peak and off-peak travel demand and travel times must be provided;

(VII) Trip distribution and mode choice must be sensitive to pricing, where pricing is a significant factor, if the network model is capable of such determinations and the necessary information is available;

(VIII) The model(s) must utilize and document a logical correspondence between the assumed scenario of land development and use and the future transportation system for which emissions are being estimated. Reliance on a formal land-use model is not specifically required but is encouraged;

(IX) A dependence of trip generation on the accessibility of destinations via the transportation system (including pricing) is strongly encouraged but not specifically required, unless the network model is capable of such determinations and the necessary information is available;

(X) A dependence of regional economic and population growth on the accessibility of destinations via the transportation system is strongly encouraged but not specifically required, unless the network model is capable of such determinations and the necessary information is available; and

(XI) Consideration of emissions increases from construction-related congestion is not specifically required.

(B) Highway Performance Monitoring System (HPMS) estimates of vehicle miles traveled shall be considered the primary measure of vehicle miles traveled within the portion of the nonattainment or maintenance area and for the functional classes of roadways included in HPMS, for urban areas which are sampled on a separate urban area basis. A factor (or factors) shall be developed to reconcile and calibrate the network-based model estimates of vehicle miles traveled in the base year of its validation to the HPMS estimates for the same period, and these factors shall be applied to model estimates of future vehicle miles traveled. In this factoring process, consideration will be given to differences in the facility coverage of the HPMS and the modeled network description. Departure from these procedures is permitted with the concurrence of DOT and EPA.

(C) Reasonable methods shall be used to estimate nonattainment area vehicle travel on off-network roadways within the urban transportation planning area, and on roadways outside the urban transportation planning area.

(D) Reasonable methods in accordance with good practice must be used to estimate traffic speeds and delays in a manner that is sensitive to the estimated volume of travel on each roadway segment represented in the network model.

(E) Ambient temperatures shall be consistent with those used to establish the emissions budget in the applicable implementation plan. Factors other than temperatures, for example the fraction of travel in a hot stabilized engine mode, may be modified after interagency consultation according to Chapter 8, Section 4(e) if the newer estimates incorporate additional or more geographically specific information or represent a logically estimated trend in such factors beyond the period considered in the applicable implementation plan.

(iii) Areas Which Are Not Serious, Severe, or Extreme Ozone Nonattainment Areas or Serious Carbon Monoxide Areas, or Before January 1, 1995.

(A) Procedures which satisfy some or all of the requirements of paragraph (i) of this section shall be used in all areas not subject to paragraph (i) of this section in which those procedures have been the previous practice of the MPO.

(B) Regional emissions may be estimated by methods which do not explicitly or comprehensively account for the influence of land use and transportation infrastructure on vehicle miles traveled and traffic speeds and congestion. Such methods must account for VMT growth by extrapolating historical VMT or projecting future VMT by considering growth in population and historical growth trends for vehicle miles traveled per person. These methods must also consider future economic activity, transit alternatives, and transportation system policies.

(iv) Projects Not From a Conforming Plan and TIP in Isolated Rural Nonattainment and Maintenance Areas. This paragraph applies to any nonattainment or maintenance area or any portion thereof which does not have a metropolitan transportation plan or TIP and whose projects are not part of the emissions analysis of any MPO's metropolitan transportation plan or TIP (because the nonattainment or maintenance area or portion thereof does not contain a metropolitan planning area or portion of a metropolitan planning area and is not part of a Metropolitan Statistical Area or Consolidated Metropolitan Statistical Area which is or contains a nonattainment or maintenance area).

(A) Conformity demonstrations for projects in these areas may satisfy the requirements of Chapter 8, Section 4(t)(x)(aa) with one regional emissions analysis which includes all the regionally significant projects in the nonattainment or maintenance area (or portion thereof).

(B) The requirements of Chapter 8, Section 4(t) shall be satisfied according to the procedures in Chapter 8, Section 4(t)(iii), with references to the "transportation plan" taken to mean the statewide transportation plan.

(C) The requirements of Chapter 8, Sections 4(x) and (aa) which reference "transportation plan" or "TIP" shall be taken to mean those projects in the statewide transportation plan or statewide TIP which are in the nonattainment or maintenance area (or portion thereof).

(D) The requirement of Chapter 8, Section 4(cc)(ii) shall be satisfied if:

(I) The project is included in the regional emissions analysis which includes all regionally significant highway and transportation projects in the nonattainment or maintenance area (or portion thereof) and supports the most recent conformity determination made according to the requirements of Chapter 8, Sections 4(t)(x) or (aa) (as modified by paragraphs (iv)(B) and (iv)(C) of this section), as appropriate for the time period and pollutant; and

(II) The project's design concept and scope have not changed significantly from those which were included in the regional emissions analysis, or in a manner which would significantly impact use of the facility.

(v) PM₁₀ From Construction-Related Fugitive Dust.

(A) For areas in which the implementation plan does not identify construction-related fugitive PM₁₀ as a contributor to the nonattainment problem, the fugitive PM₁₀ emissions associated with highway and transit project construction are not required to be considered in the regional emissions analysis.

(B) In PM₁₀ nonattainment and maintenance areas with implementation plans which identify construction-related fugitive PM₁₀ as a contributor to the nonattainment problem, the regional PM₁₀ emissions analysis shall consider construction-related fugitive PM₁₀ control measures in the applicable implementation plan, and the dust-producing capacity of the proposed activities.

(ee) Procedures for Determining Localized CO and PM₁₀ Concentrations (Hot-Spot Analysis).

(i) In the following cases, CO hot-spot analyses must be based on the applicable air quality models, databases, and other requirements specified in 40 CFR part 51, Appendix W ("Guideline on Air Quality Models" (Revised 1988), supplement A (1987) and supplement B (1993), EPA publication no. 450/2-78-027R), unless, after the interagency consultation process described in Chapter 8, Section 4(e) and with the approval of the EPA Regional Administrator, these models, databases, and other requirements are determined to be inappropriate:

(A) For projects in or affecting locations, areas, or categories of sites which are identified in the applicable implementation plan as sites of current violation or possible current violation;

(B) For those intersections at Level-of-Service D, E, or F, or those that will change to Level-of-Service D, E, or F because of increased traffic volumes related to a new project in the vicinity;

(C) For any project involving or affecting any of the intersections which the applicable implementation plan identifies as the top three intersections in the nonattainment or maintenance area based on the highest traffic volumes;

(D) For any project involving or affecting any of the intersections which the applicable implementation plan identifies as the top three intersections in the nonattainment or maintenance area based on the worst Level-of-Service; and

(E) Where use of the “Guideline” models is practicable and reasonable given the potential for violations.

(ii) In cases other than those described in paragraph (i) of this section, other quantitative methods may be used if they represent reasonable and common professional practice.

(iii) CO hot-spot analyses must include the entire project, and may be performed only after the major design features which will significantly impact CO concentrations have been identified. The background concentration can be estimated using the ratio of future to current traffic multiplied by the ratio of future to current emission factors.

(iv) PM₁₀ hot-spot analysis must be performed for projects which are located at sites at which violations have been verified by monitoring, and at sites which have essentially identical vehicle and roadway emission and dispersion characteristics (including sites near one at which a violation has been monitored). The projects which require PM₁₀ hot-spot analysis shall be determined through the interagency consultation process required in Chapter 8, Section 4(e). In PM₁₀ nonattainment and maintenance areas, new or expanded bus and rail terminals and transfer points which increase the number of diesel vehicles congregating at a single location require hot-spot analysis. DOT may choose to make a categorical conformity determination on bus and rail terminals or transfer points based on appropriate modeling of various terminal sizes, configurations, and activity levels. The requirements of this paragraph for quantitative hot-spot analysis will not take effect until EPA releases modeling guidance on this subject and announces in the Federal Register that these requirements are in effect.

(v) Hot-spot analysis assumptions must be consistent with those in the regional emissions analysis for those inputs which are required for both analyses.

(vi) PM₁₀ or CO mitigation or control measures shall be assumed in the hot-spot analysis only where there are written commitments from the project sponsor and/or operator to the implementation of such measures, as required by Chapter 8, Section 4(gg)(i).

(vii) CO and PM₁₀ hot-spot analyses are not required to consider construction-related activities which cause temporary increases in emissions. Each site

which is affected by construction-related activities shall be considered separately, using established “Guideline” methods. Temporary increases are defined as those which occur only during the construction phase and last five years or less at any individual site.

(ff) Using the Motor Vehicle Emissions Budget in the Applicable Implementation Plan (or Implementation Plan Submission).

(i) In interpreting an applicable implementation plan (or implementation plan submission) with respect to its motor vehicle emissions budget(s), the MPO and DOT may not infer additions to the budget(s) that are not explicitly intended by the implementation plan (or submission). Unless the implementation plan explicitly quantifies the amount by which motor vehicle emissions could be higher while still allowing a demonstration of compliance with the milestone, attainment, or maintenance requirement and explicitly states an intent that some or all of this additional amount should be available to the MPO and DOT in the emission budget for conformity purposes, the MPO may not interpret the budget to be higher than the implementation plan’s estimate of future emissions. This applies in particular to applicable implementation plans (or submissions) which demonstrate that after implementation of control measures in the implementation plan:

(A) Emissions from all sources will be less than the total emissions that would be consistent with a required demonstration of an emissions reduction milestone;

(B) Emissions from all sources will result in achieving attainment prior to the attainment deadline and/or ambient concentrations in the attainment deadline year will be lower than needed to demonstrate attainment; or

(C) Emissions will be lower than needed to provide for continued maintenance.

(ii) If an applicable implementation plan submitted before November 24, 1993 demonstrates that emissions from all sources will be less than the total emissions that would be consistent with attainment and quantifies that “safety margin,” the State may submit a SIP revision which assigns some or all of this safety margin to highway and transit mobile sources for the purposes of conformity. Such a SIP revision, once it is endorsed by the Governor and has been subject to a public hearing, may be used for the purposes of transportation conformity before it is approved by EPA.

(iii) A conformity demonstration shall not trade emissions among budgets which the applicable implementation plan (or implementation plan submission) allocates for different pollutants or precursors, or among budgets allocated to motor vehicles and other sources, without a SIP revision or a SIP which establishes mechanisms for such trades.

(iv) If the applicable implementation plan (or implementation plan submission) estimates future emissions by geographic subarea of the nonattainment area, the MPO and DOT are not required to consider this to establish subarea budgets, unless the applicable implementation plan (or implementation plan submission) explicitly indicates an intent to create such subarea budgets for the purposes of conformity.

(v) If a nonattainment area includes more than one MPO, the SIP may establish motor vehicle emissions budgets for each MPO, or else the MPOs must collectively make a conformity determination for the entire nonattainment area.

(gg) Enforceability of Design Concept and Scope and Project-Level Mitigation and Control Measures.

(i) Prior to determining that a transportation project is in conformity, the MPO, other recipient of funds designated under Title 23 U.S.C. or the Federal Transit Act, FHWA, or FTA must obtain from the project sponsor and/or operator written commitments to implement in the construction of the project and operation of the resulting facility or service and project-level mitigation or control measures which are identified as conditions for NEPA process completion with respect to local PM₁₀ or CO impacts. Before making conformity determinations written commitments must also be obtained for project-level mitigation or control measures which are conditions for making conformity determinations for a transportation plan or TIP and included in the project design concept and scope which is used in the regional emissions analysis required by Chapter 8, Sections 4(r)-(t) and Chapter 8, Sections (v)-(x) or used in the project-level hot-spot analysis required by Chapter 8, Sections 4(p) and (u).

(ii) Project sponsors voluntarily committing to mitigation measures to facilitate positive conformity determinations must comply with the obligations of such commitments.

(iii) The implementation plan revision required in 40 CFR part 51, Subpart T shall provide that written commitments to mitigation measures must be obtained prior to a positive conformity determination, and that project sponsors must comply with such commitments.

(iv) During the control strategy and maintenance periods, if the MPO or project sponsor believes the mitigation or control measure is no longer necessary for conformity, the project sponsor or operator may be relieved of its obligation to implement the mitigation or control measure if it can demonstrate that the requirements of Chapter 8, Sections 4(p), (r), and (s) are satisfied without the mitigation or control measure, and so notifies the agencies involved in the interagency consultation process required under Chapter 8, Section 4(e). The MPO and DOT must confirm that the transportation plan and TIP still satisfy the requirements of Chapter 8, Sections 4(r) and (s) and that the project still satisfies the requirements of Chapter 8, Section 4(p), and therefore that the conformity determinations for the transportation plan, TIP, and project are still valid.

(hh) Exempt Projects. Notwithstanding the other requirements of this subpart, highway and transit projects of the types listed in Table 2 are exempt from the requirement that a conformity determination be made. Such projects may proceed toward implementation even in the absence of a conforming transportation plan and TIP. A particular action of the type listed in Table 2 is not exempt if the MPO in consultation with other agencies (see Chapter 8, Section 4(e)), the EPA, and the FHWA (in the case of a highway project) or the FTA (in the case of a transit project) concur that it has potentially adverse emissions impacts for any reason. States and MPOs must ensure that exempt projects do not interfere with TCM implementation.

Table 2. – Exempt Projects

SAFETY

Railroad/highway crossing
Hazard elimination program
Safer non-Federal-aid system roads
Shoulder improvements
Increasing sight distance
Safety improvement program
Traffic control devices and operating assistance other than signalization projects
Railroad/highway crossing warning devices
Guardrails, median barriers, crash cushions
Pavement resurfacing and/or rehabilitation
Pavement marking demonstration
Emergency relief (23 U.S.C. 125)
Fencing
Skid treatments
Safety roadside rest areas
Adding medians
Truck climbing lanes outside the urbanized area
Lighting improvements
Widening narrow pavements or reconstructing bridges (no additional travel lanes)
Emergency truck pullovers

MASS TRANSIT

Operating assistance to transit agencies
Purchase of support vehicles
Rehabilitation of transit vehicles¹
Purchase of office, shop, and operating equipment for existing facilities
Purchase of operating equipment for vehicles (e.g., radios, fareboxes, lifts, etc.)
Construction or renovation of power, signal, and communications systems
Construction of small passenger shelters and information kiosks
Reconstruction or renovation of transit buildings and structures (e.g., rail or bus buildings, storage and maintenance facilities, stations, terminals, and ancillary structures)

Rehabilitation or reconstruction of track structures, track, and trackbed in existing rights-of-way
Purchase of new buses and rail cars to replace existing vehicles or for minor expansions of the fleet¹
Construction of new bus or rail storage/maintenance facilities categorically excluded in 23 CFR 771

AIR QUALITY

Continuation of ride-sharing and van-pooling promotion activities at current levels
Bicycle and pedestrian facilities

OTHER

Specific activities which do not involve or lead directly to construction, such as:

- Planning and technical studies
- Grants for training and research programs
- Planning activities conducted pursuant to Titles 23 and 49 U.S.C.
- Federal-aid systems revisions

Engineering to assess social, economic, and environmental effects of the proposed action or alternatives to that action
Noise attenuation
Advance land acquisitions (23 CFR 712 or 23 CFR 771)
Acquisition of scenic easements
Plantings, landscaping, etc.
Sign removal
Directional and informational signs
Transportation enhancement activities (except rehabilitation and operation of historic transportation buildings, structures, or facilities)
Repair of damage caused by natural disasters, civil unrest, or terrorist acts, except projects involving substantial functional, locational or capacity changes

¹In PM₁₀ nonattainment or maintenance areas, such projects are exempt only if they are in compliance with control measures in the applicable implementation plan.

(ii) Projects Exempt From Regional Emissions Analyses. Notwithstanding the other requirements of this subpart, highway and transit projects of the types listed in Table 3 are exempt from regional emissions analysis requirements. The local effects of these projects with respect to CO or PM₁₀ concentrations must be considered to determine hot-spot analysis is required prior to making a project-level conformity determination. These projects may then proceed to the project development process even in the absence of a conforming transportation plan and TIP. A particular action of the type listed in Table 3 is not exempt from regional emissions analysis if the MPO in consultation with other agencies (see Chapter 8, Section 4(e)), the EPA, and the FHWA

(in the case of a highway project) or the FTA (in the case of a transit project) concur that it has potential regional impacts for any reason.

Table 3. – Projects Exempt From Regional Emissions Analyses

Intersection channelization projects
Intersection signalization projects at individual intersections
Interchange reconfiguration projects
Changes in vertical and horizontal alignment
Truck size and weight inspection stations
Bus terminals and transfer points

(jj) Special Provisions for Nonattainment Areas Which Are Not Required to Demonstrate Reasonable Further Progress and Attainment.

(i) Application. This section applies in the following areas:

- (A) Rural transport ozone nonattainment areas;
- (B) Marginal ozone areas;
- (C) Submarginal ozone areas;
- (D) Transitional ozone areas;
- (E) Incomplete data ozone areas;
- (F) Moderate CO areas with a design value of 12.7 ppm or less;

and

- (G) Not classified CO areas.

(ii) Default Conformity Procedures. The criteria and procedures in Chapter 8, Sections 4(v)-(x) will remain in effect throughout the control strategy period for transportation plans, TIPs, and projects (not from a conforming plan and TIP) in lieu of the procedures in Chapter 8, Sections 4(r)-(t), except as otherwise provided in paragraph (iii) of this section.

(iii) Optional Conformity Procedures. The State or MPO may voluntarily develop an attainment demonstration and corresponding motor vehicle emissions budget like those required in areas with higher nonattainment classifications. In this case, the State must submit an implementation plan revision which contains that budget and attainment demonstration. Once EPA has approved this implementation plan revision, the procedures in Chapter 8, Sections 4(r)-(t) apply in lieu of the procedures in Chapter 8, Sections 4(v)-(x).

Section 5. Ozone nonattainment emission inventory rule.

(a) Applicability.

(i) This rule applies to a facility or source operating in an ozone nonattainment area(s), as identified in 40 CFR part 81, if:

(A) The facility or source has been granted permit approval to construct and/or operate under Chapter 6 of the Wyoming Air Quality Standards and Regulations (WAQSR); or

(B) It is an individual oil or gas facility or source; or

(C) Actual emissions from the stationary facility or source are greater than or equal to twenty-five (25) tons per year of volatile organic compounds (VOCs) as defined in Chapter 3, Section 6(a) of the WAQSR, or oxides of nitrogen (NO_x).

(I) If NO_x or VOCs are emitted from a facility or source at or above the applicability threshold identified in subsection (a)(i)(C), both air contaminants must be included in the emission inventory even if one of the air contaminants is emitted at a level below the applicability threshold.

(ii) Compliance with emission inventory requirements established under WAQSR Chapter 6, Section 3(f)(v)(G), satisfies the requirements of this rule.

(b) Reporting and Recordkeeping Requirements.

(i) As specified in the forms required in subsection (b)(v), each emission inventory shall include:

(A) Actual emissions of NO_x, VOC, and any other air contaminants as determined by the Division Administrator, in tons per year for any calendar year emission inventory, or in tons for any partial year emission inventory;

(B) The physical location at which the actual emissions occurred;

(C) The name and address of the person or entity operating or owning the facility or source; and

(D) The nature of the facility or source.

(ii) The emission inventory submittal dates are as follows:

(A) By April 30th of each year for all emissions that occurred during the previous calendar year; and

(B) No later than ninety (90) days after the end of a partial year inventory for emissions that occurred during the partial year as determined by the Division Administrator.

(iii) After the owner or operator submits an emission inventory for all facility or source emissions that occurred during calendar year 2014, the owner or operator shall submit an emission inventory for such facility or source every year thereafter.

(iv) Each owner or operator of a facility or source shall maintain a copy of the emission inventory submitted to the Division, and records indicating how the information submitted was determined, including any calculations, data, and measurements used.

(A) Records shall be kept for a period of at least five (5) years from the required submittal date listed in subsection (b)(ii) for each emission inventory.

(B) The owner or operator of the facility or source shall make the records required in subsection (b)(iv) available for inspection by any representative of the Division upon request.

(v) The owner or operator shall submit emission inventories using Division-prescribed hard copy or electronic formats.

(vi) All emission inventory submissions shall be certified as being true, accurate, and complete by a responsible official to the best of their knowledge. A responsible official is an individual who is responsible for the data provided in the emission inventory, and who accepts responsibility for the emission accuracy.

(c) Compliance. Compliance with WAQSR Chapter 8, Section 5, does not relieve any owner or operator of a facility or source from the responsibility to comply with any other applicable reporting requirements set forth in any federal or State law, rule or regulation, or in any permit.

Section 6. Upper Green River Basin permit by rule for existing sources

(a) Applicability.

(i) These regulations apply to all PAD and single-well oil and gas production facilities or sources, and all compressor stations, located in the Upper Green River Basin (UGRB) ozone nonattainment area that exist as of January 1, 2014. The UGRB ozone nonattainment area is that area which was adopted by reference from 40 CFR part 81.351, revised and published as of July 1, 2013, not including any later amendments. Copies of the Code of Federal Regulations (CFR) are available for public inspection and can be purchased from the Department of Environmental Quality, Air

Quality Division, Cheyenne Office. Contact information for the Cheyenne Office is available at: <http://deq.wyoming.gov/>. Copies of the CFR can also be purchased from Government Institutes, 15200 NBN Way, Building B, Blue Ridge Summit, PA 17214, or online at: <http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR>.

(ii) PAD and single-well oil and gas production facilities or sources, shall comply with all applicable requirements of these regulations unless a Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2 permit has been issued that meets or exceeds the control requirements of these regulations; and

(iii) A compressor station, as defined in Subsection (b), shall comply with the requirements of Subsection (g) of these regulations unless a WAQSR Chapter 6, Section 2 permit has been issued that meets or exceeds the Subsection (g) requirements; and

(iv) In spite of the requirements of Chapter 6, Section 2(a)(i) and (iii) of the WAQSR, a preconstruction permit under Chapter 6, Section 2 is not required for any control device (flare/enclosed combustion unit) or equipment identified in these regulations unless a facility or source is required to obtain a permit under Chapter 6, Section 4 or Section 13.

(v) A WAQSR Chapter 6, Section 2 permit will be required for the use of any alternative emission control device and/or equipment to be used in lieu of, or in combination with, a combustion device required by these regulations.

(b) Definitions.

“Composite extended hydrocarbon analysis” are averaged extended hydrocarbon compositions based on samples from at least five wells producing from the same formation and under similar conditions (± 25 psig).

“Compressor station” means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

“Dehydration unit” means a system that uses glycol to absorb water from produced gas before it is introduced into gas sales or collection lines.

“Extended hydrocarbon analysis” means a gas chromatograph analysis performed on pressurized hydrocarbon liquid (oil/condensate) and gas samples, and shall include speciated hydrocarbons from methane (C1) through decane (C10), and the following Hazardous Air Pollutants (HAP): benzene, toluene, ethyl-benzene, xylenes (BTEX), n-hexane, and 2-2-4-trimethylpentane.

“Facility components” consist of flanges, connectors (other than flanges), open-ended lines, pumps, valves and “other” components listed in Table 2-4 from EPA-453/R-95-017 at the site grouped by stream (gas, light oil, heavy oil, water/oil). Table 2-4 from EPA-453/R-95-017 is available online at: <http://deq.wyoming.gov/aqd/> or <http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf>.

“Flashing emissions” means VOC emissions, including HAP components, that occur when gases are released from produced liquids (oil, condensate, produced water, or a mixture thereof) that are exposed to temperature increases or pressure drops as they are transferred from pressurized vessels to lower pressure separation vessels or to atmospheric storage tanks.

“Optical gas imaging instrument” means an instrument that makes visible, emissions that may otherwise be invisible to the naked eye.

“PAD facility” means a location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location.

“Separation vessels” means all gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, and drip pots.

“Single-well facility” means a facility where production equipment is associated with only one well.

“Storage tanks” means any tanks that contain oil, condensate, produced water, or some mixture thereof.

(c) Flashing Emissions at Existing PAD and Single-Well Facilities or Sources as of January 1, 2014.

(i) VOC emissions from all existing storage tanks and all existing separation vessels are subject to these regulations.

(A) For total uncontrolled VOC emissions from flashing that are greater than or equal to 4 tons per year (tpy), flashing emissions from all produced oil, condensate, water tanks, and separation vessels shall be controlled to at least 98% manufacturer-designed VOC destruction efficiency by January 1, 2017.

(B) Storage tanks that are on site for use during emergency or upset conditions are not subject to the control requirements in this Subsection.

(C) Emergency, open-top, and/or blowdown tanks shall not be used as active storage tanks but may be used for temporary storage.

(I) Emergency tanks shall only be utilized for unavoidable equipment malfunctions as defined in Chapter 1, Section 5 of the WAQSR.

(II) If emergency, open-top, and/or blowdown tanks are utilized, they must be emptied within seven (7) calendar days after the liquid volume reaches 100 barrels, or in no event less frequently than once every ninety (90) calendar days.

(III) All tanks subject to this Subsection must have a liquid level gauge, or equivalent device, in place by January 1, 2017.

(D) Control Removal. The removal of flashing emissions control devices will be allowed pursuant to the requirements in Subparagraph (h)(iii)(E), after one (1) year from the date of installation if uncontrolled VOC flashing emissions have declined to less than, and will remain below 4 tpy.

(ii) Calculation for Flashing Emissions.

(A) Determine the average daily condensate/oil production for the previous twelve (12) calendar months in barrels per day (bpd).

(B) Use any generally accepted model in accordance with 40 CFR 60, Subpart OOOO or direct measurement of tank emissions to determine uncontrolled VOC emissions.

(C) Model input shall consist of:

(I) A site-specific analysis of liquids, or composite extended hydrocarbon analysis of liquids, taken from the pressurized, upstream separation equipment under normal operating conditions;

(II) Average daily condensate/oil production rate as determined in Subparagraph (c)(ii)(A) of these regulations;

(III) Site-specific or composite extended hydrocarbon analyses will be no older than three (3) years from date of flashing emissions calculation including;

(1.) The average, actual equipment operational parameters, including separator temperature and pressure; and

(2.) American Petroleum Institute (API) gravity and Reid vapor pressure (RVP) of sales oil.

(d) Dehydration Units at Existing PAD and Single-Well Facilities or Sources as of January 1, 2014.

(i) VOC emissions released from all existing dehydration units are subject to these regulations.

(A) For total uncontrolled VOC emissions from all dehydration units that are greater than or equal to 4 tpy, VOC emissions from all dehydration units shall be controlled to at least 98% manufacturer-designed VOC destruction efficiency and equipped with reboiler still vent condensers by January 1, 2017.

(B) Control Removal. The removal of combustion units used to achieve the 98% manufacturer-designed VOC destruction efficiency will be allowed pursuant to the requirements in Subparagraph (h)(iii)(E), after one (1) year from the date of installation if total uncontrolled VOC emissions from all dehydration units are less than, and will remain below 4 tpy, and all dehydration units are equipped with reboiler still vent condensers.

(ii) Calculation for Dehydration Units.

(A) Determine the average daily gas production rate for the previous twelve (12) calendar months in million cubic feet per day (MMCFD).

(B) Use the model GRI-GLYCalc, Version 4.0 or higher, and the annualized average daily production rate to determine annualized uncontrolled VOC emissions from the dehydration unit process vents. Process vents include reboiler still vents and glycol flash separators.

(C) Model input shall consist of:

(I) A site-specific wet gas analysis or composite extended hydrocarbon analysis of wet gas taken upstream of the contact tower under normal operating conditions;

(II) Average daily gas production rate as determined in Subparagraph (d)(ii)(A) of these regulations; and

(III) Site-specific or composite extended hydrocarbon analyses shall be no older than three (3) years from date of the dehydration unit calculation including;

(1.) The average, actual equipment operational parameters, including wet gas temperature and pressure, dry gas water content, glycol flash separator temperature and pressure, stripping gas source and rate; and

(2.) The maximum lean glycol circulation rate in gallons per minute (gpm) for the glycol circulation pump in use.

(e) Existing Pneumatic Pumps at PAD and Single-Well Facilities or Sources as of January 1, 2014. VOC emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled to at least 98% manufacturer-designed VOC destruction efficiency, or the pump discharge streams shall be routed into a sales line, collection line, fuel supply line, other closed loop system, or replaced with solar, electric, or air driven pumps by January 1, 2017.

(f) Existing Pneumatic Controllers at PAD and Single-Well Facilities or Sources as of January 1, 2014. Natural gas-operated pneumatic controllers shall be low (less than 6 standard cubic feet per hour (scfh)) or zero bleed controllers or the controller discharge streams shall be routed into a sales line, collection line, fuel supply line, or other closed loop system by January 1, 2017.

(g) Fugitive Emissions.

(i) For PAD and single-well facilities or sources, and compressor stations, in existence prior to January 1, 2014, with fugitive emissions greater than or equal to 4 tpy of VOCs, including HAP components, operators shall develop and implement a Leak Detection and Repair (LDAR) Protocol by January 1, 2017.

(A) The LDAR Protocol inspection monitoring schedule shall be no less frequent than quarterly; and

(B) Shall include a leak repair schedule; and

(C) Each quarterly inspection shall consist of some combination of 40 CFR part 60, Appendix A, Method 21, an optical gas imaging instrument, other instrument-based technologies, or audio-visual-olfactory (AVO) inspections.

(D) An LDAR Protocol consisting of only AVO inspections will not satisfy the requirements of this Subsection.

(ii) Calculation for Fugitive Emissions.

(A) Fugitive emissions shall be estimated using Table 2-4 from EPA-453/R-95-017, Protocol for Equipment Leak Emission Estimates, and the owner(s) or operator(s) facility component count.

(I) PAD and single-well facility or source component counts shall be determined by actual field count, or a representative component count from the same geographical area, taken from no less than one hundred (100) wells located at a PAD or single-well facility.

(II) Compressor station component counts shall be determined by actual field count.

(III) Emission factors in the Protocol for Equipment Leak Emission Estimates are not intended to be used to represent emissions from components that are improperly designed or equipment not maintained properly.

(B) Site-specific speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rate, estimated in Subparagraph (g)(ii)(A) above, by measured VOC and HAP weight fractions.

(h) Monitoring, Recordkeeping, and Reporting.

(i) Monitoring. The owner(s) or operator(s) of each PAD and single-well facility or source, or compressor station, shall comply with all applicable monitoring requirements as specified by this Paragraph.

(A) Operation of a combustion device used to control emissions shall be continually monitored using any device(s) that sense and record a parameter(s) that indicates whether the combustion device is functioning to achieve the 98% manufacturer-designed VOC destruction efficiency requirements as specified by these regulations.

(I) The combustion device shall be designed, constructed, operated, and maintained to be smokeless, to satisfy the requirements of Chapter 3, Section 6(b)(i) of the WAQSR.

(II) Visible emissions shall not exceed a total of five (5) minutes during any two (2) consecutive hours as determined by 40 CFR part 60, Appendix A, Method 22.

(B) All emission control devices and equipment used to reduce VOC emissions at any PAD and single-well facility or source shall be operated and maintained pursuant to manufacturer specifications or equivalent, and consistent with good engineering and maintenance practices.

(C) Owner(s) or operator(s) shall conduct a quarterly site evaluation of control equipment, systems, and devices that include, but are not limited to, combustion units, reboiler overheads condensers, storage tanks, drip tanks, vent lines, connectors, fittings, valves, relief valves, hatches, and any other appurtenance employed to, or involved with, eliminating, reducing, containing or collecting vapors and routing them to an emission control system or device.

(I) At least one (1) of the quarterly evaluations per calendar year shall consist of 40 CFR part 60, Appendix A, Method 21, an optical gas imaging instrument, or other instrument-based technologies.

(II) Owner(s) or operator(s) required to implement an LDAR Protocol have satisfied the requirements of Subparagraph (C) above.

(ii) Recordkeeping. The owner(s) or operator(s) of each PAD and single-well facility or source, or compressor station, shall comply with all applicable recordkeeping requirements as specified by this Paragraph. Records shall be maintained for a period of five (5) years and made available to the Division upon request.

(A) All emission control devices and equipment are adequately designed and sized to achieve the control efficiency required by these regulations and to accommodate fluctuations in emissions.

(B) Owner(s) or operator(s) shall maintain the following records for each combustion device:

(I) Manufacturer-designed VOC destruction efficiency.

(II) Records of the parameter monitoring during active site operation under Subparagraph (h)(i)(A) including;

(1.) A description of the reason(s) for the absence of the monitored parameter;

(2.) The steps taken to return the combustion device back to the 98% manufacturer-designed VOC destruction efficiency; and

(3.) Date and duration of periods when the combustion device and/or the associated containment and collection equipment is not functioning to achieve the 98% manufacturer-designed VOC destruction efficiency.

(III) Date and duration of visible emissions from the combustion device.

(C) Owner(s) or operator(s) shall record and maintain records for fugitive emissions pursuant to Subsection (g) of these regulations. These records shall include the dates and results of all LDAR inspections performed pursuant to the LDAR protocol for a PAD and single-well facility or source, or compressor station, including the date(s) and type of corrective action taken as a result of the required inspections.

(D) Records of the date, duration, and reason for emergency and/or blowdown tank usage, shall be maintained pursuant to Subparagraph (c)(i)(C) of these regulations.

(E) Owners or operators that utilize emergency, open-top, and/or blowdown tanks pursuant to Subsection (c) shall record and maintain monthly records for volume stored in tanks, volume removed from tanks, and the date when the removal of liquid occurred.

(iii) Reporting. The owner(s) or operator(s) of each PAD and single-well facility or source, or compressor station, shall comply with all applicable reporting requirements as specified by this Subsection.

(A) The owner(s) or operator(s) shall provide the name and location of the PAD and single-well facility or source, or compressor station, anticipated to require the installation of a combustion device, replacement of equipment, or implementation of an LDAR Protocol, if applicable, by January 1, 2016.

(B) Installation Notification of Control Device(s) and Associated Equipment (including pneumatic pumps). Owner(s) or operator(s) of each PAD and single-well facility or source subject to the requirements of these regulations shall submit a report to the Division thirty (30) days after the end of each calendar quarter, beginning January 1, 2016, containing the following, if applicable:

(I) The number of pollution control devices or equipment installed;

(II) Pollution control installation date, type of control, and equipment controlled;

(III) Name and location of the PAD and/or single-well facility or source where controls are installed.

(C) Installation Notification of Pneumatic Controller(s). Owner(s) or operator(s) of each PAD and single-well facility or source subject to the requirements of these regulations shall submit a report to the Division thirty (30) days after the end of each calendar quarter, beginning January 1, 2016, containing the following, if applicable:

(I) The number and type of pneumatic controllers installed and date of installation; and

(II) Name and location of the PAD and/or single-well facility or source where pneumatic controllers are installed.

(D) The final, quarterly notification of installation required under Subsections (B) and (C) above, shall be submitted no later than January 31, 2017, if applicable.

(E) Removal Notification of Control Device(s). The owner(s) or operator(s) of each PAD and single-well facility or source subject to the requirements of these regulations shall submit a demonstration to the Division for approval prior to removal of any pollution control device. This demonstration shall contain at a minimum:

(I) The average daily condensate/oil or gas production rate for the previous twelve (12) calendar months;

(II) Emissions as determined by utilizing paragraph (I) above, and the calculation for flashing emissions in Paragraph (c)(ii), and/or the calculation for dehydration units in Paragraph (d)(ii) of these regulations;

(III) Any additional supporting data used to calculate emissions, including but not limited to, a site specific or composite extended hydrocarbon analysis no older than three (3) years from the proposed removal date; and

(IV) Name and location of the PAD and/or single-well facility or source where controls are proposed for removal.

(F) Any PAD and single-well facility or source, or compressor station, subject to requirements of Subsection (g) of these regulations shall submit, for Division review and approval, the LDAR Protocol prior to implementation of the protocol.

(G) All report and notification submissions shall be certified as being true, accurate, and complete by a responsible official to the best of their knowledge. A responsible official is an individual who is responsible for the information provided in the reports and notifications, and who accepts responsibility for the reports and notifications.

(H) The owner(s) or operator(s) shall submit notifications or reports as required in this Subsection to the Division electronically through <https://airimpact.wyo.gov> or by hard copy to the Cheyenne Office and Lander Field Office. Contact information for the Cheyenne and Lander offices is located at: <http://deq.wyoming.gov/>.

(i) Compliance. Compliance with Chapter 8, Section 6 of the WAQSR, does not relieve any owner(s) or operator(s) of a PAD and single-well facility or source, or compressor station, from the responsibility to comply with any other applicable requirements set forth in any federal or State law, rule or regulation, or in any permit.

Section 7. **[Reserved.]**

Section 8. **[Reserved.]**

Section 9. **[Reserved.]**

Section 10. **Incorporation by reference.**

(a) Code of Federal Regulations (CFR). All Code of Federal Regulations (CFRs) cited in this chapter, including their Appendices, revised and published as of July

1, 2013, not including any later amendments, are incorporated by reference. Copies of the Code of Federal Regulations are available for public inspection and can be obtained at cost from the Department of Environmental Quality, Division of Air Quality, Cheyenne Office. Contact information for the Cheyenne Office can be obtained at: <http://deq.wyoming.gov/>. Copies of the CFRs can also be obtained at cost from Government Institutes, 15200 NBN Way, Building B, Blue Ridge Summit, PA 17214, or online at: <http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR>.



Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance

June 1997
Revised November 1998
Revised January 2000
Revised August 2001
Revised July 28, 2004 (specific guidance for Jonah/Pinedale Anticline Area)
Revised August 2007
Revised March 2010
Revised September 2013 (Added specific guidance for UGRB and revisions to JPAD)
Revised May 2016

Under § 35-11-801(e) of the Wyoming Environmental Quality Act, construction or modification of an oil and gas exploration or production well may occur prior to permitting, as long as the facility (1) is not a major source; (2) is permitted within 90 days of the first date of production (FDOP); and (3) applies Best Available Control Technology (BACT). However, any owner or operator may instead apply for a construction or modification permit under Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations prior to construction or modification of a facility.

This interpretive guidance discusses the Division's current understanding of BACT for the purpose of assisting owners and operators who choose to construct or modify oil and gas production facilities prior to initiating the permitting process. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any other person.

Owners and operators should be advised that this Guidance represents the agency's current understanding of BACT as of May 12, 2016.

This Guidance applies to surface oil and gas production facilities where hydrocarbon fluids are produced, processed and/or treated prior to custody transfer from the facility.

This Guidance does not apply to sour (H₂S containing) oil production sites. This Guidance also may not be used for sour gas (H₂S) production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H₂S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction to determine BACT requirements.

This Guidance does not apply to greenhouse gas emissions (GHGs) or major sources as defined under Wyoming Air Quality Standards and Regulations Chapter 6, Section 3 or Chapter 6, Section 13.

This Guidance does not apply to reciprocating internal combustion engines located at oil and gas production facilities unless the engine is natural gas-fired, used to power a pumping unit, is less than or equal to 50 horsepower, and meets BACT. Reciprocating internal combustion engines larger than 50 horsepower are required to obtain an air quality permit or permit waiver prior to installation.

The Presumptive BACT permitting requirements under this Guidance apply to facilities with associated wells that have a first date of production (FDOP) on/after July 1, 2016 and to facilities with a modification occurring on/after July 1, 2016.

Start up or modification of a facility may occur prior to obtaining an Air Quality Permit or Waiver only when the Presumptive BACT permitting requirements under this Guidance are met. Otherwise, an Air Quality Permit or Waiver shall be obtained prior to start up or modification of a facility.

For the purposes of this Guidance **SWA (STATEWIDE AREA)** refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin**.

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

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Table of Contents

| | |
|---|----|
| Introduction | 1 |
| Applicability | 1 |
| When is a permit needed | 1 |
| Which pollutants are associated with O&G production facilities | 2 |
| Production Facility Emission Sources | 2 |
| O&G production facility emission sources | 2 |
| BACT and Presumptive BACT (what is it and when to use it) | 4 |
| JPAD/NPL UGRB SWA Definitions | 5 |
| JPAD/NPL UGRB SWA Map | 6 |
| SWA P-BACT permitting requirements..... | 7 |
| Flashing..... | 7 |
| Dehydration Units | 8 |
| Determining potential uncontrolled and potential emissions from dehydration units | 9 |
| Pneumatic pumps | 10 |
| Pneumatic controllers..... | 11 |
| Truck loading | 11 |
| Well completions | 12 |
| Produced water tanks | 12 |
| Blowdown and venting | 13 |
| Emission sources without P-BACT requirements..... | 13 |
| UGRB P-BACT permitting requirements | 14 |
| Flashing..... | 14 |
| Dehydration Units | 15 |
| Pneumatic pumps | 16 |
| Pneumatic controllers..... | 16 |
| Fugitives..... | 17 |
| Truck loading | 17 |
| Well completions | 18 |
| Produced water tanks | 18 |
| Blowdown and venting | 19 |
| Emission sources without P-BACT requirements..... | 19 |
| JPAD/NPL P-BACT permitting requirements..... | 20 |
| Flashing..... | 20 |
| Dehydration Units | 20 |
| Pneumatic pumps | 21 |
| Pneumatic controllers..... | 21 |
| Produced water tanks | 22 |
| Fugitives..... | 22 |
| Truck loading | 23 |
| Well completions | 23 |
| Blowdown and venting | 24 |
| Emission sources without P-BACT requirements..... | 24 |



Table of Contents (cont.)

| | |
|---|----|
| Determining P-BACT emissions | 25 |
| Flashing..... | 25 |
| Dehydration Units..... | 27 |
| Kimray glycol pump rates (Table 1)..... | 28 |
| BACT Emission control requirements | 29 |
| Flashing emissions..... | 29 |
| Dehydration unit emissions..... | 30 |
| Sources without P-BACT emission control requirements..... | 31 |
| Permit applications | 32 |
| A complete application includes..... | 32 |
| How to obtain forms..... | 33 |
| When/where to file application..... | 33 |
| Example process diagram and description..... | 34 |
| Application review process, public notice, billing..... | 36 |
| Explanation of 0.6 decline factor | 37 |
| Pumping unit engines | 38 |
| Appendix A – Emission Calculations | 39 |
| AP-42 emission factors..... | 40 |
| Storage tank emissions (flashing, working, breathing losses)..... | 40 |
| Pressurized vessels (separator, treater, FWKO, flash separator, gunbarrel, gas boot)..... | 41 |
| Dehydration units..... | 41 |
| Natural gas-fired heaters..... | 42 |
| Flares..... | 43 |
| Pneumatic pumps..... | 43 |
| Pneumatic controllers..... | 44 |
| Truck loading..... | 44 |
| Fugitives..... | 45 |
| IC pumping unit engines..... | 46 |
| Mol% to Wt% conversion..... | 47 |
| Appendix B – Definitions | 48 |



Acronyms and Abbreviations

| | | | |
|------------------|---|-----------------|--|
| AQD | Air Quality Division | NESHAP | National Emission Standards for Hazardous Air Pollutants |
| API | American Petroleum Institute | NOI | Notice of Installation |
| BACT | Best Available Control Technology | NOV | Notice of Violation |
| BBL | barrel | NO _x | Nitrogen Oxides |
| BPD | barrels per day | NSPS | New Source Performance Standards |
| BTEX | Benzene/Toluene/ Ethyl-benzene/Xylenes | NSR | New Source Review |
| Btu | British thermal unit | O&G | Oil and Gas |
| C6 S2 | Chapter 6 Section 2 (of the WAQSR) | P-BACT | Presumptive BACT |
| CAA | Clean Air Act Amendments of 1990 | pph | pounds per hour |
| CO | Carbon Monoxide | PPMV | parts per million by volume |
| EPA | Environmental Protection Agency | PSD | Prevention of Significant Deterioration |
| FEM | Fugitive Emissions Monitoring | psig | pounds per square inch gauge |
| FWKO | Free water knockout | psia | pounds per square inch absolute |
| gpm | gallons per minute | SCF | standard cubic foot |
| H ₂ S | Hydrogen Sulfide | SO ₂ | Sulfur Dioxide |
| HAP | Hazardous Air Pollutants | S/W/B | Standing/Working/Breathing losses |
| HP | high pressure | TEG | Tri-Ethylene Glycol |
| Hp | horsepower | TPY | Tons per Year |
| IMPACT | <u>I</u> nventory, <u>M</u> onitoring, <u>P</u> ermitting, <u>A</u> nd <u>C</u> ompliance <u>T</u> racking online data system | VOC | Volatile Organic Compounds |
| lb | pound | WAQSR | Wyoming Air Quality Standards and Regulations |
| LP | low pressure | WDEQ | Wyoming Department of Environmental Quality |
| MMBtu | one million BTUs | | |
| MMSCF | one million standard cubic feet (SCF × 10 ⁶) (MMSCFD = 1,000,000 SCF per day) | | |
| MSCF | one thousand standard cubic feet (SCF×1000) (MSCFD=1000 SCF per day) | | |



Introduction

The Oil and Gas Production Facilities Chapter 6 Section 2 Permitting Guidance (C6 S2 Guidance) document is an interpretive policy intended to publicize the Division's current understanding of BACT for certain types of emission sources at certain types of oil and gas production facilities. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any person. Any owners or operators seeking site-specific BACT analyses may choose to follow the standard Chapter 6, Section 2 permitting process prior to the construction or modification of a facility.



Applicability

When is a permit needed?

If **ANY** air pollutant will be released to the atmosphere from a new or modified facility, the facility is subject to the Wyoming Air Quality Standards and Regulations (**WAQSR**) and the Wyoming Environmental Quality Act. This Guidance does not apply to greenhouse gas emissions, sour oil production sites, or reciprocating internal combustion engines greater than 50 horsepower. This Guidance also may not be used for sour gas production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc.

Owners/operators of **ALL** regulated air emission sources constructed or modified after May 29, 1974 shall comply with the WAQSR Chapter 6, Section 2 permitting requirements. To obtain a copy of the WAQSR contact the Wyoming Air Quality Division at (307) 777-7391 or download an electronic version from the Wyoming Secretary of State (<http://soswy.state.wy.us/Rules/default.aspx>). A link to the Secretary of State's website is available on the WDEQ's Air Quality website at <http://deq.wyoming.gov/aqd/>.

Under the Wyoming Environmental Quality Act, certain oil and gas production facilities may be constructed or modified prior to obtaining a permit or waiver, as long as they are minor sources, obtain a permit within 90 days of FDOP, and utilize BACT. Wyo. Stat. Ann. § 35-11-801(e).

Failure to comply with the Wyoming Environmental Quality Act and Wyoming Air Quality Regulations may result in an enforcement action undertaken by the State in the form of a "Notice of Violation", a complaint filed in District Court, or any other enforcement action allowed by law. The Wyoming Environmental Quality Act authorizes the assessment of penalties of up to \$10,000.00 per violation per day and/or injunctive relief.

Which pollutants are associated with oil and gas (O&G) production facilities?

The following air pollutants are commonly associated with O&G production facilities:

Volatile Organic Compounds (VOC): Hydrocarbon compounds excluding methane (C₁) and ethane (C₂). VOCs are also referred to as C₃⁺ compounds – propane, butane, pentane, hexane, etc.

Hazardous Air Pollutants (HAP): HAPs commonly associated with O&G production are BTEX and n-hexane (benzene, toluene, ethyl-benzene, xylenes and n-C₆). Section 112(b) of the Clean Air Act identified the regulated HAPs.

Nitrogen Oxides (NO_x): NO_x emissions are the result of natural gas combustion.

Carbon Monoxide (CO): CO emissions are the result of natural gas combustion.

Hydrogen Sulfide (H₂S): Contained within fields that produce sour gas.

Sulfur Dioxide (SO₂): Created when H₂S is combusted.



Production Facility Emission Sources

O&G production facilities emission sources:

Storage Tanks: Vapors containing regulated air pollutants are released from solution as oil, condensate and water are transferred from separation equipment to atmospheric storage tanks. These vapors are called **flashing losses**. Vapors evaporated or displaced from tanks are called **working and breathing (also called standing) losses (S/W/B)**.

Dehydration Units: Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. “Lean” TEG contacts the wet gas and absorbs water. The TEG, now considered “rich” is routed through a flash separator and/or reboiler for regeneration. Vapors released from the flash separator and reboiler still vent contain regulated air pollutants.

Pressurized Process Vessels: Vapors vented from gun barrels, separators, treaters, water knockouts, gas boots, flash separators, drip pots, etc. contain regulated air pollutants. The discharge lines and vents from all of these vessels shall be considered when determining emission sources.

Natural Gas-Fired Equipment: Some of the byproducts of natural gas combustion in process heaters, boilers, burners, flares, engines, etc. are regulated air pollutants.

Fugitives: All production facilities contain numerous equipment components such as valves, flanges, threaded connections, tubing connections, open-ended lines, pump seals, etc., which are manufactured and installed in ways intended to contain gases or liquids. Over time some of them begin to leak. Emissions associated with leaks are called fugitive emissions. For purposes of this Guidance, emissions from components that are improperly designed (e.g. enardo valves over pressurizing, failure of thief hatches to reseal after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open) are not considered to be fugitive emissions.

Pneumatic Pumps & Controllers: The discharge vapors from natural gas-operated pneumatic equipment contain regulated air pollutants.

Truck Loading: Vapors displaced from truck tanks during the loading of produced liquids that contain regulated air pollutants.

Venting & Blowdown: Natural gas and liquids contain regulated air pollutants.

Well Completions: Activities that occur after a well is drilled that are undertaken to produce hydrocarbon fluids from the well. These include casing, cementing, perforating, gravel packing and installing a production tree.

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BACT and Presumptive BACT

Under WAQSR Chapter 6, Section 2(c), all new or modified sources or facilities, which may generate regulated air emissions shall be permitted prior to construction or modification and **Best Available Control Technology (BACT)** shall be applied to reduce or eliminate emissions, with consideration given for technical feasibility and economical reasonableness. **BACT** is a process, not an emission limit. Regulations do not set a minimum emission threshold below which **BACT** does not need to be considered.

At O&G facilities production rates and associated pollutant emissions are usually unknown prior to start up. The AQD has tailored a permitting program allowing for the start up or modification of O&G facilities prior to permitting provided specific emission control requirements are met.

This is the **Presumptive BACT** permitting process for O&G production facilities.

Presumptive BACT requirements have been established for emissions associated with:

- Flashing & S/W/B losses from atmospheric storage tanks and pressurized vessels
- Dehydration unit process vents
- Natural gas-operated pneumatic equipment
- Natural gas-fired pumping unit engines
- Truck loading
- Produced water tanks
- Well completions
- Well blowdown/venting

If emissions **are known prior to** construction or modification, a permit shall be obtained **PRIOR TO CONSTRUCTION or MODIFICATION** and BACT, including Presumptive BACT requirements, shall be addressed in the application. Examples include:

- Construction of a central tank battery for collecting and processing production from surrounding existing wells with known production rates
- Consolidation of multiple existing facilities for which production rates have been established
- Installation of a dehydration unit for an existing well with an established gas production rate
- Installation of larger capacity equipment to replace undersized equipment
- Replacement of an emission control system or device with a different system or device

Presumptive BACT requirements have been established for three (3) areas:

SWA refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin**.

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

The **UGRB** area is defined, in accordance with the public land survey system, as:

Sublette County: (all)

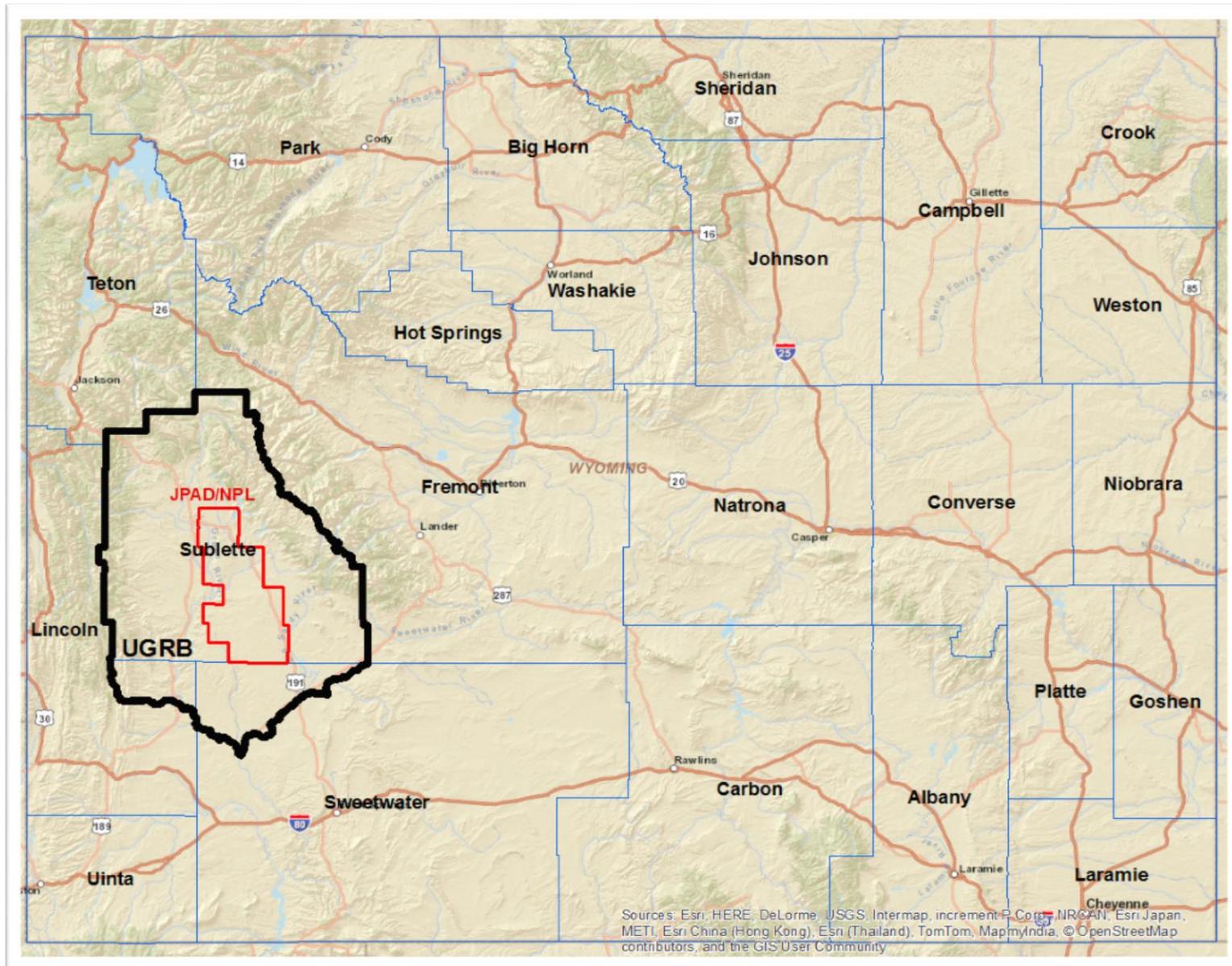
Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West (R115W) Township (T) 27 North (T27N) and the northwest corner of Section 31 R115W T27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W T22N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast along the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T26N. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T26N, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

The **JPAD/NPL** area is defined as:

Sublette County: R109W & R110W in T34N,
R109W & R110W in T33N,
R108W, R109W & R110W in T32N,
R108W, R109W & R110W in T31N,
R107W, R108W & R109W in T30N,
R107W, R108W, R109W, & R110W in T29N,
R107W, R108W, R109W, & R110W in T28N,
and R107W, R108W & R109W in T27N

The **SWA** refers to all other areas in the State excluding the **UGRB** or **JPAD/NPL**.





Presumptive BACT Requirements for SWA Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC and/or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon First Date of Production (FDOP), VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 6 Tons per Year (TPY) VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 6 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a flashing emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 6 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to all existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to a combustion unit for at least 98% control of VOC and HAP emissions. All glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.



Presumptive BACT Requirements for SWA Facilities (cont.)

All Facilities (cont.)

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.

Potential Uncontrolled VOC and HAPs emissions shall be determined using GRI-GLYCalc version 4.0 (V4.0) or higher or other method accepted by the Division and shall be based on the projected, year one, average daily dry gas throughput rate, maximum circulation rate for the glycol circulation pump(s) installed, average expected operating parameters for wet gas temperature and pressure, maximum dry gas water content or number of absorber stages and extended hydrocarbon content of the wet gas from a sample of the wet gas taken upstream of the dehydration unit contact tower. Flash separators, still vent condensers, limited operating hours, and limited glycol circulation rates shall not be considered when determining potential uncontrolled emissions.

Still vent condensers shall consist of equipment engineered and designed to achieve maximum condensation of the condensable components in the still vent vapors by providing adequate temperature differentials between the condenser outlet and still vent stream. Still vent pipes shall not be considered condensers.

Potential emissions for determining combustion device removal after one year shall be calculated using GRI-GLYCalc V4.0 or higher or other method accepted by the Division based on the past twelve calendar months of normal gas production rates, actual average wet gas temperature and pressure, actual water content of the dried gas or number of absorber stages.

Actual operating parameters for glycol flash separators may be used upon approval. Limited operating hours and limited glycol circulation rates shall not be considered for control removal.



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Pumps

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Single Well Facilities and Tank Batteries

Within 60 days of FDOP,

At sites with controls installed for flashing or dehydration unit emissions:

VOC and HAP emissions associated with the discharge streams from natural gas-operated pneumatic pumps shall be controlled by at least 98% or the discharge streams shall be routed into a closed loop system.

At sites without controls installed for flashing or dehydration unit emissions:

Pneumatic pumps (other than heat trace/heat medium/hot glycol circulation) shall be solar, electric or air-driven pumps in lieu of natural gas-operated pneumatic pumps or the discharge streams shall be routed into a closed loop system. Wherever possible, heat trace/heat medium/hot glycol circulation pumps shall be solar-operated, electric or air-driven.

Modified Facilities

Requirements are the same as above except include all new and existing pneumatic pumps and use the date of modification in place of FDOP.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flashing or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 7)



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low bleed or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for SWA Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the State. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.

For existing operators, Green Completion permit applications shall be filed with the Division by January 1, 2017. For new operators, a Green Completion permit application shall be filed with the first application for a production site.

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Produced water tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

For existing operators, well blowdown and venting permit applications shall be filed with the Division by January 1, 2017. For new operators, a well blowdown and venting permit application shall be filed with the first application for a production site.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 6 TPY VOC and HAP emissions, that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Presumptive BACT Requirements for UGRB Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 4 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of flash or dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and all glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flash or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 14)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a Fugitive Emissions Monitoring (FEM) Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, audio-visual-olfactory (AVO) inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the **UGRB**. The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of produced water tank emissions control may be allowed upon approval. (See Flashing, Page 14)



Presumptive BACT Requirements for UGRB Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Presumptive BACT Requirements for [JPAD/NPL Facilities](#)

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Modified Facilities

Upon modification, all new and existing VOC and HAP flashing emissions shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.

Dehydration Units

New Facilities

Upon FDOP, all VOC and HAP emissions from dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.

Modified Facilities

Upon modification, all VOC and HAP emissions from new and existing dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.



Presumptive BACT Requirements for [JPAD/NPL Facilities \(cont.\)](#)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

For pneumatic pump emissions controlled by a combustion unit used to control flash emissions which may be removed, the control method for pump emissions will be evaluated upon request for approval to remove the combustion unit. (See Flashing, Page 20)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.



Presumptive BACT Requirements for [JPAD/NPL Facilities \(cont.\)](#)

Produced Water Tanks

New Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of water tank emissions control may be allowed upon approval. (See Flashing, Page 20)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a FEM Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, AVO inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.



Presumptive BACT Requirements for [JPAD/NPL](#) Facilities (cont.)

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the [JPAD/NPL](#). The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.



Presumptive BACT Requirements for [JPAD/NPL Facilities \(cont.\)](#)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blow down/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blow down or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC and HAPs that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Determining P-BACT Flashing Emissions

Flashing losses occur when produced liquids (crude oil or condensate) are exposed to temperature increases or pressure drops as they are transferred from production vessels to other vessels or to atmospheric storage tanks. For purposes of this guidance, the term “**flash emissions**” refers to VOC and HAP pollutants associated with entrained natural gas vapors released to the atmosphere from hydrocarbon liquids in surface production equipment. This production equipment may include gun barrels, separators, treaters, produced water tanks, gas drips, freewater knockouts, etc. In addition to flash emissions, vessels containing hydrocarbon liquids also have emissions associated with **working** and **breathing** (also called standing) losses. These are vapors displaced from oil or condensate due to evaporation and agitating.

Use the following steps to determine projected potential flashing and working/breathing losses:

STEP 1: 30 days after the First Date of Production calculate the **average daily condensate or oil production**.

*Example: Well produced 600 BBL during the first 30 days after the First Date of Production.
average daily condensate/oil production = 600 BBL ÷ 30 days = 20 BPD*

STEP 2: Calculate the **projected first year annualized average daily condensate/oil production** rate by multiplying the average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively accounts for an 80% decline in daily production by the end of the first year. (described in more detail on page 36)

Example:

***projected first year, annualized average daily oil/condensate production** = 20 × 0.6 = 12 BPD*

If the expected decline rate is less than 80%, then the expected decline rate should be used. Using an expected decline rate > 80% requires pre-approval from the Division.

STEP 3: Use an approved flash emissions model or direct measurement of tank emissions to determine **projected first year VOC and HAP emissions associated with the projected first year average daily production rate**.

Actual flash emissions are determined the same as projected potential emissions except that the actual average daily condensate or oil production rate is used rather than a projected production rate.



Determining P-BACT Flashing Emissions (cont.)

Several methods are available to calculate or measure flash emissions with some being more accurate than others. Even though working/breathing/flashing losses are almost always mixed together and exit from a common vent at the same time, some methods only calculate working and breathing losses and some only calculate flashing losses. Some methods will calculate all three types of emissions simultaneously. Each method has specific constraints. For whichever method used, all supporting data used to calculate the emissions, including identification of the calculation method, description of sampling methods and copies of lab sampling analyses shall be provided with the emissions estimate.

| | Method | Emissions Calculated | Comments |
|---|--|---------------------------|---|
| 1 | Direct measurement | working, breathing, flash | Sampling and lab analysis required. Results are relatively accurate. |
| 2 | Process Simulator | flash, working, breathing | i.e. PROMAX, HYSIM, HYSIS Software is expensive but results are accurate when based on site-specific sampling and lab analysis. |
| 3 | API E&P TANKS Software V 2.0 and higher | working, breathing, flash | Requires site specific sampling. Not as accurate as more expensive process simulators and no longer supported by the software producer (American Petroleum Institute). |
| 4 | Laboratory measurement of the Gas-Oil-Ratio (GOR) from a pressurized liquid sample | flash only | This is a direct laboratory analysis of the flash vapors emitted from a pressurized oil/condensate sample. |
| 5 | EPA TANKS 4.0.9d | working, breathing only | Program distributed by the EPA through their website at https://www3.epa.gov/ttn/chief/software/tanks/index.html |

Extended hydrocarbon liquids analyses used for model input shall be no older than **three** years. Composite analyses may be used as input. These are averaged extended hydrocarbon compositions based on samples from at least five wells located in the same geographical area, producing from the same formation and under similar conditions ($\pm 25^\circ$ psig) as the well being permitted. Analyses used as the basis for the average shall be no older than **three** years.



Determining P-BACT Dehydration Unit Emissions

Dehydration units use glycol (TEG, DEG or EG) to absorb water from produced gas before it is introduced into gas sales or collection lines. Upon contact with wet gas, “lean” glycol absorbs water and other liquids. It is then considered “rich”. To remove impurities, or regenerate, the rich glycol is routed through a glycol flash separator and/or a reboiler. During flash separation and reboiling, water and hydrocarbon vapors containing VOC and HAP pollutants are released from the rich glycol. These are then discharged to the atmosphere from the dehydration unit process vents.

Use the following steps to determine projected potential dehydration unit emissions:

STEP 1: Once a new well has produced for 30 days after the First Date of Production, determine the average daily gas production rate.

Example:

*Well produced 100 MMCF during the first 30 days after the First Date of Production
average daily gas production = $100 \text{ MMCF} \div 30 \text{ days} = 3.3 \text{ MMCFD}$*

STEP 2: Calculate the **projected first year, annualized average daily gas production** rate by multiplying the initial average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively calculates an 80% decline in daily production by the end of the first year. (described in more detail on page 36.)

Example:

***projected first year, annualized average daily gas production** = $3.3 \times 0.6 = 2.0 \text{ MMCFD}$*

STEP 3: Use GRI-GLYCalc V4.0 or higher or other method approved by the Division with the projected first year, annualized average daily production rate to determine **potential, annualized uncontrolled VOC and HAP emissions** from the dehydration unit **process vents**. **Process vents** include reboiler still vents, glycol flash separators and still vent condensers.

Model input:

- 1) An extended hydrocarbon analysis of wet gas sampled upstream of the reboiler contact tower. Or, a composite extended hydrocarbon analysis may be used. A composite analysis is the average composition from at least five nearby wells producing from the same formation as the new well and under the same or very similar separator pressure and temperature conditions. Samples shall be no older than three years.
- 2) The projected first year average daily gas production rate (MMCFD).
- 3) Average, actual equipment operational parameters, including wet gas temperature and pressure, dry gas water content, glycol flash separator temperature and pressure, stripping gas source and rate and average operating parameters of emission control equipment.
- 4) The **maximum lean glycol circulation rate** (gpm) for the glycol circulation pump in use. Maximum circulation rates for the most commonly used Kimray Model pumps are listed in **TABLE 1**.



Determining P-BACT Dehydration Unit Emissions (cont.)

TABLE 1

| KIMRAY GLYCOL PUMP RATES | | | | |
|---------------------------------|----------------|------|------------------------|------|
| Model # | Capacity (gpm) | | Working Pressure (psi) | |
| | min | max | min | max |
| 3154 PV | 0.05 | 0.22 | 100 | 1500 |
| 1715 PV | 0.13 | 0.67 | 300 | 1500 |
| 4015 PV | 0.2 | 0.67 | 300 | 1500 |
| 9015 PV | 0.45 | 1.5 | 300 | 1500 |
| 21015 PV | 1.1 | 3.5 | 400 | 1500 |
| 45015 PV | 2.77 | 7.5 | 400 | 1500 |
| 4015 LP | 0.13 | 0.33 | 100 | 500 |
| 2015 SC | 0.13 | 0.33 | 100 | 500 |
| 5015 SC | 0.2 | 0.83 | 100 | 500 |
| 10015 SC | 0.37 | 1.67 | 100 | 500 |
| 20015 SC | 1 | 3.33 | 100 | 500 |

Data from Kimray O&G Equipment and Controls Catalog

Actual dehydration unit emissions are determined the same as projected potential emissions except that the actual average daily gas production rate is used in the GLYCalc model rather than a projected production rate.



BACT for Flashing Emissions

The following control systems or devices are accepted by the Division as meeting BACT for flash emissions:

- 1) A vapor recovery device that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
- 2) An enclosed, smokeless combustion device or flare that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
- 3) Any other control device or configuration that can be demonstrated to reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.
- 4) Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For a combustion device this may be a thermocouple and continuous recording device or any other equivalent device to detect and record the presence of the pilot flame, or a combustion chamber temperature recorder/monitor. The monitoring/recording requirements become enforceable permit conditions.
- 5) Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, thief hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Flash emissions prior to control installation will be determined using approved emission models or methods based on actual reported production and operating conditions. Reported production includes that sold during well completion activities, which are reported to the WOGCC. Flash emissions are directly proportional to production rates, provided operational parameters remain consistent, so it is acceptable to prorate emissions based on production.



BACT for Dehydration Unit Emissions

Other emission control systems or devices than those previously discussed may be used upon approval by the Division to meet BACT requirements for emissions from dehydration unit process vents (reboiler still vents and vents from glycol flash separators or glycol flash tanks). In order to be approved, the operator must provide a demonstration certifying the system or device will reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.

Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For combustion devices this may be a thermocouple and continuous recording device for the pilot flame or any other equivalent device to detect and record the presence of the pilot flame. A temperature recorder/monitor might be used to demonstrate sufficient heat of combustion or a continuous, wind-up chart recorder might be used to demonstrate continual operation by measuring and recording temperature or pressure parameters.

REMINDER: Dehydration units at oil and gas production facilities may be subject to additional NESHAP requirements under 40 CFR part 63, subpart HH. It is the operator's responsibility to comply with all applicable requirements of the NESHAP regulations.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Dehydration unit emissions occurring prior to the installation of required controls will be determined using the GRI-GLYCalc model or other method approved by the Division based on the maximum lean glycol circulation rate and the actual reported gas production rate including any gas, which was routed through the dehydration unit during well completion operations.



BACT for Sources without P-BACT Requirements

For emission sources without PRESUMPTIVE BACT requirements, BACT shall be addressed when the uncontrolled source emits greater than or equal to 6 TPY VOC and HAPs for sources located in the **SWA** or 4 TPY VOC and HAPs for sources located in the **UGRB** or **JPAD/NPL**.

For these sources **EITHER** the emission source will be controlled using previously implemented BACT **OR** a BACT cost analysis will be performed and submitted with the application showing either:

control is not technically feasible (i.e., due to physical constraints the emissions cannot be controlled)

OR

control is not economically reasonable (i.e., based on a control cost analysis the “cost to control per ton of pollutant reduced” is uneconomical).

CAUTION: **BACT** may be required at lower levels and for other emissions and emission sources than those stated in this guidance, but as a minimum, **BACT** shall be considered when equal to or above these guidance emission levels. For example, operators installing pumping unit engines according to Guidance might be asked to submit a BACT analysis for the engine.

Multiple pieces of the same type of equipment are considered one emission source for permitting purposes.

For example, there are five oily rag burners at a facility located in the **SWA**. Uncontrolled emissions from the five burners shall be aggregated for permitting purposes. If total uncontrolled VOC emissions from the five burners are less than the development area specific threshold of 6 TPY, BACT requirements are met with no control. If total uncontrolled emissions from the five burners are greater than or equal to 6 TPY VOC and HAPs, emissions from all five burners shall be reduced to less than 6 TPY VOC and HAPs in order to meet BACT requirements or the applicant shall demonstrate controlling the emissions is not economically reasonable nor technically feasible.



Permit Applications

For **JPAD/NPL**, **UGRB** and **SWA** facilities, unless a permit is issued prior to start up, a C6 S2 Oil & Gas Production Facilities permit application shall be filed within 90 days after the First Date of Production for a new facility or Date of Modification of an existing facility. The application notifies the AQD that the new or modified facility has begun operation. It describes the facility process, equipment and associated emissions/emissions controls and serves as a form of certification by the owner that the Presumptive BACT requirements have been met.

Whether the application is being filed after construction under the Presumptive BACT process or prior to construction, the appropriate application forms, depending upon the facility equipment and operating scenario, need to be filled out. A complete application includes the following

- A cover letter stating the purpose of the application
- Equipment list for the facility
- A written process description and process diagram for the facility, including each air emission source and the operational parameters of each source (examples provided on pages 34 & 35)
- The appropriate IMPACT forms
 - Cover Sheet
 - Emission Unit Form for all new or modified equipment
 - Pollutant Emissions Form for each emission unit
 - Release Point Form for each emission unit
 - Control Equipment Form (where applicable)
- The appropriate additional documentation (examples include)
 - Emission Summary
 - BACT cost analysis
- Explanations or demonstrations of all methods used to calculate or estimate emissions for each emission source, including controlled and uncontrolled sources. Emission calculation methods are described later.
- All applicable and required attachments, including:
 - Input and output for emission models/software/process simulations
 - Equipment manufacturer's emissions information
 - Laboratory analyses used for emission models/software/process simulations or calculations including a description of sampling procedures and handling, sampling locations, sampling location parameters (i.e., pressure and temperature at sampling port)
- Any additional attachments or information necessary for complete review of the application



Permit Applications (cont.)

As of September 2, 2014, the New Source Review program is processing all air quality permit applications electronically through the IMPACT System. There are two acceptable methods to submit an application. Please choose just one of the methods below:

- Applications may be submitted through the IMPACT portal (<https://airimpact.wyo.gov>). Submittals through the IMPACT portal are sufficient and paper copies are not required.
- Two paper copies (one with an original signature) of each complete permit application.

The preferred method for filing the application is through the IMPACT portal.

For facilities constructed or modified under the **Presumptive BACT** process a complete C6 S2 application shall be submitted within **90 days** of the **First Date of Production**. In the event that the IMPACT portal is not functioning properly and prevents the submittal of the application within 90 days of First Date of Production, the applicant will need to contact the Division prior to the due date of the application to inform NSR of the issue and the applicant will need to provide documentation in the permit application showing the reason for the delayed submittal. Examples of acceptable documentation include a screen shot showing the issue or a copy of email correspondence between the applicant and the Division discussing the problem.

If not submitting through the IMPACT portal, download IMPACT application forms from the AQD website:

<http://deq.wyoming.gov/aqd/new-source-review/resources/application-forms/>

The oil and gas applications forms are contained in one Microsoft Excel file. The file name for the IMPACT application forms is “01 - AQD - NSR - Application Form”.

If you need assistance with the applications forms, contact the Wyoming Air Quality Division at **(307) 777-7391**.

Address written requests to: Wyoming Department of Environmental Quality
Air Quality Division
(see WDEQ website for current mailing address)
attn: O&G NSR Permitting*

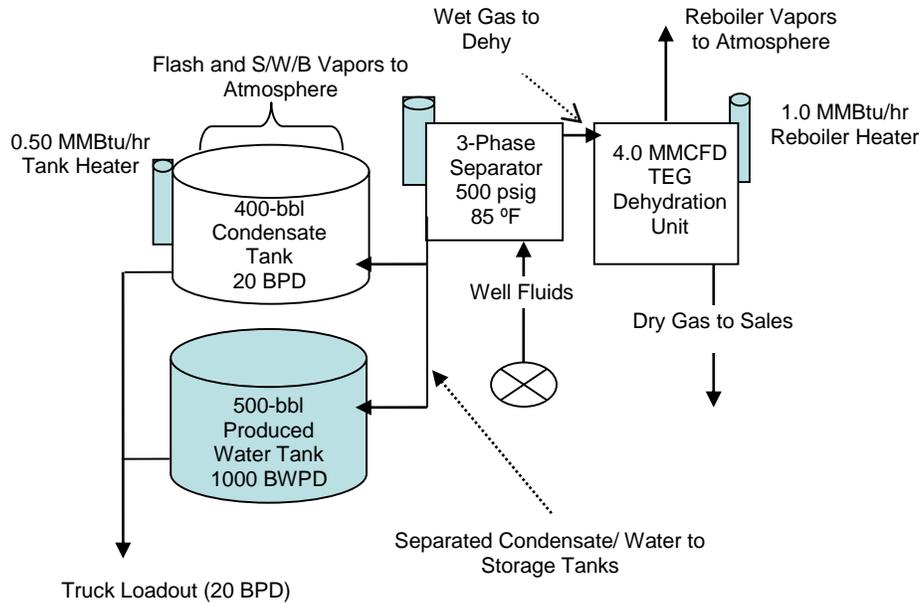
*To assist with the proper routing of the application and application materials, please make sure to address the materials to O&G NSR Permitting.

With the implementation of an electronic permitting system, the NOI process will no longer be utilized for new applications. Minor equipment installations and/or modifications that qualified for a NOI will now submit a complete application with the appropriate information listed on page 32. IMPACT forms and associated information are required for new or modified equipment.



Permit Applications (cont.)

Example Process Diagram & Description

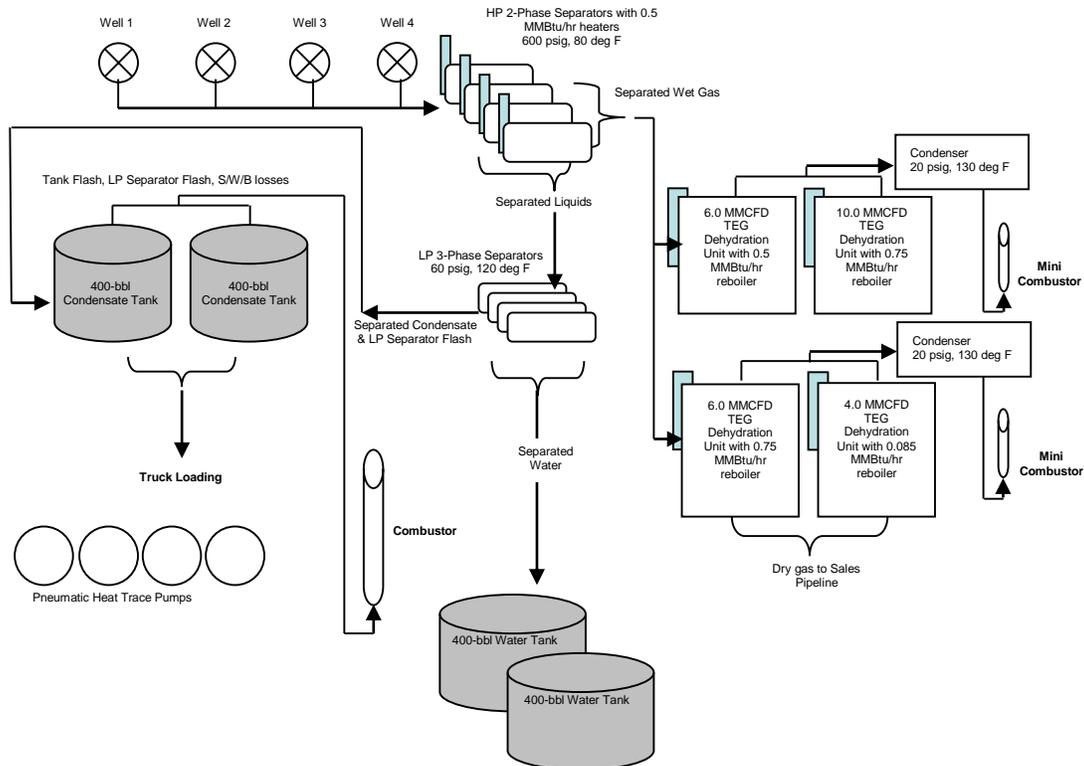


EXAMPLE: Air emission sources in the diagram are the condensate storage tank from which vapors are vented to the atmosphere, the dehydration unit reboiler still vent and the three natural gas-fired process heaters. Produced fluids are directed to the 3-phase separator for separation of condensate/water/gas. Wet gas is directed to the TEG dehydration unit for drying. Separated condensate and water are routed to the appropriate tanks for storage prior to being hauled from location via truck. Produced gas is used as burner fuel. Reboiler vapors and flash emissions are vented to the atmosphere along with S/W/B losses from the condensate tank.



Permit Applications (cont.)

Example Process Diagram & Description



EXAMPLE: Total well fluids from four wells flow to the 2-ph HP separators. Wet gas from the HP separators flows to the four dehydration units. Separated fluids from the 2-ph HP separators flows to the 3-ph LP separators. Separated condensate and water flows from the 3-ph LP separators to the storage tanks. Gas released in the 3-ph separators is routed to the condensate storage tanks. Tank vapors, including tank flash, gas from the 3-ph LP separators and S/W/B vapors are collected and directed to a 30-foot smokeless combustor. The temperature of the combustor is continually monitored and recorded using a SCADA (supervisory control and data acquisition) system. Reboiler still vents vapors flow through condensers. Condensed liquids are pumped to the condensate storage tanks. Non-condensable vapors flow to the 20-foot Mini-Combustors. The temperature of the Mini-combustors is continually monitored and recorded using a SCADA system. Pneumatic heat trace pumps operate 6 months per year using produced gas from the HP separators to operate. Vent lines from the pumps are routed into the condensate dump lines from the LP separators.

The process diagram does not need to be computer generated. A simple hand sketch is sufficient as long as the required information is included. The diagram does not need to be drawn to scale and does not need to represent the exact position of production equipment at the facility as long as the process description and operating scenario are clearly defined.



Permit Applications (cont.)

Upon receipt of a paper application, the Division must input the required application information into an electronic system (IMPACT) for processing. Once the paper application is processed, the Division sends the applicant a receipt letter. For electronic applications received via IMPACT, the Division simply issues a receipt letter after the application is received and a reviewer is assigned. The reviewer has up to 30 days to perform a completeness review to ensure adequate and correct information has been filed. If the application is deemed incomplete the reviewer will notify the applicant and request further information. Upon completeness the reviewer has 60 days to complete a technical review, write an application analysis and make any recommendations. During this process the decision to issue a permit or waiver takes place. If the decision is to issue a permit, the proposed permit, including compliance requirements, is published for a mandatory 30 day public comment period. If no comments are received the permit is issued once the public comment period ends. If comments are received these are addressed by the AQD. It is possible comments will warrant a public hearing. When this is the case, a final permit may be denied or delayed.

A minimum fee (\$464, subject to change) will be charged to each application. An hourly fee (\$58 per hour, subject to change) will be assessed for the time it takes AQD personnel to process the application. A bill will be sent to the applicant when the process is complete. Billing is handled as follows:

Initial billing (permits only) is assessed when a proposed permit is sent to public notice. The initial billing must be paid before AQD can issue a final permit.

Final billing is assessed for waivers and permits after these are issued.

Contact the Division for the current hourly rate.

NOTE: The Presumptive BACT permitting process may not be used for sour gas (H₂S) production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H₂S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction.

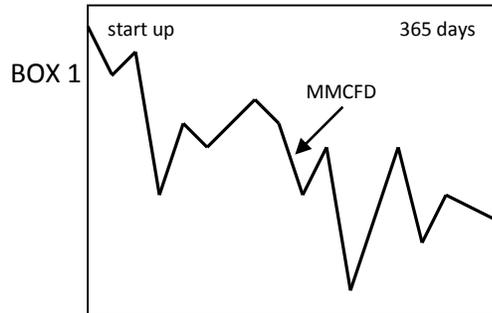
No internal combustion compressor engines or generator engines may be installed under the Presumptive BACT process.

No pumping unit engines greater than 50 Hp may be installed under the Presumptive BACT permitting process. Such engines shall be permitted prior to installation.



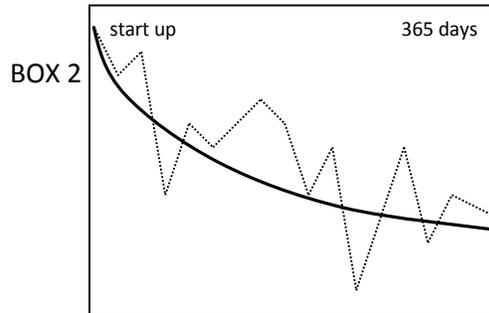
The 0.6 decline factor

The first year daily production rates are represented by the jagged line **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out **BOX 2** using statistical methods.

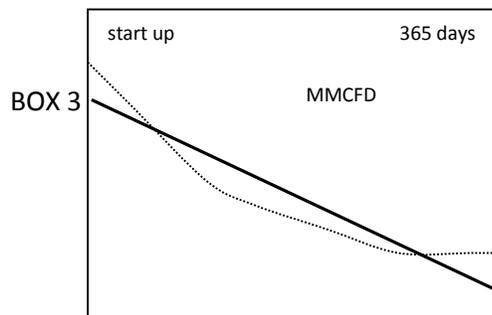


EXAMPLE - actual daily gas production rate vs time

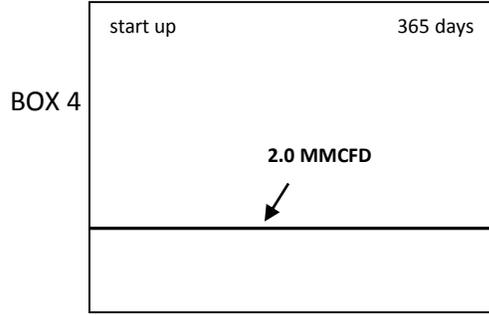
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ≈ 730 MMCF.



The jagged line representing daily production is “smoothed” out using statistical methods.



The “smoothed” curve in BOX 2 is “straightened” out using mathematical methods.



“leveled” out, projected daily gas production rate vs time

Total projected production for the first year is represented by the area under the straight line
 $2 \text{ MMCFD} \times 365 \text{ days} = 730 \text{ MMCF}$

First year projected emissions are based on 730 MMCF of produced gas.

The smoothed curve is “straightened” out in **BOX 3**, then “leveled” out in **BOX 4**. Now the total production for the first year is represented by the area under the line in **BOX 4**, which is easily calculated. Production curves from a large sampling of Wyoming wells indicate the average well declines by 80% during the first year. That 80% decline is represented by the level line in **BOX 4** after the first 30-day average production rate is multiplied by 0.6. For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year ($3.333 - 0.8(3.333) = 0.667$). Then the average daily production rate over 365 days is $(3.333 + 0.667)/2 = 2.0$ MMCFD, which is the same as $3.333 \times 0.6 = 2.0$.



Pumping Unit Engines

A pumping unit engine is an engine used to provide electrical or mechanical energy to a pump in order to produce a well.

This Guidance does not apply to compressor engines, engines used for vapor recovery, or pumping unit engines greater than 50 Hp.

This Guidance replaces the March 9, 2012 Pumping Unit Engine Emissions Policy.

Historically, AQD has allowed the installation of pumping unit engines at oil & gas production facilities as part of the Guidance. Engines were allowed to be installed prior to permit issuance, provided the engine was site rated for less than 50 Hp and emitted less than 5 TPY of NO_x.

The Guidance does not however preclude the Division from asking the applicant to submit a Best Available Control Technology (BACT) analysis to determine if emissions from the engine are technically feasible and economically reasonable to control. As demonstrated in the March 9, 2012 Pumping Unit Engine Emissions Policy, BACT is a moving target and relying on an emissions threshold of 5 TPY NO_x was no longer considered BACT for pumping unit engines less than 50 Hp. AQD will continue to allow installation of pumping unit engines prior to obtaining a permit provided the engine meets BACT and the requirements listed below.

Installation of pumping unit engines site rated for 50 Hp or less is allowed provided the engine meets NO_x emissions of 2.0 g/hp-hr and CO emissions of 3.0 g/hp-hr.

Initial and/or periodic emissions testing and monitoring of the pumping unit engine may be established in the permit or permit waiver.

APPENDIX A

EMISSION CALCULATIONS

Emissions from processes and equipment, which shall be accounted for and reported by applicants FOR ALL O&G PRODUCTION FACILITIES are:

| Emission Unit or Process | Associated Emissions |
|---|-----------------------------|
| storage tanks (flashing & S/W/B losses) | VOC HAP |
| pressurized vessels (flashing losses) | VOC HAP |
| dehydration units (reboiler still vents & glycol flash tanks) | VOC HAP |
| natural gas fired burners, heaters, flares | VOC NO _x CO |
| natural gas operated pneumatic controllers/pumps | VOC HAP |
| fugitives | VOC HAP |
| natural gas fired engines | NO _x CO VOC |
| truck load out | VOC HAP |

AP-42 EMISSION FACTORS

Throughout this Guidance reference is made to AP-42 emission factors. The complete AP-42 compilation may be downloaded from <https://www3.epa.gov/ttn/chief/ap42/index.html>.

STORAGE TANK EMISSIONS

Flashing and Standing/Working/Breathing (S/W/B) losses are the terms for emissions which occur when hydrocarbon liquids are exposed to temperature and pressure changes (i.e., from separator pressure and temperature to storage tank pressure and temperature) causing hydrocarbon vapors to be released from the liquids. The vapors may contain VOCs, HAPs and H₂S.

Software is available for modeling these emissions. Models accepted by the Air Quality Division are those using Peng-Robinson or S-R-K methods based on widely accepted principals of behavior for hydrocarbon vapors and liquids. Some common software programs for estimating these emissions are PROMAX, HYSIM, HYSYS, K-FLASH, PROSIM and API E&P TANKS (v2.0 and higher). The models require input detailing chemical properties of the fluids handled and physical operating parameters of the system(s) and production equipment. Output from the models includes volumes, rates and chemical components of the individual process streams from tanks and pressurized vessels.

Emissions from storage tanks may also be physically measured. In order to do so all tank valves, hatches, relief devices, leaks, etc. shall be sealed. Tank vapors shall only be allowed to exit the tank through a metered outlet. Usually this requires a meter capable of measuring low volumes. The measurement period shall last long enough to capture a representative tank vapor volume. An extended hydrocarbon analysis of the vapors shall be obtained along with the vapor volume.

MEASURED TANK FLASH EMISSIONS – EXAMPLE CALCULATION

The tons per year of VOC and HAP emissions associated with tank flashing are calculated as follows:

Given: Condensate tank vapors = 1000 scf/day
VOC weight % = 20
HAP weight % = 5
Condensate vapor molecular weight = 20 lb/lb-mol

TPY total flash emissions = $1000 \text{ scf/day} \times (1 \text{ lb-mol}/379 \text{ scf}) \times (20 \text{ lb/lb-mol}) \times (\text{ton}/2000 \text{ lb}) \times (365 \text{ days/year}) = 9.6 \text{ TPY}$

TPY total VOC emissions = $9.6 \text{ TPY} \times (20 \text{ weight \% VOC} / 100) = 1.9 \text{ TPY VOC}$

TPY total HAP emissions = $9.6 \text{ TPY} \times (5 \text{ weight \% HAP} / 100) = 0.5 \text{ TPY HAP}$

S/W/B losses

Not all software programs include tools for estimating S/W/B losses. There is free software available from the EPA named EPA TANKS. The most recent available version of EPA TANKS may be downloaded from the EPA website at <https://www3.epa.gov/ttn/chief/software/tanks/index.html>.

PRESSURIZED VESSELS

Whenever vapors from a pressurized vessel (separator, treater, FWKO, flash separator, gunbarrel, gas boot, etc) are released to the atmosphere, other than during times of emergency or upset conditions, emissions associated with those vapors shall be accounted for.

The same flash emission models mentioned above, for tank flash emissions, are often used to estimate emissions from pressurized vessels. Again, an extended hydrocarbon analysis of the liquids involved and actual operational conditions of the production equipment are necessary as input for the models.

Even when vapors from a pressurized vessel are collected for use as process burner fuel or fuel for an IC engine, for example, emissions associated with the total vapors shall be accounted for when considering potential emissions from a facility. If the volume and rate of vented vapors are known and an extended hydrocarbon analysis is available, associated emissions may be calculated in the same manner as described on Page 39 (calculation of flash emissions). If these are not available, the volumes shall be measured and analyzed in order to perform the calculations and determine associated emissions.

DEHYDRATION UNIT EMISSIONS

Air pollutants, mostly VOCs and HAPs, are associated vapors released from reboiler still vents and glycol flash separators. To estimate these emissions the GRI-GLYCalc v4.0 or higher model or other approved method is used. This relatively inexpensive software was created by the Gas Research Institute (GRI) for determining optimal operating parameters for dehydration units and is available from the Gas Technology Institute (GTI) with a website address of <http://sales.gastechnology.org/>.

Input for the model includes an extended hydrocarbon analysis of wet gas sampled upstream of the contact tower, actual operating parameters of all associated equipment (i.e., reboiler still vent temp., flash separator temp., dry gas flow rate, glycol recirculation rate, condenser, etc) and physical properties of the dry and wet gas streams. The model provides an estimate of individual emission components and the rates of vapor and liquid streams exiting each process vent of a dehydration unit. When submitting a GRI-GLYCalc

model it is only necessary to submit the INPUT SUMMARY, EMISSIONS SUMMARY, CONDENSER VENT OUTPUT (if applicable) and FLASH TANK OUTPUT (if applicable).

NATURAL GAS FIRED HEATERS (external combustion equipment)

NO_x, CO and VOC emissions from process unit heaters should be calculated using the emission factors (EF) below from EPA AP-42, Tables 1.4-1, 1.4-2 and 1.5-1. The following lists these factors:

Emission Factors for Industrial and Commercial Boilers

| Pollutant | Butane Gas ¹ (0.3 to 100 MMBtu/hr heat input) | Propane Gas ² (0.3 to 100 MMBtu/hr heat input) | Natural Gas ³ <100 MMBtu/hr heat input | Natural Gas ³ |
|------------------------------|---|--|--|--------------------------|
| NO _x ⁴ | 15 lb/1000 gal | 13 lb/1000 gal | 0.098 lb/MMBtu | 100 lb/MMcf |
| CO ⁴ | 8.4 lb/1000 gal | 7.5 lb/1000 gal | 0.082 lb/MMBtu | 84 lb/MMcf |
| TOC ^{4,5} | 1.1 lb/1000 gal | 1.0 lb/1000 gal | 0.010 lb/MMBtu | 11 lb/MMcf |

- 1 Based on an average heating value of 102 × 10⁶ Btu/1000 gallons of Butane.
- 2 Based on an average heating value of 91.5 × 10⁶ Btu/1000 gallons of Propane.
- 3 Based on an average heating value of 1020 Btu/SCF of natural gas.
- 4 The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factors by the ratio of the heating value of the actual gas used to the average heating values listed
 Converted EF = (EF from table above × (actual heat value/heat value in table)).
- 5 VOC emissions may be determined by multiplying the calculated TOC (total organic compounds) emission rate by the weight percent of VOC compounds in the actual fuel gas stream.

HEATER EMISSIONS - EXAMPLE CALCULATION

Given: Separator heater rating = 0.5 MMBtu/hr
 Gas Heating Value = 1300 Btu/scf
 VOC weight % = 20
 Annual operating hours = 8760
 NO_x EF = 100 lb/MMcf
 CO EF = 84 lb/MMcf
 TOC EF = 11 lb/MMcf

NO_x emissions = (0.5 MMBtu/hr) × (100 lb/MMcf) × (1300 Btu/1020 Btu) × (1 scf/1020 Btu) × (8760 hr/yr) × (ton/2000 lb) = 0.27 TPY NO_x

For CO emissions, the same calculation is used except the EF is 84 lb/MMcf.

VOC emissions = 0.5 × 11 × (1300/1020) × 1/1020 × 8760/2000 × (20% VOC/100) = 0.006 VOC TPY VOC ← INSIGNIFICANT at less than 0.1 TPY

FLARES

The NO_x and CO emissions for flares should be based on **0.14 lb NO_x/MMBtu and 0.035 lb CO/MMBtu** (Emission factors from Section 4 of EPA Document “Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations”) and the reported fuel usage based heat input. VOC and HAP emissions from flaring should be based upon the guaranteed destruction efficiency of the flare. Reported flared gases shall include pilot gas with heat content and flared gas with average estimated heat content. The rationale for using these factors as opposed to AP-42 factors for flares is that the flare factors are believed to be only applicable to chemical plant type flares engaged in burning low BTU gases. The gases typically burned in flares in Wyoming contain more than 900 Btu/scf and emissions are expected to be closer to the AP-42 factors for NO_x and CO from gas fired heaters and boilers greater than 10 MMBtu/hr.

FLARE EMISSIONS - EXAMPLE CALCULATIONS – CONDENSATE TANK FLASH

Given: Total waste gas = 125 scf/hr
Gas heating value = 1350 Btu/scf

$$\text{NO}_x \text{ emissions} = (125 \text{ scf/hr}) \times (1350 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) = 0.1 \text{ TPY NO}_x$$

FLARE PILOT EMISSIONS

Given: Flare pilot gas = 5 scf/min
Gas heating value = 1000 Btu/scf

$$\text{NO}_x \text{ emissions} = (5 \text{ scf/min}) \times (1000 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (60 \text{ min/hr}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) \\ = 0.18 \text{ TPY NO}_x$$

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

FLARE EMISSIONS EXAMPLE CALCULATION – DEHYDRATION UNITS

Given: Glycol flash separator vapors = 25 scf/min
Reboiler still vent vapors = 5 scf/min
Total waste gas = 30 scf/min (25 scf/min glycol flash vapors + 5 scf/min reboiler still vent vapors)
Gas Heating Value = 1050 Btu/scf (**assume at least 1000 BTU/SCF if the heat content is unknown**)

$$\text{NO}_x \text{ emissions} = (30 \text{ scf/min}) \times (1050 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (60 \text{ min/hr}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) \\ = 1.1 \text{ TPY NO}_x$$

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

PNEUMATIC PUMPS

If a pneumatic pump uses natural gas as the motive gas, the pump will release VOC and HAP emissions each time it strokes since all motive gas is vented by the pump. To determine emissions from the pump, manufacturer’s information regarding gas usage shall be known as well as the hydrocarbon composition of the motive gas.

PNEUMATIC PUMP EMISSIONS - EXAMPLE CALCULATION

A Texsteam Series MX pump is used to circulate hot glycol in heat trace lines. The pump moves 0.15 gallons per 40 strokes and is currently stroking at 20 strokes per minute (spm). The pump requires 24 scf for each gallon of glycol pumped. The pump motive gas weighs 20 lb/lb-mol and contains 50 wt% VOCs and 30 wt% HAPs.

$$\text{Pump usage/vent rate} = (20 \text{ strokes/min}) \times (0.15 \text{ gallons/40 strokes}) \times (24 \text{ scf/gallon}) = 1.8 \text{ scf/min}$$

$$\text{VOC emissions} = (1.8 \text{ scf/min}) \times (20 \text{ lb/lb-mol}) \times (\text{lb-mol}/379 \text{ scf}) \times (\text{ton}/2000 \text{ lb}) \times (525600 \text{ min/yr}) \times (50 \text{ wt\% VOC}/100) = 12.5 \text{ TPY VOC}$$

PNEUMATIC CONTROLLERS

Emissions from continuous bleed pneumatic controllers shall be based on the manufacturer-certified bleed rates. Emissions from intermittent vent controllers shall be based on the volume of gas required for actuation and the applicant's best engineering estimate of the frequency of actuations.

TRUCK LOADING

VOC emissions from loading oil or condensate into tank trucks should be estimated using the following formula with data from AP-42 tables.

$$L_L = 12.46 \times S \times P \times M/T$$

Where: L_L = loading loss, pound per 1,000 gallons of liquid loaded (lb/1000 gal)

S = a saturation factor (See Table 5.2-1 below)

P = true vapor pressure of liquid loaded (psia)

M = molecular weight of tank vapors (lb/lb-mol)

T = temperature of bulk liquid loaded ($^{\circ}\text{R}$) ($^{\circ}\text{R} = ^{\circ}\text{F} + 460$)

" S " values are obtained from Table 5.2-1.

" M " and " N " values are obtained from Table 7.1-2.

Table 5.2-1 Saturation (S) Factors for Calculating Petroleum Liquid Loading Losses

| Cargo Carrier | Mode of Operation | "S" Factor |
|--------------------------------|--|------------|
| tank trucks and rail tank cars | submerged loading of a clean cargo tank | 0.50 |
| | submerged loading: dedicated normal service | 0.60 |
| | submerged loading: dedicated vapor balance service | 1.00 |
| | splash loading of a clean cargo tank | 1.45 |
| | splash loading: dedicated normal service | 1.45 |
| | splash loading: dedicated vapor balance service | 1.00 |

Table 7.1-2 Properties of Selected Petroleum Liquids

Only crude oil properties are supplied here. The full table of values can be found in AP-42, Table 7.1-2)

| petroleum liquid | vapor molecular weight at 60°F (lb/lb-mol) | condensed vapor density at 60°F (lb/gal) | liquid density at 60°F (lb/gal) | true vapor pressure (psi) at various temperatures in °F | | | | | | |
|------------------|--|--|---------------------------------|---|-----|-----|-----|-----|-----|-----|
| | | | | 40 | 50 | 60 | 70 | 80 | 90 | 100 |
| | "M" | | | "P" | | | | | | |
| Crude Oil RVP 5 | 50 | 4.5 | 7.1 | 1.8 | 2.3 | 2.8 | 3.4 | 4.0 | 4.8 | 5.7 |

TRUCK LOADOUT - EXAMPLE CALCULATION

Given: Condensate loaded = 360 bbl crude/month

S = 0.6

P = 2.3 psi

M = 50 lb/lb-mol

T = 50

$$L_L = \frac{(12.46) \times (0.60) \times (2.3 \text{ psi}) \times (50 \text{ lb/lb-mol})}{(50^\circ\text{F} + 460)} = 1.69 \text{ lb/1000 gal}$$

$$\text{Loading losses (TPY)} = (1.69 \text{ lb/1000 gal}) \times (\text{annual sales of } 360 \text{ bbl/mo}) \times (12 \text{ mo/yr}) \times (42 \text{ gal/bbl}) \times (\text{ton}/2000 \text{ lb}) = 0.15 \text{ TPY}$$

Capture efficiencies are determined on a case-by-case basis for controlled sites.

FUGITIVE EMISSIONS

The easiest way to calculate total hydrocarbon fugitive emissions is to multiply the number of components at a site by the EPA Average Emissions Factors shown in the tables below. The first table lists the average emission rates of **total hydrocarbon** (THC) to be assumed for all components in hydrocarbon service installed at a site. The factors are current as of June 15, 1996 and given in pounds per component - day (lb/component-day). The second table lists speciated rates.

The only information needed for this method is a count or estimate of the number of flanges, connectors (other than flanges), open-ended lines, pumps, valves and "other" components at the site grouped by stream (gas, light oil, heavy oil, water/oil). The number of components can be determined by either counting them in the field or by estimating them.

**EPA Average Emission Factors for Total Hydrocarbon (THC) Emissions
From O&G Production Operations**
(lb/component-day)

| equipment type | equipment service category | | | |
|--------------------|----------------------------|-------------------------|-------------------------|------------------------------|
| | gas | heavy oil (< 20°API) | light oil (> 20°API) | water/light oil ¹ |
| connector | .011 | .0004 | .011 | .0058 |
| flange | .021 | .000021 | .0058 | .00015 |
| open ended line | .11 | .0074 | .074 | .013 |
| other ² | .47 | .0017 | .4 | .74 |
| pump | .13 | not available | .69 | .0013 |
| valve | .24 | .00044 | .13 | .0052 |

SOURCE: US EPA Bulletin Board (Leaks_OG.WP5; 8/9/1995)

¹ The water/light oil emission factors apply to water streams in light oil service with water content between 50% and 99%. For streams with water content > 99% the emission rate is considered negligible.

² The "other" equipment type includes compressor, pressure relief valves, diaphragms, drains, dump arms, hatches, instruments, meters, polished rods and vents.

NOTE: The emission factors in the table above are not intended to be used to represent emissions from components that are improperly designed (e.g., enardo valves over pressurizing, failure of thief hatches to reseal after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open). For example, emissions from an enardo valve on a condensate tank vent line, operating in the full or partially open position due to excessive tank vapor pressure that exceeds the pressure setting of the enardo valve, are not considered to be fugitive emissions.

Speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rates obtained from the table above by actual measured weight fractions. If measured data is not available, contact the Division for further guidance.

FUGITIVE EMISSIONS - EXAMPLE CALCULATION

Given: 25 valves in light oil service

THC emission factor = 0.13 lb/component-day

VOC weight fraction = 0.292

HAP weight fractions = 0.02430 + 0.00027 + 0.00075 + 0.00017 + 0.00036 = 0.0259

VOC emissions = 25 valves × 0.13 lb THC/valves-day × 1 ton/2000 lb × 365 day/hr × 0.292 = 0.17 TPY VOC

HAP emissions = 25 valves × 0.13 lb THC/valves-day × 1 ton/2000 lb × 365 day/yr × 0.0259 = 0.015 TPY total HAPs

INTERNAL COMBUSTION PUMPING UNIT ENGINE EMISSIONS

The method for calculating engine emissions is to use emission factors provided by the engine manufacturer, the maximum site-rated horsepower and the annual operating hours.

PUMPING UNIT ENGINE EMISSIONS - EXAMPLE CALCULATION

Given: Manufacturer's NO_x emission factor = 2 g/hp-hr
Maximum site-rated horsepower = 250 hp
Annual operating hours = 8760

NO_x emissions = (2.0 g/hp-hr) × (250 hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 4.8 TPY

For CO and VOC emissions the same calculations are used except the manufacturer's EF for CO and VOC are used.

CONVERTING MOLE PERCENT TO WEIGHT PERCENT

Many emission estimation and calculation methods require weight percent to be used, rather than mole percent. Most lab analyses list gas constituents in mole percent, however you can request the lab provide both mole and weight percent.

You may download the Excel spreadsheet to convert mole percent to weight percent, at <http://deq.wyoming.gov/aqd/new-source-review/>.

APPENDIX B

DEFINITIONS

Air Contaminant – Shall mean dust, fumes, mist, smoke, other particulate matter, vapor, gas or any combination of these; but shall not include steam or water vapor.

Air pollutants – Also known as criteria pollutants, Air pollutant emissions which have ambient air standards associated with them. Air pollutants include such emissions as volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), hazardous air pollutants (HAP) and others.

Average Daily Production – The qualified maximum total production of domestic crude petroleum and petroleum condensates including natural gas liquids produced from a well during a certain period of time (i.e. 1-month, 1-year) divided by the number of calendar days in the certain period during which the well produced. For example, the average 30-daily condensate production rate for well ABC is the qualified maximum total condensate production during the 30-day period $x(\text{BBL}) \div 30(\text{days}) = y(\text{BPD})$. If well ABC only produced 5 days out of the 30-day period, then the average daily condensate production rate for the well is $x(\text{BBL}) \div 5(\text{days}) = y(\text{BPD})$.

Closed System – A vessel (treater, separator), pipeline, sales line, gathering line, collection line, field gas supply or distribution line or any other vessel or line from which no vapors or liquids can exit through open lines, holes, vents or valves unless those lines, holes, vents or valves are connected to another closed system or to a source of continual and complete combustion, unless the vent or valve is a relief device that is designed and intended to open only during emergency situations.

Completion – An oil well shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the producing interval after the production string has been run. A gas well shall be considered completed when the well is capable of producing gas through wellhead equipment from the producing zone after the production string has been run.

Condensate – Hydrocarbon liquid separated from natural gas that condenses (becomes liquid) due to changes in temperature, pressure, or both, and remains liquid at standard conditions.

Custody Transfer – The transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Division – The Wyoming Department of Environmental Quality, Air Quality Division.

First Date of Production – The date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production from initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.

Fugitive Emissions (Fugitives) – Air emissions which result from gas vapors escaping through and around seals, packing, gaskets, threads, and other such pressure sealing connections.

Gas – All natural gases and all hydrocarbons not defined as oil.

Gas Well – A well, the principal production of which, at the mouth of the well, is gas, as defined by the Wyoming Conservation Law.

Grandfathered – A facility, installation or site which was built or in service before May 29, 1974 and that has not been physically or operationally changed, causing an increase in any pollutant (to which any state standard applies) or causing the emission of a new pollutant. (Modifications which could eliminate grandfather status are increasing production rate by fracturing, acidizing, recompletion of a zone, change in artificial lift methods, bringing new wells into a central battery or a waterflood response. Also such things as installing an engine, increasing horsepower, change in burner ratings. This list is not all inclusive and judgment should be used to determine appropriate status.)

HAP – Pollutants identified in Section 112(b) of the Clean Air Act. Typical hazardous air pollutants include benzene, toluene, ethyl-benzene, xylene, n-hexane, formaldehyde, methanol and others.

Low bleed pneumatic controller – A continuous bleed or intermittent vent device that emits less than 6 scf/hr. The Division considers controllers that are operated in accordance with manufacturer design specifications and have a manufacturer-designed emission rate that satisfies the 6 scf/hr threshold, to meet the definition of low bleed pneumatic controller.

Major Emitting Facility – A facility which either has the potential to emit 250 TPY or more of any one regulated air pollutant or is a named facility and has the potential to emit 100 TPY or more of any one regulated air pollutant. For a facility located in a non-attainment area, the definition of major emitting facility is subject to change based on the area's classification. See WAQSR Chapter 6, Section 13.

Major Source – A source which emits either 100 TPY or more of a regulated air pollutant, 10 TPY or more of a hazardous air pollutant, or 25 TPY or more of the total hazardous air pollutants.

Modified Facility – An existing facility becomes modified once production streams or production equipment associated with another well or wells is added to or tied into it. The date modification occurs to an existing facility is the First Date of Production for the added well or the date the production streams associated with an additional well or wells are tied into equipment at the existing facility.

Examples of facility modifications not involving new wells or added production from other wells are:

- Increasing the production rate above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months by fracturing, acidizing, recompletion of a current production zone, change in artificial lift methods, or a CO₂ flood/water flood response.
- Completing in additional production zones resulting in an increase in production above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months and/or emissions at the facility.
- Existing production equipment is replaced with larger equipment, resulting in increased potential or actual emissions.

Note: When equipment with Presumptive BACT requirements is added to a facility but doesn't trigger the definition of a modified facility, the Presumptive BACT requirements only have to be met for the new equipment (i.e., a pneumatic methanol pump is added, this new pump would have to either be controlled or solar, air or electric).

Oil – Crude petroleum oil and any other hydrocarbons, regardless of gravities, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

Oil Well – A well, the principal production of which, at the mouth of the well, is oil, as defined by the Wyoming Conservation Law.

PAD – A PAD facility is a location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains located at the same or contiguous and adjacent location. If the production streams or production equipment associated with one or more wells is added to an existing single well facility, that location is then considered to be a PAD facility. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility. A tank battery is not considered a PAD facility.

Potential to Emit – The maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA and the Division.

Recompletion – Any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geological interval not currently completed or producing in said existing oil or gas well.

Single Well Facility – A single well facility is one where production equipment is associated with only one well. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility.

Spud – The commencement of operations for the first boring of a hole for the drilling of an oil, gas or injection well. This includes setting conductor casing.

Synthetic Minor – “Synthetic Minor” sources are sources that do the following types of things to limit emission rates below 100 TPY: 1) limit operating hours of a source or 2) limit production rates such that source emissions are less than 100 TPY.

Tank Battery – An oil production facility with little to no produced gas that is comprised mainly of separators, heaters, and tanks. The facility does not use dehydration units. The API gravity of the produced oil is no higher than 25°.

VOC – Volatile organic compound means any organic compound which participates in atmospheric photochemical reactions; typically considered C₃⁺ or Non-methane/ethane hydrocarbon vapors.

VOC Weight Percent – This is the weight of the volatile organic compounds, expressed as a percent, as compared to the total weight of the compounds in a gas stream. (This should not be confused with the volume or mole percent of a gas stream, which is usually how it is expressed in a lab analysis of a gas.)

Wildcat Well – Any oil or gas well designated as a wildcat well by the Wyoming Oil and Gas Conservation Commission. Wildcat wells are wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive.

Workover – Any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. Workover includes but is not limited to: acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing or setting bridge plugs to isolate water productive zones from oil or gas productive zones or any combination thereof. Workover does not mean the routine maintenance, repair or replacement of downhole equipment such as rods, pumps, tubing, packers or other mechanical devices.

Worst case – A situation allowed in air permitting in the State of Wyoming where a facility, site or source (which is representative of all the facilities, sites or sources within a designated field area) may be used to represent the worst air emissions for the field area sources.

Wyoming Environmental Quality Act – Wyoming Statute, Title 35 “Public Health and Safety”, Chapter 11 “Environmental Quality” which provides the authority for the rules and regulations of the Air Quality Division.

Zero bleed controller – Electric, air-driven, or solar powered controller that does not rely on natural gas to actuate.

General Permit 18.1 Template

Equipment leaks from valves, flanges, pressure relief devices, open end valves or lines, pump seals, compressor seals (except seals regulated under 40 CFR 60.5385 or 5390, or 40 CFR 60.5385a or 5390a) in natural gas service

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.
 - (1) None
 - b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.
 - (1) None
2. The emissions unit contained in this permit must comply with various federal New Source Performance Standards (NSPS). The complete NSPS requirements may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website <http://www.ecfr.gov> or by contacting the appropriate Ohio EPA District Office or local air agency. The permittee must comply with the applicable requirements of 40 CFR Part 60 Subpart OOOO/OOOOa as they apply to the emissions source.
3. Records related to this PTIO may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

Note: The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. **Emissions Unit Group: Equipment/Pipeline Leaks, F001**

| EU ID | Operations, Property and/or Equipment Description |
|-------|---|
|-------|---|

| EU ID | Operations, Property and/or Equipment Description |
|-------|--|
| F001 | <p>Ancillary equipment¹ and associated equipment: compressors², pumps, piping, pneumatic controllers, inlet separators, gas-water/condensate/oil separators, etc.</p> <p>Equipment/pipeline leaks from valves, flanges, pressure relief devices, open end valves or lines, and pump and compressor seals (except seals regulated under 40 CFR 5380 or 5385 or 40 CFR 5380a or 5385a) in natural gas service.</p> |

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions in this permit are federally enforceable, with the exception of those listed below, which are enforceable under state law only.

a. None.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions in this permit are enforceable under state law only, with the exception of those listed below, which are federally enforceable.

a. None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|--|
| a. | OAC rule 3745-31-05(A)(3) June 30, 2008 | Develop and implement a site-specific leak detection and repair program for ancillary equipment as described in paragraph c)(2). |

¹ "Ancillary Equipment" is defined in 40 CFR Part 63, Subpart HH as "any of the following pieces of equipment: pumps, pressure relief devices, sampling connection systems, open-ended valves, or lines, valves, flanges, or other connectors." The Subpart HH definition is being used for this permit but note that the equipment leak standards found in Subpart HH do not apply for this permit because this permit is for an "area source" and the equipment leak standards do not apply to area sources.

² "Compressor" for the purpose of this permit excludes "Centrifugal compressor" and "Reciprocating compressor" as defined in 40 CFR 60.5430 or 60.5430a as appropriate.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|--|
| b. | <p>40 CFR Part 60 Subpart OOOO</p> <p>Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.</p> <p>40 CFR 60.5390(b)(1)</p> | <p>Every pneumatic controller at a natural gas processing plant must have a natural gas continuous bleed rate of zero.</p> |
| c. | <p>OAC 3745-31-05(E)</p> | <p>Emissions of Volatile Organic Compounds (VOC) shall not exceed 10.0 tons per year from fugitive equipment leaks.</p> |

(2) Additional Terms and Conditions

- a. Proposed amendments to 40 CFR Part 60, Subpart OOOO were published in the Federal Register on September 18, 2015. If final amendments to 40 CFR Part 60, Subpart OOOOa become applicable to this emissions unit, then the permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart OOOOa and 40 CFR Part 60, Subpart A instead of the associated Subpart OOOO requirements listed in this permit.

c) Operational Restrictions

(2) Ancillary Equipment Leak Detection and Repair Program

The permittee shall develop and implement a leak detection and repair program designed to monitor and repair leaks from ancillary equipment covered by this permit, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel. This program shall meet the following requirements:

- a. Leaks shall be detected by the use of either a "Forward Looking Infra-Red" (FLIR) camera or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.
- b. An initial monitoring shall be completed within 90 days of startup and quarterly thereafter for a period of four consecutive quarters (1 year).
- c. If following the initial four consecutive quarters, less than or equal to 2.0% of the ancillary equipment are determined to be leaking during the most recent quarterly monitoring event, then the frequency of monitoring can be reduced to semi-annual.

- d. If following two consecutive semi-annual periods, less than 2.0% of the ancillary equipment are determined to be leaking during the most recent semi-annual monitoring event, then the frequency of the monitoring can be reduced to annual.
 - e. If more than or equal to 2.0% of the ancillary equipment are determined to be leaking during any one of the semi-annual or annual monitoring events, then the frequency of monitoring shall be returned to quarterly.
 - f. The program shall require the first attempt at repair within five (5) calendar days of determining a leak.
 - g. The program shall require that the leaking component be repaired within 30 calendar days after the leak is detected, except as provided for in (c)(2)h.
 - h. The program shall allow for the delayed repair of a leaking component following the language found in 40 CFR 60.482-9a.
 - i. The program shall follow the Monitoring and Record Keeping requirements described in paragraph 1.d) of this permit.
- (3) In the event that a leak or defect is detected in the cover, closed vent system, process equipment, or control device, the permittee shall make a first attempt at repair no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 30 calendar days after the leak is detected as allowed in 40 CFR 60.5416(c)(4). Any delay of repair of a leak or defect shall meet the requirements of 40 CFR 60.5416(c)(5).

[40 CFR 60.5416(c)(4) and (5)], [40 CFR 60.5415(e)(3)], [40 CFR 60.482-9a], and [ORC 3704.03(T)]

d) Monitoring and/or Recordkeeping Requirements

- (1) The permittee shall perform an inspection each day that an operator is at the facility and the facility is in operation or is pressurized in any of its components, for indications of releases from the pressure relief valves, and any olfactory, visual or auditory indications of equipment leaks. The positive indication of a release or a leak shall be noted in an operations log, along with the following information:
 - a. the name of the inspector;
 - b. the date and time inspected;
 - c. the identification of the pressure relief valve that released and/or piece of equipment that leaked;
 - d. the estimated or calculated duration of the pressure relief valve release and/or equipment leak and the estimated emission totals; and

- e. any corrective actions taken to minimize or eliminate the release or leak.
- (2) The permittee shall maintain records of the maximum scf/m for scheduled maintenance venting.
- (3) Ancillary Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing FLIR Cameras
- a. Leaks shall be determined by visually observing each ancillary component through the FLIR camera to determine if leaks are visible.
 - b. The following information shall be recorded during each leak inspection:
 - i. the date the inspection was conducted;
 - ii. A description of the manufacturer, model number and serial number of the FLIR camera;
 - iii. the name of the employee conducting the leak check;
 - iv. the identification of any component that was determined to be leaking;
 - v. the date the first attempt to repair the component was made;
 - vi. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vii. the date the component was repaired and determined to no longer be leaking;
 - viii. the total number of components that are leaking; and
 - ix. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary components capable of developing a leak, and multiplied by 100.
 - c. The permittee shall maintain written records that demonstrate the FLIR camera is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
 - d. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon oral or written request.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

(4) Ancillary Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing a Method 21 Analyzer

a. Leaks shall be measured by utilizing U.S. EPA Method 21 (40 CFR Part 60, Appendix A). All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is to be compared with 500 ppm or 10,000 ppm (as applicable) for determining compliance.

b. A component is considered to be leaking if the instrument reading is equal to or greater than:

| | |
|--|------------|
| pressure relief device in gas/vapor service | 500 ppm |
| pressure relief device in light liquid service | 10,000 ppm |
| pumps in light liquid service | 2,000 ppm |
| compressor | 500 ppm |
| sampling connection system* | * |
| open ended valves or lines** | ** |
| valves in gas/vapor and light liquid service | 500 ppm |
| closed vent system | 500 ppm |
| connectors in gas/vapor and light liquid service | 500 ppm |
| all other ancillary and associated equipment | 10,000 ppm |

* must be equipped with a closed-purge, closed-loop, or closed-vent system

** must be equipped with a cap, blind flange, plug, or a second valve

c. The following information shall be recorded during each leak inspection:

- i. the date the inspection was conducted;
- ii. the name of the employee conducting the leak check;
- iii. the identification of any component that was determined to be leaking (company ID and component type (flange, pump, etc.);
- iv. the date the first attempt to repair the component was made;

- v. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vi. the date the component was repaired and determined to no longer be leaking;
 - vii. the total number of components that are leaking; and
 - viii. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary components capable of developing a leak, and multiplied by 100.
- d. The permittee shall maintain records that demonstrate the Method 21 analyzer is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
- e. In order to calibrate the analyzer, the following calibration gases shall be used:
- i. zero air, which consists of less than 10 ppm of hydrocarbon in air; and
 - ii. a mixture of air and methane or n-hexane at a concentration of approximately, but less than, 10,000 ppm of methane or n-hexane.
- f. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon oral or written request.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER be submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) Supplement to the PER for the Ancillary Equipment Leak Detection and Repair Program

For each inspection that occurred during the year, the permittee shall submit the following information with the annual PER from data collected by the ancillary equipment leak detection and repair program:

- a. the date of the inspection;
- b. the number of components determined to be leaking;
- c. the company ID and component type (flange, pump, etc.) of each leaking component;
- d. the total number of components at the site;
- e. the percent of components determined to be leaking;
- f. a list of all components that have not been repaired due to a delay of repair and the reason for the delay; and
- g. a notification indicating if the permittee has changed future inspection frequencies based on the percent of components leaking.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

f) Testing Requirements

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

(1) Emissions Limitation:

Emissions of VOC shall not exceed 10.0 tons per year from fugitive equipment leaks.

Applicable Compliance Method:

The annual VOC limitation is the estimated potential-to-emit based upon the maximum number of components and type of service (gas/vapor and light liquid) expected at this facility. Unless or until more accurate emission factors have been demonstrated or established for the site (e.g. following initial and subsequent monitoring and inspections), the appropriate emissions factors from U.S. EPA's "Protocol for Equipment Leak Emission Estimates," Table 2-4, for Oil and Gas production Operations (EPA-453/R-95-017, November 1995), shall be used to demonstrate compliance with the annual limit, as shown below, with the exception of gas-driven pneumatic controllers, for which emission factors derived from review of recent literature are listed below. The facility's potential emissions from ancillary and associated equipment shall be documented from the summation of the following calculations. Where the maximum mass per cent of VOC and corresponding specific mass of the rich gas stream are known, those values may be substituted in the calculations in lieu of 50% and 0.08097 lb/scf respectively. (note: where

multiplication by % VOC is indicated, it should be understood that multiplication by a decimal fraction is intended, i.e. a divisor of 100 is implicit):

Component Type # of components x emission factor x % VOC* = lb VOC/hr

In Gas/Vapor Service

Number of connectors x 0.000441 lb/hr x 50% VOC = lb VOC/hr

Number of valves x 0.00992 lb/hr x 50% VOC = lb VOC/hr

Number of flanges x 0.00086 lb/hr x 50% VOC = lb VOC/hr

Number of compressor seals** x 0.0194 lb/hr x 50% VOC = lb VOC/hr

(note: the emissions of reciprocating or centrifugal (wet seal or dry seal) compressors, including blowdown and leakage through seals and closed valves, may be subject to capture and control and other permitting requirements appropriate to non-fugitive categories of sources, and may, in that case, not be within the scope of this general permit)

Number of relief valves x 0.01940 lb/hr x 50% VOC = lb VOC/hr

Number of other ancillary and associated units of equipment x 0.01940 lb/hr x 50 % VOC = lb VOC/hr

Number of high bleed (exceeding a 6 scf/hr continuous bleed specification) gas driven pneumatic controllers x (50.8 continuous plus intermittent bleed, scf/hr) x 0.08097*** lb/scf x 50% VOC = lb VOC/hr
(note: these are not allowed under this general permit)

Number of low bleed (conforming to 6 scf/hr continuous bleed specification) gas driven pneumatic controllers x (14.89 continuous plus intermittent bleed, scf/hr) x 0.08097*** lb/scf x 50% VOC*** = lb VOC/hr

Number of zero bleed (i.e., zero continuous bleed) gas driven pneumatic controllers x (13.5 intermittent bleed, scf/hr) x 0.08097*** lb/scf x 50% VOC*** = lb VOC/hr

In Light Liquid Service

Number of connectors x 0.000463 lb/hr x 100% VOC = lb VOC/hr

Number of_valves x 0.00551 lb/hr x 100% VOC = lb VOC/hr

Number of_flanges x 0.00024 lb/hr x 100% VOC = lb VOC/hr

Number of_pump seals x 0.0287 lb/hr x 100% VOC = lb VOC/hr

Number of relief valves x 0.01653 lb/hr x 100% VOC = lb VOC/hr

The total summation of VOC emissions per hour shall be multiplied by 8760 hours per year and divided by 2000 pounds to calculate the tons of estimated annual fugitive VOC emissions.

Compliance with the ton per year limit shall be determined following the first 12 months of operation.

As an alternative to using the above emission factors to calculate VOC emissions, the permittee may use facility specific VOC information for site specific emission factors.

* The default % VOC for Gas/Vapor service was based on the highest percent VOC in gas analyses submitted by representative facilities.

** This emission factor is intended only for compressors not meeting the definition of "Centrifugal compressor" or "Reciprocating compressor" in 40 CFR part 60, Subpart OOOO or OOOOa as appropriate.

*** The conversion of scf/hr to lb/hr is accomplished by assuming a mean molecular weight of 30.74 and corresponding specific volume of 12.35 scf/lb (or specific mass of 0.08097 lb/scf) to be typical of a rich gas stream.

g) Miscellaneous Requirements

- (1) None.

GENERAL PERMIT 12.1 TEMPLATE

High Volume Horizontal Hydraulic Fracturing, OIL AND GAS WELL SITE PRODUCTION OPERATIONS

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.
 - (1) B.6. and B.8.
 - b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.
 - (1) B.9. and B.10.
2. The Ohio EPA has determined that this facility is subject to the requirements of 40 CFR Part 63 Subpart ZZZZ, the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines; and Part 63 Subpart HH, the National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities . At this time, the Ohio EPA is not accepting delegation for area sources subject to the Maximum Achievable Control Technology NESHAP (MACT) rules. The requirements of these rules, that are applicable to the area source(s) for hazardous air pollutants (HAP) identified in this permit, shall be enforceable by U.S. EPA. The complete requirements of this rule (including the Part 63 General Provisions) may be accessed via the Internet from the Electronic code of Federal Regulations (e-CFR) website <http://www.ecfr.gov/> or by contacting the appropriate Ohio EPA District Office or Local Air Agency.
3. Multiple emissions units contained in this permit must comply with various federal New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards. The complete NSPS and MACT requirements may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website <http://ecfr.gpoaccess.gov> or by contacting the appropriate Ohio EPA District Office or local air agency. The permittee must comply with the applicable requirements of 40 CFR Part 60 Subparts OOOO, JJJJ, and IIII and 40 CFR Part 63 Subparts HH and ZZZZ as they apply to the emissions source.
4. Air contaminant sources that qualify as de minimis under OAC rule 3745-15-05, or are exempt under OAC rule 3745-31-03(A)(1) or (4) are not subject to emission standards established within this permit. Although this permit does not apply to de minimis or exempt sources, emissions from de minimis or exempt sources must be included in the total potential to emit (PTE) calculations for this permit. PTE calculations should include sources such as:
 - a) qualifying non-road engines (exempt per 3745-31-03(A)(1)(pp)),
 - b) emergency diesel generator(s) (exempt per 3745-31-03(A)(1)(nn)),
 - c) micro turbines less than 200 kW (de minimis per OAC rule 3745-15-05), and
 - d) natural gas-fired heaters/boilers of various types that are less than 10 MMBtu/hr heat input (exempt per 3745-31-03(A)(1)(a)).
5. Emissions units permitted under a previously issued PTI/PTIO as portable sources shall be subject to the requirements of this General Permit during the time they are located at this site, provided that the emission unit(s) meets the qualifying criteria.

6. The requirements of this permit do not supersede any Ohio Department of Natural Resources requirements.
7. It is the permittee's responsibility to determine if any air pollution emitting equipment not covered by this permit needs a separate air permit.
8. Modeling to demonstrate compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F)(4)(b), is not necessary if/when the maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745-114-01, is less than 1.0 ton per year (or are subject to a standard under 40 CFR Part 63). OAC Chapter 3745-31 requires permittees to apply for and obtain a new or modified PTIO prior to making a "modification" as defined by OAC rule 3745-31-01. The permittee is hereby advised that changes in the composition of the materials or use of new materials that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new PTIO.
9. The permittee remains subject to all applicable federal law and regulations and all applicable provisions of the Ohio State Implementation Plan as approved by the Administrator of the U.S. EPA. The provisions of the Ohio State Implementation Plan are independently enforceable by the U.S. EPA.
10. If the determination that the facility is not a major source is based on actual emissions of 5 tons per year or more of any single HAP or 12.5 tons per year or more of a combination of HAP, the permittee shall update the facility's major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months of operation. Only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for major source determination at the production field facility (facility located prior to the point of custody transfer).
[40 CFR 63.760(c)] and [40 CFR 63.761]
11. Emission units and any required control and monitoring equipment shall be operated in a manner consistent with safety and good air pollution control practices for minimizing emissions.
[40 CFR 63.764(j)], [40 CFR 60.4243(b)], and [40 CFR 60.4211(g)]

C. Emissions Unit Terms and Conditions

1. Emissions Unit: Dehydration System, P001

Operations, Property and/or Equipment Description:

| | |
|------|--|
| P001 | Up to two glycol dehydration unit(s) (includes contact tower or absorption column and glycol dehydration unit reboiler) and gas-condensate-glycol (GCG) separator (flash separator), which may be vented to a condenser or BTEX (benzene, toluene, ethyl benzene, xylene) elimination system with condenser, and/or flare (less than 10 MMBtu/hr) or a facility-wide flare (see P004). |
|------|--|

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

a. 1.b)(1)d.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

b. 1.b)(1)e. and 1.b)(1)f.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|---|
| a. | OAC rule 3745-31-05(A)(3), as effective 11/30/01 | <p>For Total Organic Compounds (TOC), total hazardous air pollutants (total HAP), or benzene, compliance with the applicable control requirements of 40 CFR Part 63, Subpart HH.</p> <p>Emissions from a flare used to control emissions from the glycol dehydration unit shall not exceed:</p> <p>0.25 ton Nitrogen Oxides (NOx) per month averaged over a 12-month rolling period;</p> <p>0.23 ton VOC per month averaged over a 12-month rolling period; and</p> |

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|---|--|
| | | 0.15 ton Sulfur dioxide (SO ₂) per month averaged over a 12-month rolling period. See b)(2)a. |
| b. | OAC rule 3745-31-05(A)(3)(a)(ii) | See b)(2)b. |
| c. | ORC 3704.03(T) | Carbon Monoxide (CO) emissions from a flare used as a control device for the dehydrator shall not exceed 1.35 tons CO per month averaged over a 12-month rolling period. |
| d. | OAC rule 3745-31-05(E) | See b)(2)b. |
| e. | Part 63, Subpart HH, National Emission Standards for hazardous air pollutants (NESHAP) from Oil and Natural Gas Production Facilities | Compliance with the applicable portions of 40 CFR Part 63, Subpart HH. Any final amendments to this rule will supersede any previous Subpart HH requirement(s) in this permit. |
| f. | 40 CFR 63.11(b)(4) | No visible emissions except for 5 minutes during any 2 consecutive hours. |

(2) Additional Terms and Conditions

- a. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to OAC paragraph 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of 3745-31-05, then BAT no longer applies.
- b. These rules apply once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan:
 - i. This permit takes into account the following voluntary restrictions (including the use of any applicable air pollution control equipment) for the purpose of avoiding Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3):
 - (a) Emissions of Volatile Organic Compounds (VOC) (excludes methane and ethane) shall not exceed 5.0 tons/year;
 - (b) Use of a dehydration system flash separator that captures flash vapors; and

d) Monitoring and/or Recordkeeping Requirements

- (1) The permittee shall maintain records of the annual facility natural gas or hydrocarbon liquid throughput or a record of the maximum potential annual throughput rate attainable, based on the physical and operational design of the unit, in accordance with 40 CFR 63.760(a).
- (2) Where a flare is used to control the dehydration still vent, the permittee must:
 - a. continuously monitor the presence of the flame;
 - b. record all periods during which the automatic flare ignition system (pilot flame or electronic arc ignition system) or thermocouple was not working; and
 - c. record all periods during which there was gas being vented to the flare but the flare was not lit.
- (3) Where a condenser (or BTEX elimination system) is used to control the dehydration still vent, the permittee must:
 - a. continuously monitor and record the vapor outlet temperature of the condenser; and
 - b. record all periods of time when the condenser is not operating correctly to control the emissions from the dehydration still vent.
- (4) For each triethylene glycol (TEG) dehydration unit, the permittee shall document the method of compliance as follows:
 - a. if the permittee is using the exemption for the annual average flow rate of natural gas to the TEG dehydration unit, the permittee shall either install and operate a monitoring instrument to directly measure and record the natural gas flow rate to the glycol dehydration unit or demonstrate to the Director's satisfaction that the actual annual average natural gas flow rate to the dehydration unit is less than 85,000 scm/day, in accordance with 40 CFR 63.772(b)(1); or
 - b. if the permittee is using the exemption for the actual average benzene emissions from the TEG dehydration unit, the permittee shall keep the record of the determination (including the test methods and data used to support it) using either the GRI-GLYCalc™ model or by directly measuring benzene using the appropriate methods identified in 40 CFR 63.772(a)(1), in accordance with 40 CFR 63.772(b)(2); or
 - c. if the permittee does not meet one of the exemptions identified in 40 CFR 63.764(e) and is not located in a Urbanized Area (UA) plus offset and Urban Cluster (UC) boundary (as defined in 40 CFR 63.761), the permittee may (instead of meeting the control requirements) keep the record of the calculation for the optimal circulation rate (or alternate circulation rate as allowed using GRI-GLYCalc™ model) and records documenting this circulation rate is not exceeded in accordance with 40 CFR 63.764(d)(2); or

- d. if the permittee does not meet one of the exemptions identified in 40 CFR 63.764(e) and is located in a Urban Area (UA) plus offset and Urban Cluster (UC) boundary (as defined in 40 CFR 63.761), the permittee shall comply with the control requirements specified in 40 CFR 63.765 and the monitoring and recordkeeping requirements identified in 40 CFR 63.764(d)(1) to demonstrate compliance.

e) Reporting Requirements.

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) The permittee shall identify in the PER:
 - a. the annual facility natural gas or hydrocarbon liquid throughput for the year of the report, in accordance with 40 CFR 63.760(a);
 - b. identification of the kind of liquid glycol used in the dehydrator during the year of the report, e.g., ethylene glycol, diethylene glycol, or triethylene glycol*;
 - c. if the permittee is using triethylene glycol and meeting the exemption for the flow rate of natural gas to the TEG dehydration unit, the actual annual average natural gas flow rate to the TEG dehydration unit; and either the calculations and/or method of measurement of this flow rate or a statement that this flowrate was based on the maximum design capacity of the unit;
 - d. if the permittee is using triethylene glycol and meeting the exemption for benzene emissions, the actual annual average emissions of benzene from the TEG dehydration unit; and if these emissions were determined using the GRI-GLYCalc™ model, the method used to determine the benzene concentration entered into the model, and/or identification of the method used for direct measurement;
 - e. if the permittee is using triethylene glycol and the area source is not located in an UA plus offset and UC boundary and does not meet one of the exemptions identified in 40 CFR 63.764(e), the calculation for the optimal circulation rate and the method of measurement for the gas flowrate (MMscf/day) and inlet/outlet water content (lbs/MMscf), and a statement as to whether or not the optimal circulation rate was exceeded, to include the date, duration, and the non-compliant circulation rate measured;
 - f. if the permittee is using triethylene glycol and the area source is located in an UA plus offset and UC boundary and does not meet one of the exemptions identified in 40 CFR 63.764(e), the method of control that was used to demonstrate

compliance, the results of the compliance demonstration, and a statement as to whether or not the selected compliance option was met;

- g. where a flare is used to control the dehydration still vent, all periods of time during which the automatic flare ignition system was not functioning properly or the flare was not maintained as required in this permit, to include the date, time, and duration of each such period of time;
- h. where a condenser (or BTEX elimination system) is used to control the dehydration still vent, all periods of time when the continuous temperature monitoring device for the condenser vapor outlet temperature is not working or is not continuously recording the vapor outlet temperature when process gas is being vented to the condenser; and
- i. where the triethylene glycol dehydrator does not meet one of the exemptions in 40 CFR 63.764(e) or is not demonstrating compliance by documenting and maintaining the optimum glycol circulation rate as required in 40 CFR 63.764(d)(2), the flare or condenser used to demonstrate compliance shall meet all of the requirements of Part 63 Subpart HH.

* if not using triethylene glycol, the information in “c” through “i” is not required

[40 CFR 63.764(d) and (e)], [40 CFR 63.765], and [40 CFR 63.772(a) and(b)]

f) **Testing Requirements**

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

(1) Emissions Limitation:

For total TOC, total HAP, or benzene, compliance with the applicable control requirements of 40 CFR Part 63, Subpart HH.

Applicable Compliance Method:

The permittee may determine the annual total TOC (excludes methane and ethane), total HAP, or benzene emissions using the appropriate methods identified in 40 CFR 63.772 and/or GRI-GLYCalc™ model, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit(s) and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled “Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions” (GRI-95/0368.1);

Potential TOC, total HAP, and/or benzene emissions estimates shall be based on the maximum glycol circulation rate(s), in gallons per minute (gpm); the worst case pollutant concentrations from representative extended gas analyses of the inlet wet gas; and the maximum natural gas flow rate, as determined by 40 CFR 63.772(b)(1)(i); or for a new unit, potential emissions shall be estimated in accordance with 40 CFR 63.760(a) and increased by a factor of 1.2. The permittee may also determine the estimated annual

VOC emission through direct measurement using Method M25A or Method 18, both from Appendix A of Part 60.

[40 CFR 63.765(b)(1) and/or (c)(3)], [40 CFR 63.771(c) and (d)], [40 CFR 63.772], [40 CFR 63.773(d)], and [OAC rule 3745-31-05(E)]

(2) Emission Limitation from a flare used to control the dehydrator:

1.35 tons of CO per month averaged over a 12-month rolling period

Applicable Compliance Method:

The emissions limitation for CO is based on using the AP-42 emission factor of 0.37 lb CO/MMBtu from Chapter 13.5 for Industrial Flares, Table 13.5-1, "Emission Factors for Flare Operations" and using the estimated burner rating of 10.0 MMBtu/hr. Estimated CO emissions shall be determined by the following calculations:

$$0.37 \text{ lb CO/MMBtu} \times 10.0 \text{ MMBtu/hr} = 3.7 \text{ lbs CO/hr}$$

$$3.7 \text{ lbs CO/hr} \times 8760 \text{ hrs/yr} \times 1 \text{ ton/2000 lbs} = 16.2 \text{ tons CO/year}$$

$$16.2 \text{ tons CO} \div 12 \text{ months} = 1.35 \text{ tons CO/month averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(3) Emission Limitation from a flare used to control the dehydrator:

0.23 ton of VOC per month averaged over a 12-month rolling period

Applicable Compliance Method:

The emissions limitation for VOC is based on using the AP-42 emissions factor of 0.14 lb of hydrocarbon/MMBtu from Chapter 13.5 for Industrial Flares, Table 13.5-1 "Emission Factors for Flare Operations" excluding emissions of methane (55% per Table 13.5-2 "Hydrocarbon Composition of Flare Emissions") and using the estimated burner rating of 10 MMBtu/hr. Estimated VOC emissions shall be determined by the following calculation:

$$0.14 \text{ lb VOC/MMBtu} \times 45\% \times 10.0 \text{ MMBtu/hr} = 0.63 \text{ lb VOC/hr}$$

$$0.63 \text{ lb VOC/hr} \times 8760 \text{ hr/yr} \times 1 \text{ ton/2000 lbs} = 2.8 \text{ tons VOC/year}$$

$$2.8 \text{ tons VOC} \div 12 \text{ months} = 0.23 \text{ ton VOC/month averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(4) Emission Limitation from a flare used to control the dehydrator:

0.25 ton of NOx per month averaged over a 12-month rolling period

Applicable Compliance Method:

The emissions limitation for NO_x is based on using the AP-42 emission factor of 0.068 lb NO_x/MMBtu from Chapter 13.5 for Industrial Flares, Table 13.5-1, "Emission Factors for Flare Operations" and using the estimated burner rating of 10 MMBtu/hr. Estimated NO_x emissions shall be determined by the following calculation:

$$0.068 \text{ lb NO}_x/\text{MMBtu} \times 10.0 \text{ MMBtu/hr} = 0.68 \text{ lb NO}_x/\text{hr}$$

$$0.68 \text{ lb NO}_x/\text{hr} \times 8760 \text{ hrs/yr} \times 1 \text{ ton}/2000 \text{ lbs} = 3.0 \text{ tons NO}_x/\text{year}$$

$$3.0 \text{ tons NO}_x \div 12 \text{ months} = 0.25 \text{ ton NO}_x/\text{month} \text{ averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(5) Emission Limitation from a flare used to control the dehydrator:

0.15 ton of SO₂ per month averaged over a 12-month rolling period

Applicable Compliance Method:

The SO₂ emissions limitation is based on a fuel gas with a maximum H₂S content of 250 ppmv for sour gas.

Compliance with the ton per year SO₂ emissions limitation shall be determined by the following calculations:

$$10 \text{ MMBtu/hr} \times 1 \text{ scf}/1020 \text{ Btu} \times 1 \text{ lb-mole}/379.5 \text{ scf} \times 250 \text{ ppm H}_2\text{S} \times 64 \text{ lb SO}_2/\text{lb-mole} = 0.41 \text{ lb SO}_2/\text{hr}$$

$$0.41 \text{ lb SO}_2/\text{hr} \times 8760 \text{ hrs/year} \times 1 \text{ ton}/2000 \text{ lbs} = 1.8 \text{ tons SO}_2/\text{year}$$

$$1.8 \text{ tons SO}_2 \div 12 \text{ months} = 0.15 \text{ ton SO}_2/\text{month} \text{ averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(6) Emission Limitation:

Where the flare is used to demonstrate compliance with Part 63, Subpart HH, there shall be no visible emissions from the flare, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Applicable Compliance Method:

Compliance with the visible emissions limitation shall be determined in accordance with U.S. EPA Method 22 in Appendix A of 40 CFR Part 60.

[40 CFR 63.11(b)(4)]

g) Miscellaneous Requirements

Permit Number: [Permit Number]

Facility Name: [Facility Name]

Facility ID: [Facility ID]

Working Copy of a Permit in Progress

(1) None

2. Emissions Units: Spark Ignition Internal Combustion Engines, P002

Operations, Property and/or Equipment Description:

| | |
|------|--|
| P002 | <p>One or multiple stationary natural gas-fired spark ignition (SI) internal combustion engines (ICE) with a combined total horsepower (HP) of no more than 1,800 HP for the site.*</p> <p>Includes 2007 and later model year engines manufactured after the applicable effective date identified in 40 CFR 60.4230(a)(3); and engines manufactured before the effective date of the NSPS, where compliance with the Part 60 Subpart JJJJ emissions standards for the same size engine can be met by retrofitting the engine with a control device and demonstrated through stack testing.</p> |
|------|--|

* In order to maintain the carbon monoxide (CO) emissions below major source thresholds and nitrogen oxides (NOx) emissions below state significant impact levels, where the sum of the total horsepower (HP) of the spark ignition (SI) engines exceeds 1,300 HP, the SI engines rated at or over 100 HP may be required to meet more stringent standards for CO and NOx than is applicable to the engine.

- a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - (1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.
 - (a) None.
 - (2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.
 - (a) 2.b)(1)a.
- b) Applicable Emissions Limitations and/or Control Requirements
 - (1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|-------------------------------|---|
| a. | 40 CFR Part 60, Subpart JJJJ | Engines shall either be certified to the applicable Part 60 Subpart JJJJ emission standards and/or the exhaust emissions shall not exceed the |

| | | |
|----|---|---|
| | <p>In accordance with 40 CFR 60.4230, the engines in this emissions group are subject to the New Source Performance Standards (NSPS) for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE).</p> <p>40 CFR 60.4233(e)</p> <p>40 CFR 60.4231(a), (d), and (e)-mfg.</p> <p>Table 1 to Part 60, Subpart JJJJ</p> | <p>following emission limitations:</p> <p>the applicable emission standards for nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOC) as identified in Table 1 to Part 60, Subpart JJJJ; or</p> <p>for engines less than or equal to 25 HP, the applicable standards from 40 CFR Part 90 or Part 1054; or</p> <p>for engines greater than 25 HP and less than 100 HP, the applicable standards from Part 1048.</p> <p>Where the total summation of the SI ICE HP is equal to or less than 1,300 HP, the natural gas engine emissions together shall not exceed the worst-case emission standards for engines of 100 HP or greater from Table 1 to the subpart¹:</p> <p>2.0 grams of NOx per horsepower hour (2.0 g NOx/HP-hr);</p> <p>4.0 grams of CO per horsepower hour (4.0 g CO/HP-hr); and</p> <p>1.0 gram of VOC per horsepower hour (1.0 g VOC/HP-hr);</p> <p>In order to maintain CO emissions below major source thresholds and NOx emissions below state significant impact levels, where the total summation of the SI ICE HP is greater than 1,300 HP, the natural gas engine emissions together shall not exceed the following:</p> <p>1.45 grams of NOx per horsepower hour (1.45 g NOx/HP-hr);</p> <p>3.0 grams of CO per horsepower hour (3.0 g CO/HP-hr); and</p> <p>1.0 gram of VOC per horsepower hour (1.0 g VOC/HP-hr).</p> <p>See b)(2)c., d. and e.</p> |
| b. | <p>OAC rule 3745-17-11(B)(5)</p> <p>ORC 3704.03(T)</p> | <p>Particulate Emissions (PE) shall not exceed 0.310 lb/MMBtu for stationary small internal combustion engines rated less than or equal to 600 HP and 0.062 lb/MMBtu for stationary large</p> |

¹ Note: Each engine shall be required to meet the applicable emission standards under 40 CFR Part 60, Subpart JJJJ, based on the manufacture date and size engine, or where required, shall meet the Subpart JJJJ Table 1 standards or the limits identified in this permit by retrofitting pre-NSPS engines with a control device.

| | | |
|----|--|---|
| | | internal combustion engines rated over 600 HP. |
| c. | OAC rule 3745-17-07(A)(1) | Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20 percent opacity, as a six-minute average, except as specified by rule. |
| d. | OAC rule 3745-18-06(G) | Pursuant to OAC rule 3745-18-06(A), this stationary internal combustion engine is exempt from the sulfur dioxide (SO ₂) emission limitation specified by this rule during any calendar day in which natural gas is the only fuel burned. |
| e. | ORC 3704.03(T) | Compliance with the applicable g/HP-hr limits from 40 CFR Part 60, Subpart JJJJ for NO _x , CO and VOC. |
| f. | OAC rule 3745-31-05(A)(3), as effective 11/30/01 | See b)(2)a. |
| g. | OAC rule 3745-31-05(A)(3)(a)(ii), as effective 12/01/06 | See b)(2)b. |
| h. | 40 CFR Part 60 Subpart JJJJ 40 CFR 60.4233 and OAC 3745-31-05(F) | All SI ICE shall meet all applicable NSPS requirements where the model year is subject to these emission standards and all older model year engines shall be fitted with a control device (where required) and shall be demonstrated to meet the NSPS emission standards as applicable to 2007 and later model year engines of the same size/power. |
| i. | OAC 3745-31-05(F) | 5.75 lbs NO _x /hr from all SI engines combined. |

(2) Additional Terms and Conditions

- a. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to the Ohio Revised Code (ORC) changes effective August 3, 2006 (Senate Bill 265 changes), such that BAT is no longer required by State regulations for National Ambient Air Quality Standard (NAAQS) pollutant(s) less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1,

2006 version of OAC rule 3745-31-05 these emission limitations/control measures no longer apply.

- b. This rule applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the SO₂ emissions from this air contaminant source since the potentials to emit for SO₂ are less than ten tons per year.

- c. The stationary spark ignition (SI) internal combustion engine(s) (ICE) are subject to and shall be operated in compliance with the requirements of 40 CFR Part 60, Subpart JJJJ, standards of performance for stationary SI ICE.

[40 CFR 60.4230(a)]

- d. The owner/operator of all SI ICE shall demonstrate compliance with the emissions standards identified in 40 CFR 60.4233 of Part 60, Subpart JJJJ in accordance with 40 CFR 60.4243(b).

[40 CFR 60.4233] and [40 CFR 60.4243(b)]

- e. The gram per horsepower-hour emissions limitations are based on the emission standards from Table 1 of NSPS JJJJ for natural gas-fired engines. In order to maintain the carbon monoxide (CO) emissions below major source thresholds and nitrogen oxide (NOx) emissions below state significant impact levels, where the sum of the total horsepower (HP) of the spark ignition (SI) engines exceeds 1,300 HP, the SI engines rated at or over 100 HP shall meet the CO and NOx limits identified in the Testing Section of this permit. However, each engine installed at the natural gas production site and subject to a more stringent standard, based on the model year and engine's size, must be demonstrated to comply with the applicable emissions standard established in 40 CFR 60.4233.

c) **Operational Restrictions**

- (1) The stationary SI ICE shall be installed, operated, and maintained according to the manufacturer's recommendations or in accordance with the operator's Operation and Maintenance (O&M) Plan and in a manner consistent with good air pollution control practice for minimizing emissions. The permittee shall operate and maintain the stationary SI ICE to achieve the emission standards identified in 40 CFR 60.4233 over the entire life of the engine(s). The air-to-fuel ratio controllers shall be set by the operator according to the manufacturer's operations manual, to ensure proper operation of the engines and their control device (catalytic converter) and to minimize emissions.

[40 CFR 60.4234], [40 CFR 60.4243(b)], and [40 CFR 60.4243(g)]

d) **Monitoring and/or Recordkeeping Requirements**

- (1) The following records shall be maintained for each spark ignition engine operating at the well site:
 - a. all notifications submitted to comply with and all documentation supporting compliance with Part 60 Subpart JJJJ;

- b. all notifications submitted to comply with and all documentation supporting compliance with Part 63 Subpart ZZZZ;
- c. records of all maintenance conducted on the engines;
- d. for certified engines less than or equal to 100 HP, the certification from the manufacturer, documenting that the engine(s) meet(s) the emission standards identified in 40 CFR 60.4231 or for uncertified engines, the testing results from the initial and subsequent performance tests, as applicable, conducted to meet the requirements of 40 CFR 60.4243(b)(2)(i) or (ii); and
- e. the information identified in 40 CFR Parts 90, 1048, 1054, and/or 1060 that is required to be provided by the manufacturer to the operator/owner, as applicable to the model year and horsepower of the engines.

The permittee or owner/operator (if leased) of the engines shall keep the above records and a maintenance plan for the engines, and shall maintain documentation that the engine is maintained and operated according the manufacturer's emission-related instructions.

[40 CFR 60.4245(a)] and [40 CFR 60.4243(a) and (b)]

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) The permittee shall identify in the PER:
 - a. each SI engine located (and operated) at the production site during the year, identified by the model year, horse power, and the date of manufacturer of each engine;
 - b. a statement as to whether each engine was purchased certified by the manufacturer, in accordance with the Subpart JJJJ, i.e., the manufacturer has provided a warranty for the emissions when the engine was first sold;
 - c. a statement as to whether each engine was operated and maintained in accordance with the manufacturers emission-related instructions;
 - d. the date each uncertified SI engine was tested for compliance with the applicable emission standards identified in Part 60 Subpart JJJJ; and
 - e. identification of each engine that did not meet the applicable emission standards identified in 40 CFR 60.4233 and/or this permit, the number of hours each such

engine was in operation while not in compliance, the pollutant limitation(s) that were exceeded, and information on the date and resolution of compliance.

- (3) For each natural gas SI ICE not certified to the applicable emission standards identified in 40 CFR Part 60 Subpart JJJJ, and subject to the performance testing requirements of 40 CFR 60.4243(b)(2), the permittee shall submit a copy of the results of each performance test conducted to demonstrate compliance within 60 days after the test has been completed.

[40 CFR 60.4245(d)]

f) Testing Requirements

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods.

- (1) The SI engines shall meet the applicable emissions standards identified in 40 CFR 60.4233 and/or the applicable emission limits required in this permit. Engines greater than 100 HP shall not exceed the emission standards identified in Table 1 to Subpart JJJJ and engines less than 100 HP shall not exceed the applicable standards identified in 40 CFR 60.4231, as required per 40 CFR 60.4233, all as applicable to each engine's horsepower and model year. In order to maintain the facility below major source thresholds and significant impact levels, older engines that were manufactured before the effective date of the NSPS shall be retrofitted with controls that can demonstrate the emission limits established in this permit are met.

- (2) For each natural gas engine purchased without an EPA certificate of conformity (most engines >25 HP), the permittee shall conduct or have conducted an initial performance test to demonstrate compliance with the NSPS standards for NO_x, CO, and VOC; and for each engine greater than 500 HP, subsequent performance tests shall be conducted every 8,760 hours or 3 years, whichever comes first.

[40 CFR 60.4243(b)(2)]

- (3) Emission Limitation:

Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity, as a six-minute average, except as specified by rule.

Applicable Compliance Method:

If required, compliance shall be determined through visible emission observations performed in accordance with U.S. EPA Reference Method 9 in 40 CFR, Part 60, Appendix A.

[OAC rule 3745-17-07(A)(1)]

- (4) Emissions Limitations:

Particulate Emissions (PE) shall not exceed 0.310 lb/MMBtu for small engines ≤ 600 HP; and 0.062 lb/MMBtu for large engines > 600 HP

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the emission limitations through exhaust emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5.

[OAC 3745-17-11(B)(5)]

(5) Emissions Limitations:

2.0 grams NO_x /HP-hr for engines ≥ 100 HP; or

1.45 grams NO_x /HP-hr for engines ≥ 100 HP where the total engine power is greater than 1,300 HP; and/or

the combination of SI engines shall be calculated to not exceed 5.75 lbs NO_x/hour, based on the summation of the emission stack test results and/or the pound per hour emissions calculated from the emission rate certified by the manufacturer.

Applicable Compliance Method:

The emission limitations are based on the exhaust emission standards identified in 40 CFR 60.4231(e). Compliance with the applicable g/HP-hr NO_x standard shall be demonstrated through performance/stack testing, if not certified to the standard. The g/HP-hr limitations above are based on the emission standards from Table 1 to Part 60 Subpart JJJJ for engines 100 HP or larger. Compliance with the short term and ton per year NO_x emissions limitation shall be determined for each non-emergency spark ignition engine located on the site using the applicable compliance methods identified in Part 60 Subpart JJJJ. The combination of SI engines together shall be calculated to not exceed 5.75 lbs NO_x/hour, based on the summation of the emission stack test results and/or the pound per hour NO_x emissions calculated from the emission rate certified by the manufacturer.

Where the sum of the total HP of the facility SI ICE is no greater than 1,300 HP, the following calculations establish the pound per hour emissions of NO_x from the spark ignition engines covered in this permit:

$$2.0 \text{ g NO}_x/\text{HP-hr} \times 1,300 \text{ HP} \times 1\text{lb}/454 \text{ g} = 5.73 \text{ lbs NO}_x/\text{hr}$$

Where the sum of the total HP of the SI ICE exceeds 1,300 HP, an average NO_x limit between 2.0 grams/HP-hr and 1.45 grams/HP-hr shall be required in order to meet the 5.75 lbs/hour NO_x limitation established in this permit. The average emissions of NO_x (in grams/HP-hr) shall be calculated as follows:

$$\text{Average g NO}_x/\text{HP-hr} = \sum_{n=1}^n [\text{g/HP-hr} \times \text{HP}] / \text{total HP}$$

Where:

g/HP-hr = the standard to which each natural gas engine is certified

HP = the horsepower of each individual natural gas engine

total HP = the total horsepower or summation of the horsepower of each natural gas engine

n = number of natural gas engines at the well site

The following calculations establish the maximum pound per hour emissions of NOx from the spark ignition engines covered in this permit where the summation of the horsepower exceeds 1,300 HP, and where the average emissions of NOx is maintained at or below 1.45 grams/HP-hr:

$$1.45 \text{ g NOx/HP-hr} \times 1,800 \text{ HP} \times 1\text{lb}/454 \text{ g} = 5.75 \text{ lbs NOx/hr}$$

When required, the permittee shall demonstrate compliance with the NOx limitation according to the requirements of 40 CFR 60.4244, using the applicable test methods in Table 2 to Part 60 Subpart JJJJ.

[40 CFR 60.4233(e)], [40 CFR 60.4243(b)(2)]. [40 CFR 60.4244], and [Table 1 to Part 60 Subpart JJJJ]

(6) Emissions Limitations:

4.0 grams CO/HP-hr for engines \geq 100 HP; or

3.0 grams CO/HP-hr for engines \geq 100 HP where the total engine power is greater than 1,300 HP; and/or

the combination of SI engines shall be calculated to not exceed 11.9 lbs CO/hour, based on the summation of the emission stack test results and/or the pound per hour CO emissions calculated from the emission rate certified by the manufacturer.

Applicable Compliance Method:

The emission limitations are based on the exhaust emission standards identified in 40 CFR 60.4231(e). Compliance with the applicable g/HP-hr CO standard shall be demonstrated through performance/stack testing, if not certified to the standard. The g/HP-hr limitations above are based on the emission standards from Table 1 to Part 60 Subpart JJJJ for engines 100 HP or larger. Compliance with the short term and ton per year CO emissions limitation shall be determined for each non-emergency spark ignition engine located on the site using the applicable compliance methods identified in Part 60 Subpart JJJJ. The combination of SI engines together shall be calculated to not exceed 11.9 lbs CO/hour, based on the summation of the emission stack test results and/or the pound per hour CO emissions calculated from the emission rate certified by the manufacturer.

Where the sum of the total HP of the facility SI ICE is no greater than 1,300 HP, the following calculations establish the pound per hour emissions of CO from the spark ignition engines covered in this permit:

$$4.0 \text{ g CO/HP-hr} \times 1,300 \text{ HP} \times 1\text{lb}/454 \text{ g} = 11.5 \text{ lbs CO/hr}$$

Where the sum of the total HP of the SI ICE exceeds 1,300 HP, an average CO limit between 4.0 grams/HP-hr and 3.0 grams/HP-hr shall be required in order to meet the 11.9 lbs/hour CO limitation established in this permit. The average emissions of CO (in grams/HP-hr) shall be calculated as follows:

$$\text{Average g CO/HP-hr} = \sum_{n=1} [\text{g/HP-hr} \times \text{HP}] / \text{total HP}$$

Where:

g/HP-hr = the standard to which each natural gas engine is certified

HP = the horsepower of each individual natural gas engine

total HP = the total horsepower or summation of the horsepower of each natural gas engine

n = number of natural gas engines at the well site

The following calculations establish the maximum pound per hour emissions of CO from the spark ignition engines covered in this permit where the summation of the horsepower exceeds 1,300 HP, and where the average emissions of CO is maintained at or below 3.0 grams/HP-hr:

$$3.0 \text{ g CO/HP-hr} \times 1,800 \text{ HP} \times 1\text{lb}/454 \text{ g} = 11.9 \text{ lbs CO/hr.}$$

When required, the permittee shall demonstrate compliance with the CO limitation according to the requirements of 40 CFR 60.4244, using the applicable test methods in Table 2 to Part 60 Subpart JJJJ.

[40 CFR 60.4233(e)], [40 CFR 60.4243(b)(2)]. [40 CFR 60.4244], and [Table 1 to Part 60 Subpart JJJJ]

(7) Emissions Limitations:

1.0 gram VOC/HP-hr for engines \geq 100 HP

Applicable Compliance Method:

The emission limitations are based on the exhaust emission standards identified in 40 CFR 60.4231(e). Compliance with the applicable g/HP-hr VOC standard shall be demonstrated through performance/stack testing, if not certified to the standard. The g/HP-hr limitations above are based on the emission standards from Table 1 to Part 60 Subpart JJJJ for engines 100 HP or larger. Compliance with the short term and ton per year VOC emissions limitation shall be determined for each non-emergency spark ignition engine located on the site using the applicable compliance methods identified in Part 60 Subpart JJJJ.

The following calculations establish the pound per hour emissions of VOC from the spark ignition engines covered in this permit:

$$1.0 \text{ g VOC/HP-hr} \times 1,800 \text{ HP} \times 1\text{lb}/454 \text{ g} = 4.0 \text{ lbs VOC/hr}$$

When required, the permittee shall demonstrate compliance with the VOC limitation according to the requirements of 40 CFR 60.4244, using the applicable test methods in Table 2 to Part 60 Subpart JJJJ.

[40 CFR 60.4233(e)], [40 CFR 60.4243(b)(2)]. [40 CFR 60.4244], and [Table 1 to Part 60 Subpart JJJJ]

g) Miscellaneous Requirements

(1) Replacement of or Installation of Additional Engines

The permittee may install additional stationary engines or replace existing engines at any time during the life of this permit as long as the following are met:

- a. at any given time, the total horsepower of all natural gas engines in service at the site is no more than 1,800 HP;
- b. all natural gas engines in service at the site meet the applicable NSPS emission standards as identified in the NSPS and this permit, and all applicable State or Federal rules;
- c. the permittee maintains a list of all stationary natural gas engines used at the site; and
- d. the permittee continues to meet the qualifying criteria associated with the natural gas engines for this general permit.

(2) Stack Height of Stationary Natural Gas Engines

- a. Any engine with greater or equal to 250 HP shall be equipped with an exhaust stack that is at least 20' above ground level.
- b. Any engine with less than 250 HP shall be equipped with an exhaust stack that is at least 12' above ground level.

3. Emissions Unit: Compression Ignition Engines, P003

Operations, Property and/or Equipment Description:

| | |
|------|---|
| P003 | One or multiple stationary diesel-fired compression ignition (CI) (diesel) internal combustion engines (ICE) with a combined total horsepower (HP) of no more than 250 HP for the site ² , and that are either certified to meet the Tier 3 emission standards (from 40 CFR 60.89.112 Table 1) for diesel engines or retrofitted with a control device that demonstrates each engine meets the Tier 3 standards. |
|------|---|

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

(a) None.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

(a) 3.b)(1)a.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|---|
| a. | 40 CFR Part 60, Subpart IIII 40 CFR 60.4204(b) 40 CFR 60.4201(a) Table 1 to 40 CFR 89.112, Tier 3 | The exhaust emissions from any compression ignition (CI) internal combustion engine (ICE) shall not exceed the appropriate Tier 3 emission standards identified in Table 1 to 40 CFR 89.112. The emission limitations are based on the following worst-case Tier 3 emission standards for engines greater than or equal to 50 HP: |

² This emissions unit includes stationary diesel engines used for production. It does not include various portable engines that are temporarily used on the site nor does it include engines that are exempt from permitting. For instance, any engines qualifying for the non-road exemption found in Ohio Administrative Code (OAC) paragraph 3745-31-03(A)(1)(pp) would not be covered by this permit.

² Note: The worst case emission standards for diesel-fired engines less than 300 HP were used to establish the emissions limitation. However, each engine shall be required to meet the applicable Tier 3 emission standards (or Tier 2 standards for engines <50 HP) from Table 1 of 40 CFR 89.112.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|---|---|
| | | 0.40 gram PM/kW-hr; 4.7 grams NOx + NMHC/kW-hr; and 5.0 grams CO/kW-hr. See b)(2)c. |
| b. | 40 CFR 60.4207(b) 40 CFR 80.510(b) | The sulfur content of the diesel fuel burned in this engine shall not exceed 15 ppm or 0.0015% sulfur by weight. See b)(2)c., c)(2), d)(1), and e)(2). |
| c. | 40 CFR 89.113 | Engine(s) subject to Part 60, Subpart IIII shall be certified by the manufacturer to the following opacity standards: 20% opacity during the acceleration mode; 15% opacity during the lugging mode; and 50% opacity during the peaks in either the acceleration or lugging modes. |
| d. | OAC rule 3745-18-06 | The SO ₂ limitation established per this rule is less stringent than the limitation established in 40 CFR 80.510(b). |
| e. | OAC rule 3745-17-07(A)(1) | Visible particulate emissions from the exhaust stack serving this engine shall not exceed 20% opacity, as a six-minute average, except as specified by rule. |
| f. | OAC rule 3745-31-05(A)(3), as effective 11/30/01 | Compliance with the applicable gram/kW-hr limits found in 40 CFR Part 60, Subpart IIII for PM, NOx + NMHC, and CO. See b)(2)a. |
| g. | OAC rule 3745-31-05(A)(3)(a)(ii), as effective 12/01/06 | See b)(2)b. |
| h. | OAC rule 3745-17-11(B)(5) | The emission limitation specified by this rule is less stringent than the emission limitation established for PM pursuant to 40 CFR Part 60, Subpart IIII. |
| i. | 40 CFR Part 60 Subpart IIII 40 CFR 60.4202 | All CI ICE shall meet all applicable NSPS requirements where the model year is subject to these standards and older engines shall be fitted |

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|--|-------------------------------|---|
| | | with a control device that demonstrates the Tier 3 standards are met. |

(2) Additional Terms and Conditions

a. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to the Ohio Revised Code (ORC) changes effective August 3, 2006 (Senate Bill 265 changes), such that BAT is no longer required by State regulations for National Ambient Air Quality Standard (NAAQS) pollutant(s) less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 these emission limitations/control measures no longer apply.

b. This rule applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the PM, NOx, CO, and VOC emissions from this air contaminant source since the uncontrolled potential to emit for PM, NOx, CO, and VOC are less than ten tons per year.

c. The stationary compression ignition (CI) internal combustion engine (ICE) is subject to and shall be operated in compliance with the requirements of 40 CFR Part 60, Subpart IIII, the standards of performance for stationary CI ICE.

[40 CFR 60.4200(a)]

d. The stationary CI ICE has been or shall be purchased certified by the manufacturer to emission standards as stringent as those identified in 40 CFR 60.4201(a) and found in Tier 3 of 40 CFR 89.112, Table 1, for engines greater than or equal to 50 horsepower (37 kilowatt) and less than or equal to 250 horsepower (186 kilowatt), and to the opacity standards found in 40 CFR 89.113.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], [40 CFR 60.4203], and [40 CFR 60.4211(c)]

e. The quality of the diesel fuel burned in this engine shall meet the following specifications on an "as received" basis:

i. a sulfur content which is sufficient to comply with the allowable sulfur dioxide emission limitation of 0.0015 pound sulfur dioxide/MMBtu actual heat input; and 15 ppm sulfur or 0.0015% sulfur by weight;

- ii. a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent; and
- iii. a heating value greater than 135,000 Btu/gallon.

Compliance with the above-mentioned specifications shall be determined by using the analytical results provided by the permittee or oil supplier for each shipment of oil.

[40 CFR 60.4207(b)] and [40 CFR 80.510(b)]

c) **Operational Restrictions**

- (1) The stationary CI ICE shall be installed, operated, and maintained according to the manufacturer's emission-related written instructions over the entire life of the engine; and the permittee shall only change those emission-related settings that are allowed by the manufacturer. The CI ICE must also be installed and operated to meet the applicable requirements from 40 CFR Part 89, Control of Emissions from New and In-use Non-road CI ICE and Part 1068, the General Compliance Provisions for Engine Programs. The permittee shall operate and maintain the stationary CI ICE to achieve the Tier 3 emission standards in Table 1 to 40 CFR 89.112, as required per 40 CFR 60.4204.

[40 CFR 60.4206] and [40 CFR 60.4211(a)]

- (2) Diesel fuel burned in the CI, ICE shall not exceed the standards for sulfur as specified by 40 CFR 80.510(b), i.e., the maximum sulfur content of diesel fuel shall not exceed 15 ppm or 0.0015% sulfur by weight.

[40 CFR 60.4207(b)] and [40 CFR 80.510(b)]

- (3) If the stationary CI internal combustion engine is equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the permittee when the high backpressure limit of the engine is approached.

[40 CFR 60.4209(b)]

- (4) The summation of engine power from all the diesel engines installed at the production facility site (following well completion) shall not exceed 250 HP.

d) **Monitoring and/or Recordkeeping Requirements**

- (1) For each shipment of oil received for burning in this engine, the permittee shall maintain records of the total quantity of the diesel oil received and the oil supplier's (or permittee's) analyses for sulfur content, in parts per million (40 CFR 80.510) or percent by weight. The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR 80.580, using the appropriate ASTM methods. These records shall be retained for a minimum of 5 years and shall be available for inspection by the Director or his/her representative.

[for 40 CFR 60.4207(b)]

- (2) The permittee shall maintain the manufacturer's certification or compliant test data for non-certified engines, to the applicable Tier 3 emission standards in Table 1 of 40 CFR 89.112 at a central location for all facility ICE and it shall be made available for review upon request. If the manufacturer's certification is not kept on site, the permittee shall maintain a log for the location of each ICE and it shall identify the agency-assigned emissions unit number, the manufacturer's identification number, and the identification number of the certificate. The permittee or owner/operator (if leased) of the engines shall keep a maintenance plan and records of the maintenance conducted on each engine, to include documentation that the engine is maintained and operated according to the manufacturer's emission-related instructions.

[40 CFR 60.4211]

- (3) The permittee shall maintain a record of the diesel fuel burned in each ICE during each calendar year. The diesel fuel usage shall be calculated using the best method available to estimate the annual fuel consumption of each engine, which might include, but are not be limited to: a flow meter installed on the engine, records of the volume of diesel fuel oil received with each delivery, the fuel oil levels recorded from the diesel storage tank, and/or the recorded or estimated hours of operation along with the manufacturer's documentation of the estimated fuel flow rate.

- (4) If the stationary CI internal combustion engine is equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the permittee shall keep records of the date, time, and any corrective action(s) taken in response to the notification from the backpressure monitor, that the high backpressure limit of the engine has been approached or exceeded.

[40 CFR 60.4214(c)]

- (5) The permittee shall maintain a record of visible emission checks for the stack of diesel engines. The record shall be documented during maintenance operations.

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) The permittee shall identify in the PER:
- a. each CI engine located (and operated) at the production site during the year, to include the year of manufacture and/or year rebuilt, the horse power;
 - b. a statement as to whether each engine was purchased certified by the manufacturer, in accordance with the Subpart IIII, i.e., the manufacturer has provided a warranty for the emissions when the engine was first sold;

- c. a statement as to whether each engine was operated and maintained in accordance with the manufacturers emission-related instructions;
- d. the date each uncertified SI engine was tested for compliance with the Tier 3 emission standards from 40 CFR 89.112;
- e. identification of any uncertified engine that did not meet the applicable Tier 3 emission standards, to include the horse power and year of manufacture and/or year rebuilt; and
- f. any period of time that the quality of oil burned in each engine did not meet the requirements established in 40 CFR 80.510(b), based upon the required fuel records, to include the amount burned, the engine combusting it, the date(s), and the date the non-compliant fuel was purchased*.

* if the fuel oil is purchased before 10/1/10, the amendments of 1/30/13 allow the fuel to be used until depleted

[40 CFR 60.4207(b)] and [40 CFR 80.510(b)]

- (3) If the stationary CI internal combustion engine is equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the permittee shall include in the PER any records of the date, time, and any corrective action(s) taken in response to the notification from the monitor that the backpressure has been approached or exceeded.

[for 40 CFR 60.4214(c)]

f) **Testing Requirements**

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

(1) Emission Limitation:

Manufacturer's certification requirements related to opacity include:

20% opacity during the acceleration mode;

15% opacity during the lugging mode; and

50% opacity during the peaks in either the acceleration or lugging modes.

Applicable Compliance Method:

The CI ICE subject to the standards in 40 CFR Part 60, Subpart IIII shall be purchased certified by the manufacturer to the opacity standards of 40 CFR 89.113.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], and [40 CFR 89.113]

(2) Emission Limitation:

Visible particulate emissions from the exhaust stack serving this engine shall not exceed 20 %opacity, as a six-minute average, except as specified by rule.

Applicable Compliance Method:

Visible emission checks shall be conducted following the completion of maintenance operations. Compliance shall be determined through visible emission observations performed in accordance with U.S. EPA Reference Method 9 in 40 CFR, Part 60, Appendix A.

[OAC rule 3745-17-07(A)(1)]

(3) Emission Limitation:

0.40 gram PM/kW-hr

Applicable Compliance Method:

Compliance with the applicable g/kW-hr emissions standard shall be based on the manufacturer's certification to the standards applicable to each engine and by maintaining the engine according to the manufacturer's specifications. The g/kW-hr standard above is the worst-case Tier 3 exhaust emission standards from Table 1 of 40 CFR 89.112 for diesel engines between 50 and 300 horsepower (37 and 225 kilowatts). An uncertified engine shall either be stack tested following installation or test data shall be submitted to demonstrate compliance with the appropriate limit based on the horsepower.

If required, the permittee shall demonstrate compliance with the emission limitations through performance tests conducted in accordance with the provisions in f)(8)below.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], [40 CFR 60.4211(c)], and [40 CFR 60.4212(a) and (c)]

(4) Emissions Limitations:

4.7 grams NO_x + NMHC/kW-hr

Applicable Compliance Method:

Compliance with the applicable g/kW-hr emissions standard shall be based on the manufacturer's certification to the standards applicable to each engine and by maintaining the engine according to the manufacturer's specifications. The g/kW-hr standard above is the worst-case Tier 3 exhaust emission standards from Table 1 of 40 CFR 89.112 for diesel engines between 50 and 300 horsepower (37 and 225 kilowatts). An uncertified engine shall either be stack tested following installation or test data shall be submitted to demonstrate compliance with the appropriate limit based on the horsepower.

For the purpose of reporting emissions, where the limitation is for NO_x + NMHC, the NO_x and VOC limitations shall be calculated using a ratio of 74.6% NO_x to 25.4% VOC:*

4.7 g NO_x+NMHC/kW-hr x 74.6% NO_x* = 3.5 grams NO_x/kW-hr.

If required, the permittee shall demonstrate compliance with the emission limitations through performance tests conducted in accordance with the provisions in f)(8)below.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], [40 CFR 60.4211(c)], and [40 CFR 60.4212(a) and (c)]

(5) Emissions Limitations:

5.0 grams CO/kW-hr

Applicable Compliance Method:

Compliance with the applicable g/kW-hr emissions standard shall be based on the manufacturer's certification to the standards applicable to each engine and by maintaining the engine according to the manufacturer's specifications. The g/kW-hr standard above is the worst-case Tier 3 exhaust emission standards from Table 1 of 40 CFR 89.112 for diesel engines between 50 and 300 horsepower (37 and 225 kilowatts). An uncertified engine shall either be stack tested following installation or test data shall be submitted to demonstrate compliance with the appropriate limit based on the horsepower.

If required, the permittee shall demonstrate compliance with the emission limitations through performance tests conducted in accordance with the provisions in f)(8)below.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], [40 CFR 60.4211(c)] and [40 CFR 60.4212(a) and (c)]

(6) Emissions Limitations:

4.7 grams NO_x + NMHC/kW-hr

Applicable Compliance Method:

Compliance with the emission limitations shall be based on the manufacturer's certification and by maintaining the engine according to the manufacturer's specifications. The g/kW-hr limitation is the worst-case Tier 3 exhaust emission standards from Table 1 of 40 CFR 89.112 for diesel engines between 50 and 300 horsepower (37 and 225 kilowatts). An uncertified engine shall either be stack tested following installation or test data shall be submitted to demonstrate compliance with the appropriate limit based on the horsepower.

For the purpose of reporting emissions, where the limitation is for NO_x + NMHC, the NO_x and VOC limitations shall be calculated using a ratio of 74.6% NO_x to 25.4% VOC*:

$4.7 \text{ g NO}_x\text{+NMHC/kW-hr} \times 25.4\% \text{ NMHC}^* = 1.19 \text{ gram VOC/kW-hr.}$

If required, the permittee shall demonstrate compliance with the emission limitations through performance tests conducted in accordance with the provisions in f)(8)below.

[40 CFR 60.4204(b)], [40 CFR 60.4201(a)], [40 CFR 60.4211(c)], and [40 CFR 60.4212(a) and (c)]

*This ratio is based upon the linear relationship of NO_x to NMHC from Table 1 of Subpart IIII, Table 1 from 40 CFR 89.112, to Tables 4, 5, and 6 from 40 CFR 1039.102.

(7) Emissions Limitation:

Sulfur content 15 ppm or \leq 0.0015% by weight sulfur

Applicable Compliance Method:

Compliance shall be demonstrated through the record keeping requirements for the sulfur content of each shipment of diesel oil received. If meeting the standards in 40 CFR 80.510(b), this calculates to approximately 0.0015 lb SO₂/MMBtu.

[40 CFR 60.4207(b)] and [40 CFR 80.510(b)]

- (8) If it is determined by Ohio EPA that a compliance demonstration is required through performance testing, i.e., the engine is not certified or not operated in accordance with the manufacturer's emission-related instructions, it shall be conducted using one of the following test methods or procedures:

- a. in accordance with 40 CFR 60.4212, conduct the exhaust emissions testing using the in-use testing procedures found in 40 CFR Part 1039, Subpart F, measuring the emissions of the regulated pollutants as specified in 40 CFR Part 1065; or
- b. in accordance with 40 CFR 60.4213, conduct exhaust emissions testing using the test methods identified in Table 7 to Subpart IIII of Part 60.

If demonstrating compliance through the in-use testing procedures in 40 CFR Part 1039, Subpart F, exhaust emissions from the stationary CI ICE shall not exceed the "not to exceed" (NTE) numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112, determined from the following equation:

$$\text{NTE requirement for each pollutant} = 1.25 \times \text{STD}$$

Where:

STD = The standard specified for the pollutant in 40 CFR 89.112.

[40 CFR 60.4212(a) and (c)]

g) Miscellaneous Requirements

- (1) Replacement of or Installation of Additional Engines

- a. The permittee may install additional stationary compression ignition engines or replace existing stationary compression ignition engines at any time during the life of this permit as long as the following are met:
 - i. at any given time, the total horsepower of all stationary compression ignition engines in service at the site is no more than 250 HP;
 - ii. all stationary compression ignition engines in service at the site meet all applicable NSPS emission standards identified in the NSPS and this permit, and all applicable State or Federal rules;
 - iii. the permittee maintains a list of all stationary compression ignition engines used at the site; and

- iv. the permittee continues to meet the qualifying criteria associated with the stationary compression ignition engines for this general permit.

(2) Stack Height of Stationary Compression Ignition Engines

- a. Each stationary compression ignition engine shall be equipped with an exhaust stack that is at least 12' above ground level.

4. Emissions Unit: Enclosed or Open Flare/Combustion Device, P004

Operations, Property and/or Equipment Description:

| | |
|------|---|
| P004 | Enclosed or Open Flare(s)/Combustion Device(s) with a maximum combined capacity heat input of no more than 250 MMBtu/hr and operated at no more than 10 MMBtu per hour combined heat input from all the sources vented to the combustion device(s), except during an emergency ³ |
|------|---|

- a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - (1) For the purpose of a permit-to-install document, the emissions unit terms and conditions in this permit are federally enforceable, with the exception of those listed below, which are enforceable under state law only.
 - a. None.
 - (2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions in this permit are enforceable under state law only, with the exception of those listed below, which are federally enforceable.
 - a. 4.b)(1)d. and 4.b)(1)e.
- b) Applicable Emissions Limitations and/or Control Requirements
 - (1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|-------------------------------|--|
| a. | ORC 3704.03(T) | For VOC and where applicable, compliance with the applicable control requirements of 40 CFR Part 60, Subpart OOOO, by having a designed minimum control efficiency of 95% for an enclosed flare/combustor. Carbon monoxide (CO) emissions shall not exceed 1.35 tons per month averaged over a 12-month rolling period. |
| b. | OAC rule 3745-31-05(A)(3), as | Nitrogen Oxide (NOx) emissions shall not |

³ This emissions unit applies when a facility chooses to use a flare/combustion device to control VOCs emitted from the entire facility (including, but not limited to, flash vessel/storage tanks, truck loading for water and/or petroleum liquids, and the dehydrator). If a separate flare is used to control dehydrator emissions, then the flare requirements found in the dehydrator emissions unit terms govern the dehydrator flare.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|--|
| | effective 11/30/01 | <p>exceed 0.25 ton per month averaged over a 12-month rolling period.</p> <p>Sulfur Dioxide (SO₂) emissions shall not exceed 0.15 ton per month averaged over a 12-month rolling period.</p> <p>See b)(2)a.</p> |
| c. | OAC rule 3745-31-05(A)(3)(a)(ii), as effective 12/01/06 | See b)(2)b. |
| d. | <p>Part 63, Subpart HH, National Emission Standards for hazardous air pollutants (NESHAP) from Oil and Natural Gas Production Facilities</p> <p>Control/operational requirements applicable to area source TEG dehydration units not meeting one of the exemptions found in 40 CFR 63.764(e).</p> | <p>For a triethylene glycol dehydration unit subject to the standards, compliance with the applicable portions of 40 CFR Part 63, Subpart HH. Design and operate the enclosed flare/combustion device in accordance with the requirements of 40 CFR 63.771(d)(1), i.e., reduce the mass content of either TOC or total HAP, in the gases vented to it (from the closed vent system), by 95% by weight or greater; or reduce the concentration of TOC or total HAP to less than or equal to 20 ppm by volume on a dry basis corrected to 3% oxygen, in accordance with 40 CFR 63.772(e); or design the open flare in accordance with 40 CFR 63.11(b).</p> |
| e. | <p>Part 60, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution</p> <p>Control requirements applicable to each storage vessel constructed, modified, or reconstructed after 8/23/11 with potential VOC emissions equal to or greater than 6 tons/year.</p> | <p>For a storage vessels subject to the standards, compliance with the applicable portions of 40 CFR Part 60, Subpart OOOO. By the applicable compliance date, design and operate an enclosed combustion device in accordance with the requirements of 40 CFR 60.5412(d)(1) to reduce the mass content of VOC by 95% by weight or greater; or install a combustion control device that's model has been tested by the manufacturer in accordance with 40 CFR 60.5413(d); or install an open flare designed in accordance with 40 CFR 60.18(b).</p> |
| f. | 40 CFR 60.5412(d)(1)(iii) | <p>If required to install controls in accordance with 40 C FR 60.5393, an enclosed combustion device must be operated with no visible emissions except for periods not to exceed a total of 1 minute in any 15 minute period, conducting Method 22 once every calendar month.</p> |

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|--|-------------------------------|--|
| | 40 CFR 60.5413(e)(3) | If demonstrating compliance using a combustion control device that is performance tested by the manufacturer, in accordance with 40 CFR 60.5413(d), the combustion device must be operated with no visible emissions except for periods not to exceed a total of 2 minutes in any 1 hour of operation, conducting Method 22 once per calendar quarter. |

(2) Additional Terms and Conditions

- a. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to the Ohio Revised Code (ORC) changes effective August 3, 2006 (Senate Bill 265 changes), such that BAT is no longer required by State regulations for National Ambient Air Quality Standard (NAAQS) pollutant(s) less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 these emissions limitations/control measures no longer apply.
- b. This rule applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the PE, NO_x, and SO₂ emissions from this air contaminant source since the uncontrolled potential to emit for PE, NO_x, and SO₂ are less than ten tons per year.
- c. Pit flaring is prohibited.

c) Operational Restrictions

- (1) The flare or combustion device shall be operated with a flame present at all times when gases are vented to it.
- (2) An automatic flame ignition system shall be installed to meet one of the following requirements:
 - a. If using a pilot flame ignition system, the presence of a pilot flame shall be monitored using a thermocouple or other equivalent device to detect the presence of a flame. A pilot flame shall be maintained at all times in the flare's pilot light burner. If the pilot flame goes out and does not relight, then an alarm shall sound; or

- b. If using an electric arc ignition system, the arcing of the electric arc ignition system shall pulse continually and a device shall be installed and used to continuously monitor the electric arc ignition system.
- (3) The flare, its auto ignition system, and its recorder shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations, instructions, and operating manuals.
 - (4) If the dehydrator does not qualify for one of the exemptions found in 40 CFR Part 63.764(e) or if it has been determined that any storage vessel emits 6 tons or more of VOC per year, the enclosed flare/combustion device must be designed and operated to reduce VOC, TOC, or total HAP, as applicable, by 95% by weight; or the concentration of TOC or Total HAP, as applicable, to 20 ppm by volume on a dry basis and corrected to 3% oxygen, in accordance with the applicable rule; or the open flare shall be designed and operated in accordance with 40 CFR 63.11(b) or 40 CFR 60.18(b).
 - (5) This flare/combustion device shall operate at no more than 10 MMBtu/hr heat input at all times except:
 - a. when a malfunction occurs, e.g., when excess gas must be safely disposed of by venting it to the flare/combustion device; or
 - b. for repair pressure blow-downs; or
 - c. when another well is being drilled or fractured and the gas must be safely disposed of by venting it to the flare/combustion device.
- d) **Monitoring and/or Recordkeeping Requirements**
- (1) If the permittee is using the flare/combustion device to demonstrate compliance with 40 CFR 63.771(d) for the TEG dehydrator or to demonstrate compliance with 40 CFR 60.5412(d) for each storage vessel calculated to have VOC emission equal to or exceeding 6 tons per year, the permittee shall maintain the appropriate records to demonstrate that the enclosed flare/combustion device is designed and operated to reduce VOC, TOC, or total HAP by 95% by weight; or the concentration of TOC or Total HAP to 20 ppm by volume on a dry basis and corrected to 3% oxygen, all in accordance with the applicable rules; or shall maintain the records required to demonstrate that the open flare is designed and operated in accordance with 40 CFR 63.11(b) or 40 CFR 60.18(b), as applicable per federal rules.
 - (2) The permittee shall:
 - a. continuously monitor the presence of the flame;
 - b. record all periods during which the automatic flare ignition system (pilot flame or electronic arc ignition system) or thermocouple was not working and gas was being vented to the flare/combustion device; and
 - c. record all periods of time during which gas was being vented to the flare/combustion device and there was no flame

- (3) The permittee shall maintain a record of all periods of time (date and number of hours) during which the flare/combustion device is burning collected gases at a heat input greater than 10 MMBtu per hour, along with a description of the emergency and/or the reason the heat input was greater than 10 MMBtu/hr.

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) If the permittee is using an enclosed flare/combustion device to demonstrate compliance with 40 CFR 63.771(d) for the TEG dehydrator or to demonstrate compliance with 40 CFR 60.5412(d)(1) for each storage vessel calculated to have VOC emission equal to or exceeding 6 tons per year, the permittee shall submit the results of the compliance demonstration, conducted in accordance with the applicable subpart, in the PER.
- (3) If the permittee is using an open flare to demonstrate compliance, the permittee shall submit all visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance or reporting period, as applicable by rule.
- (4) The permittee shall identify in the PER:
 - a. all periods of time when the pilot flame or electronic arc ignition system is not working when process gas is being vented to it, including the date, time, and duration of each such period; and
 - b. all periods of time during which the flare/combustion device was operated at greater than 10 MMBtu per hour heat input rate, including the date, time, and duration of each such period, and a description of the reason why the heat input exceeded 10 MMBtu per hour.

f) Testing Requirements

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

- (1) Emission Limitation:

1.35 tons CO/month averaged over a 12-month rolling period

Applicable Compliance Method:

The emissions limitation for CO is based on using the AP-42 emission factor of 0.37 lb CO/MMBtu from Chapter 13.5 for Industrial Flares, Table 13.5-1, "Emission Factors for

Flare Operations” and using the normal operation rate of 10 MMBtu/hr. Estimated CO emissions shall be determined by the following calculations:

$$0.37 \text{ lb CO/MMBtu} \times 10 \text{ MMBtu/hr} = 3.7 \text{ lbs CO /hr}$$

$$3.7 \text{ lbs CO/hr} \times 8760 \text{ hrs/yr} \times 1 \text{ ton}/2000 \text{ lbs} = 16.2 \text{ tons CO/year}$$

$$16.2 \text{ tons CO} \div 12 \text{ months} = 1.35 \text{ tons CO/month averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(2) Emission Limitation:

For VOC and where applicable, compliance with the applicable control requirements of 40 CFR Part 60, Subpart OOOO, by having a designed minimum control efficiency of 95% for an enclosed flare/combustor.

Applicable Compliance Method:

See the compliance method described in the flash vessel/storage vessel(s) emissions unit (T001).

(3) Emission Limitation:

$$0.25 \text{ ton NOx/month averaged over a 12-month rolling period}$$

Applicable Compliance Method:

The emissions limitation for NOx is based on using the AP-42 emission factor of 0.068 lb NOx/MMBtu from Chapter 13.5 for Industrial Flares, Table 13.5-1, “Emission Factors for Flare Operations” and using the normal operation rate of 10 MMBtu/hr. Estimated NOx emissions shall be determined by the following calculation:

$$0.068 \text{ lb NOx/MMBtu} \times 10 \text{ MMBtu/hr} = 0.68 \text{ lb NOx /hr}$$

$$0.68 \text{ lb NOx/hr} \times 8760 \text{ hrs/yr} \times 1 \text{ ton}/2000 \text{ lbs} = 3.0 \text{ tons NOx/year}$$

$$3.0 \text{ tons NOx} \div 12 \text{ months} = 0.25 \text{ ton NOx/month averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(4) Emission Limitations:

$$0.15 \text{ ton SO}_2\text{/month averaged over a 12-month rolling period}$$

Applicable Compliance Method:

The SO₂ emissions limitation is based on a fuel gas with a maximum H₂S content of 250 ppmv for sour gas.

Compliance with the ton per year SO₂ emissions limitation shall be determined by the following calculations:

$$10 \text{ MMBtu/hr} \times 1 \text{ scf/1020 Btu} \times 1 \text{ lb-mole/379.5 scf} \times 250 \text{ ppm H}_2\text{S} \times 64 \text{ lb SO}_2/\text{lb-mole} = 0.41 \text{ lbs SO}_2/\text{hr}$$

$$0.41 \text{ lb SO}_2/\text{hr} \times 8760 \text{ hrs/year} \times 1 \text{ ton/2000 lbs} = 1.8 \text{ tons SO}_2/\text{year}$$

$$1.8 \text{ tons SO}_2 \div 12 \text{ months} = 0.15 \text{ ton SO}_2/\text{month} \text{ averaged over a 12-month rolling period}$$

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

(5) Visible Emissions Limitation for an enclosed combustion control device used to demonstrate compliance with Part 60 Subpart OOOO:

An enclosed combustion device used to demonstrate compliance must be operated with no visible emissions except for periods not to exceed a total of 1 minute in any 15 minute period, conducting Method 22 once every calendar month.

[40 CFR 60.5412(d)(1)(iii)]

OR

If demonstrating compliance using a combustion control device that is performance tested by the manufacturer, in accordance with 40 CFR 60.5413(d), the combustion device must be operated with no visible emissions except for periods not to exceed a total of 2 minutes in any 1 hour of operation, conducting Method 22 once per calendar quarter.

[40 CFR 60.5413(e)(3)]

Applicable Compliance Method:

Compliance with the visible emissions limitation shall be determined in accordance with U.S. EPA Method 22 in Appendix A of 40 CFR Part 60.

[40 CFR 60.5412(d)(1)(iii)] [40 CFR 60.5413(e)(3)] and [40 CFR 60.5413(a)(1)]

g) **Miscellaneous Requirements**

- (1) Any final amendments to Part 63 Subpart HH and/or Part 60 Subpart OOOO will supersede any previous Subpart HH or Subpart OOOO requirement(s) in this permit.

5. Emissions Unit Group: Equipment/Pipeline Leaks, F001

| EU ID | Operations, Property and/or Equipment Description |
|-------|---|
| F001 | <p>Ancillary equipment⁴ and Associated equipment: compressors, pumps, piping, pneumatic controllers, inlet separators, gas-water/condensate/oil separators, etc.</p> <p>Equipment/pipeline leaks from valves, flanges, pressure relief devices, open end valves or lines, and pump and compressor seals in VOC or wet gas service.</p> |

- a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - (1) For the purpose of a permit-to-install document, the emissions unit terms and conditions in this permit are federally enforceable, with the exception of those listed below, which are enforceable under state law only.
 - a. None.
 - (2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions in this permit are enforceable under state law only, with the exception of those listed below, which are federally enforceable.
 - a. 5.b)(1)b.
- b) Applicable Emissions Limitations and/or Control Requirements
 - (1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|---|---|
| a. | ORC 3704.03(T) | Develop and implement a site-specific leak detection and repair program for ancillary equipment as described in paragraph 5.c)(2). |
| b. | 40 CFR Part 60 Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. | Each natural gas-driven pneumatic controller designed and operated to have a bleed rate less than or equal to 6 standard cubic feet per hour (scf/hr) and maintained in accordance with the manufacturer’s instructions, shall not be considered an affected facility, subject to Part 60 Subpart |

⁴ “Ancillary Equipment” means the same as defined in 40 CFR Part 63, Subpart HH. The Subpart HH definition is being used for this permit but note that the equipment leak standards found in Subpart HH do not apply for this permit because this permit is for an “area source” and the equipment leak standards do not apply to area sources.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|--|--|
| | 40 CFR 63.5365(d); 40 CFR 60.5390; and 40 CFR 60.5410(d) | OOOO. Each pneumatic controller constructed, modified, or reconstructed on or after 10/15/13, located between the wellhead and a natural gas processing plant, and designed to have a bleed rate equal to or greater than 6 scf/hr is an affected facility subject to the requirements of Part 60 Subpart OOOO. Each pneumatic controller affected facility that is constructed after 8/23/11 and is subject to these standards shall be tagged with the month and year of installation. |
| c. | OAC 3745-31-05(F) | Emissions of Volatile Organic Compounds (VOC) shall not exceed 10.56 tons per year from fugitive equipment leaks. |

(2) Additional Terms and Conditions

a. None

c) Operational Restrictions

(1) Pneumatic Controller Restrictions

Unless it can be demonstrated that the pneumatic controller needs to have a higher bleed rate based on functional needs in accordance with 40 CFR 60.5390(a), each natural gas-driven pneumatic controller affected facility installed, modified, or reconstructed on or after 10/15/13 and located between the wellhead and the point of custody transfer to an oil pipeline or a natural gas transmission line or storage facility, must be designed and operated with a bleed rate less than or equal to 6 standard cubic feet per hour (6 scf/hr).

[40 CFR 60.5390(c)(1), (d), and (e)], [40 CFR 60.5365(d)], [40 CFR 60.5410(d)], and [40 CFR 60.5415(d)(1)]

(2) Ancillary Equipment Leak Detection and Repair Program

The permittee shall develop and implement a leak detection and repair program designed to monitor and repair leaks from ancillary equipment covered by this permit, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel. This program shall meet the following requirements:

a. Leaks shall be detected by the use of either a “Forward Looking Infra Red” (FLIR) camera or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.

- b. An initial monitoring shall be completed within 90 days of startup and quarterly thereafter for a period of four consecutive quarters (1 year).
 - c. If following the initial four consecutive quarters, less than or equal to 2.0% of the ancillary equipment are determined to be leaking during the most recent quarterly monitoring event, then the frequency of monitoring can be reduced to semi-annual.
 - d. If following two consecutive semi-annual periods, less than 2.0% of the ancillary equipment are determined to be leaking during the most recent semi-annual monitoring event, then the frequency of the monitoring can be reduced to annual.
 - e. If more than or equal to 2.0% of the ancillary equipment are determined to be leaking during any one of the semi-annual or annual monitoring events, then the frequency of monitoring shall be returned to quarterly.
 - f. The program shall require the first attempt at repair within five (5) calendar days of determining a leak.
 - g. The program shall require that the leaking component is repaired within 30 calendar days after the leak is detected.
 - h. The program shall allow for the delayed repair of a leaking component following the language found in 40 CFR 60.5416(c)(5).
 - i. The program shall following the Monitoring and Record Keeping requirements described in paragraph 5.d) of this permit.
- (3) In the event that a leak or defect is detected in the cover, closed vent system, process equipment, or control device, the permittee shall make a first attempt at repair no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 30 calendar days after the leak is detected as allowed in 40 CFR 60.5416(c)(4). Any delay of repair of a leak or defect shall meet the requirements of 40 CFR 60.5416(c)(5).

[40 CFR 60.5416(c)(4) and (5)], [40 CFR 60.5415(e)(3)], and [ORC 3704.03(T)]

d) Monitoring and/or Recordkeeping Requirements

(1) Pneumatic Controller Monitoring and Record Keeping

- a. Each natural gas-driven pneumatic controller affected facility installed or reconstructed on or after 8/23/11, located between the wellhead and natural gas processing plant shall be tagged with the month and year of installation, reconstruction, or modification and with information that can identify or trace the records for the manufacturer's design specifications.
- b. The following records shall be maintained for each natural gas-driven pneumatic controller installed at the facility after 8/23/11:
 - i. records of the date installed or reconstructed, the location and/or equipment each controller is servicing, and the manufacturer specifications;

- ii. if applicable, the records needed to demonstrate why the operations require the use of a pneumatic controller with a bleed rate greater than 6 scf/hr and the functional basis for requiring the higher bleed rate; or
 - iii. if installed on or after 10/15/13, records of the manufacturer's specification indicating that the pneumatic controller is designed to have a natural gas bleed rate less than or equal to 6 scf/hr; or
 - iv. if the pneumatic controller has been installed on or after 8/23/11 and before 10/15/13, the manufacturer's designed bleed rate; and
 - v. where a higher bleed rate has not been demonstrated to be needed, the records of any deviations from the 6 scf/hr bleed rate for each pneumatic controller installed on or after 10/15/13.
- c. Once a gas-driven pneumatic controlled has been documented to have a bleed rate less than or equal to 6 scf/hr, it is no longer subject to the requirements of Part 60 Subpart OOOO. The manufacturer's specifications for the pneumatic controller and/or other records demonstrating compliance or exemption from the requirements should be maintained until the well site is closed.

[40 CFR 60.5390(c) and (f)], [40 CFR 60.5410(d)], [40 CFR 60.5415(d)(3)], [40 CFR 60.5420(c)(4)], and [40 CFR 60.5365(d)]

(2) Ancillary Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing FLIR Camera's

- a. Leaks shall be determined by visually observing each ancillary component through the FLIR camera to determine if leaks are visible.
- b. The following information shall be recorded during each leak inspection:
 - i. the date the inspection was conducted;
 - ii. the name of the employee conducting the leak check;
 - iii. the identification of any component that was determined to be leaking;
 - iv. the date the first attempt to repair the component was made;
 - v. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vi. the date the component was repaired and determined to no longer be leaking;
 - vii. the total number of components that are leaking; and
 - viii. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary components capable of developing a leak, and multiplied by 100.

- c. The permittee shall maintain records that demonstrate the FLIR camera is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
- d. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon verbal or written request.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

(3) Ancillary Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing a Method 21 Analyzer

- a. Leaks shall be measured by utilizing U.S. EPA Method 21 (40 CFR Part 60, Appendix A). All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm or 10,000 ppm (as applicable) for determining compliance.
- b. A component is considered to be leaking if the instrument reading is equal to or greater than:

| | |
|---|------------|
| pressure relief device in gas/vapor service | 10,000 ppm |
| pressure relief device in light liquid service | 10,000 ppm |
| pumps in light liquid service | 10,000 ppm |
| compressor | 500 ppm |
| sampling connection system* | * |
| open ended valves or lines** | ** |
| valves in gas/vapor and light liquid service | 10,000 ppm |
| closed vent system | 500 ppm |
| connectors | 10,000 ppm |
| all other ancillary and associated equipment in VOC service | 10,000 ppm |

* must be equipped with a closed-purge, closed-loop, or closed-vent system

** must be equipped with a cap, blind flange, plug, or a second valve

- c. The following information shall be recorded during each leak inspection:
 - i. the date the inspection was conducted;
 - ii. the name of the employee conducting the leak check;
 - iii. the identification of any component that was determined to be leaking (company ID and component type (flange, pump, etc.);

- iv. the date the first attempt to repair the component was made;
 - v. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vi. the date the component was repaired and determined to no longer be leaking;
 - vii. the total number of components that are leaking; and
 - viii. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary components capable of developing a leak, and multiplied by 100.
- d. The permittee shall maintain records that demonstrate the Method 21 analyzer is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
- e. In order to calibrate the analyzer, the following calibration gases shall be used:
- i. zero air, which consists of less than 10 ppm of hydrocarbon in air; and
 - ii. a mixture of air and methane or n-hexane at a concentration of approximately, but less than, 10,000 ppm of methane or n-hexane.
- f. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon verbal or written request.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) Supplement to the PER for the Ancillary Equipment Leak Detection and Repair Program
- For each inspection that occurred during the year, the permittee shall submit the following information with the annual PER from data collected by the ancillary equipment leak detection and repair program:
- a. the date of the inspection;
 - b. the number of components determined to be leaking;

- c. the company ID and component type (flange, pump, etc.) of each leaking component;
- d. the total number of components at the site;
- e. the percent of components determined to be leaking;
- f. a list of all components that have not been repaired due to a delay of repair and the reason for the delay; and
- g. a notification indicating if the permittee has changed future inspection frequencies based on the percent of components leaking.

[40 CFR 60.5416(c)] and [ORC 3704.03(T)]

(3) **Pneumatic Controller Reporting**

The permittee shall submit an initial annual report, for each natural gas-driven pneumatic controller installed at the facility after 8/23/11, within 90 days after the end of the initial compliance period as determined according to 40 CFR 60.5410. Subsequent annual reports are due on the same date each year following the initial report. The annual reports may contain multiple facilities if each pneumatic controller is clearly identified along with its location, and the report includes the following information from 40 CFR 60.5420 for each natural gas-driven pneumatic controller:

- a. company name and address of the affected facility;
- b. identification of each affected facility included in the annual report*;
- c. beginning and ending dates of the reporting period;
- d. the identification of each pneumatic controller and the equipment it controls;
- e. the month and year each pneumatic controller was installed, reconstructed, or modified;
- f. a statement as to whether the manufacturer's specifications indicate the controller is designed to maintain a natural gas bleed rate less than or equal to 6 scf/hour; or the explanation of why the bleed rate needs to be operated to exceed this and the manufacturer's specifications for the bleed rate;
- g. records of any deviations from the appropriate natural gas bleed rate; and
- h. certification of the responsible official of truth, accuracy, and completeness.

* One report for multiple affected facilities may be submitted provided the report contains all of the information required and is clearly separated and identified for each well site.

[40 CFR 60.5410(d)], [40 CFR 60.5420(b)(1) and (5) and (c)(4)], [40 CFR 60.5390(f)], and [40 CFR 60.5415(d)(2)]

f) **Testing Requirements**

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

(1) Emissions Limitation:

Emissions of VOC shall not exceed 10.56 tons per year from fugitive equipment leaks.

Applicable Compliance Method:

The annual VOC limitation is the estimated potential-to-emit based upon the maximum number of components and type of service (gas/vapor and light liquid) expected at the natural gas production site. Unless or until more accurate emission factors have been demonstrated or established for the site (e.g. following initial and subsequent monitoring and inspections), the appropriate emissions factors from U.S. EPA's "Protocol for Equipment Leak Emission Estimates", Table 2-4, for Oil and Gas production Operations (a conservative estimate), shall be used to demonstrate compliance with the annual limit. The facility's potential emissions from ancillary and associated equipment shall be documented from the summation of the following calculations:

Component Type # of components x emission factor x % VOC* = lb VOC/hr

In Gas/Vapor Service

Number of connectors x 0.000441 lb/hr x 50% VOC = lb VOC/hr

Number of valves x 0.00992 lb/hr x 50% VOC = lb VOC/hr

Number of flanges x 0.00086 lb/hr x 50% VOC = lb VOC/hr

Number of compressor seals x 0.01940 lb/hr x 50% VOC = lb VOC/hr

Number of relief valves x 0.01940 lb/hr x 50% VOC = lb VOC/hr

Number of high bleed pneumatic controllers x 0.0194 lb/hr x 50% VOC = lb VOC/hr

In Light Liquid Service

Number of connectors x 0.000463 lb/hr x 100% VOC = lb VOC/hr

Number of valves x 0.00551 lb/hr x 100% VOC = lb VOC/hr

Number of flanges x 0.00024 lb/hr x 100% VOC = lb VOC/hr

Number of pump seals x 0.0287 lb/hr x 100% VOC = lb VOC/hr

Number of relief valves x 0.01653 lb/hr x 100% VOC = lb VOC/hr

Number of high bleed pneumatic controllers x 0.01653 lb/hr x 100% VOC = lb VOC/hr

The total summation of VOC emissions per hour shall be multiplied by 8760 hours per year and divided by 2000 pounds to calculate the estimated annual fugitive VOC emissions.

Compliance with the ton per year limit shall be determined following the first 12 months of operation.

As an alternative to using the above emission factors to calculate VOC emissions, the permittee may use facility specific VOC information for site specific emission factors.

* The % VOC for Gas/Vapor service was based on the highest percent VOC in gas analyses submitted by representative facilities.

(2) Emission Limitation:

Each natural gas-driven pneumatic controller installed after 10/15/13 shall be operated with a bleed rate less than or equal to 6 scf/hr, unless it can be demonstrated that the pneumatic controller needs to have a higher bleed rate based on functional needs.

Applicable Compliance Method:

Natural gas shall be used as a surrogate for VOC. If required, the detection of leaks of natural gas into the ambient air from the pneumatic controller(s) may be determined using Method 21 from 40 CFR 60 Appendix A; however, compliance is demonstrated through maintaining the manufacturer's design specifications, showing that the controller is designed to operate with a bleed rate less than 6 scf/hr. If required, Method 21 may be used during inspections of the facility.

[40 CFR 60.5390(a) or (c)(1)], [40 CFR 60.5410(d)], and [40 CFR 60.5415(d)(1)], with [ORC 3704.03(T)]

g) **Miscellaneous Requirements**

- (1) Any amendment to Part 60, Subpart OOOO shall supersede the Subpart OOOO compliance limitations and/or options contained in this permit.

6. Emissions Unit: Flash Vessel/Storage Vessels and truck loading for produced water, crude oil, condensate, and/or petroleum liquids: T001

Operations, Property and/or Equipment Description:

| | |
|------|--|
| T001 | One or multiple vertical fixed roof flash vessel/storage vessel(s) with a combined capacity of no more than 252,000 gallons (6,000 barrels), where each flash vessel/storage vessel has an individual capacity of no more than 39,894 gallon (950 barrel). |
|------|--|

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

(a) None.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

(a) 6.b)(1)c.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|----|-------------------------------|--|
| a. | ORC 3704.03(T) | <p>Total VOC emissions (including breathing losses, working losses, and flashing losses) from all storage vessels combined at the site shall not exceed 4.28 tons per month averaged over a 12-month rolling period.</p> <p>In order to comply with the tons per month emission limit, utilize one or more of the following controls:</p> <p>Use of add-on control (vapor recovery, flare or equivalent) to control emissions from storage vessels as needed to comply with the annual VOC emission limitations. If a flare is used, it must meet the requirements</p> |

| | | |
|----|---|--|
| | | detailed in emissions unit P004. |
| b. | OAC Rule 3745-21-09(L) | See b)(2)a. |
| c. | Part 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution | <p>The facility must calculate the potential for VOC emissions for each single storage vessel using an accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to 10/15/13 for Group 1 storage vessels*, or determined for a 30-day period of production prior to 4/15/14 or 30 days after startup for Group 2 storage vessels**.</p> <p>Where these potential VOC emissions are calculated to equal or exceed 6 TPY, the permittee must either maintain the uncontrolled actual VOC emissions at less than 4 TPY and maintain monthly emission calculations in accordance with 40 CFR 60.5395(d)(2); or install a control device, closed vent system, and covers designed and operated to reduce VOC emissions by 95.0%, and by 4/15/14 or 60 days after startup for Group 2 storage vessels or by 4/15/15 for Group 1 storage vessels.</p> <p>Conduct monthly inspections of collection and control equipment.</p> <p>Any final amendments to this rule will supersede the requirement(s) in this permit.</p> <p>See b)(2) b. through f.</p> |
| d. | 40 CFR 60.5413(d) | Option to demonstrate compliance with Part 60 Subpart OOOO through the use a control device model tested by the manufacturer. |
| e. | 40 CFR 60.5412(d)(1)(iii) 40 CFR 60.5413(e)(3) | <p>If required to install controls in accordance with 40 CFR 60.5395, an enclosed combustion device must be operated with no visible emissions except for periods not to exceed a total of 1 minute in any 15 minute period, conducting Method 22 once every calendar month.</p> <p>If demonstrating compliance using a combustion control device that is performance tested by the manufacturer, in accordance with 40 CFR 60.5413(d), the combustion device must be operated with no</p> |

| | | |
|----|--|---|
| | | visible emissions except for periods not to exceed a total of 2 minutes in any 1 hour of operation, conducting Method 22 once per calendar quarter. |
| f. | 40 CFR 60.5365(e) OAC 3745-31-05(F) | The permittee accepts a voluntarily limit to restrict the potential VOC emissions from each storage vessel to less than 6 tons per year. |

(2) Additional Terms and Conditions

- a. The permittee shall not place, store, or hold in these fixed roof tanks any petroleum liquid other than crude oil and condensate where there is no custody transfer, unless such tank is designed or equipped in accordance with the requirements of paragraph (L)(1) of OAC rule 3745-21-09 with an internal floating roof or equivalent control approved by the Director, prior to storing such petroleum liquids.

[OAC rule 3745-21-09(L)]

- b. Any storage vessel subject to and controlled in accordance with the requirements for storage vessels in 40 CFR Part 60 Subpart Kb, or 40 CFR Part 63 Subparts G, CC, HH, or WW are not subject to Part 60 Subpart OOOO.

[40 CFR 60.5395(h)]

- c. If the storage vessel affected facility is installed with a floating roof to reduce VOC emissions, it must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in Part 60, Subpart Kb.

[40 CFR 60.5395(e)(2)]

- d. The permittee shall calculate the potential for VOC emissions for each single storage vessel (defined in 40 CFR 60.5430) using an accepted model or calculation methodology. Emissions of VOC shall be based on the maximum average daily throughput determined for:

- i. a 30-day period of production prior to 10/15/13 for storage vessels installed after 8/23/11 and on or before 4/12/13, i.e., Group 1 storage vessels; and/or
- ii. a 30-day period of production prior to 4/15/14 or 30 days after startup for storage vessels installed after 4/12/13, i.e., Group 2 storage vessels.

[40 CFR 60.5410(h)] and [40 CFR 60.5365(e)]

- e. Unless meeting the requirements of 40 CFR 60.5395(d)(2), where the uncontrolled actual VOC emissions can be demonstrated to be less than 4 tons per year, or where it has been demonstrated that the potential VOC emissions are less than 6 TPY, the VOC emissions from each storage vessel affected facility shall be reduced by 95.0 percent by April 15, 2014, or within 60 days after

startup, for Group 2 storage vessels; or by April 15, 2015 for Group 1 storage vessels.

[40 CFR 60.5395] and [40 CFR 60.5415(e)(3)]

- f. Any vapors from storage vessels that are recovered and routed to a vapor recovery unit (VRU) system meeting the cover and closed vent system requirements specified in 40 CFR 60.5411(b) and (c) are not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status for NSPS Subpart OOOO. However, if the VRUs are removed or if the system fails to meet the cover and closed vent system requirements of Subpart OOOO, the potential VOC emissions from each such storage vessel shall be calculated within 30 days of the removal or non-compliant operations of the VRU system.

[40 CFR 60.5365(e)]

c) Operational Restrictions

- (1) Total capacity of all storage vessels storing condensate and/or condensed water shall not exceed 252,000 gallons (6000 barrels) combined, excluding any exempt or de minimis vessels.
- (2) Each storage vessel subject to the control requirements of Part 60 Subpart OOOO shall be equipped with a cover that meets the requirements of 40 CFR 60.5411(b); and the storage vessel shall be connected through a closed vent system designed and operated with no detectable emissions, as determined using olfactory, visual and auditory inspections, and in accordance with 40 CFR 60.5411(c) to either: 1. an enclosed combustion control device, designed and operated in accordance with 40 CFR 60.5412(d) or 40 CFR 60.5413(d); 2. an open flare meeting the requirements identified in this permit; or 3. to a process. The collection and control systems shall be operated at all times when gases, vapors, and fumes are vented from the subject storage vessels to a control device; and where routing emissions to a process it must be operational 95% or more of the year.

[40 CFR 60.5365(e)], [40 CFR 60.5395], [40 CFR 60.5410(h)], [40 CFR 60.5411(b) and (c)(1) and (2)], and [40 CFR 60.5412(d)] or [40 CFR 60.5413(d)], and [40 CFR 60.5415(e)(3)]

- (3) In the event that a leak or defect is detected in the cover or closed vent system that is used to demonstrate compliance, the permittee shall make a first attempt at repair no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 30 calendar days after the leak is detected in accordance with 40 CFR 60.5416(c)(4) and (5). A record of the leak detected and repairs must be maintained for a period of five years.

[40 CFR 60.5416(c)(4) and (5)] and [40 CFR 60.5415(e)(3)]

- (4) Where the closed vent system (used to demonstrate compliance) contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or a process, the requirements identified in 40 CFR 60.5416(c)(3) shall be met.

[40 CFR 60.5416(c)(3)], [40 CFR 60.5411(c)(3)] and [40 CFR 60.5415(e)(3)]

- (5) Each enclosed combustion device, used to meet the emission reduction standard in 40 CFR 60.5395(d), shall be installed and operated in accordance with 40 CFR 60.5412(d) and 40 CFR 60.5417(h). As an alternative, a combustion control device may be installed whose model has been tested by the manufacturer in accordance with 40 CFR 60.5413(d), and the facility can instead meet the criteria in 40 CFR 60.5413(d)(11) and 40 CFR 60.5413(e).

[40 CFR 60.5410(h)], [40 CFR 60.5412(d)], [40 CFR 60.5417(d)(1)(iii) and (h)], and [40 CFR 60.5415(e)(3)]

d) Monitoring and/or Recordkeeping Requirements

- (1) The permittee shall maintain the following records documenting the facility's determination of emissions from each storage vessel:

- a. the maximum average daily throughput determined for a 30-day period of production prior to 10/15/13 for Group 1 storage vessels and prior to 4/15/14 or 30 days after startup for Group 2 storage vessels;
- b. the content of each storage vessel;
- c. the lab analyses, calculations, and process simulation model results documenting the annual emissions from breathing, working, and flashing losses; and
- d. the records for the content and annual throughput (in gallons per year) for each storage vessel.

These records shall be maintained for at least 5 years and shall be made available to the Director or his representative upon verbal or written request.

[40 CFR 60.5365(e)] and [40 CFR 60.5410(h)]

- (2) Where using vapor recovery unit(s) (VRU) for compliance, the permittee shall maintain records that document the VRU system is operated in compliance with the cover and closed vent system requirements of 40 CFR 60.5411(b) and 40 CFR 60.5411(c).

[40 CFR 60.5365(e)]

- (3) Where required, the permittee shall conduct monthly inspections for each closed vent system, each cover, and the combustion control device used to demonstrate compliance in accordance with 40 CFR 60.5416(c) and 40 CFR 60.5417(h); and shall maintain the records identified in 40 CFR 60.5420(c).

[40 CFR 60.5416(c)], [40 CFR 60.5417(h)], [40 CFR 60.5411(b) and (c)], [40 CFR 60.5415(e)(3)], and [40 CFR 60.5420(c)]

- (4) Where the facility is using an enclosed combustion device for compliance, the permittee shall maintain the appropriate records to demonstrate that the control device is designed and operated to reduce VOC by 95.0% by weight and is operated and maintained in accordance with 40 CFR 60.5412(d); or if the model device has been performance tested by the manufacturer in accordance with 40 CFR 5413(d), the device shall be monitored, operated and maintained in accordance with 40 CFR 5413(e).

[40 CFR 60.5410(h)], [40 CFR 60.5412(d)] or [40 CFR 60.5413(d) and (e)]

- (5) Where using an open flare for compliance, the permittee shall maintain the records required to demonstrate that the open flare is designed and operated in accordance with Part 60 Subpart OOOO and the requirements of this permit.
- (6) Where the permittee has accepted a voluntarily limit to restrict the potential VOC emissions to less than 6 tons per year and less than 0.50 tons per month averaged over a 12-month rolling period, the records documenting the maximum monthly potential VOC emissions (calculated in accordance with 40 CFR 60.5365(e)) shall be maintained and made readily available upon request.

[40 CFR 60.5365(e)] and [OAC 3745-31-05(F)]

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER is submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) The permittee shall submit an initial annual report within 90 days after the end of the initial compliance period for each storage vessel determined to have potential VOC emissions equal or greater than 6 tons per year. Subsequent annual reports are due no later than the same date each year following the initial report. The reports shall include the information identified in 40 CFR 60.5420(b).

[40 CFR 60.5420(b)] and [40 CFR 60.5410(h) and (i)]

f) Testing Requirements

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

- (1) Emissions limitation:

Total VOC emissions from all storage vessels (including breathing losses, working losses, and flashing losses) shall not exceed 4.28 tons per month averaged over a 12-month rolling period.

Compliance with the tons/month averaged over a 12-month rolling period shall be determined following the first 12 months of operation.

For each storage vessels not meeting the collection and control requirements of Part 60 Subpart OOOO, the potential annual VOC emissions must be documented to be less than 6 tons/year; or the uncontrolled actual VOC emissions shall be calculated to be less than 4 tons/year in accordance with 40 CFR 60.5395(d)(2) through monthly determinations.

For each storage vessel with potential emissions equal to or greater than 6 tons VOC/year, reduce VOC emissions by 95.0% by installing a closed vent system designed and operated with no detectable emissions, that routes all gases, vapors, and fumes to a process or a combustion control device meeting the requirements of 40 CFR 60.5412(d) or 40 CFR 60.5413(d).

Applicable Compliance Method, documenting emissions:

Annual emissions from breathing, working, and flashing losses from each storage vessel shall be calculated based on the maximum average daily throughput determined for a 30-day period of production prior to 10/15/13 for Group 1 storage vessels and/or prior to 4/15/14 or 30 days after startup for Group 2 storage vessels.

Flashing losses shall be calculated using a generally accepted model or process simulation software program(s) and/or calculation methodology such as, but not limited to, E&P Tank, HYSIM, HYSIS, VMG, or ProMax, to calculate the VOC emissions.

Pressurized samples shall be taken after the separator and at the same time from the flash gas and condensate/oil lines for flash gas analyses; and the data from these lab analyses shall be used in the process simulation software to document emissions from flashing.

Instead of taking pressurized samples from the separator(s) or from the storage vessels, the permittee may utilize pressurized samples acquired from another similar facility operating under similar conditions, or choose to take a representative reservoir sample from a well in another part of the play. If the permittee chooses to use pressurized samples from another facility, the flash gas analyses shall be submitted along with documentation demonstrating that the facility's pressurized condensate/oil and gases would have similar chemical compositions and would be under similar pressures; and provide evidence that if pressurized samples were taken and lab analyses were conducted, the results would provide equivalent or lower emissions. "Similar", in this case, means that the chemical composition, pressures, and operating parameters/conditions of the similar facility are close enough to this facility's condensate/oil and gas composition, pressures, and operations, that the expected emissions would be equivalent to or less than the emissions calculated from the flash gas analyses obtained from the similar facility. If the permittee chooses to use a representative reservoir sample, the analyses must be incorporated into an approved process simulation modeling program utilizing site-specific operating parameters. "Representative", in this case, means having an API gravity no more than 3 degrees below the API gravity of the condensate detected at the facility being permitted. A representative sample with a higher API gravity results in a more conservative emissions estimate and is, therefore, not a concern. If changes to the operating conditions and/or liquid composition are such that the emissions would be expected to exceed those determined with the representative analyses, the permittee shall either submit site-specific analyses using pressurized samples from the separator (with the highest pressures, if more than one), or submit emissions estimates using another representative analyses. The Director reserves the right to require the owner/operator to obtain samples from the facility in order to verify compliance.

Working and breathing losses may be calculated using E&P Tank, EPA Tanks 4.0 software, or other accepted calculation methodology; and/or the working/loading emissions may be calculated using the "Loading Loss Equation" from AP-42, Section

5.2, for Transportation and Marketing of Petroleum Liquids, which is based on multiplying a loading loss factor (L^*) by the annual petroleum liquid throughput in gallons per year, as follows:

$$*L = 12.46 \text{ SPM/T}$$

For uncontrolled loading, the VOC emissions shall be calculated by multiplying an uncontrolled loading loss factor (L_{UC}) by the rolling, 12-month summation of the throughput of condensate and petroleum liquids (in gallons) and dividing by 2000 lbs/ton. The result will be added to the breathing and flashing emission estimates.

$$L_{UC} = 12.46 \text{ SPM/T}$$

For controlled loading, the VOC emissions shall be calculated by multiplying a controlled loading loss factor (L_C) by the rolling, 12-month summation of the throughput of condensate and petroleum liquids (in gallons) and dividing by 2000 lbs/ton. The result will be added to the breathing and flashing emission estimates.

$$L_C = 12.46 \text{ SPM/T} [1 - \text{Efficiency}/100]$$

Where:

$$\text{Capture Efficiency} = 97\%$$

$$\text{Destruction Efficiency} = 98\%$$

$$\text{Control Efficiency} = 97\% \times 98\% = 95\%$$

Where:

L = loading loss, pounds per 1000 gallons loaded (Q)

S = saturation factor

P = vapor pressure of liquid loaded, pounds per square inch absolute

M = molecular weight of vapor

T = temperature of bulk liquid ($^{\circ}\text{R}$)

Applicable Compliance Method, through design of collection and controls:

Initial compliance with the Part 60, Subpart OOOO standards for storage vessel affected facilities shall be demonstrated by complying with the applicable portions of 40 CFR 60.5411(b) and (c), and 40 CFR 60.5412(d) or 40 CFR 60.5413(e) if the control device is tested by the manufacturer.

Continuous compliance with the Part 60, Subpart OOOO standards for storage vessel affected facilities shall be demonstrated by complying with the applicable portions of 40 CFR 60.5415(e), 40 CFR 60.5416(c), and 40 CFR 60.5417(d) or (h).

Group 1 storage vessels (installed between 8/24/11 and 4/12/13) must be in compliance by April 15, 2015; and Group 2 storage vessels (installed after 4/12/13) must be in

compliance by 4/15/14 or within 60 days after startup. In the event an amendment to NSPS Subpart OOOO requires a performance test for the combustion control device to demonstrate compliance, the permittee shall schedule such performance test as required by the amended rules.

[40 CFR 60.5365(e)], [40 CFR 60.5395], [40 CFR 60.5410(h)], [40 CFR 60.5411(b) and (c)], [40 CFR 60.5412(d) or 40 CFR 60.5413(d)], [40 CFR 60.5415(e)(3)], and [ORC 3704.03(T)]

(2) Visible Emissions Limitation for an enclosed combustion control device used to demonstrate compliance with Part 60 Subpart OOOO:

An enclosed combustion device used to demonstrate compliance must be operated with no visible emissions except for periods not to exceed a total of 1 minute in any 15 minute period, conducting Method 22 once every calendar month.

[40 CFR 60.5412(d)(1)(iii)]

OR

If demonstrating compliance using a combustion control device that is performance tested by the manufacturer, in accordance with 40 CFR 60.5413(d), the combustion device must be operated with no visible emissions except for periods not to exceed a total of 2 minutes in any 1 hour of operation, conducting Method 22 once per calendar quarter.

[40 CFR 60.5413(e)(3)]

Applicable Compliance Method:

Compliance with the visible emissions limitation shall be determined in accordance with U.S. EPA Method 22 in Appendix A of 40 CFR Part 60.

[40 CFR 60.5412(d)(1)(iii)] [40 CFR 60.5413(e)(3)] and [40 CFR 60.5413(a)(1)]

g) **Miscellaneous Requirements**

- (1) Any amendment to Part 60, Subpart OOOO shall supersede the Subpart OOOO compliance limitations and/or options contained in this permit.

Concepts for Proposed General Permit for Well Pads and Proposed GP-5 Modifications

Oil and Gas Technical Advisory Board Meeting
March 31, 2016

Background

- On January 19, 2016 Governor Tom Wolf announced a four-point methane emission reduction strategy for Oil and Gas operations.
 - DEP will develop a new general permit for new unconventional well pad operations.
 - DEP will revise its current general permit (GP-5) updating the permitting requirements.
 - DEP will develop a regulation for existing sources for consideration by the Environmental Quality Board.
 - DEP will establish best management practices, including leak detection and repair programs to reduce emissions along production, gathering, transmission and distribution lines.

Key Concepts for the proposed New GP for Well Pad Operations

- Currently, natural gas compressor stations are permitted under general plan approval and/or general operating permit number 5 (GP-5).
- Oil and natural gas wells may be exempted from permitting requirements provided the owner or operator complies with the conditions set forth in plan approval exemption #38.
- As part of the Department's Methane Emission Reduction Strategy, the Department is in the process of developing a new general permit to replace exemption #38 and revising the current GP-5.

Key Concepts for the proposed New GP for Well Pad Operations

- Most of the substantive requirements for exemption #38 are expected to be included in the new general permit.
- The Department is exploring the possibility of requiring that diesel-fired engines used on drill rigs meet the EPA's Tier 4 standards.
- The requirement for leak detection and repair (LDAR) may be similar to the current GP-5, including quarterly LDAR inspections using optical gas imaging system and monthly Audio Video Olfactory (AVO) inspections.

Key Concepts for the proposed New GP for Well Pad Operations

- The first attempt at leak repair must be done within five (5) calendar days of leak detection. If purchase of parts is necessary, the leak must be repaired within 15 calendar days, after the purchase of parts.
- VOC emissions from storage tanks must be controlled by at least 95%.
- Permitting requirements addressing fugitive dust control measures may be included.

Concepts for the proposed New GP for Well Pad Operations

- The Department is exploring the requirement for no-bleed and/or low-bleed pneumatic controllers and pumps.
- Emissions from pumps may also be controlled through routing pump discharge streams into a closed loop system or a vapor recovery unit.
- The permit may require the operation of pig launchers without venting hydrocarbons into the atmosphere.

Concepts for the proposed New GP for Well Pad Operations

- The Department is considering that plunger lifts or flaring be required to reduce methane emissions from wellbore liquid unloading.
- The permit may explicitly address the emission from produced water impoundment tanks. The Department is exploring the feasibility of add-on controls on enclosed storage tanks or a closed loop system for an efficient reuse of produced water.
- Annual compliance certifications may be required to be submitted to the Department by the responsible official, as is the case with the current GP-5.

Concepts for GP-5 Modifications

- The applicability of GP-5 may be extended to natural gas transmission operations.
- The Department may require no-bleed and/or low-bleed pneumatic controllers.
- The first attempt at leak repair must be done within five (5) calendar days of leak detection. If purchase of parts is necessary, the leak must be repaired within 15 calendar days, after the purchase of parts.

Concepts for GP-5 Modifications

- The Department is exploring the requirement that owners and operators prevent venting of VOCs and methane during all compressor maintenance and operational activities.
- The Department is considering a requirement that storage tanks must control air contaminant emissions by at least 95%.
- The permit may require the operation of pig launchers without venting hydrocarbons into the atmosphere.

Concepts for GP-5 Modifications

- The Department is considering the requirement to use electric pumps or routing pumps discharged to closed systems when electricity is not available.
- Emissions from pneumatic pumps driven by natural gas may also be controlled through routing pump discharge streams into a closed loop system or a vapor recovery unit, or the pumps may be replaced with zero bleed pumps.
- The use of dry seals or control of wet seal venting of methane from each compressor by 95%.

Useful Links

- [Methane Reduction Strategy Page](#)
 - <http://www.dep.pa.gov/Business/Air/Pages/Methane-Reduction-Strategy.aspx>
- [Methane Strategy Briefing Paper](#)
 - <http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf>
- [Methane Strategy Briefing Paper Appendix](#)
 - <http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/Appendix%20A%20-%20Comparison%20of%20PA-%20EPA%20NSPS%20Proposal-%20CSSD%20-%20CO%20Requirements%20for%20the%20Oil%20and%20Gas%20Sector%20%2012-15-2015.pdf>





pennsylvania

DEPARTMENT OF ENVIRONMENTAL PROTECTION



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**COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM**

**GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT
BAQ-GPA/GP-5**

Natural Gas Compression and/or Processing Facilities

SECTION A. GENERAL CONDITIONS

1. Statutory/Regulatory Authority and General Description

In accordance with Section 6.1(f) of the Air Pollution Control Act (“APCA”), 35 P.S. § 4006.1(f) and 25 *Pa. Code* Chapter 127, Subchapter H (relating to general plan approvals and general operating permits), the Department of Environmental Protection (hereinafter referred to as “Department” or “DEP”) hereby issues this General Plan Approval and/or General Operating Permit (“General Permit” or “GP-5”) for natural gas, compression and/or processing facilities (hereinafter referred to as “facility”) constructed or operating in this Commonwealth.

2. Definitions

Words and terms that are not otherwise defined in this General Permit shall have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 *Pa. Code* § 121.1 (relating to definitions) unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Federal Code of Regulations including 40 CFR Part 60 Subparts Kb, KKK, LLL, JJJJ, KKKK, and OOOO or 40 CFR Part 63 Subparts HH and ZZZZ shall also apply to this General Permit.

Coal bed methane – Methane that is released from the coal and surrounding rock strata.

Natural gas compression and/or processing facility – A facility that produces, compresses and/or processes natural gas, coal bed methane, or gob gas starting with gas dehydration, compression, fractionation, and storage.

3. Applicability/Scope

- (a) This General Permit authorizes the construction, modification, and/or operation of natural gas compression and/or a gas processing facility. The applicability of this General Permit may include any of the following:
 - (i) Natural gas-fired spark ignition internal combustion engines (hereinafter referred to as “engine”).
 - (ii) Natural gas-fired simple cycle turbines (hereinafter referred to as “turbine”).

- (iii) Centrifugal compressors.
 - (iv) Storage vessels/tanks.
 - (v) Glycol dehydration units and associated equipment including Gas-Condensate-Glycol (“GCG”) separators (Flash tank separators).
 - (vi) Natural gas fractionation process units (such as De-propanizer, De-ethanizer, De-butanizer).
 - (vii) Equipment leaks.
 - (viii) Pneumatic controllers.
 - (ix) Sweetening units.
- (b) If a source is exempted from plan approval requirements under 25 *Pa. Code* § 127.14 (relating to exemptions), the authorization to use this GP-5 may be requested for the operation of the source.
- (c) If any source located at the natural gas, compression and/or processing facility cannot be regulated under this General Permit, a plan approval and/or an operating permit issued in accordance with 25 *Pa. Code*, Chapter 127, Subchapter B (relating to plan approval requirements) and/or Subchapter F (relating to operating permit requirements) will be required.

4. Prohibited Use of GP-5

GP-5 may not be used for the construction, modification or operation of any of the following air contamination sources:

- (a) A proposed source located at a Title V facility.
- (b) A proposed source that is subject to Title V permitting requirements specified in 25 *Pa. Code* Chapter 127, Subchapters F and G, prevention of significant deterioration and nonattainment new source review requirements specified in 25 *Pa. Code* Chapter 127, Subchapters D (relating to prevention of significant deterioration) or E (relating to new source review).
- (c) Any engine or turbine that is used as a “peak shaving engine generator” or source participating in an Emergency and Economic Load Response Program.
- (d) Any engine or turbine that is used on a natural gas transmission line. Transmission line means a pipeline, other than a gathering line, that transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center.

5. General Plan Approval Best Available Technology Requirement

This General Permit establishes Best Available Technology (“BAT”) requirements and authorizes the construction or modification of a natural gas compression and/or processing facility and any air cleaning devices that meet the BAT requirements established under 25 *Pa. Code* §§ 127.1 and 127.12(a)(5).

The owner or operator of any existing facility for which a plan approval was previously issued pursuant to 25 *Pa. Code* § 127.11 (relating to plan approval requirements) shall continue to comply with the BAT requirements established in the previously issued plan approval if they are more stringent than the BAT requirements established in this General Permit.

6. General Operating Permit Requirements

Any facility or air contamination source that is constructed or modified under this General Permit may be operated on a temporary basis to facilitate shakedown of sources and air cleaning devices provided that the owner or operator notifies the Department in accordance with Section A, Condition 11 (relating to notice requirements) of this General Permit.

7. Municipal Notifications

A facility owner or operator proposing to use this General Permit shall notify the local municipality and county where the air pollution source is to be located that the applicant has applied for an authorization to use GP-5. The notification shall clearly describe the proposed sources and/or modifications. The owner or operator shall also submit to the Department proof of submittal of the municipal notification along with a copy of the Application for Authorization to Use GP-5.

8. Application for Use

Pursuant to 25 *Pa. Code* § 127.621 (relating to application for use of general plan approvals and general operating permits), any person proposing to construct, operate or modify a natural gas compression and/or processing facility listed in Condition 3 in Section A, under this General Permit shall submit to the Department the Application for Authorization to Use GP-5. This application shall be accompanied by the Compliance Review Form required under 25 *Pa. Code* §§ 127.12a (relating to compliance review) and § 127.412 (relating to compliance review forms), appropriate application fees specified in Section A, Condition 13 of this General Permit, proof of the municipal notification and any additional forms and information requested by the Department. This General Permit authorizes the specific sources and the specific location of the facility as described in the application.

9. Compliance Requirements

- (a) The owner or operator authorized to use this General Permit shall comply with the specifications in the application and terms and conditions of this General Permit.
- (b) All sources and associated air pollution control equipment located at a natural gas compression and/or processing facility shall be:
 - (i) Operated in such a manner as to not cause air pollution, as that term is defined in 25 *Pa. Code* § 121.1;

- (ii) Operated and maintained in accordance with the manufacturer's specifications, procedures, recommended maintenance schedule, and the specifications in the Application for Authorization to Use GP-5, or an alternate procedure approved by the Department that achieves equal or greater emission reductions;
 - (iii) Operated and maintained in such a manner that no owner or operator may permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source such that the malodors are detectable outside the property of the owner or operator on whose land the facility is being operated in accordance with *25 Pa. Code* § 123.31 (relating to odor emissions); and
 - (iv) Operated and maintained in accordance with the fugitive emission requirements of *25 Pa. Code* § 123.1 (relating to prohibition of certain fugitive emissions) and *25 Pa. Code* § 123.2 (relating to fugitive particulate matter).
- (c) The emissions from all sources and associated air pollution control equipment located at a natural gas compression and/or processing facility shall not equal or exceed any of the following on a 12-month rolling sum basis:
- (i) Nitrogen oxides (NO_x) – 100 tons.
 - (ii) Carbon monoxide (CO) – 100 tons.
 - (iii) Sulfur oxides (SO_x) – 100 tons.
 - (iv) Particulate matter with an aerodynamic diameter less than 10 microns (PM₁₀) – 100 tons.
 - (v) Particulate matter with an aerodynamic diameter less than 2.5 microns (PM_{2.5}) – 100 tons.
 - (vi) Volatile organic compounds (VOCs) – 50 tons.
 - (vii) Any individual hazardous air pollutant (HAP) – 10 tons.
 - (viii) Total hazardous air pollutants (HAPs) – 25 tons.
 - (ix) Greenhouse gases, expressed as carbon dioxide equivalent (CO₂e) – 100,000 tons.
 - (x) In addition, the emissions from all sources and associated air pollution control equipment located at a natural gas compression and/or processing facility in Bucks, Chester, Delaware, Montgomery, or Philadelphia counties shall not equal or exceed any of the following on a 12-month rolling sum basis:

- (A) Nitrogen oxides (NO_x) – 25 tons.
- (B) Volatile organic compounds (VOCs) – 25 tons.

10. Modification, Suspension, Revocation of GP-5 and Authorizations to Use the General Permit

- (a) The Department may modify, suspend, or revoke and reissue this General Permit if it is determined that GP-5 does not comply with the Clean Air Act, Air Pollution Control Act or regulations adopted under these acts.
- (b) This General Permit may be modified, suspended, or revoked if the Department determines that the natural gas compression and/or processing facilities cannot be adequately regulated under this General Permit.
- (c) An authorization to construct and/or operate a natural gas compression and/or processing facility under this General Permit may be suspended or revoked if the Department determines that, at any time, the owner or operator has failed to construct and/or operate the facility in compliance with the terms and conditions of this General Permit or information identified in the Application for Authorization to Use GP-5, or supplemental material included with the application that the Department used to determine if the proposed sources will comply with the GP-5.
- (d) Upon suspension or revocation of authorization to construct and/or operate a natural gas compression and/or processing facility under this General Permit, the owner or operator shall cease construction immediately of the facility. The owner or operator of the facility shall not restart the construction and/or operation prior to receipt of written approval from the Department.

11. Notice Requirements

- (a) The applications and notifications required by 25 *Pa. Code* § 127.621 and Section A, Condition 5 of this General Permit shall be submitted to the appropriate DEP Regional Office responsible for issuing authorizations to use general permits in the county in which the natural gas compression and/or processing facility is or will be located.
- (b) As required under 25 *Pa. Code* § 127.621(b), the application shall be either by hand delivery or courier (i.e., Federal Express, United Parcel Service, United States Postal Service, etc.) to the Department or sent by certified mail, return receipt requested.
- (c) The owner or operator shall notify the Department, in writing, no later than five (5) business days after the following activities:
 - (i) Initial commencement date of construction of the source(s) authorized under this General Permit.

- (ii) Final completion date of construction.
 - (iii) Any lapse in construction activity of eighteen (18) months or more that may take place in between the initial and start-up dates in (a) and (b) above.
- (d) At least five (5) business days prior to commencing operation of the source or facility, the owner or operator shall provide a written notification to the Department of the intent to commence operation of the natural gas compression and/or processing facility authorized by this General Permit . When multiple sources at the facility are subject to different commencement of operation schedules, written notice shall be submitted to DEP prior to the commencement of operation of each source.
- (e) *Malfunctions.* The owner or operator shall notify the Department by telephone within twenty-four (24) hours of the discovery of any malfunction at a natural gas compression and/or processing facility operating pursuant to this General Permit, or any malfunction of pollution control equipment associated with a facility, which results in, or may possibly be resulting in, the emission of air contaminants in excess of any applicable limitation specified herein. Following the telephone notification, a written notice also be submitted to DEP as specified below.
- (i) If the owner or operator is unable to provide notification by telephone to the appropriate Regional Office within twenty-four (24) hours of discovery of a malfunction due to a weekend or holiday, the notification shall be made to the Department by no later than 4 p.m. on the first business day for the Department following the weekend or holiday.
 - (ii) Any malfunction that poses an imminent danger to the public health, safety, welfare, or environment shall be reported by telephone to the Department and the County Emergency Management Agency immediately after the discovery of an incident. The owner or operator shall submit a written report of instances of such malfunctions to the Department within three (3) business days of the telephone report.
 - (iii) Unless otherwise required by this General Permit, any other malfunctions shall be reported to the Department, in writing, within five (5) business days of malfunction discovery.

12. Term of Authorization to Use General Permit

The authorization to construct and/or operate a natural gas compression and/or processing facility under this General Permit is granted for a fixed period of five (5) years except that the authorization to construct a facility will expire eighteen (18) months from the date of the Department authorization if the owner or operator fails to commence construction. If construction commences within eighteen (18) months of the date of receipt of authorization from the Department, but it is not yet completed, the authorization to construct the facility under this General Permit is automatically extended, provided there is no subsequent lapse in construction

activity of eighteen (18) months or more, up to a maximum of five (5) years from the date of Department authorization. If the construction, modification or installation is not commenced within eighteen (18) months of the authorization of this GP-5 or if there is more than an 18-month lapse in construction, modification or installation, a new application for authorization of GP-5 shall be submitted. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.

13. General Permit Fees

Each applicant seeking authorization to use GP-5 shall submit the applicable fees required under this condition to the appropriate DEP regional office. The following fees schedule applies to this General Permit:

- (a) General Plan Approval application fee:
One thousand and seven hundred dollars (\$1,700)
- (b) General Operating Permit fee:
Three hundred and seventy-five dollars (\$375)
- (c) Annual operating permit administration fee, payable by March 1st for the previous calendar year:
Three hundred and seventy-five dollars (\$375)
- (d) The Department may increase the applicable fees for this General Plan Approval/General Permit in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees) following notice in the *Pennsylvania Bulletin*.

14. Recordkeeping and Reporting Requirements

The owner or operator of the facility shall maintain records that clearly demonstrate to the Department that the facility is not a Title V facility. In addition, the owner or operator of the facility shall keep records to verify compliance with the facility-wide emission limitations. These records shall be maintained at a minimum on a monthly basis and the emissions shall be calculated on a 12-month rolling sum. These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request. The Department reserves the right to request additional information necessary to determine compliance with this General Permit.

15. Annual Source Reporting Requirements

In accordance with 25 Pa. Code § 135.3, the owner or operator of natural gas compression and/or natural gas processing facilities shall submit to the Department by March 1st each year a source report for the preceding calendar year for all sources regulated under this General Permit. The report shall include all emissions information for all previously reported sources and new sources which were first operated during the preceding calendar year. Emissions data including, but not limited to the following, shall be reported: carbon monoxide,

oxides of nitrogen (“NO_x”), particulate matter less than 10 micrometers in diameter (PM₁₀), particulate matter less than 2.5 micrometers in diameter (PM_{2.5}), sulfur dioxide, volatile organic compounds, total hazardous air pollutants (“HAP”), speciated individual HAP emissions, and greenhouse gases, expressed as CO_{2e}.

16. Public Records and Confidential Information

- (a) As required under Section 13.2 of the APCA, 35 P.S. § 4013.2, the records, reports or information obtained by the Department under this General Permit shall be available to the public, except as provided in paragraph (b) of this condition.
- (b) Upon cause shown by the owner or operator that the records, reports or information, or a particular portion thereof, but not emission data, to which the Department has access under the APCA, if made public, would divulge production or sales figures or methods, processes or production unique to that person or would otherwise tend to affect adversely the competitive position of that person by revealing trade secrets, including intellectual property rights, the Department will consider the record, report or information, or particular portion thereof confidential in the administration of the APCA.

17. Circumvention

- (a) The owner or operator of a natural gas compression and/or processing facility may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying or engaging in incremental construction over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.
- (b) No person may permit the use of a device, stack height that exceeds good engineering practice stack height, dispersion technique or other technique that without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants that would otherwise be in violation of this plan approval, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior written approval of the Department, the device or technique may be used for control of malodors.

18. NSPS and NESHAP Submittals

- (a) The owner or operator of a natural gas compression and/or processing facility shall submit to the appropriate DEP Regional Air Quality Office requests, reports, applications, submittals and other communications concerning applicable New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants.

- (b) In accordance with 40 CFR § 60.4 (relating to address) and 40 CFR § 63.10 (relating to recordkeeping and reporting requirements) copies of all requests, reports, applications, submittals and other communications shall also be submitted to the EPA Region III Office. Copies submitted to EPA shall be sent to the following address:

Office of Air Enforcement and Compliance Assistance (3AP20)
United States Environmental Protection Agency
Region III
1650 Arch St.
Philadelphia, PA 19103-2029

19. Emission Limitations and/or Operating Requirements Previously Established for Best Available Technology and/or to Restrict Operations

- (a) This General Permit cannot be used to relax best available technology or other emission limitations or requirements previously established through the air quality permitting process.
- (b) An owner or operator of a natural gas compression and processing facility may apply to the Department for a plan approval for any air contamination source in lieu of seeking authorization to use the general plan approval for natural gas compression and/or processing facilities.

20. Transfer of Ownership

The authorization to use GP-5 may not be transferred from the owner or operator of a natural gas compression and processing facility except when the change of ownership is demonstrated to the satisfaction of the Department and the Department approves the transfer of the authorization in writing. Within thirty (30) days after a change of ownership of the facility, the new owner or operator shall submit to the Department a GP-5 Application, compliance review form, and applicable fees in accordance with Condition 13 of this General Permit.

21. Expiration and Re-authorization of the Use of GP-5

- (a) The authorization granted by the Department to construct and/or operate under this General Permit shall terminate on the date of expiration of the authorization unless a complete application for the use of GP-5 is submitted to the Department at least thirty (30) days prior to the expiration date of the authorization.
- (b) Upon receipt by the Department of a timely and administratively and technically complete application for re-authorization to operate under this General Permit, the owner or operator may continue to operate the natural gas compression and/or processing facility subject to final action by the Department on the GP-5 application provided that the facility is operated in compliance with all terms and conditions of this General Permit. The authorization to use GP-5 shall cease to exist if the owner or operator fails to

submit, by the deadline specified by the Department, any additional information requested by the Department to process the application.

22. Source Test Requirements

The owner or operator of any source subject to performance testing requirements in this General Permit shall comply with the following:

- (a) Within one hundred eighty (180) days after the initial startup of the engine or turbine, the owner or operator shall demonstrate compliance with the applicable emission limits and furnish the Department a written report of the result of such performance test.
- (b) At least thirty (30) calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, a Test Protocol shall be submitted to the Department's Division of Source Testing and Monitoring and the appropriate Regional Office for review and approval. The Test Protocol shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual. The emissions testing shall not commence prior to receipt of a protocol acceptance letter from the Department.
- (c) At least fifteen (15) calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, written notification of the date and time of testing shall be provided to the Department's appropriate Regional Office. Notification, in writing, shall also be sent to the Department's Bureau of Air Quality, Division of Source Testing and Monitoring, so that an observer may be present. The Department is under no obligation to accept the results of any testing performed without adequate advance written notice to the Department of such testing.
- (d) Within fifteen (15) calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be sent to the Department's Division of Source Testing and Monitoring and the appropriate Regional Office indicating the completion date of the on-site testing.
- (e) A complete test report shall be submitted to the Department's Division of Source Testing and Monitoring and the appropriate Regional Office no later than sixty (60) calendar days after completion of the on-site testing portion of an emission test program required by this General Permit.
- (f) The complete test report shall include a summary of the emission results at the beginning of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:

- (i) A statement that the owner or operator has reviewed the report from the emissions testing company and agrees with the findings;
 - (ii) Permit number(s) and condition(s) that are the basis for the evaluation;
 - (iii) Summary of results with respect to each applicable permit condition;
and
 - (iv) Statement of compliance or non-compliance with each applicable permit condition.
- (g) All submittals with the exception of periodic monitoring data shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.
- (h) All testing with the exception of periodic monitoring shall be performed in accordance with any applicable federal regulations (such as New Source Performance Standards), 25 *Pa. Code*, Chapter 139, and the current revision of the Department's Source Testing Manual or an alternative test method as approved by the Department. The owner or operator of the facility shall use the following federal reference methods or alternative test methods approved, in writing, by the Department to demonstrate compliance:
- 40 CFR Part 60, Appendix A, Method 5 and EPA Test Method 202 shall be used to determine the Total Particulate Matter emissions.
- 40 CFR Part 60, Appendix A, Method 7E shall be used to determine the nitrogen oxide (NO_x) emissions.
- 40 CFR Part 60, Appendix A, Method 10 shall be used to determine the carbon monoxide (CO) emissions.
- 40 CFR Part 60 Methods 25A and 18 or 40 CFR Part 60 Method 25A and 40 CFR Part 63 Method 320 shall be used to determine the NonMethane Non-Ethane Hydrocarbon (NMNEHC) emissions.
- 40 CFR Part 63 Appendix A, Method 320 or Method 328 shall be used to determine the Formaldehyde (HCHO) emissions.
- (i) Reports, protocols and test completion notification with the exception of periodic monitoring data shall be submitted through PSIMS*Online available through <https://www.depgreenport.state.pa.us/ecommm/Login.jsp>. If internet submittal is not feasible, copies of the submittal shall be sent to the appropriate Pennsylvania Department of Environmental Protection Regional Office and to the attention of the Department's Bureau of Air Quality, Division of Source Testing and Monitoring, 400 Market Street, 12th Floor Rachel Carson State Office Building, Harrisburg, PA 17105-8468, with deadlines verified through document postmarks.

- (j) The owner or operator shall ensure that all applicable federal reporting requirements are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between federal and state laws and regulation, the owner or operator shall comply with the most stringent provision, term, condition, method or rule.
- (k) If, at any time, the Department has notified the owner or operator that the air contaminant emissions from the source operating under this General Permit are, or may be, in excess of any applicable air contaminant emission limitation, the owner or operator shall conduct source tests deemed necessary by the Department to determine the actual air contaminant emission rate. The testing shall be conducted in accordance with the applicable provisions of *25 Pa. Code*, Chapter 139 (relating to sampling and testing) as well as in accordance with any additional requirements or conditions established by the Department at the time the owner or operator is notified, in writing, of the need to conduct testing.

23. Applicable Laws

Nothing in this General Permit relieves the facility owner or operator from the obligation to comply with all applicable Federal, state and local laws and regulations including *25 Pa. Code* Article III (relating to air resources). Applicable Federal regulations include, but are not limited to, the following New Source Performance Standards codified at 40 CFR Part 60 (incorporated by reference in *25 Pa. Code* § 122.3) and National Emission Standards for Hazardous Air Pollutants codified at 40 CFR Part 63 (incorporated by reference in *25 Pa. Code* § 127.35):

- (a) 40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.
- (b) 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.
- (c) 40 CFR Part 60, Subpart LLL – Standards of Performance for Onshore Natural Gas Processing: SO₂ Emissions
- (d) 40 CFR Part 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
- (e) 40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.
- (f) 40 CFR Part 60, Subpart OOOO– Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

- (g) 40 CFR Part 63, Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.
- (h) 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

SECTION B. REQUIREMENTS FOR NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES

1. Emission Standards for Existing Engines

In accordance with 25 *Pa. Code* §§ 127.1 and 127.12(a)(5), any existing engine operating under GP-5 authorizations approved by the Department prior to the issuance of this General Permit shall continue to comply with the emissions standards and other requirements in Condition 1(a) or 1(b) of this section.

- (a) The engine shall be operated or equipped with air cleaning devices to meet the following emission levels:
 - (i) Oxides of Nitrogen (“NO_x”) (as NO₂) at rated brake horsepower (bhp) and operating at rated speed of two (2.0) grams per bhp-hour (gm/bhp-hr).
 - (ii) Non Methane Hydrocarbon excluding formaldehyde (NMHC) (as propane) at rated bhp and operating at rated speed of two (2.0) gm/bhp-hr.
 - (iii) Carbon Monoxide (“CO”) at rated bhp and operating at rated speed of two (2.0) gm/bhp-hr.
- (b) At operating conditions less than rated capacity, internal combustion engines shall, on a pounds-per-hour basis, emit no more than they emit at rated bhp and rated speed.
- (c) In accordance with 25 *Pa. Code* §§ 127.1 and 127.12(a)(5), visible emissions shall not exceed either of the following limitations:
 - (i) Equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour.
 - (ii) Equal to or greater than 30 percent at any time.
- (d) The owner or operator of the engine shall comply with the applicable Standards of Performance (“NSPS”) for Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (“NESHAP”) for Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

2. Emission Standards for New Stationary Engines

- (a) In accordance with 25 Pa. Code §§ 127.1 and 127.12 (a) (5), a new engine for which construction or reconstruction commenced after the effective date of this General Permit shall not exceed the emissions standards specified in the following table:

| Engine Type | Rated bhp | NO _x | CO | NMNEHC as propane (excluding HCHO) | HCHO |
|-----------------------------|--------------|-----------------|--|------------------------------------|---|
| NG-fired Lean and Rich burn | ≤100 | 2.0 gm/bhp-hr | 2.0 gm/bhp-hr | - | - |
| NG-fired Lean-burn | >100 to ≤500 | 1.0 gm/bhp-hr | 2.0 gm/bhp-hr | 0.70 gm/bhp-hr | - |
| NG-fired Lean-burn | >500 | 0.50 gm/bhp-hr | 47 ppmvd @ 15% O ₂ or 93% reduction | 0.25 gm/bhp-hr | 0.05 gm/bhp-hr |
| NG-fired Rich-burn | >100 to ≤500 | 0.25 gm/bhp-hr | 0.30 gm/bhp-hr | 0.20 gm/bhp-hr | |
| NG-fired Rich-burn | >500 | 0.20 gm/bhp-hr | 0.30 gm/bhp-hr | 0.20 gm/bhp-hr | 2.7 ppmvd @ 15% O ₂ or 76% reduction |

- (b) The owner or operator of the engine shall also comply with all other applicable NSPS requirements established in 40 CFR Part 60, Subpart JJJJ, Subpart OOOO, and the NESHAP requirements in 40 CFR Part 63, Subpart ZZZZ.
- (c) In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), visible emissions from the engine shall not exceed either of the following limitations:
- (i) Equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one (1)-hour; and
 - (ii) Equal to or greater than 30 percent at any time.

3. Start-up and Shut-down Exception for Engines

The emission limitations specified in Section B, Conditions 1 and 2 of this General Permit shall apply at all times except during periods of start-up and shut-down provided that the duration of start-up and shut down does not exceed 30 minutes per occurrence. The owner or operator shall operate the engine in a manner consistent with good air pollution control practices for minimizing emissions at all times, including periods of startup and shutdown. The emissions from start-up and shut-down shall be included in the 12-month rolling sum of emissions. The owner

or operator of the engine shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subpart JJJJ, and 40 CFR Part 63, Subpart ZZZZ.

4. Performance Testing Requirements for Engines

- (a) For a new or reconstructed engine which has a rated capacity less than or equal to 500 brake horsepower, vendor guarantees or Department-approved data from test conducted within 12-months on an identical engine for NO_x, CO, and NMHC or NMNEHC shall be sufficient to verify emissions rates. However, the Department reserves the right to require additional information to verify any emission rates that may include source testing in accordance with applicable provisions of 25 *Pa. Code* Chapter 139 (relating to sampling and testing). The vendor guarantees shall not be construed to satisfy the engine certification requirements specified in 40 CFR § 60.4243.
- (b) For a new or reconstructed engine which has a rated capacity greater than 500 brake horsepower, within one hundred eighty (180) days after initial start-up or re-authorization of this General Permit, the owner or operator shall perform source testing on each affected engine in accordance with applicable provisions of 25 *Pa. Code* Chapter 139 (relating to sampling and testing) on each affected engine for NO_x, CO, HCHO, and NMHC or NMNEHC and furnish the Department a written report of the result of such performance test. Engine testing load conditions shall be representative to within 10 percent of 100% peak or the highest achievable load. The source testing shall be conducted in accordance with the requirements specified in Conditions 21 and 22 in Section A of this General Permit.
- (c) In addition to the source testing required by Condition 4(b) of Section B, every 2,500 hours of operation and no sooner than forty-five (45) days from the previous test, the owner or operator shall perform periodic monitoring for NO_x and CO emissions to verify continued compliance upon each of the respective engines which has a rated capacity greater than 500 brake horsepower and subject to the BAT as specified in Section B, Conditions 1 and 2 of this General Permit. A Department-approved test that has been performed within 45 days prior to the scheduled periodic monitoring may be used in lieu of the periodic monitoring for that time period. A portable gas analyzer may be used to satisfy the requirements of this condition utilizing three test runs of twenty (20) minutes for each test run. The Department may alter the frequency of portable analyzer tests based on the test results. The frequency of portable gas analyzer tests may be altered with written Departmental approval. The portable gas analyzer shall be used and maintained according to the manufacturer's specifications and the procedures specified in ASTM D 6522 or equivalent as approved by the Department.
- (d) Within thirty (30) calendar days after the completion of periodic monitoring, the owner or operator shall submit the results to the appropriate DEP Regional Office. The Department reserves the right to require source tests in

accordance with EPA reference methods should the data from the portable analyzer warrant such tests.

5. Work Practice and Monitoring Requirements for Engines

- (a) In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of a new or reconstructed natural gas-fired engine shall install, maintain, and operate each engine and associated air pollution control equipment in accordance with manufacturer's specifications.
- (b) The owner or operator shall maintain comprehensive accurate records of number of hours per month that each engine operated using a non-resettable hour meter, the amount of each fuel type that is used per month in each engine, the date the GP-5 authorization was issued, the date construction began, the date of initial startup, the date testing is required, parameters required to be tested, and the date testing was performed for each engine.
- (c) In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of an engine shall comply with the monitoring requirements specified in 40 CFR §§ 60.4237 and 63.6625.

6. Notification, Recordkeeping and Reporting Requirements for Engines

- (a) The owner or operator of an engine shall also comply with the applicable notification, reporting, and recordkeeping requirements specified in 40 CFR §§ 60.4245 and 63.6645.
- (b) Submittal of reports in accordance with the requirements and schedules outlined in this General Permit.
- (c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

SECTION C. REQUIREMENTS FOR NATURAL GAS-FIRED SIMPLE CYCLE GAS TURBINES

1. Emissions Standards for Turbines

The owner or operator of a new or reconstructed turbine with a rated capacity equal to or greater than 1000 bhp or 10.7 gigajoules per hour (10 MMBtu/ per hour), based on the higher heating value (HHV) of the fuel that commenced construction, modification, or reconstruction after February 18, 2005, shall comply with applicable requirements specified in 40 CFR Part 60, Subpart KKKK.

- (a) In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of a new or reconstructed turbine shall not exceed the following emissions standards:

| Turbine Size (BHP) | NO _x ppmvd corrected at 15% O ₂ | CO ppmvd corrected at 15% O ₂ | NMNEHC (as Propane) ppmvd corrected at 15% O ₂ | Total Particulate Matter Lbs/MMBtu |
|--------------------|---|--|---|------------------------------------|
| ≥1,000 and <5,000 | 25 | 25 | 9 | 0.03 |
| ≥5,000 and <15,000 | 15 | 25 | 9 | 0.03 |
| ≥15,000 | 15 | 10 ppm or 93% reduction | 5 ppm or 50% reduction | 0.03 |

- (b) Compliance with the emissions standards in this section shall be considered compliance with the NSPS emissions standards specified in 40 CFR Part 60, Subpart KKKK and 25 Pa. Code Chapter 122 (relating to national standards of performance for new stationary sources).

2. Start-up and Shut-down Exception for Turbines

The emission limitations specified in Section C, Condition 1 of this General Permit shall apply at all times except during periods of start-up and shut-down, provided, however, that the duration of start-up and shut-down do not exceed thirty (30) minutes per occurrence. The turbine shall be operated in a manner consistent with good air pollution control practices for minimizing emissions, at all times, including periods of startup, shutdown, and malfunction. The emissions from start-up and shut-down shall be included in the 12-month rolling sum of emissions. The owner or operator of a turbine shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subpart KKKK.

3. Performance Testing Requirements for Turbines

- (a) For a new or reconstructed turbine, within one hundred eighty (180) days after initial start-up or re-authorization of this General Permit, the owner or operator shall perform source testing on each affected turbine for NO_x, CO, NMNEHC, Total Particulate Matter, and furnish the Department a written report of the results of such performance testing. Turbine testing load conditions shall be within 10 percent of the 100% peak or the highest achievable load. The source testing shall be conducted in accordance with the requirements specified in Conditions 21 and 22 of Section A in this General Permit.
- (b) In addition to the source testing required by this condition, every 2,500 hours of operation and no sooner than forty-five (45) days from the previous test, the owner or operator shall perform periodic monitoring for NO_x and CO emissions to verify that each turbine is in compliance with the BAT requirements established in Section C, Condition 1 of this General Permit for turbines. If a Department-approved test has been performed within 45 days prior to the scheduled periodic monitoring, this test may be used in lieu of the periodic monitoring for that time period.

A portable gas analyzer may be used to satisfy the requirements of this condition utilizing three 20-minute test runs. The Department may alter the frequency of portable analyzer tests based on the results. The portable gas analyzer shall be maintained according to the manufacturer's specifications and the procedures specified in ASTM D 6522 or equivalent as approved by the Department. The Department may also waive all or parts of this requirement if the owner or operator demonstrates compliance, in lieu of testing, through alternate means satisfactory to the Department.

- (c) Within thirty (30) calendar days after the completion of periodic monitoring, the owner or operator shall submit the results to the appropriate DEP Regional Office. The Department reserves the right to require source tests in accordance with EPA reference methods should the data from the portable analyzer warrant such tests.

4. Work Practice and Monitoring Requirements for Turbines

- (a) In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of a new or reconstructed turbine shall install, maintain, and operate the turbine and associated air pollution control equipment in accordance with manufacturer's specifications.
- (b) The owner or operator shall maintain comprehensive, accurate records of number of hours per month that each turbine operated using a non-resettable hour meter, amount of each fuel type that is used per month in each, date GP-5 issued, date construction began, date of initial startup, date testing is required, parameters required to be tested, and date testing was performed for each turbine.
- (c) The owner or operator of any turbine shall comply with the applicable monitoring requirements specified in 40 CFR §§ 60.4335 through 60.4370.

5. Notification, Recordkeeping and Reporting Requirements for Turbines

- (a) The owner or operator of a turbine shall comply with the notification, reporting, and recordkeeping requirements specified in 40 CFR §§ 60.4245 and 63.6645.
- (b) Submittal of reports in accordance with the requirements and schedules outlined in this General Permit.
- (c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

SECTION D. REQUIREMENTS FOR CENTRIFUGAL COMPRESSORS

The owner or operator of centrifugal compressors shall also comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO.

SECTION E. REQUIREMENTS FOR STORAGE VESSELS / STORAGE TANKS

The owner or operator of each storage vessel / storage tank shall also comply with the applicable requirements specified in 40 CFR Part 60, Subparts Kb and OOOO and 40 CFR Part 63, Subpart HH (relating to national emission standards for hazardous Air pollutants from oil and natural gas production facilities).

1. In accordance with 25 *Pa. Code* §§ 127.1 and 127.12(a)(5), the owner or operator of each storage tank with a capacity greater than 40,000 gallons shall also comply with the requirements specified in 25 *Pa. Code* § 129.56.
2. In accordance with 25 *Pa. Code* §§ 127.1 and 127.12(a) (5), the owner or operator of each storage tank with a capacity less than or equal to 40,000 gallons shall also comply with the requirements in 25 *Pa. Code* § 129.57.

SECTION F. REQUIREMENTS FOR GLYCOL DEHYDRATORS

1. The owner or operator of each glycol dehydrator located at natural gas compression and/or processing facility shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH. The owner or operator of each glycol dehydrator located at natural gas compression, and/or processing facility shall also comply with the visible emissions and malodor requirements in Conditions 2 (d) and (e) of this section.
2. The owner or operator of any existing glycol dehydrator, which has a total uncontrolled potential emission rate of VOC in excess of ten (10) tons per year, and authorized to operate under previously issued GP-5, shall continue to comply with the emissions standards and other requirements in paragraph (a) through (j) of this condition and any applicable requirements established in 40 CFR Part 63, Subpart HH.
 - (a) The VOC emissions from the glycol dehydrator still vent stream shall be controlled either by at least 85% with a condenser, a flare or other air cleaning device, or any alternative methods as approved by the Department. This control efficiency requirement must be demonstrated to the satisfaction of the Department.
 - (b) A glycol dehydrator using a condenser as an air cleaning device shall daily achieve an average final exhaust temperature of less than 110 degrees Fahrenheit (110 °F).
 - (c) A glycol dehydrator using a flare as an air cleaning device shall ensure destruction of VOC emissions to the flare stack by maintaining the heat content of the flare gas above 300 Btu/scf. The owner or operator shall document daily visual observations of the continuous presence of a flame. Alternatively, the owner or operator may equip the flare with a heat sensing monitoring device with a continuous recorder that indicates the continuous ignition of the pilot flame. The flare shall be designed and operated in accordance with the applicable requirements in 40 CFR § 60.18.

- (d) Visible emissions from a glycol dehydrator using a flare shall not exceed either of the following limitations:
 - (i) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
 - (ii) Equal to or greater than 30% at any time.
 - (e) A glycol dehydrator shall not emit malodorous air contaminants in such a manner that the malodors are detectable outside the facility property.
 - (f) The owner or operator of a glycol dehydrator shall maintain records of the results of any testing conducted to determine compliance with paragraphs (a) through (e) of this condition.
 - (g) If a condenser is installed as an air cleaning device on a glycol dehydrator, the owner or operator shall maintain records of final exhaust temperature and time observed twice per week on different days during daylight hours.
 - (h) If a flare is used as an air cleaning device for the glycol dehydrator, the owner or operator shall maintain a record of daily visual observations of the continuous presence of a flame or a record of the continuous recorder that indicates the continuous ignition of the pilot flame.
 - (i) The owner or operator of the glycol dehydrator shall maintain records of the date of any maintenance and repair of the required air cleaning device and duration of uncontrolled emissions during such activities.
 - (j) The owner or operator of a glycol dehydrator shall maintain the following records:
 - (i) VOC emissions using GRI-GLYCalc computer software or an alternative method as approved by the Department.
 - (ii) A record of actual throughput per day and the glycol circulation rate.
- 3.** The owner or operator of a new glycol dehydrator, which is not subject to the requirements established in 40 CFR Part 63, Subpart HH and has a total uncontrolled potential emission rate of VOC in excess of five (5) tons per year shall be controlled either by at least 95% with a condenser, a flare or other air cleaning device, or any alternative methods as approved by the Department. This control efficiency requirement must be demonstrated to the satisfaction of the Department. The owner or operator of a new glycol dehydrator shall also comply with the requirements in Condition 2 (b) through (j) of this section.
- 4.** The owner or operator of a new glycol dehydrator, which is not subject to the requirements established in 40 CFR Part 63, Subpart HH and has a total uncontrolled potential VOC emission rate of equal to or less than five (5) tons per

year shall comply with the requirements in Condition 2 (d), (e), and (j) of this section.

SECTION G. REQUIREMENTS FOR ONSHORE NATURAL GAS PROCESSING PLANTS

In accordance with 25 Pa. Code §§ 127.11 and 127.12(a)(5), the owner or operator of a fractionation unit located at an onshore natural gas processing plant shall comply with 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants.

SECTION H. REQUIREMENTS FOR EQUIPMENT LEAKS

1. The owner or operator of the natural gas compression and/or processing facility shall, at a minimum, on a monthly basis perform a leak detection and repair program that includes audible, visual, and olfactory (“AVO”) inspections.
2. Within 180 days after the initial startup of a source, the owner or operator of the facility shall, at a minimum on a quarterly basis, use forward looking infrared (“FLIR”) cameras or other leak detection monitoring devices approved by the Department for the detection of fugitive leaks. The Department may grant an extension for use of FLIR camera upon receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.
3. If any leak is detected, the owner or operator of the facility shall repair the leak as expeditiously as practicable, but no later than fifteen (15) days after the leak is detected, except as provided in 40 CFR § 60.482-9. The owner or operator shall record each leak detected and the associated repair activity. These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

SECTION I. REQUIREMENTS FOR PNEUMATIC CONTROLLERS

The owner or operator of each pneumatic controller affected facility shall also comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO.

SECTION J. REQUIREMENTS FOR SWEETENING UNITS

In accordance with 25 Pa. Code §§ 127.11 and 127.12(a)(5), the owner or operator of a sweetening unit shall also comply with the applicable requirements of 40 CFR Part 60, Subparts KKK and OOOO.

Approved by: 
Krishnan Ramamurthy
Chief, Division of Permits
Bureau of Air Quality

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Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites

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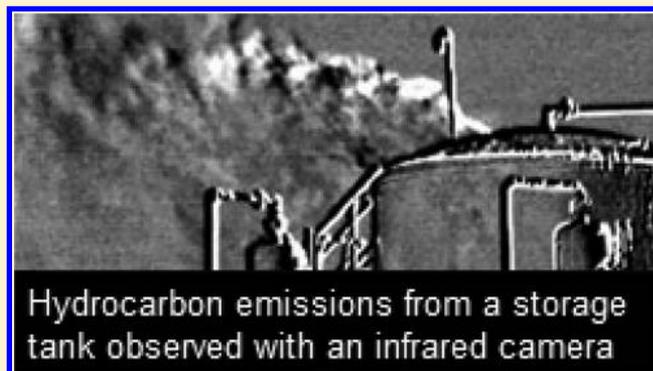
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S Supporting Information

ABSTRACT: Oil and gas (O&G) well pads with high hydrocarbon emission rates may disproportionately contribute to total methane and volatile organic compound (VOC) emissions from the production sector. In turn, these emissions may be missing from most bottom-up emission inventories. We performed helicopter-based infrared camera surveys of more than 8000 O&G well pads in seven U.S. basins to assess the prevalence and distribution of high-emitting hydrocarbon sources (detection threshold $\sim 1\text{--}3\text{ g s}^{-1}$). The proportion of sites with such high-emitting sources was 4% nationally but ranged from 1% in the Powder River (Wyoming) to 14% in the Bakken (North Dakota). Emissions were observed three times more frequently at sites in the oil-producing Bakken and oil-producing regions of mixed basins ($p < 0.0001$, χ^2 test).

However, statistical models using basin and well pad characteristics explained 14% or less of the variance in observed emission patterns, indicating that stochastic processes dominate the occurrence of high emissions at individual sites. Over 90% of almost 500 detected sources were from tank vents and hatches. Although tank emissions may be partially attributable to flash gas, observed frequencies in most basins exceed those expected if emissions were effectively captured and controlled, demonstrating that tank emission control systems commonly underperform. Tanks represent a key mitigation opportunity for reducing methane and VOC emissions.



Hydrocarbon emissions from a storage tank observed with an infrared camera

■ INTRODUCTION

Hydrocarbon emissions from oil and gas (O&G) facilities pose multiple risks to the environment and human health. Methane, the primary constituent of natural gas, is a short-lived greenhouse gas with 28–34 and 84–86 times the cumulative radiative forcing of carbon dioxide on a mass basis over 100 and 20 years, respectively.¹ Burning natural gas instead of other fossil fuels may increase net radiative forcing for some time, even if carbon dioxide emissions decline, depending on the loss rate of methane across the O&G supply chain.² O&G hydrocarbon emissions also include volatile organic compounds (VOCs), which are defined by the United States Environmental Protection Agency (U.S. EPA) as photochemically reactive organic compounds excluding methane and ethane. VOCs contribute to regional ozone formation and have been linked to elevated ozone levels in several O&G producing regions.^{3,4} Certain VOCs such as benzene are toxic and may be connected to increased risk of cancer and respiratory disease in some areas with O&G development.^{5,6}

Hydrocarbons (HC) can be emitted from vented, fugitive, or combustion sources. Vented HC emissions are intentional releases of natural gas from blowdowns (releasing gas to depressurize equipment for maintenance or safety) or sources that emit as part of routine operations such as pneumatic controllers. Fugitive HC emissions are unplanned releases from equipment leaks or malfunctioning equipment. Combustion HC emissions include uncombusted hydrocarbons in the exhaust of combustion sources such as compressor engines and flares. HC emissions can also occur from storage tanks for oil, natural gas condensate, and produced water. Tanks can be the source of both vented emissions, such as flashing losses when liquids are dumped from high-pressure separators to atmospheric pressure tanks, and fugitive emissions caused by

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malfunctioning separators or control devices. Unlike emissions of raw natural gas, which are primarily composed of methane, oil and condensate tank flashing emissions tend to be dominated by heavier alkanes such as propane and butane.⁷

Recent studies have used two broad approaches to estimate methane or VOC emissions: top-down methods that quantify emissions at the regional or larger scale at one or more points in time, and bottom-up methods that use activity data and emission factors to scale up component- or facility-level measurements to generate emission inventories. Generally, top-down estimates of methane emissions have been greater than bottom-up estimates.^{8,9} In the Barnett Shale, a coordinated campaign with simultaneous top-down and bottom-up methods was able to reconcile aircraft mass balance estimates of regional O&G methane emissions with a custom emission inventory based on local and national facility-level measurements.^{10,11} Compared to traditional bottom-up inventories, the coordinated campaign inventories estimated higher emissions due to more comprehensive activity data and the inclusion of high emission “supermitter” sites in the development of emission factors.^{11,12}

Many types of O&G facilities have highly skewed emission distributions with a small fraction of sites contributing the majority of emissions.^{13–17} These high emission facilities, often referred to as supermitters, may include some sites with persistent emissions and others with intermittent episodes of large releases.¹⁸ High emission rates are likely due to both fugitive emissions caused by malfunctions and vented emissions such as tank flashing or blowdowns. The identification and mitigation of high emission sites is critical to reducing regional emissions since these facilities contribute a large portion of total O&G emissions.^{18,19} If the identity of these sites can be predicted, then it would be effective to focus mitigation efforts on sites with characteristics most often associated with high emissions. However, if the occurrence of high emissions is stochastic, then the only viable mitigation solution would be frequent or continuous monitoring of all sites in order to quickly identify and mitigate those with excess emissions.

A common method to detect HC leaks at O&G facilities is optical gas imaging, which has been proposed by U.S. EPA as a regulatory requirement for new and modified sources.²⁰ Since methane and other HC emissions are invisible to the naked eye, infrared (IR) cameras are used to visualize HC plumes.²¹ IR cameras can not differentiate individual HC species nor quantify emissions under field conditions, but their ability to identify the exact location of an emission source is highly valuable for mitigation. A skilled technician on the ground can use an IR camera to quickly survey thousands of components at an O&G facility for leaks.²² Helicopter-based IR camera surveys have been used by operators and regulatory agencies to inspect large numbers of sites for high emission rate sources that may indicate equipment issues or noncompliance with environmental regulations.²³

In this study, we use data collected during helicopter-based IR camera optical gas imaging surveys of more than 8000 O&G well pads to assess the prevalence and distribution of high-emitting HC sources in seven U.S. O&G basins. Survey data were analyzed to determine patterns and statistical relationships of observed emissions with well pad and operator parameters. In turn, observed frequencies of high emission sources were compared to predicted frequencies of observable tank flashing emissions with and without controls to assess if detected

emission sources indicate the presence of malfunctioning emission control systems.

METHODS

Survey areas were selected by stratified random sampling in seven U.S. O&G basins accounting for 33% and 39% of U.S. oil and gas production, respectively: Bakken (North Dakota/Montana), Barnett (north central Texas), Eagle Ford (south Texas), Fayetteville (Arkansas), Marcellus (Appalachian Basin), Powder River (Wyoming/Montana), and Uintah (Utah). Subregions in each basin were selected on the basis of their suitability for helicopter surveys (<1500 m above sea level, unrestricted airspace) and subdivided into 10 × 10 km grid cells. Due to their large size, subregions in the Bakken, Marcellus, and Powder River were centered on areas with active drilling in northwest North Dakota, southwest Pennsylvania, and eastern Wyoming, respectively. Data on well pad characteristics for each of these subregions were obtained for wells with an active status from the production database Drillinginfo, which contains data compiled and cleaned from state databases.²⁴

One or two defining characteristics were identified for each region that best characterized the heterogeneity of the basin's O&G production and could be the basis for stratified sampling. The selected strata were gas-oil ratio (GOR) in produced fluids (Barnett and Uintah), well age (Bakken), a combination of well age and GOR (Marcellus), and well type of oil, gas, or coal-bed gas (Powder River). These strata were chosen to reflect the distinguishing characteristics in each region (e.g., GOR does not vary greatly in the Bakken, so no meaningful stratification is possible along that dimension). Parameter thresholds separating strata were selected independently for each basin to divide grid cells into two or three quantiles of average parameter values. After assigning grids to strata based on their average parameters, a list of grids in each stratum was randomly selected for survey. In two basins, this design was not followed. In the Fayetteville, a single 20 × 20 km area was selected due to limited survey time and homogeneous production across the basin (dry gas without oil). In the Eagle Ford, two unstratified 40 × 15 km survey areas that each covered the basin's broad range in GOR were selected to facilitate efficient measurements by additional research aircraft. A map of surveyed basins is shown in Figure S1.

Survey area boundaries were provided to a professional firm with extensive experience performing leak detection surveys of O&G sites from a helicopter using optical gas imaging (Leak Surveys, Inc.).²⁵ Flights occurred from June to October 2014 using an R44 helicopter. The survey team identified O&G well pads, compressor stations, and small gas processing plants in the survey areas; for this paper, only data from active well pads are included in the analysis. Camera operators used a FLIR GasFindIR infrared camera to visually survey sites for detectable hydrocarbon plumes at an elevation of approximately 50 m above ground level. At each site with detected emissions, the survey team reported the site's latitude/longitude and the number and equipment type of each observed emission source. Additionally, an IR video was recorded at each site with detected emissions, typically by circling the site and focusing on observed emission sources for 20 to 80 s. Videos were reviewed by the lead author to verify the number and type of detected sources.

Two independent methods were used to estimate the minimum detection limit of optical gas imaging with an IR

camera deployed from the survey helicopter. First, an operator in the Fayetteville performed a controlled release of dry natural gas (97% CH₄) from a pipeline pig receiver at a midstream facility while being observed by the helicopter survey team from a typical survey position during cloudy conditions. A variable orifice was used to release natural gas at three rates. These rates were quantified by the bagging method at ~3, 8, and 27 g s⁻¹, respectively. The helicopter survey team recorded observable plumes from all three controlled release tests with the lowest release rate producing only faint images that appeared to represent the detection threshold under test conditions. Second, an aircraft with a methane analyzer used the atmospheric budget method to quantify methane emissions at 19 well pads and compressor stations within 1 h of detection by the helicopter survey team (See the [Supporting Information](#) for methodological details). Measured site emission rates ranged from 1 to 24 g CH₄ s⁻¹ with 84% of central estimates above 3 g CH₄ s⁻¹ (Table S1). Additionally, the helicopter survey team qualitatively ranked the size of emission sources based on the apparent size and density of plumes, but there was no correlation between the qualitative magnitude of emission sources estimated from experienced camera operators and the quantified methane emission rates; potential reasons are discussed in the [Supporting Information](#). Variability in the IR camera's sensitivity to different hydrocarbons (HC) is expected to impact the detection limit. The GasFindIR camera can detect at least 20 different HCs with differing functionality and has the highest sensitivity to alkanes; the reported minimum detectable emission rate under controlled conditions is 2–4 times lower for propane than methane under controlled conditions.²¹ While there may be differences in the ratio of minimum detectable emissions rates in the field compared to controlled conditions, a ratio of 3 was chosen as representative of the increased sensitivity of the camera to higher molecular weight HCs. Therefore, the helicopter survey detection limit was assumed to be ~3 g HC s⁻¹ for dry gas sources with emissions composed primarily of methane and ~1 g HC s⁻¹ for sources such as tanks with emissions composed primarily of higher HCs such as propane. The detection limit of the IR camera is also affected by wind speed. We assessed the average wind speed during surveys based on hourly data during daytime hours from local weather stations. Average wind speed ranged from 2.7 m s⁻¹ in the Uintah to 6.4 m s⁻¹ in the Powder River (Table S2). On the basis of the power law relationship between wind speed and detection limit reported in Benson et al., the difference in wind speed would cause the average detection limit to be 3–4 times higher in the Powder River compared to the Uintah.²¹ Therefore, variability in wind speed contributes uncertainty to the detection limit of a similar magnitude as variable gas composition.

Because survey results were reported for unique well pads rather than by individual well (i.e., many sites had multiple wells), the latitude/longitude of individual wells in surveyed areas were used to aggregate wells into pads by spatially joining all active wells within a 50 m buffer distance.¹⁸ For each pad, well-level data were used to determine the operator, well production type (oil, gas, oil and gas, coal bed methane), well drill type (vertical, horizontal, directional), number of wells, pad age (months since initial production of newest well), gas production, hydrocarbon liquid production, and water production.²⁴ Hydrocarbon liquid production includes both crude oil and natural gas condensate; for this analysis, the term "oil" is used to refer to all hydrocarbon liquids. Water

production data were not available for individual wells in the Fayetteville or Marcellus basins. Parameters were specific to the same survey month for all basins except the Marcellus, for which only annual and semiannual data were available for conventional and unconventional wells, respectively. In addition to pad-specific parameters, operator-specific parameters were calculated for each basin based on operators' full population of wells in each basin. Surveyed sites with detected emissions were matched to individual pads in the survey area using the reported latitude/longitude as well as Google Earth imagery.

The helicopter-based team surveyed 8220 well pads located throughout an area of 6750 km². Average well pad characteristics by basin and strata are summarized in Table S3. The average number of wells per pad ranged from 1.1 in the Uintah to 2.7 in the Fayetteville. Well pads were newest in the Fayetteville (average age of newest well on each pad of 4.1 years) and oldest in the Barnett (13.4 years). Average gas production ranged from 65 Mcf pad⁻¹ day⁻¹ in the Uintah to 1438 Mcf pad⁻¹ day⁻¹ in the Fayetteville. Average oil production ranged from 0 bbl pad⁻¹ day⁻¹ in the Fayetteville to 312 bbl pad⁻¹ day⁻¹ in the Eagle Ford. For the basins with oil production, GOR was lowest in the Bakken (1.2 Mcf bbl⁻¹) and highest in the Marcellus (153 Mcf bbl⁻¹). To assess the representativeness of surveyed sites, we compared these parameters between surveyed sites and the total population of active wells in each basin in 2014 (Table S4). For almost all parameters, surveyed sites had statistically different distributions than the entire basin (Kolmogorov–Smirnov $p > 0.05$) but the percent difference for most values was <25% from the basin mean and almost always within 50%. In all basins, surveyed wells were younger than the full population; in the Bakken, Barnett, Eagle Ford, Marcellus, and Powder River, surveyed wells had higher gas production and/or oil production than the basin average. These slight biases likely resulted from selecting subregions with active drilling to include young sites in our survey areas. Overall, our sampled strata account for the full range of diversity within and across basins and are appropriate for assessing patterns in high emissions.

Pearson's correlation coefficients (r) were used to assess correlation between the presence (nondetect = 0, detect = 1) or number of detected emissions by source type and pad or operator parameters. Binomial generalized linear models (GLM), also known as logistic regression models, were used to predict the probability of detected emissions at a well pad (P_{detect}) from site and operator parameters. Analysis of variance models and Tukey's Honest Significance Difference test were used to assess significant differences in P_{detect} among basins, strata, well type, and drill type. Poisson GLMs were used to predict the number of detected sources by emission type at each pad. For the full data set and individual basins, several single parameter and multiparameter GLMs were evaluated on the basis of their simplicity, Akaike Information Criteria, Pearson's r , and Hosmer-Lemeshow goodness of fit between observed and predicted values to select models meaningful for explaining the effects of parameters on emissions. An alpha level of 0.05 was used to determine statistical significance in all tests. For statistical analyses, percent energy from oil was used as a surrogate for GOR since it has a discrete range and is more normally distributed; this metric was calculated from oil and gas production using an assumed energy content of 5.8 MMBtu bbl⁻¹ for oil and 1.05 MMBtu Mcf⁻¹ for natural gas.²⁶

Table 1. Infrared Camera Survey Results by Basin and Strata^a

| basin | strata | detected sources | | | | well pads with detected sources | |
|--------------|-----------------------|------------------|--------------|----------------|-----------------|---------------------------------|---------------------|
| | | number | % tank vents | % tank hatches | % other sources | number | % of pads |
| Bakken | young | 109 | 9% | 83% | 7% | 57 | 14.9% ^a |
| | old | 61 | 10% | 85% | 5% | 37 | 12.4% ^a |
| | all surveyed | 170 | 9% | 84% | 6% | 94 | 13.8% ^w |
| Barnett | high GOR | 10 | 60% | 50% | 0% | 7 | 0.7% ^a |
| | medium GOR | 9 | 22% | 67% | 11% | 6 | 1.4% ^a |
| | low GOR | 60 | 55% | 40% | 3% | 46 | 20.6% ^b |
| | all surveyed | 79 | 52% | 44% | 4% | 59 | 3.5% ^y |
| Eagle Ford | east | 70 | 61% | 34% | 3% | 29 | 11.0% ^a |
| | west | 1 | 0% | 100% | 0% | 1 | 0.3% ^b |
| | all surveyed | 71 | 61% | 35% | 3% | 30 | 5.4% ^{xy} |
| Fayetteville | all surveyed | 24 | 17% | 83% | 0% | 13 | 4.4% ^{xyz} |
| Marcellus | high GOR, younger age | 17 | 76% | 12% | 12% | 13 | 1.4% ^a |
| | high GOR, older age | 0 | | | | 0 | 0.0% ^b |
| | low GOR | 15 | 13% | 87% | 0% | 11 | 10.7% ^c |
| | all surveyed | 32 | 47% | 47% | 6% | 24 | 1.2% ^z |
| Powder River | coal bed methane | 0 | | | | 0 | 0.0% ^a |
| | oil/CBM mix | 0 | | | | 0 | 0.0% ^a |
| | oil | 18 | 44% | 39% | 22% | 15 | 11.2% ^b |
| | all surveyed | 18 | 44% | 39% | 22% | 15 | 1.0% ^z |
| Uintah | high GOR | 3 | 67% | 0% | 33% | 3 | 2.2% ^a |
| | medium GOR | 59 | 75% | 5% | 20% | 52 | 6.3% ^{ab} |
| | low GOR | 38 | 63% | 21% | 16% | 37 | 8.8% ^b |
| | all surveyed | 100 | 70% | 11% | 19% | 92 | 6.6% ^x |
| all basins | | 494 | 40% | 52% | 8% | 327 | 4.0% |

^aFor the percentage of pads with detected emissions (P_{detect}), letters indicate statistically significant differences among strata within each basin (a–c) and among basins (w–z) as determined by Analysis of Variance models and Tukey's HSD ($p < 0.05$). For example, within the Barnett, P_{detect} in the low GOR strata is statistically different than the high GOR and medium GOR strata; the overall Barnett P_{detect} is statistically different than overall P_{detect} of the Bakken, Marcellus, Powder River, and Uintah.

Table 2. Correlation of Well Pad and Operator Parameters with P_{detect} (the Detection of Emissions at a Site; Nondetect = 0, Detect = 1) or the Number of Detected Sources by Type^a

| parameters | | P_{detect} | total sources | tank vents | tank hatches | nontank sources |
|------------------------------|-------------------|---------------------|---------------|------------|--------------|-----------------|
| well pad parameters | well count | 0.15 | 0.16 | 0.15 | 0.10 | |
| | well age | −0.12 | −0.10 | −0.08 | −0.07 | −0.03 |
| | gas production | 0.12 | 0.11 | 0.15 | 0.04 | |
| | oil production | 0.20 | 0.28 | 0.24 | 0.19 | |
| | water production | 0.06 | 0.06 | 0.04 | 0.06 | |
| | % energy from oil | 0.19 | 0.16 | 0.10 | 0.12 | 0.06 |
| operator regional parameters | well count | −0.11 | −0.09 | −0.06 | −0.06 | −0.05 |
| | gas production | −0.05 | −0.03 | −0.03 | | −0.04 |
| | oil production | 0.09 | 0.10 | 0.06 | 0.08 | |
| | water production | −0.06 | −0.06 | −0.04 | −0.03 | −0.06 |
| | % energy from oil | 0.17 | 0.14 | 0.08 | 0.12 | 0.06 |

^aWell pad parameters represent the individual site. Operator parameters represent all regional well pads operated by the same company as each surveyed site. Reported values are Pearson correlation coefficients (r) that are significantly different than zero ($p < 0.05$).

RESULTS AND DISCUSSION

A total of 494 unique high emissions sources at 327 well pads were detected by the helicopter survey team out of 8220 surveyed well pads in seven basins. The percentage of total well pads with detected HC emissions (P_{detect}) was 4% but ranged from 1% in the Powder River to 14% in the Bakken (Table 1). There were statistically significant differences in P_{detect} by basin with the Bakken higher than all other basins (see Table 1 for full pairwise comparisons). Emissions were more often

observed in oil-producing areas with an average P_{detect} of 13% in the Bakken and low gas-to-oil ratio strata of mixed production basins ($p < 0.0001$, χ^2 test). For example, in the Barnett, 21% of well pads in the low GOR strata showed detectable emissions compared to <1% of sites in the high GOR strata (Table 1). There were also significant differences in P_{detect} by well production type (oil and gas > oil > gas > coal bed methane) and well drill type (horizontal > directional and vertical).

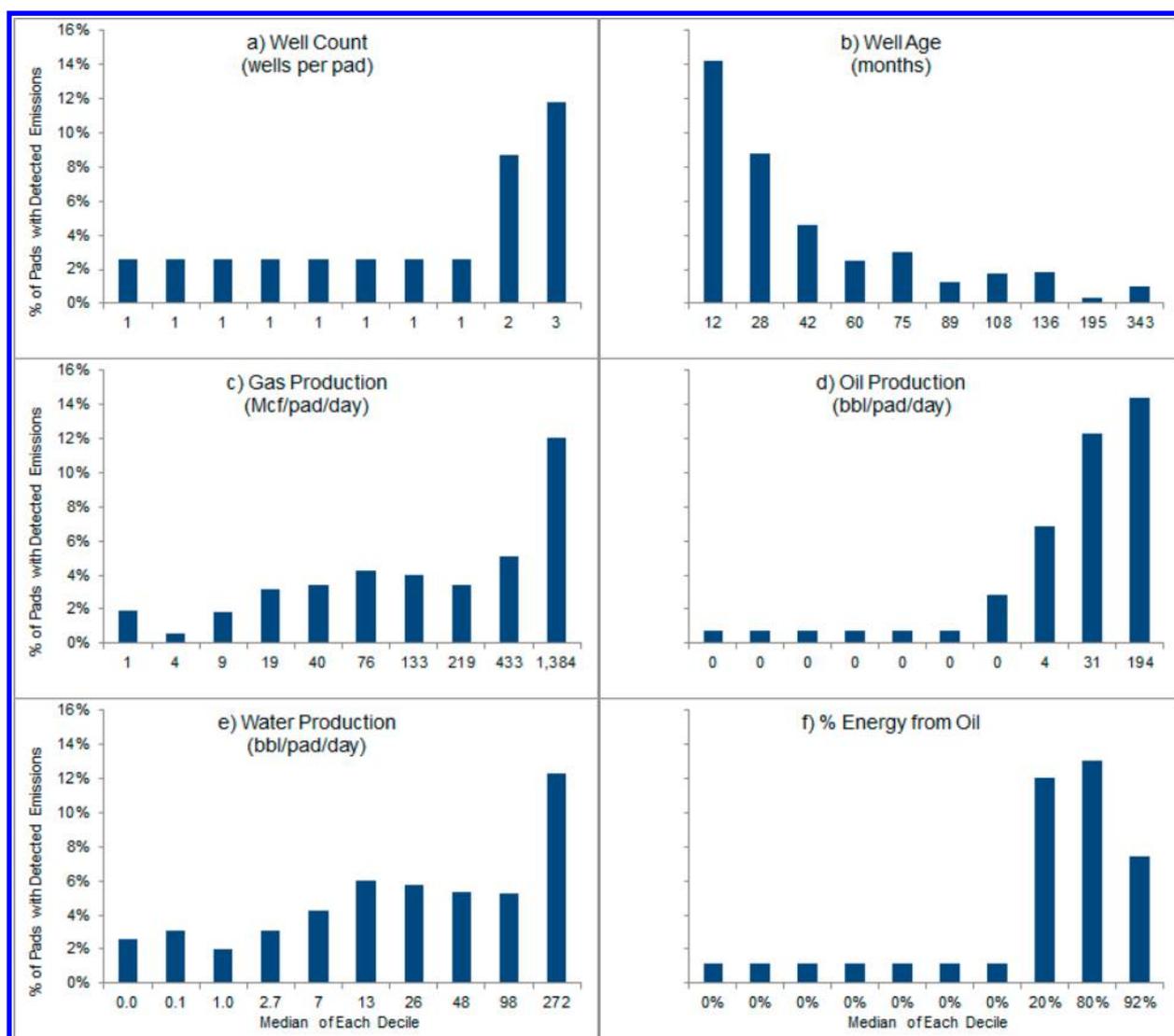


Figure 1. Percentage of well pads with detected emissions by deciles of well pad parameters: (a) well count (wells per pad), (b) well age (months since initial production of newest well), (c) gas production (Mcf/day), (d) oil production (bbl/day), (e) water production (bbl/day), and (f) % energy from oil. The median values of each decile are displayed on the x-axes.

Tank hatches and tank vents were the most common source type of detected emissions, comprising 92% of observed sources (Table 1). The remaining 8% of detected emission sources were dehydrators, separators, trucks unloading oil from tanks, and unlit or malfunctioning flares. Detected emission sources represent individual release points with HC emission rates exceeding the survey's estimated detection limit of approximately 3 g s^{-1} for CH_4 or 1 g s^{-1} for heavier HC. Given this detection limit, no emissions were observed from equipment leaks, pneumatic controllers, or chemical injection pumps, consistent with two recent studies that observed a maximum emission rate of $1.5 \text{ CH}_4 \text{ g s}^{-1}$ at over 1000 such measured sources.^{27,28}

There are several factors that may account for differences among basins in P_{detect} including operational practices, emission control regulations, and the mix of produced hydrocarbons. The effect of weather conditions on the detection limit may also have impacted the frequency of observed emissions. In particular, the higher average wind speed in the Powder River may have contributed to the low frequency of observations.

Statistical Analyses. There were statistically significant but relatively weak positive correlations between detection and numerous well pad parameters: well count, gas production, oil production, water production, and percent energy from oil (Table 2; $r = 0.06$ to 0.20). Detection was negatively correlated with well age ($r = -0.12$), meaning that newer wells were more likely to have detected emissions. The average P_{detect} by decile of analyzed pad parameters is shown in Figure 1. One binomial generalized linear model, GLM A4, predicted detection that was not significantly different than that observed (Hosmer-Lemeshow >0.05); this multiparameter model used basin, the numerical pad parameters well count, well age, gas production, oil production, and percent energy from oil, and the interactions of basin with each numerical parameter, to explain 14% of the variance in P_{detect} ($r^2 = 0.14$). Three other multiparameter GLMs had observed and predicted detections that were statistically different and explained 3–8% of the variance: A1, using basin only; A2, using numerical parameters only; and A3, using basin and the numerical parameters but not their interactions (Table S5, $r^2 = 0.03$, 0.07 , and 0.08 , respectively). The increase in predictive power indicates that

the effect of well pad numerical parameters on P_{detect} varies by basin. For example, in the Marcellus, Powder River, Barnett, and Uintah basins, which have a mix of produced hydrocarbons with a wide range of GOR, there was a significant positive effect of percent energy from oil on predicted P_{detect} , while there was no significant effect of this parameter in the basins with more homogeneous production.

The most predictive GLM, A4, only explained 14% of the variance, which indicates that the presence of high emissions was primarily stochastic or driven by operational characteristics not included in this analysis. Therefore, statistical models have limited utility for predicting the occurrence of individual high emission sources. However, the relatively weak, statistically significant correlation of several parameters with P_{detect} does provide some insights into factors affecting the likelihood of high emissions. To assess the effects of well pad characteristics on detection, we evaluated single parameter GLMs for the full data set and individual basins (Table S6). For the full data set, the GLMs with the best fit between observed and predicted detection were based on well age ($r^2 = 0.04$), oil production ($r^2 = 0.03$), and percent energy from oil ($r^2 = 0.03$). The relative strength of the effects of parameters on the likelihood of detection can be assessed by the ratio of GLM predicted P_{detect} at the 97.5th and 2.5th percentile of parameter distributions. For example, predicted probability of detection for a pad at the 97.5th percentile of well count ($P_{\text{detect}} = 0.11$; 5 wells per pad) is 3.2 times higher than for a pad at the 2.5th percentile ($P_{\text{detect}} = 0.03$; 1 well per pad). For individual basins, single parameter GLMs with statistically significant fits had the same directional effects as the full data set but varied in their relative strength. The best fit GLMs were based on well count in the Bakken and Marcellus, well age in the Powder River and Uintah, and oil production in the Barnett and Eagle Ford. In the Fayetteville, no single parameter GLM had a statistically significant fit. Detailed parameters for GLM A4 and single parameter GLMs are reported in Tables S16 and S17.

Other studies have reported a weak positive correlation between gas production and methane emissions.^{13,28,29} In a prior study of the Barnett Shale, the top 7% of well pads by gas production were estimated to contribute 29% of total methane emissions; this was attributed to higher absolute emissions yet lower proportional loss rates of produced gas at high production sites.¹⁸ The positive correlation between oil production and emission detection may be related to a higher frequency of tank flashing with increased oil production. Brantley et al. reported that oil production was negatively correlated with methane emissions as part of a multivariate linear regression model, which the authors attributed to lower methane content relative to heavier HCs in gas from oil producing wells.¹³ In this study, the opposite effect would be expected since the IR camera detects all HCs with higher sensitivity to heavier HCs. The positive relationship between the number of wells per pad and P_{detect} may be due to greater complexity and potential emission sources at multiwell pads. The negative effect of well pad age, the parameter with the strongest predictive power, is likely related to the inverse relationship between well age and oil and gas production, although all parameters remain significant in multiparameter GLMs. Pads with a well in its first two months of production had over five times the frequency of detected emissions than older pads ($p < 0.001$). Due to the steep decline in production rates of unconventional wells with age, equipment and control devices may be undersized for handling this period of maximum

production. Although older sites would be expected to have a greater likelihood of malfunctions caused by equipment wear, young sites may have initial issues caused by poor setup that have yet to be detected and repaired.

Similar statistical analyses were performed for basin-specific operator characteristics; there were several statistically significant but weak correlations between P_{detect} and these parameters (Table 2) with the strongest positive and negative correlations for an operator's regional percent energy from oil ($r = 0.17$) and regional well count ($r = -0.11$). Binomial GLMs predicting P_{detect} from operator parameters are described in the Supporting Information. Relationships between the number of detected emissions by source type and well pad or operator characteristics were also evaluated (Table 2). For tank vents and hatches, the number of detected sources at a pad was most strongly correlated with oil production ($r = 0.24$ and 0.19). For nontank sources, correlations were weaker ($r = -0.06$ to 0.06). Poisson GLMs predicting the number of detected sources by type from pad parameters are described in the Supporting Information.

Potential Causes of Observed Emissions. High-emitting sources detected by the survey team may have been caused by both malfunctions and normal operations. For nontank sources, IR videos provide evidence that most sources were the result of malfunctions or intentional releases. There were 14 observations of malfunctioning flares that were unlit or operating with poor combustion efficiency. Emissions were detected from the pressure relief valves of four separators; although these pressure relief valves may have been functioning properly for safety purposes, the overpressurization that triggered their release indicates abnormal operations. Eight emission sources were observed from vents associated with trucks unloading oil from tanks, which may be intentional to relieve pressure of gas that is released as oil is pumped into trucks. Fifteen dehydrators were observed to have HC emissions, primarily from still vents that remove water vapor from the water-saturated glycol solution. On the basis of pad gas production and HC emission factors, no more than three of these dehydrators would be expected to have still vent emissions close to the 1 g s^{-1} detection limit.³⁰ Therefore, most observed emissions from dehydrators were likely the result of abnormal operations that allowed excess HC to slip through the vent. In addition to the IR videos of individual sources, the very weak fit between observed and predicted emissions suggests that nontank emission sources are strongly driven by stochastic processes such as malfunctions.

Attributing tank vent and hatch emissions to malfunctions or normal operations is more difficult due to the many potential causes of tank emissions. As part of normal operations, uncontrolled tanks emit HCs from working, breathing, and flashing losses. Tank working and breathing losses generally are expected to be less than 1 g HC s^{-1} , but emissions in excess of this rate can occur from tank flashing after a separator dumps liquids into a tank.^{13,31} As discussed below, the emission rate and frequency of tank flashing emissions can be predicted on the basis of parameters including oil production.

Another routine cause of tank emissions is when wells are vented to unload liquids accumulated in the wellbore, which also releases gas. Emissions from well unloadings can be very large; the average emission rate of over 100 measured unloading events was $111 \text{ g CH}_4 \text{ s}^{-1}$.³² U.S. EPA Greenhouse Gas Reporting Program (GHGRP) data were used to estimate the percentage of wells expected to be venting at any one time in surveyed basins.³³ Assuming the duration of unloading events was 1 h, 0.24% and 0.15% of wells in the Fayetteville

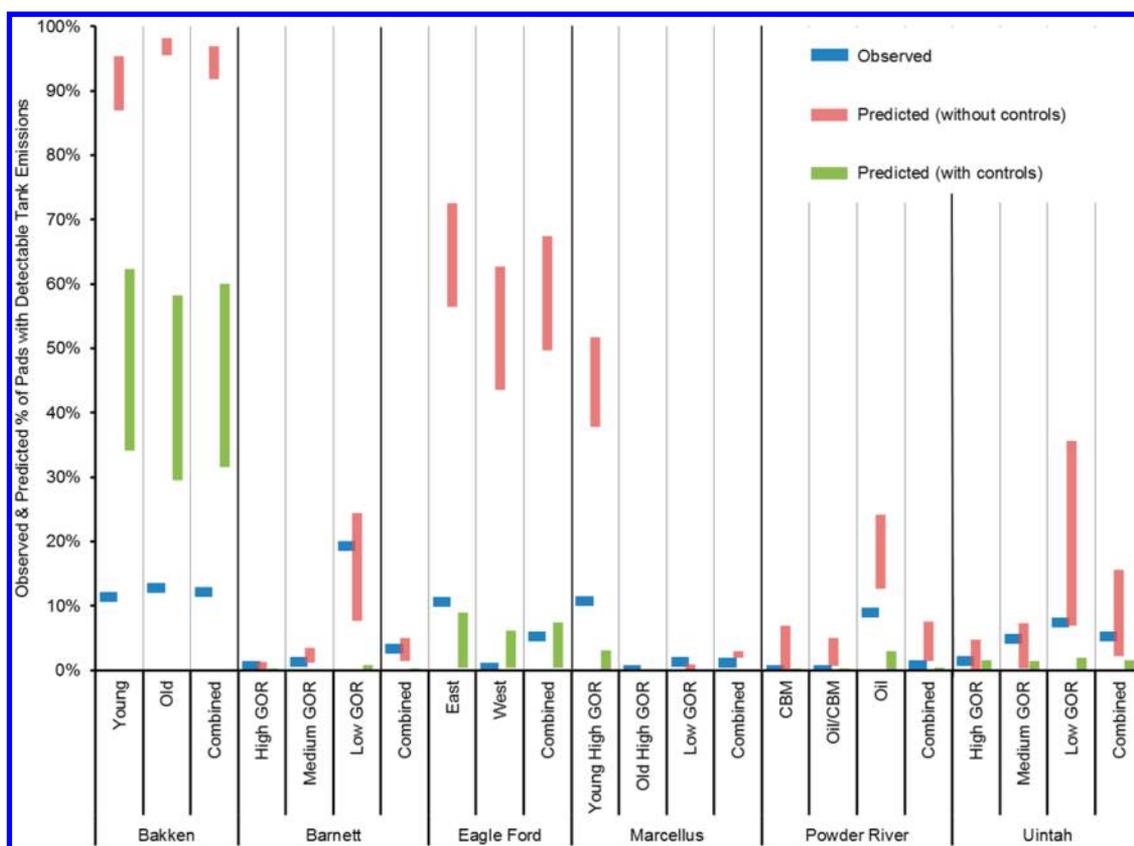


Figure 2. Comparison of the observed and predicted frequencies of well pads with detected tank hydrocarbon emissions assuming an observation threshold of 1 g s^{-1} and basin-level data from the EPA O&G Estimation Tool. Two sets of predicted estimates are provided: red bars reflect predicted frequencies based on potential emissions without controls; green bars reflect the application of controls to the highest emitting tanks (see text for details). Predicted frequencies are shown as a range reflecting different temporal profiles of tank flashing emissions. For several basins and strata, observed frequencies are lower than frequencies predicted without controls but higher than predicted with controls. For example, the combined Uintah observation of 5.8% is within the range predicted for potential emissions but greater than the maximum of 1.5% predicted if all tank control systems were functioning effectively.

(Arkoma) and Uintah basins would have been venting due to liquids unloading at any one time, respectively; all other surveyed basins are predicted to have had less than 0.1% of wells venting from unloading. Therefore, liquids unloading events likely could be detected by the helicopter survey but only can explain a small fraction of observed tank sources.

Finally, abnormal emissions can occur if a separator dump valve fails to properly close and allows produced gas to flow through the tank instead of the sales line. These sources can have very large emission rates, theoretically up to a well's entire gas production if the valve is stuck fully open. In 2014, operators reported over 7000 malfunctioning dump valves to the U.S. EPA GHGRP.³³ On the basis of the reported number of hydrocarbon tanks, approximately 5% of GHGRP tanks was associated with stuck dump valves. Operators do not report the duration of stuck dump valves, but a median duration of 7 days can be back calculated from other GHGRP data. Consequently, less than 0.1% of tanks are expected to have emissions from stuck dump valves at any one time.

Influence of Flashing Emissions by Basin. To determine if flashing could account for the observed P_{detect} of tank emission sources, potential HC emissions from tank flashing were estimated for surveyed well pads. Flash emission rates per unit of liquids production vary by parameters such as separator pressure and API gravity (a measure of HC liquid density). Since these values were not known for individual sites, basin-

level data were obtained from the U.S. EPA O&G Emission Estimation Tool 2014 version 1, which includes a compilation of best available data from several sources including state regulatory agencies.³⁴ The tool provides separate emission factors for produced water, condensate, and crude oil (Table S11). For hydrocarbon liquids, a weighted average emission factor was derived from basin-level oil and condensate production. If tanks at a well pad are manifolded together with a common vent, then flash emissions will occur when any well's separator dumps to the tank battery. Therefore, site-level production was used as a conservatively high estimate of flashing emissions. The temporal variability of flash emissions depends on the frequency and duration of separator dumps and duration of subsequent flash gas venting. Brantley et al. reported that a tank at a Denver-Julesburg well pad producing 29 bbl d^{-1} condensate flashed ten times in 20 min; the duration of flash events in the study ranged from 30 to 120 s.³¹ This indicates that, although individual flash events are short-lived, some sites may have near continuous tank flashing emissions due to frequent venting from separator dumps. To estimate the percentage of sites expected to have flash emissions $\geq 1 \text{ g HC s}^{-1}$ detection limit at any one time, the frequency and emission rate of flash emissions were calculated using two sets of assumptions: continuous emissions at a constant rate or intermittent emissions at the detection limit. Both these estimates use the same daily average emission rate but serve

as lower and upper bounds for the fraction of sites with concurrent emissions at or above the detection limit. The effects of these assumptions were tested with a sensitivity analysis including alternative emission factors and a 3 g HC s^{-1} detection limit (Tables S12–S15). In all basins, the range of predicted frequencies of sites with uncontrolled tank flashing emissions $\geq 1 \text{ g HC s}^{-1}$ included or exceeded observed frequencies (Figure 2; Fayetteville was excluded due to lack of reported liquids production). This indicates that tank flashing could explain observed emissions in the absence of tank emission control devices.

There are several state and federal regulations that require some oil and condensate storage tanks to control VOC emissions, including in North Dakota, Pennsylvania, Utah, and Wyoming.^{35,36} For example, during the time of the survey, U.S. EPA New Source Performance Standard Subpart OOOO required all tanks that began construction after April 12, 2013 and had a potential to emit ≥ 6 tons per year VOC to install control devices with at least 95% control effectiveness within 60 days of initial production.³⁷ Tank emission control devices include flares, combustors (enclosed flares), and vapor recovery units. The improper design, construction, or maintenance of tank control devices can reduce the capture or control efficiency of tank control devices.³⁸ Combustion devices can fail to ignite or have poor combustion efficiency, which causes HC emissions from the combustor stack. Emissions may not be fully captured if control systems are undersized or if condensed liquids in vent lines restrict the flow of gas, which can lead to tank overpressurization that triggers the release of gas from a pressure relief valve or tank hatch. Additionally, tank hatches that are left open accidentally or improperly sealed can allow some portion of vented flash gas to circumvent control devices. To determine if the frequency of observed tank emissions indicates failure of tank control systems, we estimated the percentage of sites expected to be equipped with tank controls by applying basin-level control data from the U.S. EPA O&G Emission Estimation Tool (Table S11).³⁴ For every surveyed well pad, potential emissions from oil, condensate, and water flashing were estimated with basin-level emission factors. Well pads were ranked by potential emissions, and then, controls were assumed to be equipped at a fraction of sites equal to the percentage of tanks with flares reported in the tool (28–86%). Emissions were assumed to be controlled at the reported basin-level capture efficiency (100%) and control efficiency (91–98%).³⁴ If these assumptions were true, then no emissions should be observed from hatches or vents of controlled tanks since all emissions are captured by the control device, but emissions could be observed exiting control devices if uncombusted HC in flare exhaust exceeds the detection limit.

In the Barnett, Powder River, Marcellus, and Uintah Basins, the observed frequency of well pads with detected tank emissions exceeded the maximum predicted frequency based on controlled tank flashing emissions, while in the Bakken the observed frequency was lower than expected (Figure 2). U.S. EPA recently issued a compliance alert that reports inspectors frequently observe emissions from tank hatches and pressure relief valves.³⁸ After an inspection of almost a hundred tanks in Colorado found numerous instances of ineffective control systems caused by design issues such as undersized control devices, an O&G operator entered a consent decree with U.S. EPA and the State of Colorado to evaluate and improve their control systems.³⁹ In the Bakken and Barnett, we inspected Google Earth imagery to assess the presence of tank control

devices at well pads with observed tank emissions; 86% and 56% of well pads with extant imagery, respectively, had apparent control devices. This study's observation that tank hatches and vents were the origin of the majority of detected large emission sources, even at controlled sites, suggests that the U.S. EPA O&G Emission Estimation Tool's assumption of 100% capture efficiency is inaccurate and incomplete capture of emissions by tank control systems is a widespread issue.

Policy Implications. There are several strategies for reducing emissions from tanks, such as installing vapor recovery towers or stabilizers to reduce the vapor pressure of liquids entering tanks, properly sizing control equipment, and maintaining pressure relief valves and tank hatches to prevent leaks. Since this study found a higher frequency of detected emissions at sites within the first few months of production, controlling tank emissions as soon as a site enters production could reduce overall emissions. U.S. EPA New Source Performance Standard Subpart OOOO allows the installation of control devices to be delayed up to 60 days after startup, despite this being a period of maximum production, especially for unconventional wells characterized by rapid production decline.³⁷ The use of properly sized control devices as soon as production is initiated would address a substantial source of emissions. For example, the average Bakken site produces oil about twice the rate in the first two months as it does during the rest of the first year of production.²⁴ Given the evidence reported in this study that the frequency of observed tank emissions is greater than what would be expected if control systems were functioning effectively, it is clear that identifying anomalous emissions through regular or continuous monitoring of hydrocarbon emissions and/or equipment status, such as leak detection and repair programs, would be an effective strategy to reduce emissions.

Currently, U.S. EPA estimates total annual emissions from all oil and gas production sources of 3.1 Tg VOC and 2.9 Tg CH_4 with $0.6 \text{ Tg CH}_4 \text{ yr}^{-1}$ attributed to oil and condensate tanks.^{40,41} The qualitative nature of the IR survey data precludes an accurate estimate of hydrocarbon or methane emissions, but with knowledge of the detection limit of the technology deployed, our observations can be used to estimate a lower bound for tank emissions. Our observation of more than 450 detected tank sources with emission rates $\geq 1 \text{ g HC s}^{-1}$ represent at least 450 g HC s^{-1} (a more likely estimate is $\sim 1575 \text{ g HC s}^{-1}$ based on the median aircraft quantified well pad emission rate of $3.5 \text{ g CH}_4 \text{ s}^{-1}$). While these emissions likely include both intermittent and continuous sources, the assumption of a relatively constant emission rate across a large number of sites is robust and yields an emission rate of at least $14.2 \text{ Gg HC yr}^{-1}$. Since our observations were limited to summer/fall and daylight hours, we were not able to assess how annual average prevalence may be affected by seasonal or diurnal trends such as higher tank breathing losses during warmer conditions. The 8220 surveyed well pads include 1.1%, 3.7%, and 4.5% of U.S. active wells, gas production, and oil production, respectively. There is uncertainty in scaling up emissions from our sample given that the representativeness of surveyed wells to the U.S. national population of O&G wells has not been assessed and there are only weak correlations between the prevalence of high emissions and these parameters. However, scaling up by the best fit parameter, oil production, yields a minimum national HC emission rate of 0.32 Tg yr^{-1} from high emission tank sources. This national emission estimate of tank emissions represents a lower bound for high-

emitting tanks and excludes common, lower emission rate sources such as tank working and breathing losses. This study provides evidence that the cause of some observed emissions is anomalous conditions rather than routine, intermittent tank flashing. U.S. EPA may be underestimating emissions from O&G tanks by overestimating control effectiveness and failing to comprehensively include abnormal, high emission sources. It is reasonable to assume that tanks are a major contributor to the gap between top-down and bottom-up estimates of O&G CH₄ emissions reported by several studies, as well as to the fat-tail emissions observed in a previous study of the Barnett that closed the gap.¹¹

Even though this study found statistically significant correlations between the presence of detected emissions and several well pad and operator parameters, these relationships were weak and GLM models were able to explain less than 15% of the variance. This low degree of predictability indicates that these large emission sources are primarily stochastic and the frequent and widespread inspection of sites to identify and repair high emission sources is critical to reducing emissions. In addition to helicopter-based IR surveys, continuous site-based and mobile leak detection systems may be valuable for quickly identifying these large sources.^{13,14,42–44} Tank vents and hatches account for the vast majority of high emission sources detected at well pads across the U.S. Although routine tank flashing may be responsible for some of these emission sources, there is evidence that substantial emissions are caused by abnormal conditions such as ineffective tank control systems. Installing tank control devices on existing sources combined with maintenance and monitoring to ensure control systems are operating effectively would be an important step for reducing emissions of methane and VOCs. Tanks and other high emission sources are an important contributor to total hydrocarbon emissions from oil and gas well pads and offer a promising opportunity to reduce emissions, but further reductions targeting the numerous emission sources that are individually smaller but collectively large will also be necessary to minimize the health and climate impacts of oil and gas production.

■ ASSOCIATED CONTENT

● Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.6b00705.

8 infrared videos and description of observed sources (ZIP)

Supporting text, 17 tables, and 2 figures (PDF)

Calculations used in tank flashing analysis (XLSX)

Site-level parameter data for well pads in the surveyed areas and basins (XLSX)

List of surveyed sites by latitude/longitude (XLSX)

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Notes

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Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol

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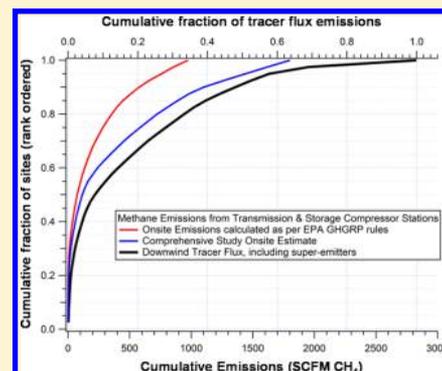
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S Supporting Information

ABSTRACT: Equipment- and site-level methane emissions from 45 compressor stations in the transmission and storage (T&S) sector of the US natural gas system were measured, including 25 sites required to report under the EPA greenhouse gas reporting program (GHGRP). Direct measurements of fugitive and vented sources were combined with AP-42-based exhaust emission factors (for operating reciprocating engines and turbines) to produce a study onsite estimate. Site-level methane emissions were also concurrently measured with downwind-tracer-flux techniques. At most sites, these two independent estimates agreed within experimental uncertainty. Site-level methane emissions varied from 2–880 SCFM. Compressor vents, leaky isolation valves, reciprocating engine exhaust, and equipment leaks were major sources, and substantial emissions were observed at both operating and standby compressor stations. The site-level methane emission rates were highly skewed; the highest emitting 10% of sites (including two superemitters) contributed 50% of the aggregate methane emissions, while the lowest emitting 50% of sites contributed less than 10% of the aggregate emissions. Excluding the two superemitters, study-average methane emissions from compressor housings and noncompressor sources are comparable to or lower than the corresponding effective emission factors used in the EPA greenhouse gas inventory. If the two superemitters are included in the analysis, then the average emission factors based on this study could exceed the EPA greenhouse gas inventory emission factors, which highlights the potentially important contribution of superemitters to national emissions. However, quantification of their influence requires knowledge of the magnitude and frequency of superemitters across the entire T&S sector. Only 38% of the methane emissions measured by the comprehensive onsite measurements were reportable under the new EPA GHGRP because of a combination of inaccurate emission factors for leakers and exhaust methane, and various exclusions. The bias is even larger if one accounts for the superemitters, which were not captured by the onsite measurements. The magnitude of the bias varied from site to site by site type and operating state. Therefore, while the GHGRP is a valuable new source of emissions information, care must be taken when incorporating these data into emission inventories. The value of the GHGRP can be increased by requiring more direct measurements of emissions (as opposed to using counts and emission factors), eliminating exclusions such as rod-packing vents on pressurized reciprocating compressors in standby mode under Subpart-W, and using more appropriate emission factors for exhaust methane from reciprocating engines under Subpart-C.



INTRODUCTION

The growing production and utilization of natural gas in the United States (US) has raised questions about methane emissions from the natural gas system.^{1,2} Methane, a greenhouse gas (GHG), is the primary component of natural gas. The US Environmental Protection Agency (EPA) estimates that the natural gas system contributed about 23% of annual US methane emissions in 2012 by relying heavily on data collected

in the 1990s.³ Recent studies have suggested that the EPA and other emissions inventories may underestimate US national methane emissions from all sources by 25–75%.^{4–6}

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The 2012 EPA Greenhouse Gas Inventory (GHGI) attributes one-third of methane emissions from the US natural gas system to the transmission and storage (T&S) sector.³ This sector comprises about 2000 compressor stations distributed along approximately 300,000 miles of pressurized pipelines, underground storage facilities, and associated equipment.³ The EPA GHGI for the T&S sector is largely based on emission factors from a 1996 GRI/EPA study.⁷ During the past two decades, there have been substantial changes in the natural gas system, which warrants a re-examination of methane sources and emission rates, e.g. Allen et al.⁸ Two more recent studies reported emissions data from 13 T&S compressor stations,^{9,10} two fewer than the GRI/EPA study. The lack of methane emissions data was identified as a critical issue for assessing the environmental impacts of natural gas use.¹¹

Starting in 2011, T&S facilities that emit more than 25,000 t of carbon dioxide equivalent (MT-CO₂e) report their emissions under the EPA Greenhouse Gas Reporting Program (GHGRP; 40 CFR §98, Subpart C and Subpart W) using a combination of onsite emission measurements and emission factors. In 2012, 495 transmission and underground storage facilities reported methane emissions under this program, about one-quarter of the total facilities in the T&S sector.³ The EPA GHGI does not yet use the GHGRP emissions or activity data, but the EPA GHGRP represents a potentially important new data source for the next generation of natural gas system emissions inventories. However, the use of leak counts and emission factors for certain equipment types, the exclusion of emissions from sources in certain operating modes, and the use of a single emission factor for all unburned methane emissions in engine exhaust regardless of prime mover type (turbine or reciprocating engine) raise questions over the GHGRP's completeness as a basis for emissions inventories.

This paper presents methane emissions measurements made at 45 compressor stations in the T&S sector, more than the three previous studies combined.^{7,9,10} At each site, two independent yet complementary measurement methodologies were employed—comprehensive onsite emissions measurements and downwind dual-tracer flux. Results from the two independent methodologies are compared to investigate uncertainties in site-level emission estimates, EPA GHGI, and EPA GHGRP. Zimmerle et al.¹² use these results, industry-reported activity and emissions data from the GHGRP, and other data to estimate the 2012 national methane emissions for the T&S sector.

METHODOLOGY

Measurements were performed to characterize the methane emissions from 45 compressor stations in the T&S sector during the summer and fall of 2013. The measurements were made in collaboration with six major natural gas pipeline operators. Two independent yet complementary measurement methodologies were employed. Onsite emissions measurements provide a “bottom-up” estimate of site-level methane emissions by direct measurement of individual emission sources, which are then combined to provide a site-level estimate. Tracer flux techniques provide a “top-down” estimate of site-level emissions derived from measured methane and tracer gas concentrations in downwind plumes. The two approaches were deployed on the same day(s) to facilitate direct comparison of the two independent estimates of the site-level methane emissions, to evaluate site-level closure between

the top-down and bottom-up approaches, and to increase confidence in the results.

Study Sites. Methane emissions were measured at 36 compressor stations in the transmission system and nine compressor stations associated with underground storage facilities operated by six partner companies. The stations were located in 16 states across the South, Mid-Atlantic, Northeast, Midwest, and the Mountain West. The stations were equipped with two types of compressors: reciprocating compressors driven by natural gas-fired reciprocating engines, and centrifugal compressors driven by gas-fired turbines (though a few are driven by electric motors). Nineteen stations were equipped with only reciprocating compressors; the average number of compressors at these sites was 4.8 with an average capacity of 2335 hp per compressor. Twenty-one stations were equipped with only centrifugal compressors; the average number of compressors at these sites was 2.4 with an average capacity of 11,741 hp per compressor. Five sites were “mixed” sites with both compressor types. At least one compressor was operating at 20 sites. Twenty-five sites reported to the EPA GHGRP in 2012. Additional site details are summarized in Tables S1 and S2 in the Supporting Information.

Site selection was performed by the study team from lists of sites provided by the six partner companies. Site selection was not random but instead was based on a number of factors: geographic location, technology, partner company greenhouse survey team schedules, and site suitability for tracer flux measurements. We sought to achieve broad geographic coverage, while we also acknowledged the travel schedule of the field teams. Sites were selected to span a range of technologies (centrifugal versus reciprocating compressors; wet versus dry seal centrifugal compressors), operating states (operating, standby depressurized, and standby pressurized), and GHG reporting status (reporter if required to report under GHGRP, otherwise nonreporter). The majority of the measurements were performed in partnership with partner company GHG onsite survey teams, which required schedule coordination. Finally, local road access and meteorological conditions were evaluated to determine the suitability of each site for tracer flux measurements.

The overall goal of the site selection process was to develop a site list that was broadly representative of the partner company fleets, which comprise ~56% of the interstate transmission facilities reported to the US Federal Energy Regulatory Commission (FERC) under Form 2.¹² Comparisons indicate that this objective was largely achieved. For example, the study sites had 187 compressors, of which 69% were reciprocating compressors; this is slightly lower than the census of reciprocating compressors at all partner-company stations (75% of 3052 compressors). Analysis of the GHGRP or equivalent data for 2012 indicates that the methane emissions from the study sites are representative of the broader company fleets; details are provided in the Supporting Information. Briefly, GHGRP-equivalent annual methane emissions data were available for 2012 from 343 Partner sites. This includes 29 study sites. A two-sample Kolmogorov–Smirnov (K–S) goodness-of-fit hypothesis test indicates that these two sets of 2012 methane emissions data were drawn from the same underlying distribution at 95% confidence (Figure S1, Supporting Information.)

Onsite Measurements. The onsite emissions measurements involved comprehensive leak detection followed by

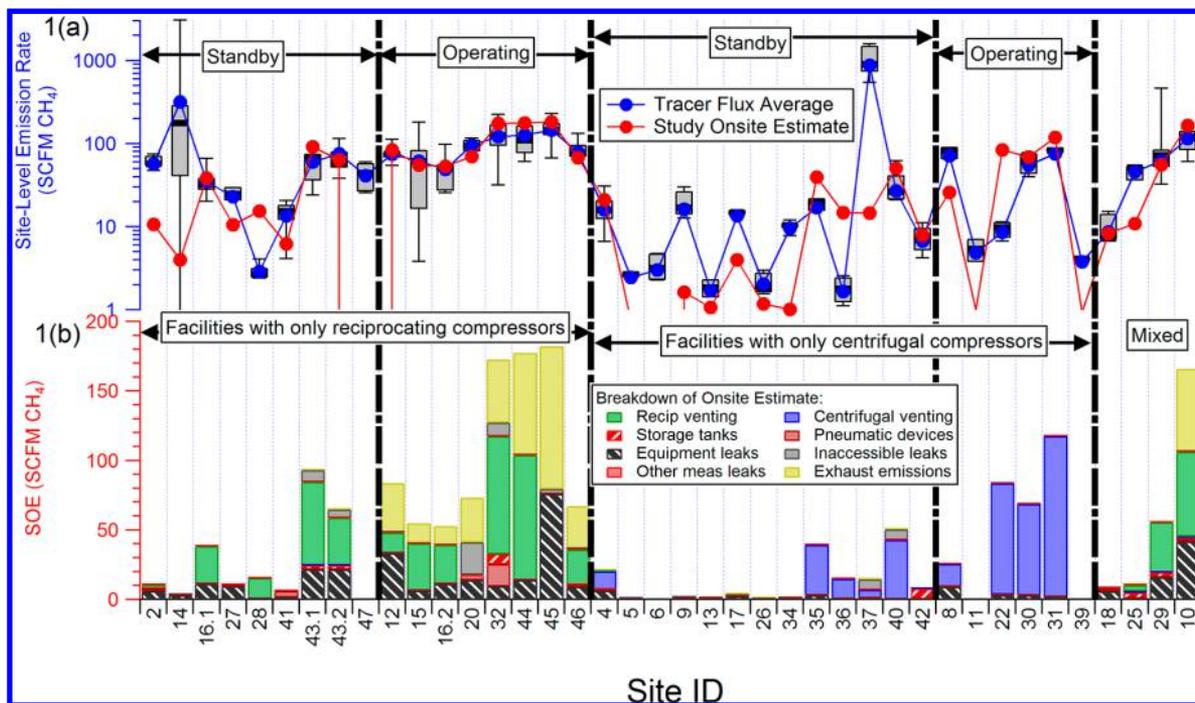


Figure 1. (a) Tracer flux-based site-level methane emission rates for the 40 sites for which both tracer flux and onsite emissions data are available in the same operating state. The boxes represent the 25th and 75th percentiles of the tracer flux data at a site; whiskers represent the 95th and 5th percentiles. The blue line represents the average tracer flux emissions rate, while the red line is the SOE. (b) The SOE broken down by source categories (Table S3, Supporting Information). Sites 18, 25, and 29 were on standby and had both reciprocating and centrifugal compressors (“mixed” sites). Mixed site 10 had one turbine and two reciprocating compressors on standby and four operating reciprocating compressors.

direct measurement of all safely accessible sources of nonengine exhaust methane emissions. Equipment leaks from valves, flanges, connectors, open ended lines, etc. were identified using infrared imaging. The methane emissions from all identified leaks and vented sources (reciprocating compressor rod-packing, blowdown vents, centrifugal wet seals, etc.) were then directly quantified using Bacharach Hi-Flow samplers, anemometers, turbine flow meters, or calibrated bags; in one case, a rotameter was used. Additional details of the onsite emissions measurement protocol are described in the Supporting Information.

A total of 1398 individual onsite methane emissions measurements were collected in this study (Table S5, Supporting Information). For each site, all measured onsite data were combined to create a bottom-up estimate of the site-level methane emissions, called the study onsite estimate (SOE), which is as comprehensive as possible to maximize comparability with the tracer flux measurements of site-level methane emissions. The SOE uses emission estimates in only two situations: (1) inaccessible sources (identified leaks or vents that could not be safely accessed) were estimated using “study factors”; (2) unburned methane in engine/turbine exhaust, not measured in this study, was estimated using AP-42 emission factors (see Supporting Information for details). Study factors are the average of all study measurements for the same component or leak type (Table S10, Supporting Information).

At 34 stations, the onsite methane emissions measurements were made by either the partner company or a partner-supported third-party contractor as part of the company’s ongoing, EPA-mandated GHGRP reporting activities. At 11 stations, the onsite emissions measurements were made by a project-supported contractor (URS Corporation). No significant differences were seen between the partner- and study-

funded onsite contractor data sets when compared against the corresponding downwind tracer flux measurements. At 13 of these stations (Table S2, Supporting Information), the partner contractor only performed a less comprehensive GHGRP-compliant onsite survey, not the more complete study onsite protocol; however, this does not appear to have made a significant difference except at one superemitter site discussed below. Differences between the two protocols are discussed in the Supporting Information.

Downwind Tracer Flux. Downwind tracer flux (or just “tracer flux”) is a technique developed to quantify the aggregate, site-level emissions of methane (or other species) from large, often complex sites with multiple leak points.^{13–15} The dual tracer flux method used here is described in detail by Roscioli et al.¹⁶ Briefly, two tracer gases (nitrous oxide and acetylene) were released at known emission rates from the target site. Each tracer was released from a single point onsite. The release points for the two tracers were separated from each other by up to 750 feet orthogonal to the wind direction so as to bracket the expected sources. The concentrations of the two tracers, methane, ethane, and other species were measured 0.5–3 km downwind of the site using high time-resolution instrumentation (1-Hz or faster, Aerodyne QC-TILDAS and/or Picarro cavity ring-down spectroscopy) deployed on a mobile sampling laboratory. Plume profiles were obtained for each facility by driving the mobile laboratory at a constant speed on a road roughly perpendicular to the wind direction. This process was repeated to obtain multiple plume transects downwind of each site; an average of eight plumes per site met study quality criteria.

The facility-level methane emission rate was calculated for each downwind plume based on the known tracer release rate and the background-corrected methane-to-tracer concentration

ratios.¹⁶ Modeling of pollutant dispersion is not required—this complexity is empirically captured by the tracers. Roscioli et al.¹⁶ describes the different types of plumes and data analysis procedures. Method assumptions and uncertainties are discussed in the Supporting Information. Each plume represents the site-wide emissions in the 1–3 min duration of each transect. While the study plan called for dual-tracer measurements at every site, instrument detection limits and malfunctions on certain days resulted in both dual-tracer and traditional single-tracer plume measurements. Multiple downwind plumes were obtained at each station providing multiple measures of the site-level emissions. The average methane emission rate for each site was calculated by averaging results from each plume weighted by plume-type-specific uncertainty ($1/\sigma^2$; see Supporting Information). The uncertainty of the site average emission rate is calculated as the unbiased sample variance of the mean (using Bessel's correction).

RESULTS

The site-level emissions data are summarized in Figure 1, panel a. The tracer flux measurements indicate that the methane emissions varied by almost three orders of magnitude across the 45 study sites. The methane emission rate from the lowest emitting site was 1.7 ± 0.2 SCFM versus 880 ± 120 SCFM for the highest emitting site (SCFM = standard cubic feet per minute at 1 atm and 15.6 °C; 1 SCFM = 19.2 g CH₄/min). The box-and-whisker plots show the distribution of emissions measured for each plume transect. At most sites, the plume-to-plume differences were small (coefficient of variation less than 20% at 35 sites, Table S9, Supporting Information), which indicates that emissions were relatively invariant in time. Therefore, the variation in emissions at a given site was much lower than variation across sites.

The ethane/methane ratio has been shown to effectively distinguish thermogenic (natural gas) methane from biogenic methane.¹⁷ Figure 2 shows excellent agreement between the ethane/methane ratio measured in the downwind plumes and gas composition data provided by the partner companies (slope 0.94 ± 0.02 , $R^2 = 0.97$, excluding one outlier). This demonstrates that the background-corrected methane measured in each plume is associated with the target facility and not some other source(s). The one outlier in this comparison (site 24) had a significant off-site source of natural gas methane that interfered with the downwind tracer flux measurements; that site is excluded from the subsequent analysis.

Although the tracer flux technique characterizes site-level emissions, it does not identify the specific sources that drive the emissions. The onsite data can address this shortcoming. However, a potential concern with onsite surveys is systematic bias due to inaccessible sources and leaks not detected, especially at large and complex compressor stations with hundreds of valves, vents, and other potential emission points. Therefore, before the onsite data are examined, we compare the SOE calculated from the onsite measurements to the tracer flux data.

Comparison of Tracer Flux and SOE. Figure 3 compares the SOE and tracer flux estimates of the site-level methane emissions at the 40 sites where valid tracer flux and onsite data were collected at the same site in the same operating state on the same day(s). The sites are grouped by compressor type and operational state; if at least one compressor was running, the site is classified as “operating.” The inset of Figure 3 shows the comparison for all 40 sites with simultaneous tracer flux and

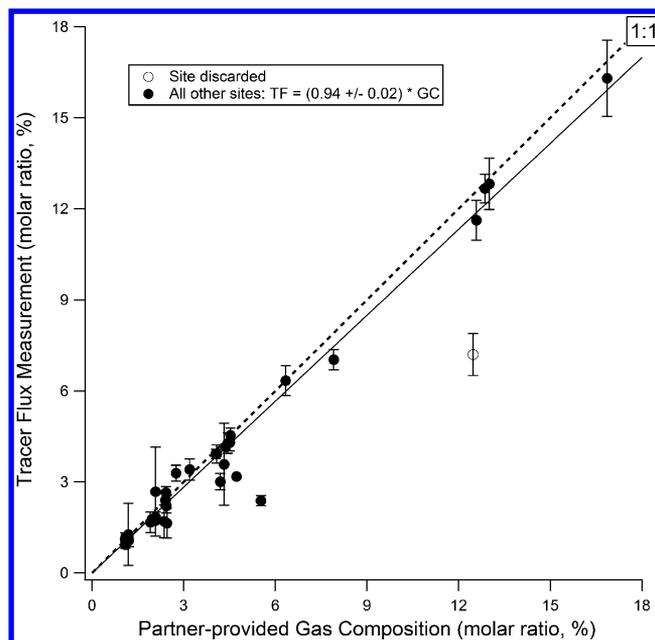


Figure 2. Comparison of ethane/methane molar ratios from partner-company-provided gas composition data with the downwind tracer flux measurements. Disregarding the one site with a known off-site interfering methane source, the two sets of data are strongly correlated ($R^2 = 0.97$).

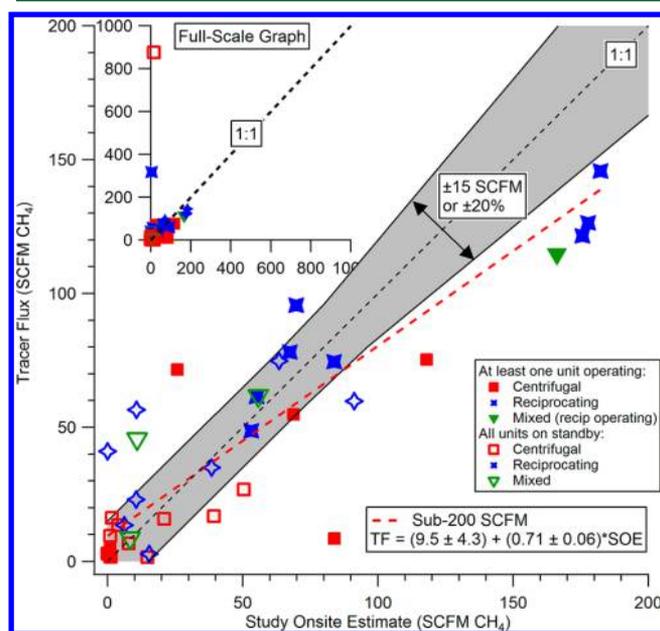


Figure 3. Comparison of the site-level tracer flux average and SOE methane emissions. The main panel shows 38 sites with emissions less than 200 SCFM, while the inset shows the full data set of 40 sites. Open symbols indicate sites where all compressors were in standby mode; solid symbols indicate sites where at least one compressor was running. Gray-shaded area indicates ± 15 SCFM or $\pm 20\%$ uncertainty bars (whichever is larger). Red dashed line is a linear fit (Deming regression) to sub-200 SCFM data.

onsite data, while the main panel shows data for the 38 sites that emitted less than 200 SCFM.

At most sub-200 SCFM sites, there is reasonable agreement between the two independent measures of site-level emissions. For example, Figure 3 shows that the onsite and tracer flux data

for the 38 sub-200 SCFM sites are scattered about the one-to-one line. At 24 of these sites, the two independent measurements agree to within ± 15 SCFM or $\pm 20\%$ (whichever is greater), and data for five other sites are within $\pm 40\%$. The average 95% confidence interval of the tracer flux data is $\pm 29\%$ (Table S9, Supporting Information). Therefore, the data from well over half the sites agree within this bound before even accounting for uncertainty in the SOE. Unfortunately, the dominant uncertainty of the SOE is likely nonparametric uncertainty of uncharacterized emissions (undetected or identified but inaccessible) rather than parametric uncertainty associated with individual measurements or instruments. This nonparametric uncertainty applies to every site (operating and standby) but is impossible to quantify. We expect that the uncertainty of the SOE at most sites to be comparable to that of the tracer flux data. Hence, the site-level emissions at essentially all the sub-200 SCFM sites likely agree within measurement uncertainty.

There appears to be a systematic trend between the two data sets for the sub-200 SCFM sites—a Deming regression yields an intercept of 9.5 SCFM and a slope of 0.71. Therefore, for this subset of sites, the tracer flux method systematically measured somewhat higher methane emission rates than the SOE at lower-emitting sites, while SOE was higher than tracer flux at higher emitting sites. No single common factor explains the discrepancies between the two data sets. Potential explanations include identified but inaccessible sources, estimated engine exhaust emissions, and potential biases in both tracer flux and onsite measurement techniques. For example, the four highest SOE sites had operating reciprocating engines (#10, #32, #44, and #45). At these sites, engine exhaust emissions estimated with AP-42 emission factors contributed 27–57% of SOE. The AP-42 emission factors may overestimate engine methane emissions at these sites; it is also possible that the downwind measurement did not fully capture lofted exhaust emissions.¹⁶ Emissions from identified but unmeasured leaks (when the emission point was not safely accessible) may be greater than the study factors used to estimate them. At some sites, the onsite team followed a GHGRP-compliant protocol (Table S2, Supporting Information) and did not measure all onsite leaks; the tracer flux data was higher than SOE at many of these sites. These and other potential factors are described in more detail in the Supporting Information.

The inset of Figure 3 indicates that the tracer flux estimate was almost two orders of magnitude larger than the SOE at two sites. At both of these sites, there were known issues with the onsite survey. Site 37 had one standby pressurized centrifugal compressor and two standby depressurized centrifugal compressors. The SOE at this site was 15 SCFM versus 880 ± 120 SCFM for the tracer flux. One of the station isolation valves at this site was frosted over and hissing, indicating a very significant leak. The onsite survey team followed a GHGRP-compliant survey and used an acoustic measurement device (VPAC) to characterize the leak at this valve, reporting a leak of only 3 SCFM. Although acoustic devices are approved by EPA to measure leaks across valves, they have been shown to substantially underestimate leak rates.¹⁰ This appears to have occurred at site 37. The other site with a very large discrepancy was site 14, a large storage facility. The SOE at this site was 4 SCFM versus 320 ± 160 SCFM for the tracer flux. This site was undergoing maintenance, during which there was significant venting of isolation valves on a pipeline from the storage field to the compressor station. However, this vent could not be

safely measured by the onsite team. Therefore, its emissions were estimated using the open ended line study factor, which likely substantially underestimated the actual venting. The partner company reported that the venting occurred for 15–20 h. The data for these two sites (37 and 14) highlight the challenges of safely performing onsite measurements of large emission sources.

DISCUSSION

Superemitters and Skewed Distributions. Figure 4, shows that the cumulative distributions of the site-level

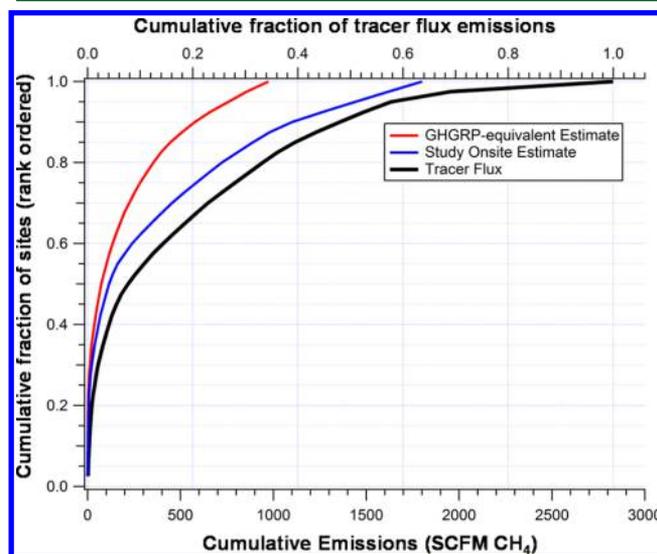


Figure 4. Cumulative distributions of site-level methane emissions from the 40 sites with both tracer flux and onsite emissions measurements obtained in the same operating state. Two different onsite estimates are shown: the SOE, which includes all measured emissions, and the GHGRP-equivalent estimates, which are based on EPA GHGRP protocols (see text for details).

methane emissions measured by this study are highly skewed with a small number of sites contributing disproportionately to the total overall emissions. For example, the highest emitting 10% of the sites contribute over 50% of the aggregate tracer flux emissions across all sites; conversely, the lowest emitting 50% of the sites contributed less than 10% of the aggregate emissions. A large fraction of this is driven by the two superemitters (sites 14 and 37) that were captured by tracer flux but not by onsite measurements. However, the SOE distribution is only modestly less skewed than the tracer flux data, with just 15% of the tested sites responsible for 50% of the cumulative SOE. Not capturing the two superemitters results in the SOE underestimating the total emissions from all sites by 35% relative to the tracer flux technique. The component-level emissions data are similarly skewed.¹²

The skewness of T&S methane emissions, which is quantified here for the first time, appears similar to other natural gas sectors. For example, 10% of the gas wells contributed nearly 70% of the emissions from 250 Texas gas wells measured as part of the Fort Worth study.^{1,9} Highly skewed emissions dominated by a small number of sites have important implications for the construction of emission inventories.⁶

Major Onsite Sources of Fugitive and Vented Emissions. Although there are differences between the tracer

flux and SOE for the 38 nonsuperemitter sites, the difference in the cumulative emissions measured by the two techniques across this subset of sites is small (9%). This means that the comprehensive onsite measurements performed by this study did not systematically miss important emission sources for this subset of sites, and that the onsite measurements can be used to identify major methane sources at these sites.

Figure 1, panel b shows the SOE for each site broken down into major source categories (data are in Tables S9 and S10, Supporting Information). The relative importance of each source category varied from site to site, and no one category was associated with every high emitting site. Compressor venting was the most important source category and contributed almost 50% of the aggregate SOE across all sites. All but two of the sites with above-average emissions had substantial compressor vent emissions. For reciprocating-only stations on standby, comprehensive onsite measurements showed significant compressor rod-packing vent emissions when at least one compressor was in the standby pressurized mode; no compressor vent emissions were observed at sites where every reciprocating compressor was depressurized. Only 14 facilities had natural-gas-driven pneumatic devices; these were not a major source of methane. There was no correlation of methane emissions with site size (as measured by either total horsepower or number of compressors). Additional discussion of the onsite data is in the Supporting Information.

The onsite measurements indicate clear trends in the study-average emissions if one controls for compressor technology (reciprocating-only versus centrifugal-only stations) or operating state (standby versus operating). Figure 1, panel b shows that sites with at least one compressor operating generally emitted more methane than sites completely on standby. Figure 5 shows that these differences are due to emissions from compressor vents and components. However, the onsite data did not capture the superemitter emissions; both superemitter sites were on standby. There are not enough data from this study to conclude whether superemitters are more commonly found in standby or operating modes.

For sites on standby, Figure 5, panel a shows that there are greater per-compressor emissions from reciprocating compressors than from centrifugal compressors, with rod-packing vent emissions from standby pressurized reciprocating compressors the main contributor to this difference. For operating sites, the emissions from centrifugal-only and reciprocating-only sites were comparable on a per-compressor basis. However, centrifugal compressors had five times the horsepower rating of reciprocating compressors in this study; therefore, centrifugal compressors have much lower methane emissions than reciprocating compressors when normalized to horsepower rating or throughput capacity. Zimmerle et al.¹² show that over the past 20 years, centrifugal compressors have become much more common in the T&S sector; therefore, these differences in methane emissions based on compressor technology have important implications for the national inventory.

Operation of reciprocating engines emitted considerably more engine exhaust methane than centrifugal compressors (Figure 1b). The study-average AP-42-based exhaust emissions for reciprocating engines were 13 SCFM/compressor versus only 0.5 SCFM/compressor for turbines.

Emissions are often expressed as a loss rate relative to the methane throughput.^{2,4,6} However, 25 of the study sites were on standby, so they had zero throughput. Figure 2 indicates that substantial (>20 SCFM) methane emissions were

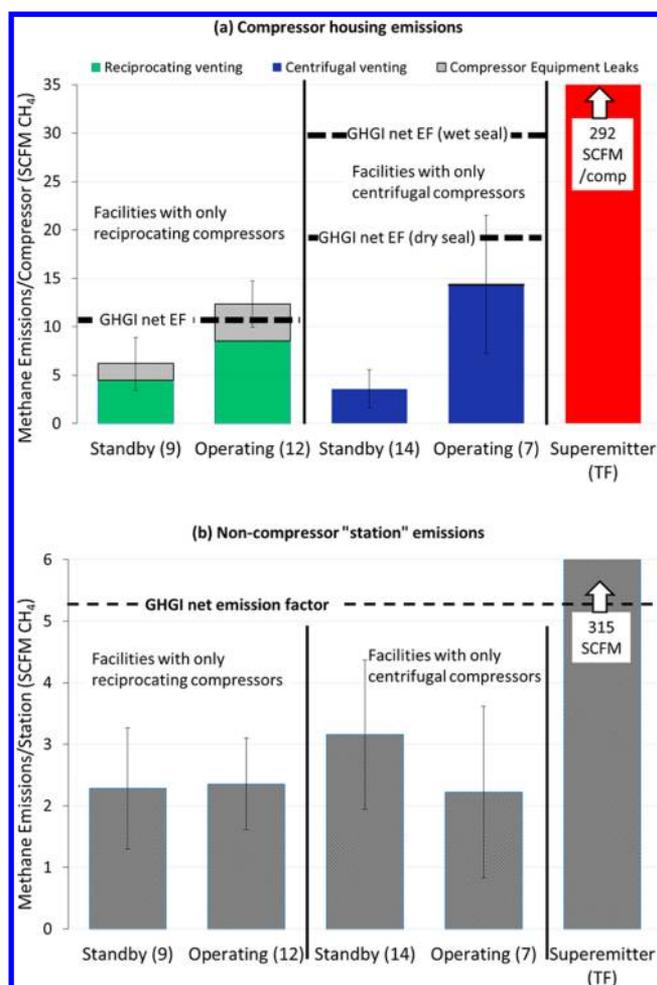


Figure 5. Study-average onsite methane emissions compared to GHGI net emission factors (EFs) for transmission compressor stations: (a) compressor housing, and (b) noncompressor sources. The left four bars in each panel are averages of onsite measurements (numbers in parentheses on the x-axis labels indicate the number of sites in each average), which did not capture the superemitter emissions. The right-most bars show tracer flux data for the two superemitter sites; these two bars extended well beyond the y-axis scales to the value listed on each panel. GHGI net emission factors for compressor stations at storage sites (not shown) are comparable or even higher than those used for transmission.¹² Both dry and wet seal centrifugal compressors were sampled in this study but are combined into one category for simplicity. GHGI net emission factors are a composite of all operating conditions, as discussed in the text. Error bars are one standard of error.

measured at about half of these sites; in fact, the two superemitter sites (site 37 and 14) were on standby. Figure 1, panel b indicates that emissions from standby sites are associated with leaky isolation valves, rod-packing vents on standby pressurized reciprocating compressors, and miscellaneous leaks from other pressurized equipment. T&S stations are often on standby in the summer when the demand for natural gas is lower. Station utilization has also been influenced by the development of new shale gas plays, such as the Marcellus, which have reduced the need to transport gas from the southeast/Texas to the northeast US.

Implications for the EPA GHG Inventory. The EPA GHG inventory for methane categorizes emissions from T&S compressor stations into compressor housing emissions,

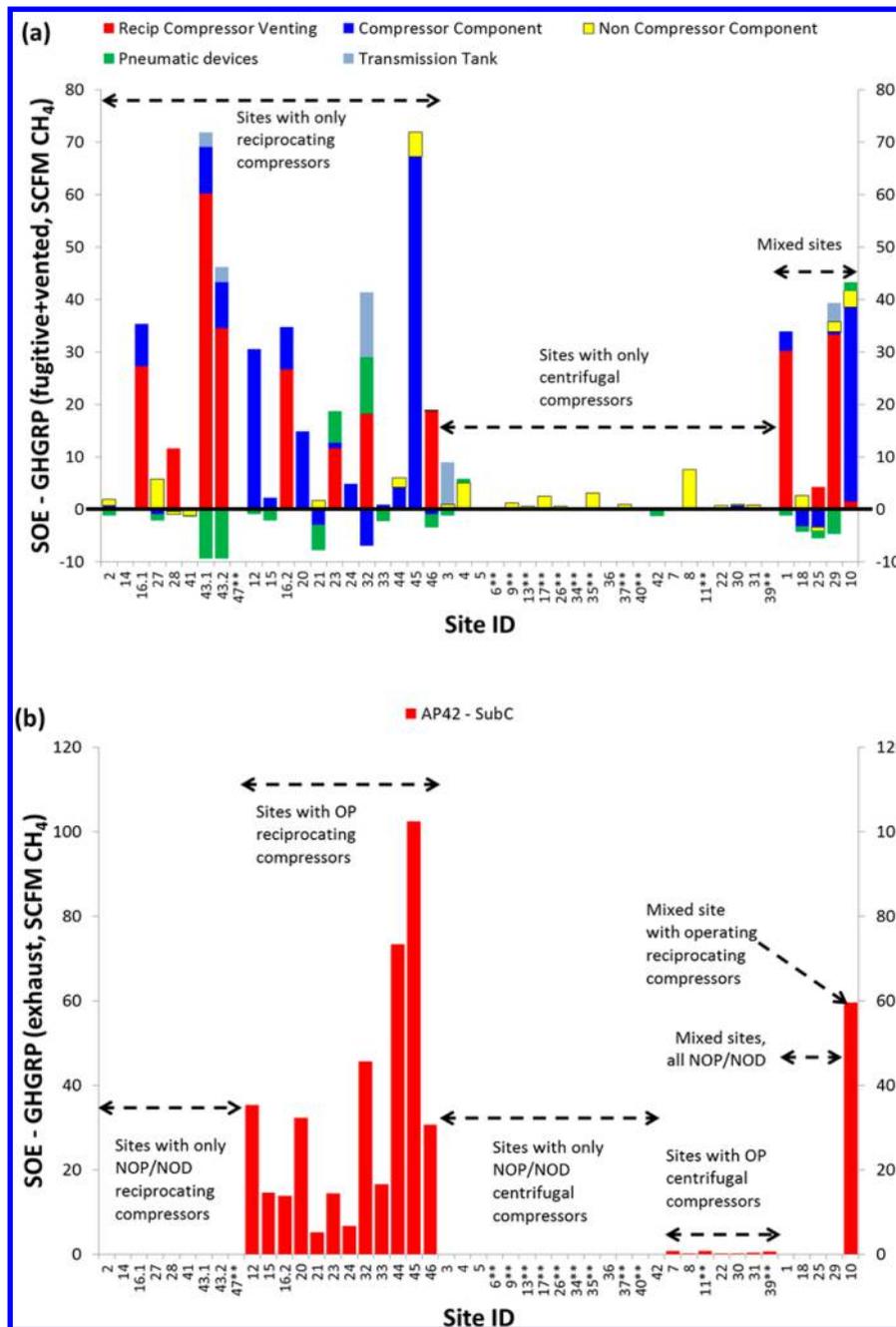


Figure 6. Differences by source category (Table S3, Supporting Information) between the SOE and the GHGRP-equivalent estimate for (a) fugitive and vented emissions and (b) turbine/engine exhaust emissions. Centrifugal compressor vents are minor (less than 0.02 SCFM per site) and therefore excluded for visual clarity in panel a. The SOE uses AP-42-based emission factors to estimate the exhaust emissions of methane, while the GHGRP exhaust emissions are based on Subpart-C. Site IDs with two asterisks indicate that the GHGRP-compliant onsite protocol was used at that site.

noncompressor “station” emissions, exhaust emissions, blow-downs, and emissions from pneumatic devices. The onsite data from this study can be used to evaluate two of these categories: compressor housing and station emissions. The EPA GHGI compressor housing emission factors are a composite of emissions from rod-packing vents (or wet seal or dry seal vents for centrifugal compressors), blowdown and isolation valves, and other compressor equipment (excluding exhaust emissions), weighted by time in operating and standby modes, by mostly using component counts and emissions measurements from the 1990s. Unfortunately, the weighting factors

used by the EPA GHGI are not well documented. This complicates making direct comparisons with the study data.

To make comparisons with our data, effective or net GHGI emission factors were derived from the 2012 GHGI by normalizing the reported net annual emissions (potential less EPA-estimated reductions) in each category by the corresponding GHGI activity. For example, in the transmission sector, GHGI estimates that 7235 reciprocating compressors emit 772.6 Gg/year of methane (activity count in Table A-129, net emissions in Table A-141 of ref 3). Therefore, the net GHGI emission factor is 107 Mg/year for each reciprocating compressor, or 10.6 SCFM (assuming 8760 h/year). The

same calculation was performed for centrifugal compressors. The EPA GHGI does not break out reductions into all categories, so reductions were proportionally distributed across the unspecified categories.¹²

To make more meaningful comparisons with the GHGI, we calculated average emissions from the study onsite data for four types of sites: reciprocating-only sites with all compressors on standby; reciprocating-only sites with one or more compressors operating; centrifugal-only sites with all compressors on standby; and centrifugal-only sites with one or more compressors operating. We also separated the study data into two categories that correspond to those used by the GHGI: compressor housing (compressor vents, valves, and other components, but not engine or turbine exhaust emissions) and station/noncompressor components (storage tanks and non-compressor housing equipment leaks). Before averaging, the compressor housing emissions from each site were normalized by the number of compressors at that site.

Figure 5, panel a compares the different study averages calculated from the onsite data for compressor components to the EPA GHGI net emission factors for reciprocating and centrifugal compressors from the transmission sector. Since the GHGI net emission factor is an annualized composite of operating and nonoperating compressors, it should be bounded by the study-average emission rates for operating and nonoperating compressors. This occurs for sites with only reciprocating compressors, which indicates that there is reasonable agreement between these two data sets for this type of compressor. However, the GHGI methane emission factors for both dry and wet seal centrifugal compressors are larger than the study-average results based on the onsite emissions measurements. The GHGI net emission factors for wet seal and dry seal centrifugal compressors are both larger than the study average of the onsite measurements at sites with operating compressors by a factor of two and 34%, respectively; the difference is even larger for study sites on standby.

Figure 5, panel b shows that study-average noncompressor methane emissions based on the onsite data are comparable across all four categories of stations, independent of compressor type as might be expected. However, the study-average data are about half the EPA GHGI noncompressor emission factor for transmission stations and one-sixth the GHGI net emission factor for storage facilities. The differences between the GHGI and study onsite data shown in Figure 5 are probably, at least partially due to technology improvements and other factors that have occurred over the past two decades.¹²

Although the comparisons with onsite data shown in Figure 5 suggest that the EPA GHGI may overestimate emissions from certain source categories, these comparisons exclude the contribution of the superemitter emissions, which were only measured by the tracer flux method. The superemitter emissions are shown using separate bars in Figure 5. Figure 5, panel a shows tracer flux data from site 37, since the high emissions at this site were likely from the compressor housing; Figure 5, panel b shows tracer flux data from site 14, where the superemitter venting was yard piping ("station" emissions). Average emissions based on this study would likely exceed the EPA GHGI net emission factors if these superemitter emissions were included in the analysis. For example, that could happen if superemitter emissions similar to those shown in Figure 5 occurred at a few percent of sites nationally. However, we lack the data to determine whether the magnitude and frequency of

the superemitters encountered in this study are representative of the entire T&S sector.

Implications for the EPA GHG Reporting Program. In 2011, the EPA started requiring compressor stations in the T&S sector that emit more than 25,000 MT-CO₂e to report their methane emissions under the EPA GHGRP, which is by far the largest effort to date to collect methane emissions data from the T&S sector. These publically available data will likely be a critical input for the next generation of methane emission inventories. The comprehensive onsite measurements in this study can be used to construct a GHGRP-equivalent estimate for the methane emissions from each study site to evaluate the GHGRP protocols.

The GHGRP-equivalent estimate uses the Subpart-W methodology for onsite fugitives and venting and Subpart-C emission factors for engine/turbine exhaust emissions. Briefly, Subpart-W estimates emissions from leaking components are based on leaker counts and emission factors; it excludes emissions from sources in certain operational modes, specifically rod-packing vent emissions from standby pressurized reciprocating compressors. Subpart-C uses a single emission factor for all engines/turbines irrespective of the prime mover type, unlike AP-42, which has specific emission factors depending on engine type (rich burn or lean burn, two-stroke or four-stroke reciprocating engines, and turbines). Methodological differences between the GHGRP-equivalent estimate of site-level emissions and SOE are summarized in Table S3 of the Supporting Information.

Figure 6 shows the source-category-by-source-category differences between the SOE and the GHGRP-equivalent estimate across all study sites. The aggregate SOE for the 45 sites was 2097 SCFM versus only 1148 SCFM for the aggregate GHGRP-equivalent estimate. Since only 25 sites exceed the annual 25,000 MT-CO₂e GHGRP reporting threshold (which is largely determined by fuel combustion CO₂, not methane), the aggregate GHGRP-equivalent methane emissions drop further to 790 SCFM. Therefore, only 38% of the aggregate SOE would be reported under the current EPA GHGRP rules. In addition, the onsite measurements did not capture the two superemitters, so the bias is even larger relative to the total emissions. Only 27% of the aggregate tracer flux methane emissions would be reported under the current GHGRP due to a combination of the GHGRP rules, the GHGRP reporting threshold, and gaps (superemitters) in the onsite measurements.

The 45% difference between the aggregate GHGRP-equivalent estimate and the aggregate SOE for all study sites was almost evenly divided between fugitive/vented emissions and exhaust emissions. Figure 6, panel b indicates that there are very large differences between the AP-42 and Subpart-C methane emission factors for reciprocating engines (0.8 SCFM for Subpart-C versus 451 SCFM using AP-42 emission factors). Therefore, Subpart-C significantly underestimates the unburned methane in reciprocating engine exhaust emissions. Reciprocating engines, in particular two-cycle engines, can emit significant methane due to cyclic combustion, piston ring blow-by, etc.,¹⁸ while modern turbine combustors operate with 99% or higher combustion efficiency.¹⁹

Figure 6, panel a shows large differences between the GHGRP-equivalent estimate and the SOE for fugitive/vented emissions. A major cause of this difference is that the EPA GHGRP does not (as of 2014) require reporting of rod-packing vent emissions from standby pressurized reciprocating

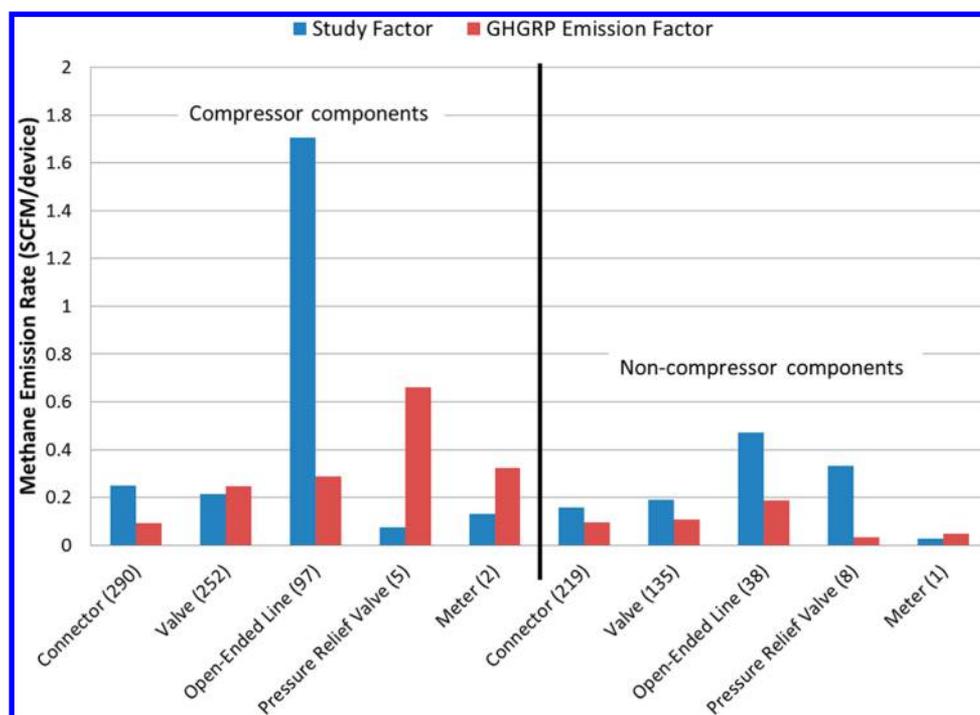


Figure 7. Comparison of the study-average emissions factors (study factors) with the EPA GHGRP emission factors for compressor and noncompressor component sources. Numbers in parentheses on the *x*-axis labels indicate number of study measurements in each category.

compressors. These vents contributed 273 SCFM (13%) to the aggregate SOE and therefore represent an important gap in the GHGRP protocol. Outdated GHGRP emission factors for component leaks account for most of the remaining gap between the measured fugitive/vented emissions and the emissions reportable under GHGRP. For example, Figure 7 indicates that the study-average emission factor for compressor connectors is three times the GHGRP emission factor; the study-average emission factor for open-ended lines is six times larger than the GHGRP emission factor. The study average measurements of leaks from noncompressor connectors and open-ended lines are also larger than the corresponding GHGRP emission factors.

The EPA GHGI does not yet utilize the information in the GHGRP database. This database provides valuable new information on the T&S sector in terms of compressor types, component counts, and other activity factors that are relevant to an emissions inventory. However, before using the GHGRP for inventory calculations, one must account for all the biases and uncertainties in the emissions data shown in Figures 4 and 6; this is done by Zimmerle et al.¹² The value of the GHGRP data for emissions inventory development would be improved by requiring more direct measurements of emissions (as opposed to using counts and emission factors), avoiding the use of acoustic devices, eliminating exclusions such as rod-packing vents on standby pressurized reciprocating compressors, and using more appropriate emission factors for exhaust methane from reciprocating engines.

■ ASSOCIATED CONTENT

⑤ Supporting Information

Description of the 45 study sites; comparison of the annual GHGRP emissions reported for the study sites with the corresponding data for the Partner fleet of compressor stations; methodological details for the onsite emissions measurements,

the EPA GHGRP, and tracer flux; and site-level onsite and tracer data presented in this manuscript. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Notes

The authors declare no competing financial interest.

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Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results

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S Supporting Information

ABSTRACT: Facility-level methane emissions were measured at 114 gathering facilities and 16 processing plants in the United States natural gas system. At gathering facilities, the measured methane emission rates ranged from 0.7 to 700 kg per hour (kg/h) (0.6 to 600 standard cubic feet per minute (scfm)). Normalized emissions (as a % of total methane throughput) were less than 1% for 85 gathering facilities and 19 had normalized emissions less than 0.1%. The range of methane emissions rates for processing plants was 3 to 600 kg/h (3 to 524 scfm), corresponding to normalized methane emissions rates <1% in all cases. The distributions of methane emissions, particularly for gathering facilities, are skewed. For example, 30% of gathering facilities contribute 80% of the total emissions. Normalized emissions rates are negatively correlated with facility throughput. The variation in methane emissions also appears driven by differences between inlet and outlet pressure, as well as venting and leaking equipment. Substantial venting from liquids storage tanks was observed at 20% of gathering facilities. Emissions rates at these facilities were, on average, around four times the rates observed at similar facilities without substantial venting.



■ INTRODUCTION

Methane is the primary component of natural gas; it is also a potent greenhouse gas (GHG). The Environmental Protection Agency (EPA) estimates that the natural gas system contributes 23% of U.S. anthropogenic methane emissions.¹ However, there are discrepancies between recent studies and EPA GHG inventories in some natural gas producing areas.^{2–4} The EPA GHG inventories largely rely on data collected in the early 1990s⁵ and may not reflect recent changes in technology, operations, and regulation. New measurements are needed to characterize methane emissions from the natural gas system.

This study investigates the methane emissions from natural gas gathering and processing (G&P) facilities, which, collectively, gather natural gas from production wells, remove impurities, and deliver it to inter- and intrastate pipeline networks. We define gathering and processing as the equipment and pipeline network between the sales points at well pads and downstream delivery points. This includes gathering pipelines, and the equipment at gathering facilities: compressors (driven by electric motors (“motors”) and/or natural gas-fired internal combustion engines (“engines”) or turbines), dehydration

systems to remove water, and treatment systems to remove hydrogen sulfide and/or carbon dioxide. Processing plants often house this equipment on a larger scale, acting as central nodes in a system of smaller gathering facilities. Processing plants also separate natural gas liquids (NGLs) (such as ethane, propane, butane, and heavier hydrocarbons) from methane. For this study, processing plants are defined as the facilities that meet the 40 CFR Part 60 Subpart KKK definition of “natural gas processing plant” based on the presence of NGL extraction. Facilities that only fractionate NGLs were not included in this study.

This paper presents facility-level measurements of methane emission rates at 130 G&P facilities (114 gathering and 16 processing). A mobile laboratory was used to perform downwind tracer flux measurements, which is an established technique to estimate the total emissions of methane (or other

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Figure 1. Locations of G&P facilities measured in this study. Numbers indicate the number of facilities sampled within outlined (red) oil and gas basins as defined by the American Association of Petroleum Geologists.²⁶ G&P facilities were sampled in each of the orange-colored states (www.map-generator.org).

species) from complex facilities with multiple emission points.^{6–8} Onsite observations with an infrared camera were used to identify emission sources. Companion papers describe the downwind tracer flux methodology and its application to this study⁹ and scaling of these data to estimate emissions for all U.S. G&P facilities.¹⁰

2. METHODS

Downwind tracer flux measurements were conducted at 136 G&P facilities between October 2013 and April 2014. Measurements were successful at 130 G&P facilities. These facilities are located in top gas producing states (including all of the top ten) and basins (Figure 1). The sampled facilities were operated by five natural gas midstream “partner” companies, which provided access and facility data to the study team. The project only investigated emissions from G&P facilities, not the gathering pipeline network that connects these facilities.

2.1. Selection of G&P Facilities for Measurement. The sampling strategy sought to obtain methane emissions data from a wide range of G&P facilities, which vary by age (reflecting technological and regulatory changes), inlet gas composition/pressure, regulatory environment, and regional/local and/or corporate design and operations. In most states, the basic census data needed to design a sampling program that systematically captures variation among G&P facilities are lacking. Therefore, the study team sought to replicate the diversity among G&P facilities owned by the five partner companies. They operate more than 700 gathering facilities and 27 processing plants in all regions of the country—roughly one-quarter and 5%, respectively, of all gathering and processing facilities nationally (Supporting Information (SI) A). All of these facilities were considered by the study team in developing the project sampling plan. This plan sought to (1) sample at the maximum number of processing plants, (2) maximize the number of successful measurements in the top gas producing

regions and across all major gas types (e.g., shale, coal bed methane, etc.), and (3) sample a distribution of facility types representative of the partner company assets.

Details of the facility selection procedures are in SI A. Briefly, the study team was provided a list of all partner company G&P assets (>700 facilities). The study team performed desktop screening of the facilities using aerial imagery (Google Earth) to remove facilities with limited road access on their periphery (desired range of 0.5–2 km) or facilities that were located near obvious potential sources of methane interference. The list of prescreened facilities was then shared with partner companies, with a request for additional feedback regarding potential issues with road access or nearby nonpartner facilities, as needed. Over the course of the field campaign, fewer than ten facilities were removed from the prescreened lists by request of the partner companies. Reasons for removal included issues such as commissioning, decommissioning, transactions (sale of asset), construction, or litigation. Final selection for most gathering facilities was made by the study team from the prescreened list the evening before or the day of sampling, considering road access, wind forecasts, and logistics. Sampling at processing plants was scheduled in advance to align with operator and operations schedules.

The tracer teams were usually escorted to the target facilities by a company representative who was instructed to continue normal operations of the facility. At 14 facilities the study team onsite observer noted that the company personnel adjusted processes or fixed equipment during the sampling, presumably these changes were performed as part of normal operations (SI E). At only one facility (#44) did a tracer team note changes in facility operation that were likely not normal practice as the changes were undone after measurements had been completed. Company representatives were notified. All indications are that this was an isolated occurrence.

Partner company gathering assets were classified based on three equipment-specific functions in gathering systems

Table 1. Summary of Sampled Facilities and Partner Assets (total and %) by Facility Type^a

| | facility type | | | | | | | | | | | |
|----------------|---------------|-----|-----|-----|-------|----|----|----|-----|----|----|-----|
| | C | | C/D | | C/D/T | | D | | D/T | | P | |
| sampled | 34 | 26% | 66 | 51% | 8 | 6% | 5 | 4% | 1 | 1% | 16 | 12% |
| partner assets | 267 | 36% | 379 | 51% | 16 | 2% | 23 | 3% | 28 | 4% | 27 | 4% |

^aC, compression only; C/D, compression and dehydration; C/D/T, compression, dehydration, and treatment; D, dehydration only; D/T, dehydration and treatment; and P, processing.

(compression (“C”), dehydration (“D”), and treatment (“T”)) into five facility types (C, C/D, C/D/T, D, and D/T). Table 1 summarizes facility types sampled by the tracer teams compared to all partner company G&P assets as of August 2013. The distribution of facility types sampled in this study closely resembles the partner assets. The study facilities are also similarly proportioned to lower-48 U.S. gas production:¹¹ Fifty-two percent of the study facilities handled shale gas, 32% conventional, 8% coal-bed methane, 6% tight sands, and 2% offshore.

Detailed information on all 130 G&P facilities is included in SI B, Tables S1–S3. Sampling was conducted at 34 C facilities, which had reciprocating and/or centrifugal compressors. Engines were the primary driver at 31 of the C facilities. Scrubbers, strainers, filter separators, and/or coalescing filters were usually installed upstream of compressors. Produced water and condensate removed from the gas stream were stored in tanks onsite. Air and/or gas pneumatic devices (e.g., liquid level controllers) were also present at all G&P facilities.

Sampling was conducted at 66 C/D facilities, which had dehydration equipment installed downstream of compressor(s) to remove vapor-phase water from the pressurized gas stream, reducing problems with hydrate formation and corrosion.¹² These were typically glycol dehydration systems which operate by contacting the gas stream (via absorbers) with a hydroscopic solvent (usually triethylene glycol), which is regenerated (by heating) and reused.¹³

Sampling was performed at five D only facilities, which represent 4% of partner gathering assets. These removed vapor-phase water from gas produced at nearby wells that had sufficient pressure to move downstream without compression.

Treatment (T) equipment was installed at gathering facilities that handle a raw gas stream rich in acidic gases, carbon dioxide (CO₂) and/or hydrogen sulfide (H₂S). Acid gas removal is based on absorption with one or more amine variants, separation, and regeneration of the amine solution. Treatment equipment were utilized at 6% of partner facilities. Eight C/D/T facilities and one D/T facility were sampled, representing 6% and 1% of study facilities, respectively.

Processing plants (P) are central nodes in most producing areas. They are generally much larger than the typical gathering facilities and are staffed by operators 24 h a day. Compression, dehydration, and treatment equipment are typical for processing plants. These plants also include equipment to separate natural gas liquids from the methane gas stream, such as cryogenic turboexpander and refrigeration skids. These plants will sometimes use fractionation processes to further separate high-value natural gas liquids into separate components of ethane, butane, propane, and hydrocarbons larger than pentane. The study team ruled out conducting measurements at 11 (out of 27) processing plants mainly due to the presence of interfering natural gas facilities (usually other processing plant(s)) owned by a different company.

Figure S1 (SI C) compares facility throughput, inlet and outlet pressure, and total horsepower for C, C/D, C/D/T, and P facilities. The C facilities included in this study had generally lower throughput, inlet and outlet pressures, and horsepower than the other types of facilities with compressors. Methane content ranged from 59% to 98% (mol/mol) across all facilities, but was not related to facility type. Gas composition data are summarized in SI C, Figure S2.

Despite efforts to prescreen facilities, the study team conducted measurements at 29 facilities that were either collocated (e.g., on the same pad or side-by-side) with nonpartner equipment or adjacent to other natural gas facilities. Nonpartner equipment was generally associated with gas production (e.g., wellheads, produced water and/or condensate tanks, flares, etc.). Both infrared camera surveys and proximal mobile lab measurements (immediately downwind of equipment) were performed to assess potential contribution of nonpartner equipment. At most facilities with nonpartner equipment, the methane contribution from such equipment appeared to be negligible in comparison to partner-operated equipment. Therefore, methane emissions estimates have not been modified to account for potential emissions from collocated nonpartner equipment. Facilities with collocated equipment and information on this equipment are summarized in SI D, Table S4.

2.2. Tracer Flux Measurements and Facility Survey.

Roscoli et al.⁹ describes the tracer flux methodology used by this study in detail. Briefly, at each facility, two tracer gases (nitrous oxide and acetylene; both chosen based on their availability and ability to be measured at high time-resolution) were released at known flow rates from points configured to bracket the target facility’s emissions relative to prevailing wind direction (SI G, Figure S3). Concentrations of methane, ethane, acetylene, nitrous oxide, carbon monoxide, and carbon dioxide were measured using a mobile laboratory equipped with high time resolution instrumentation (1-Hz or faster, Aerodyne QC-TILDAS and/or Picarro cavity ring-down spectroscopy).⁹ Measurements were made immediately upwind of each target facility to check for background contamination. Methane plumes were measured approximately 0.5–3 km downwind from the target facility. Multiple plume profiles, each about 30–120 s long, were obtained for each facility by driving the mobile laboratory at a constant speed on a road roughly perpendicular to the wind direction. When the winds were highly variable, plumes were sometimes measured while the mobile lab was stationary. Downwind measurements in the mobile lab were performed over 1–5 h period at most facilities.

While tracer flux measurements were being performed, a dedicated member of the study team served as an “onsite observer,” who documented the initial operating state of the facility and any changes or repairs that were made (SI E, Table S5). The onsite observer also performed a comprehensive survey of the facility, including recording an equipment census (operational state and characteristics such as horsepower), and

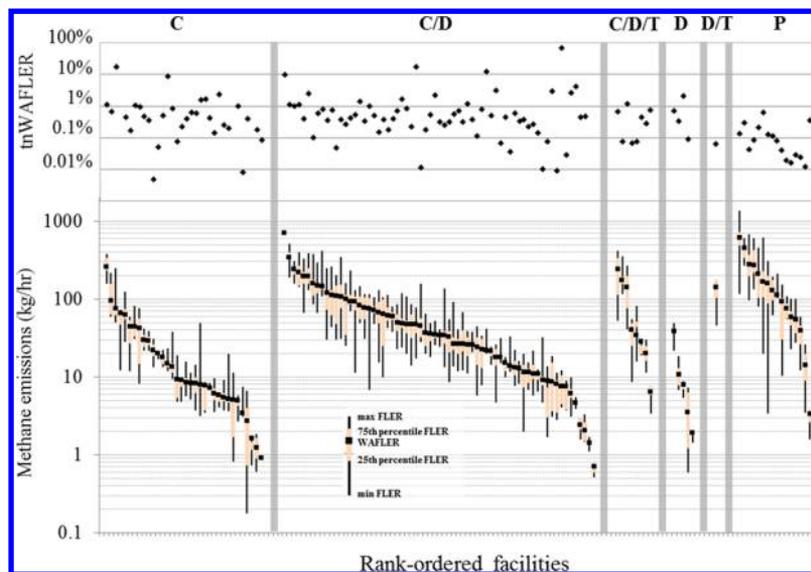


Figure 2. Tracer flux-based facility-level methane emission rates (FLER) for 130 G&P facilities. Facilities are sorted by type (C, D, C/D, etc.) and then rank ordered by WAFLER (square) within each facility type. Emissions are presented in log scale. The vertical boxes represent the 25th and 75th percentiles of FLER data at a facility; whiskers represent the min and max. Throughput-normalized methane emissions rates (tmWAFLER) for 124 facilities (as % CH₄ throughput on the day of sampling) are presented in the top panel in log scale.

readings of facility throughput, inlet and outlet gas pressure (SI B, Tables S1–S3). At 108 of the gathering facilities, the onsite observer also performed an infrared camera survey of all equipment to identify and document potential sources noncombustion methane emissions (SI F, Table S6). Gas composition data (% methane, ethane, etc.) were obtained from company records (SI B, Table S1).

2.3. Analysis of Tracer Flux Data. The tracer flux data were analyzed systematically to quantify the methane emission rate, ensure proper attribution of methane emissions to target facility, and validate codispersion of tracer(s) with methane. The methane facility-level emission rate (FLER) was calculated for each downwind plume based on tracer release rate and the background-corrected methane-to-tracer concentration ratios.⁹ No modeling of pollutant dispersion is required—that complexity is empirically captured by the tracers. Therefore, the FLER is an estimate of the aggregate (or total) methane emissions from the target facility during a 30–120 s period (the typical duration of a plume transect). Roscioli et al.⁹ describes the types of plumes measured, the acceptance criteria, and the process used to analyze each plume.

Multiple downwind plumes were obtained at each facility and the FLER was estimated for each plume. The weighted-average FLER (WAFLER) was calculated by weighting each FLER estimate by its estimated plume-specific uncertainty ($1/\sigma^2$), providing more weight to the plume types meeting the most stringent acceptance criteria.⁹ The weighted sample variance of WAFLER was divided by a correction factor $[1 - ((\sum_{i=1}^n w_i^2) / (\sum_{i=1}^n w_i)^2)]$ to obtain the unbiased weighted sample variance, where w_i represents the weight of each plume. Complete results, including number of accepted plumes, distance downwind, 25th, 75th, minimum and maximum FLER, WAFLER, and the unbiased standard deviation of WAFLER are in SI H, Tables S7–S8. All emissions results are presented as grams CH₄ (19.26 g per standard cubic foot CH₄ at 15.6 °C and 1 atm¹⁴).

Sampling occurred at one gathering facility in two distinct operating states, before and after substantial venting from a

pipe at the top of a tank storing liquids was stopped. The venting was stopped by closing a dump valve on the first stage scrubber that was stuck open. Two WAFLER estimates are reported for this facility (#s 35 and 59), based on the before and after measurements, respectively.

The tracer flux method assumes that the tracer gases codisperse with the methane being emitted from the target facility. Since the tracer release points were set up to bracket the facility, the use of two tracers provides a stringent test on the horizontal dispersion of the emissions. 75% of accepted plumes were dual tracer, covering 112 facilities (83% of the gathering facilities and 100% of the processing plants). Codispersion of tracer gases with methane emissions from elevated vents, flares, and exhaust stacks in the vertical plane is more difficult to verify. Roscioli et al.⁹ modeled tracer codispersion with the exhaust of natural gas-powered engines and turbines using Gaussian dispersion modeling with Briggs plume rise equations.^{9,15} Exhaust is discharged at high temperatures (up to 540 °C) and high velocities (up to 45 m/s). A conservative, worst-case analysis suggests the potential bias in WAFLER from low recovery of methane emissions in engine or turbine exhaust is small (<30%) for almost four-fifths of the G&P facilities in this study (SI J). Processing plants (but typically not gathering facilities) can also have elevated flares, vents, or other emissions sources; the potential bias due to partial recovery of methane from these sources was not examined in this study.

3. RESULTS

The study team recorded more than 1400 plumes which passed the acceptance criteria⁹ and therefore provided a valid measure of the facility-level emission rate (FLER) of methane. Roscioli et al.⁹ provides plots of example plume profiles. Within a plume, methane concentrations are tens to thousands of ppbv above background. The average number of plumes per facility is 11 with a range of 2–42. Each plume provides a short snapshot of the facility-level emissions over the duration of the plume transect (30–120 s). The plume-to-plume differences in the

FLER values provide a measure of the variability of the methane emissions at a given facility.

Figure 2 presents box-and-whisker plots of the accepted plumes for all 130 facilities (131 WAFLEs). The facilities have been sorted by type (C, D, C/D, etc.) and then rank ordered by WAFLE within each facility type. Methane (CH₄) throughput (tonnes/h) was calculated from natural gas throughput (tonnes/h) recorded onsite and the inlet gas composition data provided by the companies. The CH₄ throughput-normalized WAFLE (tnWAFLE), ratio of WAFLE to the CH₄ throughput, is also plotted in Figure 2 for 124 facilities (125 tnWAFLE estimates; five facilities had zero throughput and no throughput data were recorded at one facility).

Across all 114 gathering facilities, WAFLE ranged from 0.7 to 700 kg/h, while tnWAFLE ranged from 0.004% to 70% for the subset of the facilities with nonzero/known CH₄ throughput ($n = 108$). The WAFLE estimates varied widely within and across facility types. However, in general, the plume-to-plume variability in FLER estimates at a given facility is relatively small; the median relative standard deviation or coefficient of variation (CV) is 0.36 and more than two-thirds of the facilities had CVs less than 0.5. This suggests that the emissions from most facilities were relatively stable over the several hour measurement period. The CV at 11 facilities is >0.8. Large CVs may be associated with intermittent sources (e.g., pressure relief valves) and/or changes in facility operation. For example, FLER estimates at Facility #102 (CV 0.62) were much higher after the onsite observer documented increased flame height and smoke production at the flare as well as significant flashing events at the condensate tank batteries. This facility was shut down for maintenance after measurements were completed. At five facilities, a brief methane release event was observed which was associated with specific operations such as a compressor blowdown or startup. All of these events that were measured are cataloged in SI Table S9. They only occurred for a small fraction of the overall measurement period and therefore were not included in the WAFLE calculations.

WAFLE estimates for C/D and C/D/T are higher than those C and D facilities. For example, the median WAFLE for C and D facilities are 8.8 and 7.8 kg/h, respectively, while those of C/D and C/D/T facilities were 35 and 37 kg/h, respectively. However, across the gathering facility types there are no systematic trends in the tnWAFLE because C/D and C/D/T facilities also have higher throughputs. Median tnWAFLE for C, C/D, C/D/T, and D facilities are 0.46, 0.45, 0.36, and 0.51% of CH₄ throughput, respectively.

Figure 2 indicates that methane emissions are generally a small fraction of CH₄ throughput. tnWAFLE is less than 1% at 85 (out of 108) gathering facilities and less than 0.1% at 19 of them. tnWAFLE exceeded 5% at six gathering facilities (two C and four C/D). Five of these had very low CH₄ throughput (<0.5 tonnes/h). The exception is facility #35 (throughput: 7.7 tonnes/h), which was venting a substantial amount of gas when sampling started. At facility #94, which had the highest tnWAFLE (70%) and the lowest throughput (1.4 × 10⁻² tonnes/h), a substantial leak from a pipe union was observed.

Median WAFLE and tnWAFLE of the 16 processing plants are 120 kg/h and 0.079%, respectively. With one exception, the processing plants were high CH₄ throughput facilities, averaging 250 tonnes/h on the day of measurements (range 1.6–780 tonnes/h; SI B, Table S2). WAFLE at processing plants ranged from 3 to 600 kg/h. tnWAFLE for

processing plants were lower than for gathering facilities, ranging from 0.012% to 0.62% of CH₄ throughput.

Partial recovery of lofted emissions is a concern at processing plants, most of which had high flares as well as elevated exhaust stacks, vents, and other components that may emit methane. Using previously mentioned dispersion modeling, we estimate that, under conservative, worst case assumptions, only two (out of 16) processing plants may have >30% bias in WAFLE due to low recovery of uncombusted methane in engine and/or turbine exhaust (facility #'s 123 and 126, SI J). The potential bias due to low recovery of exhaust methane at processing plants is lower than gathering facilities because the majority of the compression power at processing plants in this study was provided by turbines or motors, which have much lower exhaust methane emissions than engines.^{16,17} For example, all of the compressors at four other processing plants were driven by either turbines (facility #'s 118, 127, and 129) or motors (facility #125). Therefore, low recovery of exhaust methane for these plants is a small issue despite the fact that all of the tracer flux measurements were performed <0.5 km downwind from these plants, which was not optimal for codispersion of lofted methane and tracers. A larger concern may be methane emissions associated with high flares and elevated vents or leaks, but these have not been investigated by this study.

The cumulative methane emissions rate summed across all 114 gathering facilities in this study was 6300 kg/h with a cumulative tnWAFLE (\sum WAFLE/ \sum CH₄ throughput) of 0.20%. Cumulative methane emissions from all 16 processing plants was 2,700 kg/h, with a cumulative tnWAFLE of 0.075%. Accounting for potential biases in WAFLE due to uncombusted methane emissions from gas-driven engines and turbines only has a small impact on cumulative emissions (SI J). For example, adding the conservative, worst-case estimate of unrecovered exhaust methane to WAFLE would lead to cumulative methane emissions from all gathering facilities to 7400 kg/h, versus 6300 kg/h previously, and increase the cumulative tnWAFLE from 0.2% to 0.24%. Unrecovered exhaust methane emissions from processing plants would increase from 2700 kg/h to 3100 kg/h, and cumulative tnWAFLE would increase from 0.075% to 0.085%. While recovery of methane emissions from high flares or elevated sources common at processing plants is uncertain, it seems unlikely that such emissions could be large enough to significantly alter normalized emissions at high-throughput processing plants.

Five gathering facilities (#4, 28, 32, 100, and 101) had zero throughput, but were still emitting methane (65, 5.1, 1.6, 1.4, and 0.7 kg/h, respectively). The highest WAFLE (65 kg/h) at a zero-throughput facility was attributed to atmospheric venting from two liquids storage tanks via infrared camera survey. Unlike the other zero-throughput facilities, facility #4 was flowing gas before measurements began. Emissions at the other zero throughput facilities were observed from various sources, including venting from a liquids storage tank and an engine fuel purge (facility #28) and a broken hose leading to a nonoperational pressurized (NOP) compressor (facility #32). The only sources of methane emissions observed at facility #101 with the infrared camera were collocated nonpartner equipment (a dehydration unit and a fuel scrubber).

4. DISCUSSION

4.1. Comparison to Existing G&P Emissions Data.

Relatively little data have been published on methane emissions

from G&P facilities. One of the GRI/EPA studies reported methane emissions at seven processing plants in the TX/LA and West regions.^{8,18} More recent measurements, using comprehensive onsite measurements (including exhaust methane), have been made at nine processing plants.^{19,20} The reported methane emissions rates ranged from 45 to 840 kg/h (this study: 3–600 kg/h CH₄). The cumulative throughput-normalized methane emissions rate was 0.16% versus 0.075% for the 16 plants reported here. Higher normalized emission rates were reported in the GRI/EPA study, which also used the tracer flux method. The cumulative methane emissions rate normalized by cumulative plant capacity (throughput data were not given) for the GRI/EPA data was 0.38%. This is likely a lower bound estimate because processing plants may operate below rated capacity.

Even fewer data are available for gathering facilities. The GRI/EPA study measured methane emissions from two gathering facilities of 86 and 120 kg/h (this study: <1 to 700 kg/h CH₄). No throughput or capacity data were reported for GRI/EPA facilities, precluding comparison of normalized emission rates. Measurements were performed at seven gathering facilities between 2004 and 2005, but only summary data were reported.²⁰ The raw data from previous studies are reproduced and additional comparisons are made in SI K.

All of the processing plants included in this study have reported methane emissions to the EPA greenhouse gas reporting program (GHGRP, 40 CFR 98, Subpart W and Subpart C). Valid comparisons of WAFLER to GHGRP are not possible due to a range of issues in how emissions are calculated under GHGRP. For example, GHGRP does not require reporting of all onsite methane emissions sources (including tanks, acid gas removal units, and gas-driven pneumatics); it excludes other sources in certain operating modes, such as rod-packing vents from NOP reciprocating compressors; and it includes blowdown emissions.²¹ Furthermore, combustion emissions reported under Subpart-C may not provide a realistic characterization of uncombusted methane from operating engines.²²

4.2. Sources of Methane Emissions. Figure 3 indicates that there is some relationship between WAFLER and tnWAFLER and facility natural gas throughput. The absolute methane emissions are generally higher at facilities with larger throughput, but the normalized methane emissions rates (tnWAFLER) generally decrease with increasing natural gas throughput. The opposite relationship of WAFLER and tnWAFLER with throughput (Figure 3) indicates that some of the methane emissions are likely independent of throughput. A leak, for example, may emit the same amount of methane whether the facility is at full or partial capacity.

One-third of the variance ($r^2 = 0.38$) in WAFLER is explained by linear regression with throughput, Figure 3(a). Although throughput explains some of the trend in the emissions data, WAFLERs vary by about an order of magnitude at facilities handling similar volumes of gas. This underscores that there are many factors influencing emissions. Numerous noncombustion emissions sources were documented by the onsite observer via infrared camera survey, which was conducted at 108 gathering facilities (infrared cameras were not used at processing plants, which are subject to regular leak detection and repair (LDAR) for regulatory compliance). Observable emissions sources (leaking and/or venting) were noted at 71 out of 108 gathering facilities (SI F, Table S6). This included venting (flashing and off-gassing) from liquids storage

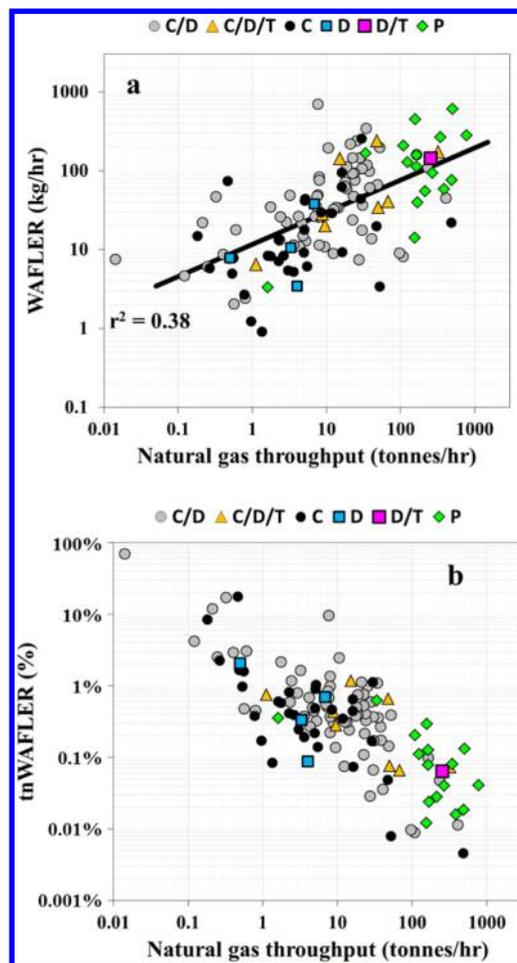


Figure 3. (a) WAFLER and (b) tnWAFLER (% CH₄ throughput) versus reported natural gas throughput on the day sampling was conducted in log–log scale. The line in (a) is a linear regression of the data.

tanks at 48 facilities, leaking or venting from compression equipment at 42 facilities, and gas pneumatics at 28 facilities.

On the basis of the infrared camera videos and other onsite information, a subset of the observed noncombustion emission sources have been classified as substantial (SI M, Tables S17 and S18). These specific sources appeared to be emitting substantially more methane than other sources of the same type (e.g., valves and vents). Since the infrared camera only provides a qualitative indication of the magnitude of the emissions, classification of a source as substantial also involved discussion with company representatives and, if possible, proximal methane measurements using the mobile laboratory. The onsite observer and/or company representative was often able to identify the substantial emission sources without the aid of an infrared camera.

Venting from liquids storage tanks was the most common noncombustion source classified by the onsite observer. It is normal for some flashing or off-gassing from stored liquids to occur. Tank venting, however, may not have always been caused by an issue with the liquids storage tanks themselves, but to a problem elsewhere on the facility (e.g., the stuck dump valve mentioned earlier) that was connected to the tanks. Of the 48 gathering facilities with observable venting from liquids storage tanks, substantial venting from tanks was observed at 23 (SI M). Abnormal process conditions were identified at six of

the 23 facilities. Through the strategic placement of the tracer release locations, the methane emissions rates from liquids storage tanks were estimated at five facilities with substantial venting. These tank-related methane emissions ranged from around 10 to 650 kg/h (SI Table S17). At three gathering facilities (#38, 61, and 76) a company representative made adjustments that had a noticeable impact on tank venting (SI Table S5). Other substantial sources included leaking valves and pipe unions, venting from the dehydrator, and compressor crank case/rod packing vents (SI Table S18). Some of the issues observed in the field (e.g., stuck valves or open thief hatches) that were causing substantial methane venting were addressed by the company representative without interrupting operations. At a few facilities, emissions sources had already been tagged (usually a ribbon) by prior inspections but the issue had not yet been addressed.

Multiple linear least-squares regressions were performed to quantify the contribution of different factors to the WAFLER at gathering facilities (SI M). Only gathering facilities with positive throughput were included in the regression. Variables describing engine and turbine horsepower, facility throughput, and pressure were significant in all models tested. The independent variables in the final regression model were natural log of throughput, delta pressure, and dummy variables for facilities with turbine-driven compressors ($n = 7$) and facilities classified with substantial venting from liquids storage tanks ($n = 22$; one facility with substantial tank venting had zero throughput). Horsepower was not included in the final model because it was highly correlated with throughput, which made the individual contribution of these variables difficult to resolve. The adjusted r^2 of this model is 0.67 and the Root Mean Square Error is 0.754 (diagnostic plots in SI M, Figures S8–S11).

For the 22 gathering facilities flagged by the onsite observer for substantial methane emissions from liquids storage tanks, the average WAFLER is 300% higher than nonflagged facilities. In other words, facilities classified as having substantial methane emissions from liquids storage tanks (~20% of gathering facilities) have around four times the methane emissions than similar, nonflagged facilities.

The regression model also indicates that the WAFLER at facilities with turbine-powered compressors was, on average, 75% lower than at facilities with only engine-powered compressors. The cumulative \ln WAFLER among the seven facilities with turbines is <0.01% of CH_4 throughput. It is not known if the lower emissions at these facilities were due solely to the use of turbines, which have much less exhaust methane than engines, or if it is indicator for some other characteristics of facilities equipped with turbines. Lower methane emissions were also observed from turbine equipped facilities in the transmission and storage sector.²²

Finally, the regression model indicates that the WAFLER increased with the pressure difference across the facility. The magnitude of some fugitive leaks scale with pressure. The number of stages of compression also increases with delta pressure.

4.3. Distribution of Methane Emissions. Figure 4 presents cumulative distributions of WAFLER (as a percentage of the total methane emissions) separately for the gathering (C, C/D, C/D/T, D, D/T) facilities and processing plants. Distributions are presented on two bases: facility number (Figure 4(a)) and cumulative CH_4 throughput (Figure 4(b)).

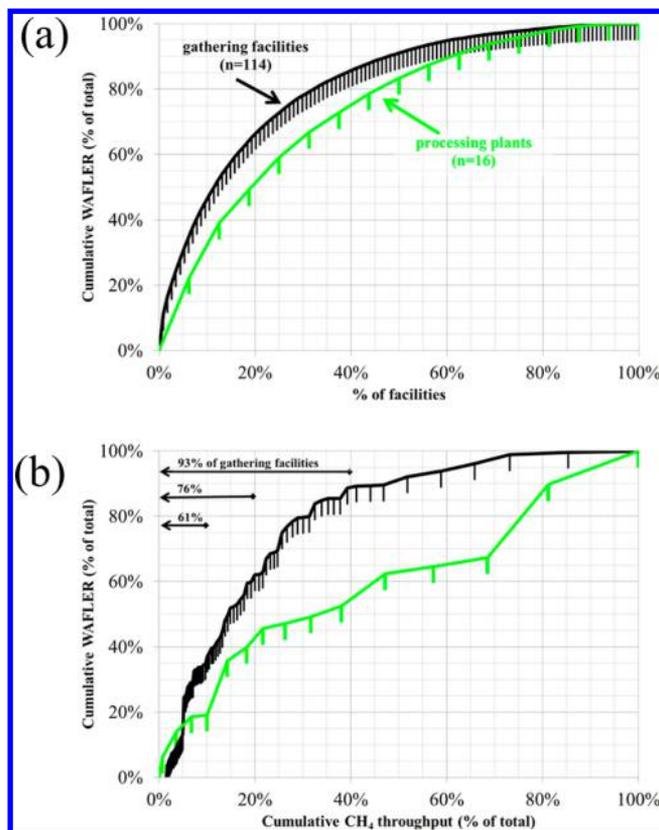


Figure 4. Skew in the methane emissions data illustrated by cumulative distributions of WAFLER (as a % of total methane emissions) of gathering facilities (black) and processing plants (green) sorted in (a) by WAFLER in descending order and (b) by CH_4 throughput (as a % of total) in ascending order. Each tick represents a single facility, and, in (b), the space between ticks represents % of total throughput accounted for by each facility. In (a), more than 80% of emissions come from about 30% of gathering facilities. In (b), the percentage of gathering facilities that contribute 10, 20, and 40% of throughput are indicated by arrows (top left). For example, 76% of the gathering facilities contribute only 20% of the throughput, but account for more than 60% of the emissions. (Included are three C facilities and two C/D facilities that had zero throughput but were still emitting methane.)

The cumulative distributions of WAFLER are skewed, similar to methane emissions data for production wells^{23,24} and transmission and storage facilities.²² In Figure 4(a), the skew is demonstrated by the fact that a minority of facilities contribute to the majority of the emissions. For example, less than 30% of gathering facilities (37 total) are responsible for almost 80% of the total methane emissions. One facility (facility #35) accounts for 10% of total gathering methane emissions. The five zero throughput facilities contributed 1% of the total gathering methane emissions.

Figure 4(b) shows that the emissions are also skewed when viewed from a CH_4 throughput basis. There are many low throughput facilities—61% of the facilities only contributed 10% of the total CH_4 throughput, but almost 40% of the total gathering methane emissions. At the other end of the distribution, nine facilities accounted for more than 60% of the total gathering throughput, but emissions from these nine facilities were only around 10% of the total gathering methane emissions. Without these nine facilities, the cumulative \ln WAFLER of all study gathering facilities would increase

from 0.20% to 0.43%. Cumulative distributions for C and C/D gathering facilities are included in SI N.

Normalized emissions from processing plants were generally lower than gathering facilities (Figure 3(b)) and their cumulative distributions of WAFLER less skewed (Figure 4). One factor may be the LDAR programs employed at processing plants, which are intended to reduce emissions. It is also unlikely that a single, high-magnitude leak would go unnoticed at any processing plant because they are typically staffed by an operator at all times. For example, a 1% leak at the average processing plant (250 tonnes/h) would emit more than 2500 kg/h. A single emission source at even a fraction of this magnitude would likely be visible and/or audible, making detection without infrared camera survey possible. Of the 25 facilities with the lowest tnWAFLER, 19 were staffed by full-time operator(s) (8–24 h/day). All of the processing facilities, but only about 14% of gathering facilities, were staffed. The other facilities were checked by their operator at least a few times a week, most daily.

The skewed distributions shown in Figure 4 are important to consider when making national emissions estimates.²⁵ These data provide insight into the frequency of high emitters (the “fat tail”). However, the sensitivity of the normalized emissions rates presented here to the skewed distributions complicates comparisons to existing GHG inventories. Marchese et al.¹⁰ use these emissions data to estimate the total methane emissions from natural gas gathering and processing in the U.S.

■ ASSOCIATED CONTENT

● Supporting Information

A, Facility selection process; B, facility information collected by onsite observer; C, summary figures of onsite information; D, nonpartner equipment collocated with study facilities; E, documented changes to equipment and/or facility state(s); F, observations from infrared camera surveys at gathering facilities; G, brief description of tracer flux methodology; H, tracer flux measurements results; I, measurements of intermittent methane release events; J, downwind recovery of exhaust stack methane; K, comparison of facility-level emissions at processing plants; L, multiple linear least-squares regression variables and results; M, summary of high emitters; and N, cumulative distributions for C and C/D facilities. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Notes

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■ ABBREVIATIONS

| | |
|----------|--|
| FLER | Facility-level emission rate (for the duration of a plume) |
| OP | Operational pressurized (compressor) |
| NOP | Nonoperational pressurized (compressor) |
| NOD | Nonoperation depressurized (compressor) |
| scfm | Standard cubic feet (of gas) per minute at 60 °F and 1 atm |
| WAFLER | Weighted-average facility-level emission rate (of methane) |
| tnWAFLER | Throughput-normalized weighted-average facility level emission rate (of methane) |

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Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings

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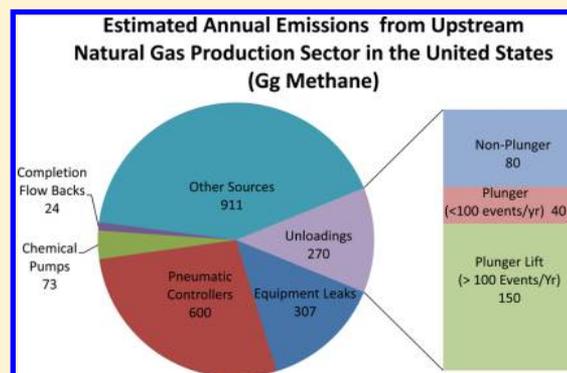
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S Supporting Information

ABSTRACT: Methane emissions from liquid unloadings were measured at 107 wells in natural gas production regions throughout the United States. Liquid unloadings clear wells of accumulated liquids to increase production, employing a variety of liquid lifting mechanisms. In this work, wells with and without plunger lifts were sampled. Most wells without plunger lifts unload less than 10 times per year with emissions averaging 21 000–35 000 scf methane (0.4–0.7 Mg) per event (95% confidence limits of 10 000–50 000 scf/event). For wells with plunger lifts, emissions averaged 1000–10 000 scf methane (0.02–0.2 Mg) per event (95% confidence limits of 500–12 000 scf/event). Some wells with plunger lifts are automatically triggered and unload thousands of times per year and these wells account for the majority of the emissions from all wells with liquid unloadings. If the data collected in this work are assumed to be representative of national populations, the data suggest that the central estimate of emissions from unloadings (270 Gg/yr, 95% confidence range of 190–400 Gg) are within a few percent of the emissions estimated in the EPA 2012 Greenhouse Gas National Emission Inventory (released in 2014), with emissions dominated by wells with high frequencies of unloadings.



INTRODUCTION

Natural gas production in the United States is increasing, driven by increased use of horizontal drilling and hydraulic fracturing.¹ As natural gas production has increased, interest has increased in the emissions of greenhouse gases along the natural gas supply chain.^{2–10} Methane, the primary component of natural gas, is a potent greenhouse gas, and a variety of sources contribute to methane emissions along the natural gas supply chain. For some of these sources, emission measurements are sparse, including measurements of emissions from pneumatic controllers and liquid unloadings.¹¹ Measurements of emissions from pneumatic controllers have been described in a companion manuscript.¹² This work reports on emissions from gas well liquid unloadings.

A liquid unloading may be necessary when a gas well that also produces oil or water accumulates liquids in the well bore. The liquids accumulation may be due to a variety of causes, including decreases in gas velocity in the well, decreases in reservoir pressure, or changing gas to liquid ratios. As liquids accumulate, well production can decline and an operator may choose to unload the liquids from the well to restore production. Liquids can be unloaded in a variety of ways. For example, the well tubing can be modified to increase gas velocity or a pump may be installed to remove downhole

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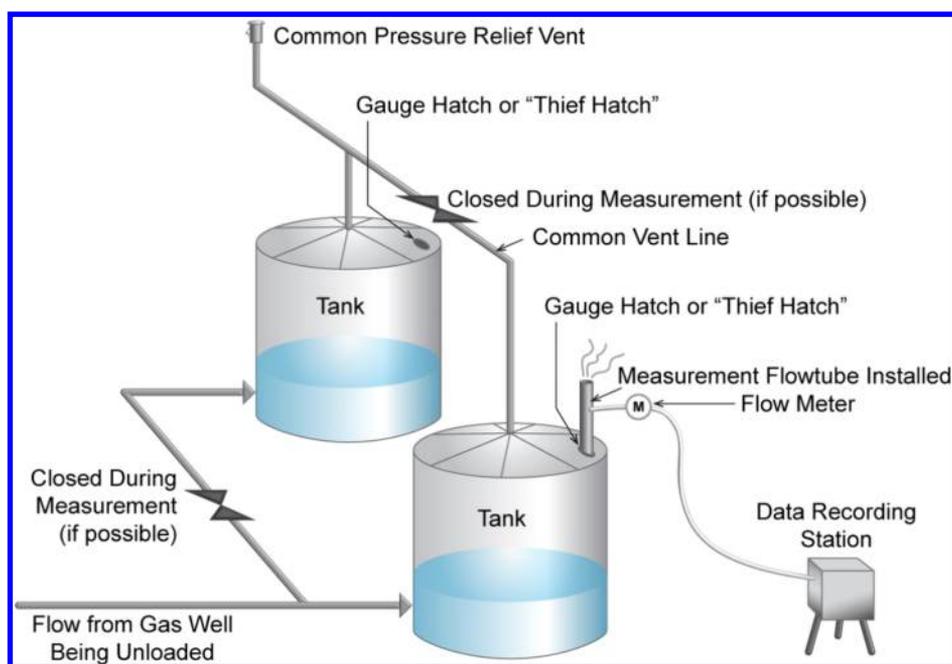


Figure 1. Conceptual diagram of a tank layout on a well site and the positioning of the temporary stack used to measure volume of gas vented during a liquid unloading.

liquids. Neither of these methods lead to venting emissions. Other unloading methods, such as temporarily diverting the flow from the well to an atmospheric vent, do lead to emissions. This work focuses on unloadings that result in emissions.

In the most recent national inventory of greenhouse gas emissions (for calendar year 2012, released in 2014, referred to here as the EPA 2012 GHG NEI),¹³ the EPA estimates that 60 810 natural gas wells, out of an estimated 470 913 natural gas wells in the United States (not including oil wells with associated gas production), have liquid unloadings that result in methane emissions. This represents 13% of gas wells in the EPA 2012 GHG NEI. Collectively, liquid unloadings from these wells are estimated to emit 273.6 Gg of methane per year (14.2 billion standard cubic feet, bcf), or approximately 14% of the estimated 1992 Gg of methane emissions from the natural gas production portion of the natural gas supply chain.

The estimates of methane emissions from liquid unloadings in EPA 2012 GHG NEI are generally consistent with more recent information collected through the EPA's Greenhouse Gas Reporting Program (for calendar year 2012, released in 2013, referred to here as the EPA 2012 GHGRP).¹⁴ The GHGRP reports approximately 276 Gg of methane emissions from liquid unloadings at facilities that meet threshold reporting requirements. Information for 58 663 wells that have unloading emissions was reported in 2012. In October 2014, GHGRP data were released for reporting year 2013 as well as revised data for reporting year 2012. In the 2014 data release, the number of wells with methane emissions from unloadings was reported as 55 491 for 2013, a 5.4% decrease from the number of wells originally reported for 2012. The number of wells with methane emissions from unloadings in 2012 was revised from 58 663 (released in October 2013) to 59 162 (released in October 2014). In this work, the 2012 data are used in order to allow comparisons with the 2012 GHG NEI. The originally released data are used since changes in reporting for 2012, as reflected in the well count, were relatively minor. Some changes were more significant, however, so a

sensitivity analysis, using revised 2012 and 2013 GHGRP data, is reported in Supporting Information (SI). The liquid unloading emission estimates from the EPA GHGRP are shown, by production region, in SI (Section S1).

Emissions from liquid unloadings of natural gas wells are not uniformly distributed in time or space. Estimated emissions from liquid unloadings are spatially concentrated in Rocky Mountain production regions. Wells in the Rocky Mountain region account for more than half of estimated emissions from liquid unloadings in the 2012 GHGRP. Temporal distributions also vary. Some wells release unloading emissions several times per day while others may release unloading emissions only once per year or once during the well's production life cycle. Wells may only release unloading emissions for a portion of their production lifetime, leading to a dependence of unloading emissions on well age. In addition to spatial and temporal variability in emissions of wells that vent, both estimates and measurements indicate that a small fraction of wells that vent account for a majority of emissions. For example, for one type of well with unloading emissions (wells without plunger lifts, see definition later in text), emission estimates reported by the American Petroleum Institute/America's Natural Gas Alliance (API/ANGA), indicate that three percent of wells accounted for half of emissions from this type of well and half of the wells accounted for more than 90% of emissions.¹⁵ In a limited number of measurements of methane emissions from a single type of well with unloading emissions (wells without plunger lifts—see definition later in text), Allen et al.¹¹ found that 95% of the emissions came from less than half of the wells.

Emission estimates, and a limited number of measurements of methane emissions from liquid unloadings, both suggest that a small fraction of wells, in particular geographical regions, and at particular times in the well's life cycle, account for a large fraction of liquid unloading emissions. These characterizations of unloadings emissions are primarily based on emission estimates, however, and there are few data in the scientific literature to test the reliability of emission estimates. This leads

to potentially large uncertainties in the emissions from this source category. More measurement data are needed, along with a better understanding of the relationships between well characteristics and unloading emissions.

This work reports measurements of methane emissions from 107 natural gas wells with emissions associated with liquid unloading. These data represent the most extensive set of measurements of emissions from liquid unloadings in the scientific literature. The relationships between emissions magnitude, unloading event frequency and other well characteristics are explored.

■ MATERIALS AND METHODS

Emission Measurements. The liquid unloadings reported in this work are grouped as plunger-lift unloadings and unloadings of wells without plunger lifts.

In a manually triggered unloading of a well without a plunger lift, an operator manually diverts the well's flow from a production separator, which typically operates at pressures of multiple atmospheres, to an atmospheric pressure tank. This allows the well to temporarily flow to a lower pressure destination (the atmospheric pressure tank or vent, rather than the pressurized separator). The resulting higher pressure gradient allows more gas to flow, increasing velocity in the production tubing and entraining and lifting liquids out of the well. Gas is discharged through the tank vent to the atmosphere until liquids are cleared. In a small number of wells (~0.1% of wells reported by companies participating in this work), this process is automated, resulting in two subcategories of unloadings for wells without plunger lifts, manual and automatic. All of the measurements reported in this work for wells without plunger lifts are for wells that had unloadings that were manually triggered; no wells without plunger lifts were observed in the sampling that had automated unloadings.

Emissions from unloadings of wells without plunger lifts were measured in this work by directing flow through a temporary stack installed on top of the vent. Figure 1 shows a conceptual diagram of a tank layout on a well site and the positioning of the temporary stack. Grounded metal or metal lined tubing was used to construct the temporary stack, to prevent static discharge. Flow rate through the temporary stack was measured continuously, near the centerline of the temporary stack, using a thermal gas mass flow meter. The thermal meter was extended into the middle of the temporary stack, which was between two and eight inches in diameter, with the diameter depending on the anticipated flow rate. Since the width of the meter's probe was approximately 3.5 cm (1.4 in.), the thermal meter recorded a centerline velocity. Total volumetric flow was calculated by multiplying the product of the measured gas velocity and the cross-sectional area of each stack by a correction factor to convert the centerline velocity in the stack to an estimated average velocity in the stack, accounting for the change in velocity profile from friction near the stack walls and accounting for the cross sectional area of the stack obstructed by the flow meter (see SI Section S2). In some well configurations (31 of the 107 wells on which measurements were made), measurement through a temporary stack on the atmospheric tank was not technically feasible. In these cases, measurements were made by inserting a segment of pipe (with the thermal gas mass flow meter in the pipe) into the process line between the separator and the atmospheric tank in order to measure the flow into the tank.

The methane fraction of the vented gas was assumed to be equal to the methane fraction in the normally produced gas. This was presumed to be a more accurate indicator of total methane emissions than measurements of the gas composition made through the temporary stack. The gas exiting through the temporary stack during the unloading period is a combination of the unloaded gas from the well and the gas initially in the vapor space of the tank (typically much lower in methane than the site's produced gas). At the end of the unloading, the tank will contain more methane, from the unloading, than was in the tank at the start of the unloading. This methane, which is associated with the unloading event, will eventually be released as part of normal tank operations. Multiplying the measured vented gas volume by the methane fraction of the produced gas captures these emissions that occur because of the unloading but that are not released during the period when the tank is actively venting.

Uncertainty in these measurement methods is estimated at 10–20% of the measured emissions and this estimate is dominated by the assumed uncertainty in the flow, which includes both uncertainties in the stack gas volumetric flow measurement, and determining when flows return to zero. Variability in the gas composition from the well is expected to be much less than 10%. As described in the Results section, these measurement uncertainties are small compared to the combined measurement uncertainty and uncertainty introduced by selecting only a subpopulation of wells for measurement (sampling uncertainty), which are 50% or more of measured emissions.

Liquids can also be unloaded from a well using a plunger lift system. This liquid removal operation holds a plunger at the top of the well, and either manually or by automation occasionally closes (shuts-in) the well and releases the plunger, allowing it to fall down the well bore below the accumulated liquids. The well is then reopened, allowing the gas to push the plunger and the liquid back up the well bore as a slug of liquid. If the plunger returns to the top and the liquid and gas flow to the separator, there is no venting and all gas from the separator is routed to sales. In some cases, if the plunger does not return to the surface as expected, the plunger controller may bypass the separator and direct the flow to an atmospheric pressure vent, such as a vented tank. Directing flow to the lower pressure vent causes the plunger to return to the surface but also allows gas to vent. Plunger cycles may be initiated manually, on a timed interval, or based on certain well parameters such as a reduced gas flow. In this work, measurements were made on both wells in which the unloading was automated through use of a controller (automatically triggered), and wells in which the plunger lift cycle was manually initiated by an operator (manually triggered).

In both the manually triggered plunger lift unloadings and the automatically triggered plunger lift unloadings, the volume of vented gas was measured using the same procedures as used for the wells without plunger lifts. For the automatically triggered unloadings, the measurement equipment was typically left in place for one to several days, making measurements continuously. This allowed automated plunger unloading venting events to be measured only when and if they occurred in routine operation, without artificially triggering the events. For all the plunger lift unloading events, the composition of the vented gas was assumed to be the same as the composition of the gas produced by that well. Produced gas composition was provided by site operators.

Table 1. Unloading events measured in this work. Wells with manual unloadings typically had one event per well, while automated Plunger Lift Unloadings Had Multiple Events Per Well; A Mapping of Region Boundaries is Provided in Supporting Information

| type of well | initiation system | wells with unloadings sampled | | | | |
|--------------|-------------------|-------------------------------|-------------|----------------|------------|---------------|
| | | U.S. total | Appalachian | Rocky Mountain | Gulf Coast | Mid-Continent |
| plunger | auto | 25 | 0 | 20 | 1 | 4 |
| | manual | 50 | 7 | 29 | 1 | 13 |
| non- plunger | manual | 32 | 4 | 2 | 14 | 12 |
| total | | 107 | 11 | 51 | 16 | 29 |

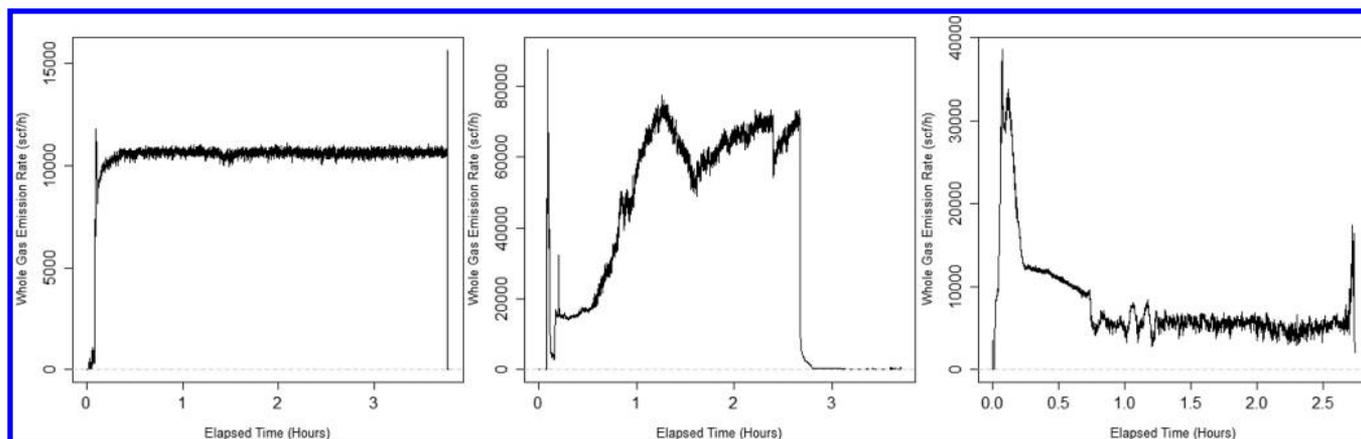


Figure 2. Representative time series of methane flow rates during manually triggered liquid unloadings from wells without plunger lifts (USH-47-0201 left; USH-47-0701 middle; UCG-03-0301 right); Note differences in horizontal and vertical scales.

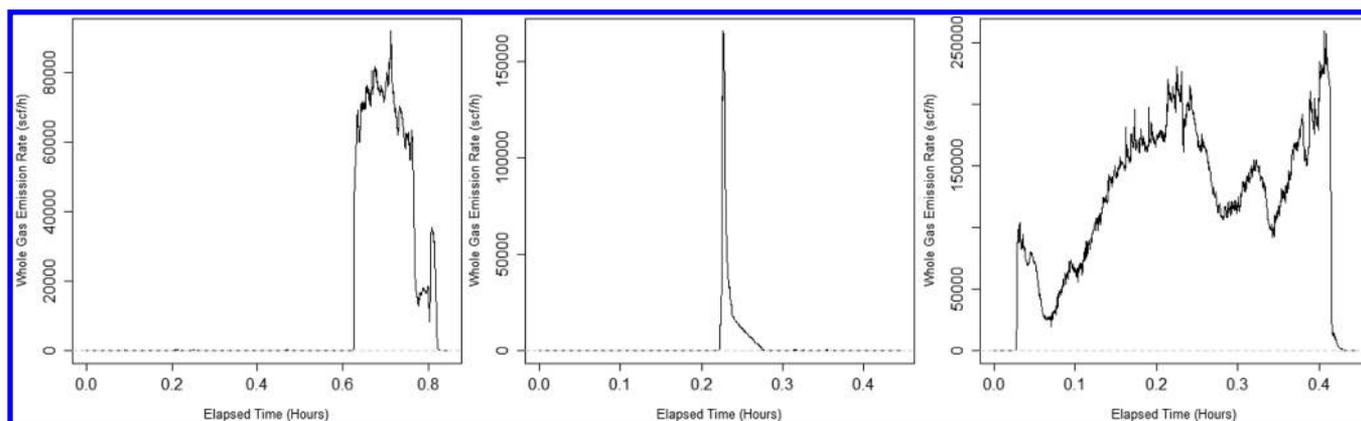


Figure 3. Representative time series of methane flow rates during manually triggered liquid unloadings from wells with plunger lifts (UBB-45-0101 left; UJR-46-0601 middle; USH-45-0202 right); Note differences in horizontal and vertical scales.

Sampling Strategies. Emission estimates reported through the EPA 2012 GHGRP¹⁴ indicate that a small fraction of wells, in particular geographical regions, account for a large fraction of emissions from liquid unloadings. The sampling strategy employed in this work was to sample most extensively in regions that were likely to dominate emissions (SI, Section S1). Details of the sampling approach are provided in SI. Briefly, the sampling team would visit a region for one or multiple weeks and sample a randomly selected subset of those wells that were unloading during that period. Consequently, more samples were collected on wells that unloaded more frequently. The features of these sample collection methods (preferential sampling in regions with high estimated emissions from unloadings and sampling of wells that tended to have high unloading frequencies) are important to consider when the data

presented in this work are used to establish national emission estimates.

RESULTS AND DISCUSSION

Methane emissions from liquid unloadings were measured at 107 natural gas wells. A summary of the geographical locations of the wells sampled is provided in Table 1.

For the 32 wells without plunger lifts (manually unloaded) sampled in this work, one event was typically sampled for each well; a few wells had more than one event sampled and for these wells, average values are reported. The unloadings of wells without plunger lifts sampled in this work had durations that lasted between 0.17 and 4.5 h, and vented methane volumes that ranged between 550 and 135 000 standard cubic feet (scf) of methane per event (0.011–2.6 Mg). Representative time series for the methane emissions from wells without

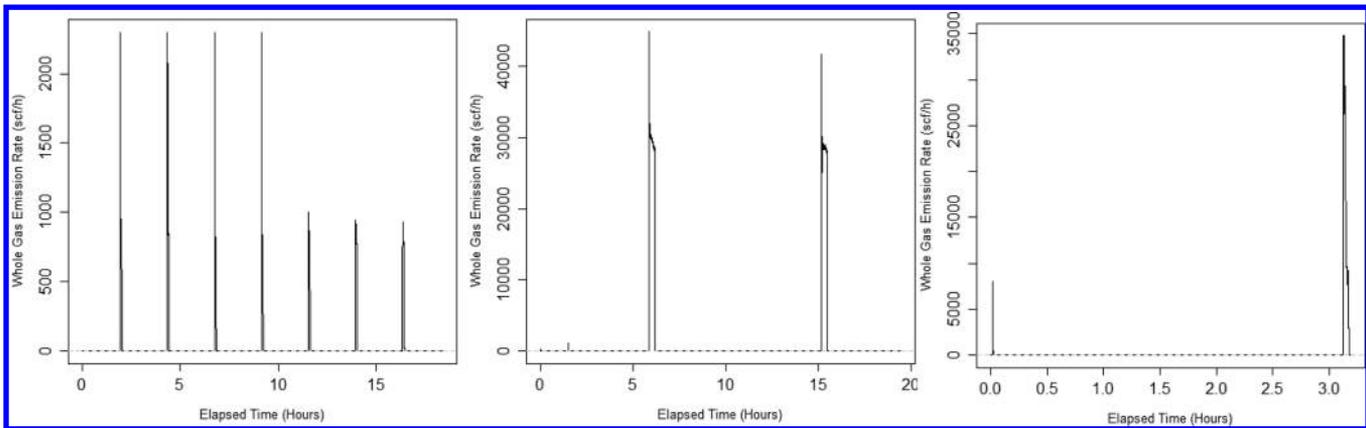


Figure 4. Representative time series of methane flow rates during automatically triggered liquid unloadings from wells with plunger lifts (UBB-42-0401 left; UBB-42-0201 middle; UEF-49-0501 right); Note differences in horizontal and vertical scales.

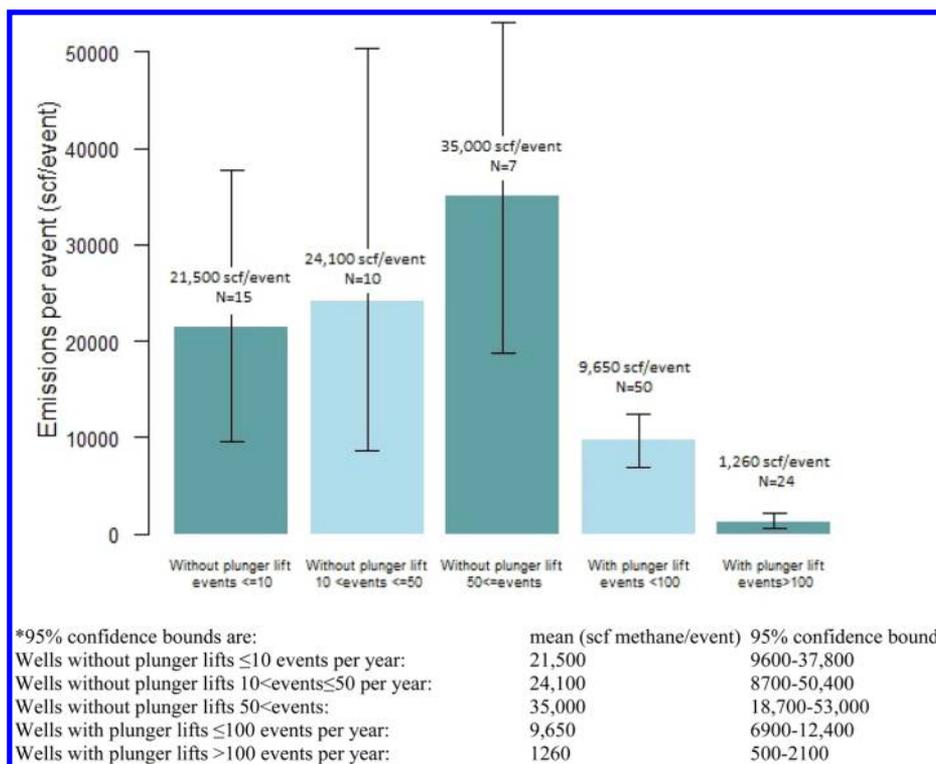


Figure 5. Average emissions per event for wells with and without plunger lifts, sorted by frequency of events (events per year per well).

plunger lifts are shown in Figure 2. These three events shown had durations that ranged from 2.72 to 3.75 h. Vented volumes for these three events shown ranged between 21 000 and 135 000 scf methane (0.40–2.6 Mg). As illustrated by these representative time series, some manual unloadings without plunger lift rapidly rose to a high flow rate, then maintained a steady flow throughout the event; others rose more slowly to a peak flow, then had variable flow during the event; still others rapidly rose to a peak flow, then had declining flows throughout the event. This complex flow behavior makes it difficult to generalize about the flow characteristics for manually triggered unloadings of wells without plunger lifts.

For the 50 plunger lift wells with manually triggered unloadings, one event was typically sampled for each well. The manual unloadings of wells with plunger lifts sampled in this work had durations that lasted between 0.03 h and more than 3 h, and had vented methane volumes that ranged

between approximately 200 and 49 000 scf methane per event (0.004–0.94 Mg). Representative time series for the methane emissions from a manual unloading are shown in Figure 3. These three events shown had durations that ranged from 1.2 to 20 min. Vented volumes ranged between 1220 and 27 000 scf methane for the three events shown (0.02–0.52 Mg). As illustrated by these representative time series, some manually triggered unloadings with plunger lift rapidly rose to a high flow rate, then almost immediately fell rapidly, leading to a relatively short duration event; others rose rapidly to a peak flow that was maintained for 5–10 min or more; still others had complex flow patterns over an event lasting 10 min or more. As was the case for manually triggered unloadings without plunger lifts, this complex flow behavior makes it difficult to generalize about the flow characteristics.

For automated plunger lift wells, the sampling equipment was left in place for one to several days at each well, and

typically more than one event was sampled for each well. The automatically triggered unloadings (with plunger lift) sampled in this work had durations that lasted between <1 min and more than 20 min, and vented methane volumes that ranged from 50 scf methane to more than 8000 scf methane per event) (0.001–0.15 Mg). The numbers of events sampled per well ranged from 2 to more than 70; average values of emissions per event were used when multiple events were recorded. Representative time series for the methane emissions from automated plunger lift unloadings are shown in Figure 4. Individual unloading events for these three wells had durations that ranged from 2 to 20 min. Vented volumes per event ranged between 60 and 8600 scf methane for the three wells shown (0.001–0.15 Mg). As illustrated by these representative time series, some plunger lift wells with automated unloadings had emissions per event that were quite similar, and that occurred with a regular frequency. In contrast, however, some automated plunger lift wells had events that had qualitatively different emissions and/or variable event frequencies.

SI (Section S3) provides details of the unloading emissions and well characteristics for each of the 107 wells sampled in this work. A summary is provided in Figure 5. A relatively small number of wells have high emissions and most wells have much lower emissions. For example, 20% (6 of 32) of the wells account for 83% of the annual emissions for wells without plunger lifts, where annual emissions are estimated by multiplying the emission for an unloading event, measured in this work, by the number of times that well unloaded during calendar year 2012 or 2013 (whichever was the most recent report available), as reported by the well operator. The six wells that account for 83% of the annual emissions of wells without plunger lifts vent 6% of their collective annual production. For manually and automatically triggered plunger lift wells, 20% of the wells account for 65% and 72% of the annual emissions, respectively. These wells vent 2% and 20% of their collective annual production, for manually and automatically triggered wells, respectively.

Because the distributions of event emissions are not normally distributed about a mean, uncertainties in the average values of emissions per event are reported based on the results of a bootstrapping method, rather than as a simple standard deviation of the data set. In the bootstrapping procedure, the original data set of each type of well was recreated by making random event selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence intervals for the emission estimates represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. So, for example, for the 25 automatically triggered plunger lift wells, a mean value for emissions per event, for each well, was calculated by selecting 25 emission measurements, at random and with replacement. This mean was tabulated and the process was repeated 1000 times to generate 1000 mean values. The 2.5% and 97.5% percentiles were determined to be 538 and 2085 scf methane per event, and these values are the 95% confidence bounds for the mean value of the measurements (in this case 1260 scf methane/event). The bootstrapping procedure leads to a combined sampling and measurement uncertainty. This uncertainty has a much larger range (typically 50% or more of the mean value, see Figure 5) than would be estimated from the uncertainty associated with the measurement alone (approximately 10–20% of the measured value) and is a

reflection of the heterogeneity of well characteristics in the data sets and the underlying population of wells with unloading emissions.

Statistical analyses were conducted to identify well and unloading event characteristics that could explain the variability in the measured emission data. Variables that were considered included well pressures, well bore volumes, well ages, unloading event durations and unloading frequencies. The variable that explained the largest amount of variability in the observed annual well emissions was unloading frequency, although there was also a positive correlation of event frequencies with well age (older wells had more unloading events per year than younger wells) and a negative correlation of annual emissions with well depth (deeper wells, which were generally newer, had lower annual emissions than shallower, generally older, wells). Correlations with emissions per event were generally weaker than for annual emissions. Additional details are provided in SI (Section S4). As shown in Figure 5, for wells without plunger lifts, average emissions for individual unloading events range between 21 000 and 35 000 scf methane per event, if the events are binned into wells that have less than 10 events per year, between 11 and 50 events per year, and 51 or more events per year. The differences in annual emissions from manually unloaded wells without plunger lifts are largely due to the frequency of events, rather than the volume of gas emitted per event. For wells with plunger lifts, Figure 5 reports average emissions in two frequency bins. Manually triggered plunger lift wells were binned as a single group; all had less than 100 events per year (maximum observed value of 52 events per year). Automatically triggered plunger lift wells were also considered as a single category since all of these wells had more than 180 unloadings per year (average of 1870 unloadings per year in the sampled population). Plunger lift wells that were manually triggered had average emissions per event of 9650 scf methane. Plunger lift wells with automated triggering of the unloading had average emissions of 1260 scf methane per event.

The measured emissions per event were compared to predictions made using emission estimation methods commonly used in EPA GHGRP reporting. For wells with plunger lifts, the emission estimates averaged 4500 scf/event as compared to an average of 8000 scf/event for the study measurements (difference is statistically different, $p = 0.004$). Despite the differences in mean predicted and observed emission rates, the paired measurements and estimates were weakly, but statistically significantly correlated. For wells without plunger lifts, the emission estimates averaged 31 000 scf/event as compared to an average of 27 000 scf/event for the measurements (difference is not statistically significant), however, while the averages are similar, the estimates were not well correlated with the observations. See SI (Section S4) for more details.

Implications for National Emission Estimates. National emissions, based on the measurements made in this work, are estimated by multiplying an emission factor, based on the measurements, by an activity factor. Emission event counts, stratified into categories based on emission events per year per well, were chosen for the activity factor because of the process used for selecting wells to be sampled and because annual emission estimates for wells with unloadings depended most strongly on event frequency.

As documented in SI (Section S1), the measurement team typically visited production Basins for approximately a week, and sampled randomly selected wells that had scheduled (for

manually triggered wells) or anticipated (for automatically triggered wells) unloading events for that week of sampling. This meant that the study team was far more likely to sample wells that unloaded weekly or more frequently, rather than wells that unloaded just a few times per year. This sampling approach resulted in a representative distribution of events, but not a representative distribution of wells. For example, 85% of the wells, without plunger lift, that have unloading emissions and that are operated by the companies that provided sampling sites in this work, had fewer than 10 emission events per year (See SI, Section S5). In the measurements performed for this work, 15 of the 32 wells without plunger lift (47%) had 10 or less events per year. These wells are therefore under-represented in the measurement data, relative to their presence in the participating companies' overall well population. Because of differences in the distributions of event frequency between the sampled wells and the national population of wells, it would not be appropriate to choose an emission factor of emissions per well per year and an activity factor of number of wells, without adjusting for this difference in event frequency distribution.

An additional reason for stratifying wells by frequency of events in the activity factor is the data shown in Figure 5, which indicate a reasonable degree of consistency in per event emissions. Wells without plunger lifts had measured mean values of 21 000–35 000 scf methane/event. Wells with plunger lifts had measured mean values of 1000–10 000 scf methane/event, but much larger ranges of event frequencies. For the calculations reported in this work, national, rather than regional averages of emissions per event will be used, due to the limited number of observations in individual regions.

In this work, national estimates of numbers of unloading events were based on a survey of the participating companies (see SI, Section S5). Data on event counts from the EPA GHGRP were not used since event counts for plunger and nonplunger wells are either partially reported or of uncertain quality. The national event counts were assumed to have the same distributions as reported in the participant survey. Based on this survey, it was estimated that the 32 225 wells with plunger lifts (based on data from the 2012 GHGRP) have a total of 6.8 million events per year. Only 206 500 of these 6.8 million events are associated with wells that vent less than 100 times per year. Total annual emissions from plunger lift wells are estimated at 10 billion cubic feet of methane per year (bcf/yr) (190 Gg/yr), with 80% of those emissions associated with wells that vent more than 100 times per year (additional details in SI, Section S5). For wells that vent more than 100 times per year, the average emissions per well per year are 1 400 000 scf per well per year (27 Mg/yr) with 95% confidence bounds of 600 000–2 500 000 scf (10–50 Mg, based on the confidence bounds in the emissions per event).

For wells without plunger lifts, it was estimated that 26 438 wells (based on data from the 2012 GHGRP) vent a total of 177 000 times per year, with total emissions of 4.4 bcf/yr (84 Gg/yr). Again, the wells that vent with highest frequency have the highest emissions per well. The 1.1% of wells that vent more than 50 times per year have average emissions of 3.2 million scf methane/yr. For wells without plunger lifts, however, these wells account for only 1.1% of the wells with unloading emissions, so the emissions from these wells venting at high frequency account for only 25% of emissions from wells without plunger lifts. Additional details are provided in SI, Section S5).

The overall emission estimate for liquid unloadings (plunger and nonplunger wells), based on the measurements made in this work, is 270 Gg (14 bcf/yr), which is within a few percent of the national emissions estimated in either the 2012 GHG NEI (273 Gg/yr) or the 2012 GHGRP (276 Gg/yr). The 95% confidence range for this estimate is 190–400 Gg/yr, based on the reported confidence ranges in the per event emission factors, but not accounting for uncertainties in event counts. SI (Section S5) reports sensitivity analyses that suggest uncertainties in event count estimates may be large, up to a factor of 2 or more, which could have a significant impact on national emission estimates. Regardless of the exact national total of emissions, however, wells with high frequencies of unloadings have annual emissions that are a factor of 10 or more greater than the annual emissions of wells with low frequencies of unloadings.

■ ASSOCIATED CONTENT

📄 Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agency's Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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**Methane Emissions from Process Equipment at Natural Gas Production Sites
in the United States: Pneumatic Controllers
Supporting Information**

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Contents

S1. Methods for site selection

S2. Corrections to Instrument Flow Measurements based on Gas Composition

S3. Field and laboratory comparisons of supply gas meter and Hi Flow measurements

S4. Pneumatic controller emission data

S5. Estimates of emissions from devices with no emissions detected during 15 minute sampling period

S6. Numbers of controllers per well

S7. Estimates of emissions from pneumatic controllers in the United States

S8. Summary of data on 40 highest emitting devices

S1. Methods for site selection

Goals and overall sampling strategy Sampling of pneumatic controllers was conducted in four major regions (Appalachian, Gulf Coast, Mid-continent, Rocky Mountain); based on current characterizations of pneumatic controller design types (continuous vent or intermittent vent, on/off or throttling), it was anticipated that several types of controller designs would need to be sampled; it was also anticipated that there would be multiple types of controller service (e.g., separator level control service) that would influence actuation frequency and other parameters that affect emissions. To sample regions, controller design types and controller service types, it was anticipated that approximately 350-400 devices would need to be sampled.

Selection of Basins Data from EPA's Greenhouse Gas Reporting Program (GHGRP, Reporting Year 2012) were used to identify the Basins where the ten participant companies had reported pneumatic emissions. Based on this distribution of available Basins in which to sample, the study team selected at least two companies to sample in each region (Appalachian, Gulf Coast, Mid-continent, Rocky Mountain), such that all ten participant companies were sampled. Where possible, the study team selected Basins that produced a mix of device design and service types, rather than visiting sites that reported only one device type. The Study Team was solely responsible for the selection of regions and Basins in which to sample.

Once basins and companies to be sampled in each basin were selected, 2-3 day site visits were planned. In each of these site visits, the focus was on sampling well pads for a single company in a single basin. Thirteen of these 2-3 day visits were conducted.

Selection of well pads Local contacts for participant companies provided descriptions or lists of the well pad sites or central facilities (e.g. sites with separators for multiple wells) in the area to be sampled. The study team selected the sites; all sites identified by the local contacts were available for sampling; depending on the distances between sites, the study team either randomly selected sites or selected sites that were relatively proximate to the starting location, so that a relatively large number of samples could be made without losing efficiency due to long travel times between pad locations. The goal was to sample a cross section of typical facilities. If a company had a mix of old and new facilities, or acquired and company built facilities, the study team selected pad types in proportion to the population in the area.

Sampling of devices on well pads or central facilities Once at a site, the Study Team measured emissions from all pneumatic devices at the site, unless safety or operational issues or lack of access prohibited sampling. This was done to achieve a sample population that would represent controller service and design types currently in use.

S2 Corrections to Instrument Flow Measurements based on Gas Composition

The supply gas flow meter was calibrated by the manufacturer (Fox Thermal Instruments) using pure methane; instrument flow rates were corrected to account for natural gas compositions, which varied from site to site. Because the flow meter measurement is based on thermal conductivity, the composition correction was based on the relative thermal conductivities of the gas used by pneumatic devices at each site and the pure methane used as a calibration gas.

$$scf/h_{corrected} = scf/h_{inst} \left(\frac{k_{CH_4}}{k_{gas}} \right)$$

where scf/h_{inst} is the raw instrument flow rate reading in standard cubic feet per hour, k_{CH_4} is the pure component thermal conductivity (W/m*K) for methane at standard conditions (70°F and 14.7 psia), and k_{gas} is the thermal conductivity of the gas sampled at standard conditions as determined from the company-provided gas analysis for the site. The thermal conductivity of the sampled gas (k_{gas}) was calculated as a molar weighted average:

$$k_{gas} = \sum_{i=1}^6 k_i n_i$$

where n_i is the mole fraction of species i in the gas sample for the site and k_i is the pure component thermal conductivity of the species (<http://webbook.nist.gov/chemistry/fluid/>) under standard conditions. For this work, the pure component species considered were methane, ethane, propane, nitrogen, and carbon dioxide. All higher hydrocarbons with a carbon count of four or greater were lumped with butane for purposes of the gas composition correction. The pure component properties used in the calculations are shown in Table S2-1. For the range of natural gas compositions from sites visited in this project, the composition correction factor ranged between 1.009 (0.9% increase from raw instrument data) and 1.215 (21.5% increase from raw instrument flow data).

| Species | Thermal Conductivity (W/m*K) |
|----------------|------------------------------|
| Methane | 0.033759 |
| Ethane | 0.020491 |
| Propane | 0.017884 |
| Butane + | 0.016181 |
| Nitrogen | 0.025473 |
| Carbon Dioxide | 0.016331 |

Table S2-1. Thermal conductivity (<http://webbook.nist.gov/chemistry/fluid/>) of natural gas components at standard conditions (14.7 psia and 70°F).

S3. Field and laboratory comparisons of supply gas and Hi Flow® measurements

Laboratory measurements

The measurement instruments were laboratory tested using gas flows generated with a mass flow controller. The test flows were designed to mimic the patterns of time varying flow expected from intermittent vent controllers. The flow out of the mass flow controller was routed through the in-line supply gas meter then fed directly into the feed for the Hi Flow® system (the supply gas meter had a sample frequency of 10 Hz, while the Hi Flow® had a sampling frequency of 0.3 – 0.5 Hz). Tests for the High Flow instrument were completed both with the emissions point bagged and with the emissions being directly fed into the Hi Flow® inlet. In selected experiments, the mass flow controller output was compared to the results of a dry test meter.

Multiple tests were conducted. Figure S3-1 shows the results of one test scenario with a pure methane gas stream. The initial flow pattern consisted of three step up-step down flows with a maximum flow of 100 scfh (a simulated controller actuation). The duration of each step was 30 seconds, and the period between simulated actuations was 2.5 minutes. The second part of the test consisted of three step up-step down flows that also had a maximum flow of 100 scfh. Each step had a duration of 3 seconds, and the period between simulated actuations was 2.5 minutes.

The time integrated flow per simulated actuation from the mass flow controller was compared to the time integrated flow for the supply gas meter and the Hi Flow® device. The ratio of the integrated supply gas meter flow to the integrated mass flow controller flow averaged 1.07 for this test; the ratio of the integrated Hi Flow® device flow to the integrated mass flow controller flow averaged 0.983.

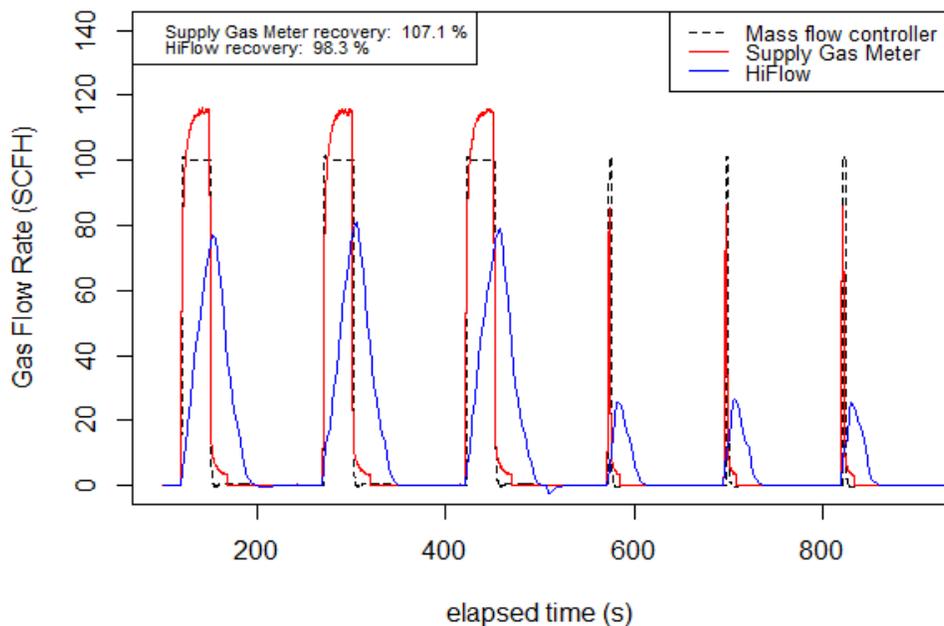


Figure S3-1. Laboratory test comparing supply gas meter to Hi Flow® and mass flow controller. The test consisted of two sets of three 100 scfh simulated actuations; the first set of actuations had a duration of 30 seconds while the second set of actuations had durations of 3 seconds.

For another test (with pure methane test gas), four simulated actuations were performed (30 seconds between actuations), with an increasing maximum flow rate (10, 30, 50, and 100 scfh, respectively); each simulated actuation had a duration of 20 seconds (Figure S3-2). In this test, the ratio of the integrated supply gas meter flow to the integrated mass flow controller flow averaged 1.035; the ratio of the integrated Hi Flow® device flow to the integrated mass flow controller flow averaged 0.952.

Table S3.1 summarizes the laboratory tests that were conducted, showing the relative ratio of integrated flows for each case (with pure methane test gas).

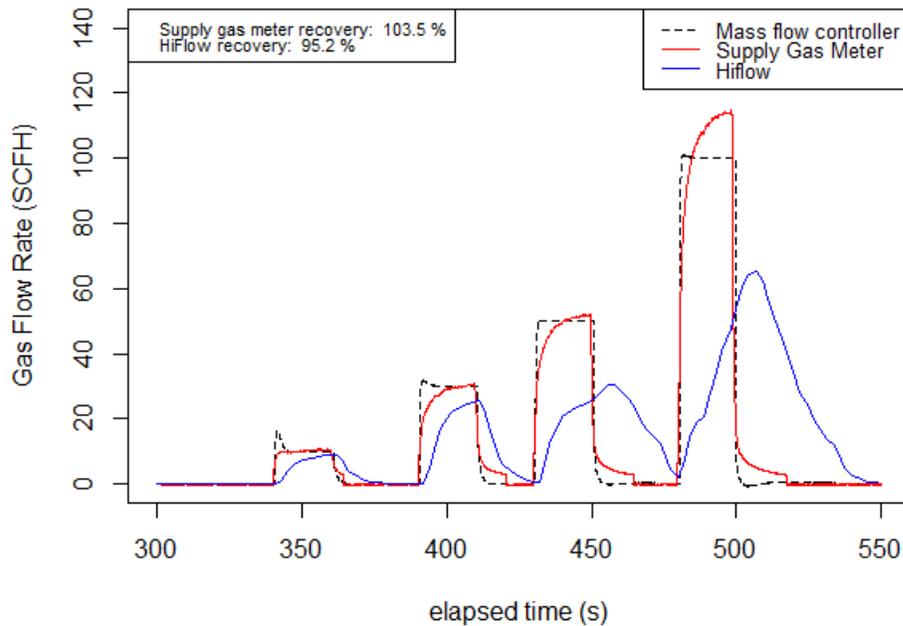


Figure S3-2. Laboratory test comparing Supply Gas Meter to Hi Flow® and Mass Flow Controller. The test consisted of four actuations with maximum flows of 10 scfh, 30 scfh, 50 scfh, and 100 scfh, with a duration of 20 seconds and an interval between actuations of 30 seconds.

| Test Description | Ratio of integrated supply gas meter flow to integrated mass flow controller flow | Ratio of integrated Hi Flow® device flow to integrated mass flow controller flow |
|--|---|--|
| <i>Step up-step down flow. Maximum flow was 100 scfh, duration of each step was 30 seconds and the period between simulated actuations was 2.5 minutes.</i> | 1.07 | 0.983 |
| <i>Set of actuations with maximum flow of 10 scfh, 30 scfh, 50 scfh, and 100 scfh with a duration of 20 seconds per actuation, and an interval of 30 seconds between actuations.</i> | 1.03 | 0.952 |
| <i>Set of actuations with a maximum flow of 100 scfh, 30 scfh and 10 scfh, with a duration of 1 second per actuation and an interval of 1 second between actuations.</i> | 0.856 | 0.959 |
| <i>Set of three actuations with a maximum flow of 100 scfh with a duration of 30 seconds per actuation. Interval of 2.5 minutes between actuations.</i> | 1.10 | 0.922 |
| <i>Set of three actuations with a maximum flow of 100 scfh with a duration of 3 seconds per actuation. Interval of 2.5 minutes between actuations.</i> | 0.829 | 1.58 |

Table S3-1. Laboratory tests simulating controller actuations, using pure methane, comparing the Supply Gas Meter to the Hi Flow® device.

Additional tests with a wet gas surrogate (70.5% methane by volume) were completed in the lab before field sampling (Table S3-2). For the tests listed in Table S3-2, the average ratio of instrument reported mass flow rate to the controller mass flow rate (uncorrected for composition) is 0.878 for the supply gas meter and 0.608 for the Hi Flow®.

| Test Number | Ratio of integrated supply gas meter flow to integrated mass flow controller flow | Ratio of integrated Hi Flow® device flow to integrated mass flow controller flow |
|-------------|---|--|
| 1 | Not Tested | 0.663 |
| 2 | 0.857 | 0.552 |
| 3 | 0.898 | Not Tested |

Table S3-2. Laboratory tests simulating controller actuations, comparing the supply gas meter to the Hi Flow® device with a wet gas surrogate (70.5% methane by volume). Each test consisted of three 30 second bursts at 3 scf/h and at 50 scf/h.

If the supply gas meter is corrected for composition, the average ratio of instrument reported mass flow rate to the controller mass flow rate is 1.034 for the wet gas tests. The Hi Flow® instrument reading is difficult to correct for composition for non-steady flows. At low emission rates, the composition correction would be based on a molar flow rate of carbon, since the sampled gas is catalytically oxidized before it is sent to a thermal conductivity detector. In

contrast, at high flow rates, the sample is sent directly to a thermal conductivity detector and the gas composition adjustment would be based on a molar weighted thermal conductivity (see Section S2). These two adjustments would require precise identification of the transitions between sampling regimes, making the interpretation of field data difficult. Therefore, to adjust Hi Flow® measurements for gas composition in field measurements, the following procedure was used:

1. Determine whether a wet gas or dry gas adjustment will be used; if the percentage methane in the produced gas at a site was greater than 85%, a dry gas correction was used; otherwise a wet gas correction was used
2. For dry gas sites, the Hi Flow® measurement, uncorrected for gas composition, was converted to a supply gas measurement, uncorrected for gas composition. This conversion is based on the laboratory data collected on pure methane reported in Table S3-1 (ratio of Supply gas flow rate to Hi Flow® flow rate of 1.12). The uncorrected supply gas flow rate was then corrected for composition using the method described in Section S2.
3. For wet gas sites, the Hi Flow® measurement, uncorrected for gas composition, was converted to a supply gas measurement, uncorrected for gas composition. This conversion is based on the laboratory data collected on a surrogate wet gas reported in Table S3-2 (ratio of Supply gas flow rate to Hi Flow® flow rate of 0.878/0.608; 1.44). The uncorrected supply gas flow rate was then corrected for composition using the method described in Section S2.

Field Measurements

In field measurements, for 29 controllers, both supply gas and Hi Flow® measurements were made, simultaneously. Four of those measurements will not be analyzed because they occurred at a site (DL02) where the Hi Flow® was capturing a leak signal from equipment located inside the enclosure where the pneumatic devices were installed (not part of the controller). An additional measurement (device XQ01-PC04) will not be analyzed because it was concluded that the controller was not completely bagged.

For the final data set of 24 controllers with coupled measurements, 11 (46%) had emissions of less than 0.005 scf/h of whole gas, as measured by the supply gas meter. The results for the remaining 13 devices are shown in Table S3-2. For devices with an average emission rate greater than 6 scfh (measured by the supply gas meter), the supply gas meter to Hi Flow® measurement ratio is between 0.7 and 1.1. These results suggest that for controllers that account for most of the emissions, the two methods produce similar results. For lower flow rates, the lack of agreement is generally due to higher supply gas measurements, relative to Hi Flow® measurements. This is likely due to leaks in the controller/control valve gas line that were not captured by the Hi Flow® enclosure (e.g., leaks in the downstream valve that the controller was operating). For the samples where the Hi Flow® device was measuring higher emissions than the supply gas meter, the Hi Flow® may have been sampling emissions that were not in the controller/control valve gas line (e.g., a leak in any of the equipment upstream of the meter or near the controller but not in the controller supply line).

Table S3-2. Supply gas meter and Hi Flow® for thirteen controllers where both instruments were used to make measurements.

| Device Name | Supply Gas meter - avg. emission rate Whole Gas (scf/h) | Hi Flow® - avg. emission rate Whole Gas (scf/h) | Supply Gas meter to Hi Flow® measurement ratio |
|-------------|---|---|--|
| AP04-PC02 | 0.111 | 0 | - |
| AP04-PC03 | 0.036 | 0.007 | 5.4 |
| AP05-PC01 | 0.169 | 0.197 | 0.9 |
| DL02-PC11 | 0.528 | 0.881 | 0.6 |
| DL02-PC15 | 1.360 | 0.696 | 2.0 |
| DL02-PC42 | 0.504 | 0.001 | 553 |
| LB03-PC01 | 50.0 | 55.3 | 0.9 |
| LB06-PC05 | 22.5 | 20.8 | 1.1 |
| LB07-PC01 | 36.3 | 51.3 | 0.7 |
| LB07-PC04 | 27.0 | 33.9 | 0.8 |
| RB01-PC14 | 4.16 | 0.194 | 21.5 |
| RQ05-PC02 | 0.008 | 5.15 | 0.0 |
| RQ07-PC03 | 18.2 | 21.0 | 0.9 |

S4. Pneumatic controller emission data

Tables S4-1 to S4-5 contain the data collected for each of the 377 measured devices. The first letter of the device code indicates the host company that operated the site where the measurement was performed. The second letter of the device code indicates the basin where the measurement was performed. Letters for these codes were randomly selected, but are used consistently (i.e., specific letters always represent the same company or basin). Figure S4-1 shows the boundaries of the geographical regions into which controllers were grouped. Figure S4-2 summarizes the application types, well types, and service types of the sampled population

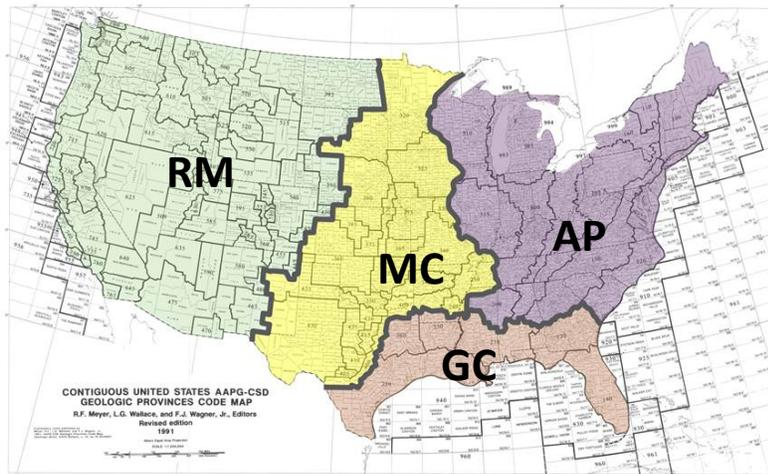


Figure S4-1. Measurements of emissions from pneumatic controllers were categorized into Appalachian (AP), Gulf Coast (GC), Mid-Continent (MC) and Rocky Mountain (RM) regions.

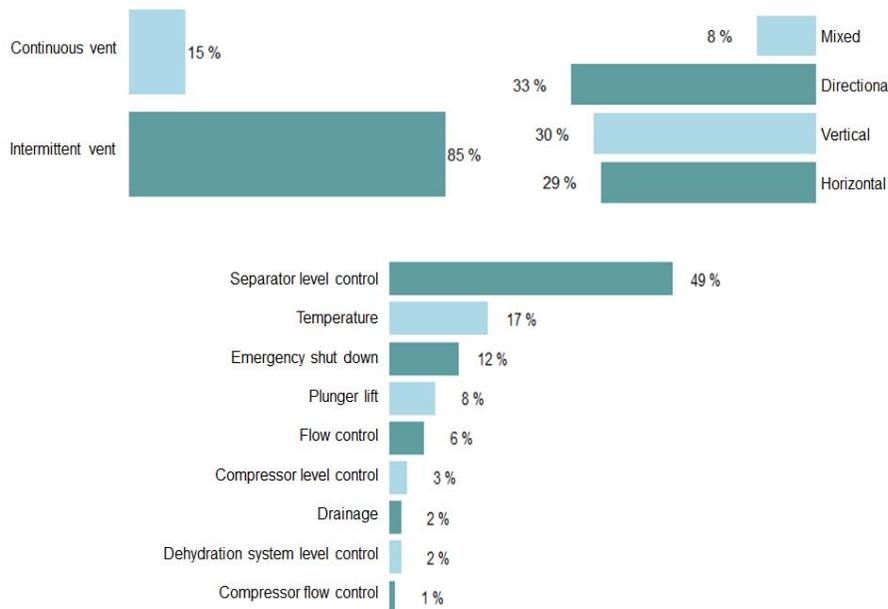


Figure S4-2. Sample population characterized by the service type (upper left, continuous vent or intermittent vent, where intermittent-vent indicates a clear actuation pattern, returning to zero between actuations, and continuous-vent indicates a non-zero pattern with no temporal variability), well type (upper right, horizontal, vertical, directional or mixed type), and type of application in which the controller is used (lower, e.g., separator level control).

Table S4-1 – Descriptive data of measured devices, showing the pneumatic controller application (level, pressure or temperature), process unit they are servicing, and if they are linked to a single well or multiple wells.

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| AA01-PC04 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC05 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC06 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC07 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC08 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC09 | MC | Level | Separator | Separator - Level Control | Y |
| AA01-PC11 | MC | Pressure | Compressor | Compressor | Y |
| AA02-PC04 | MC | Level | Compressor | Other | Y |
| AA02-PC05 | MC | Level | Compressor | Compressor | Y |
| AA02-PC06 | MC | Level | Compressor | Compressor | Y |
| AA02-PC07 | MC | Level | Compressor | Compressor | Y |
| AA02-PC08 | MC | Pressure | Compressor | Compressor | Y |
| AA02-PC09 | MC | Level | Compressor | Compressor | Y |
| AP01-PC01 | MC | Level | Separator | Separator - Level Control | N |
| AP01-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| AP01-PC03 | MC | Level | Separator | Separator - Level Control | Y |
| AP01-PC04 | MC | Level | Separator | Separator - Level Control | Y |
| AP01-PC05 | MC | Level | Separator | Separator - Level Control | Y |
| AP01-PC12 | MC | Level | Separator | Separator - Level Control | N |
| AP02-PC01 | MC | Level | Separator | Separator - Level Control | N |
| AP02-PC02 | MC | Level | Separator | Separator - Level Control | N |
| AP02-PC03 | MC | Level | Separator | Separator - Level Control | N |
| AP02-PC04 | MC | Level | Separator | Separator - Level Control | N |
| AP03-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| AP03-PC02 | MC | Level | Separator | Separator - Level Control | N |
| AP04-PC01 | MC | Level | Separator | Separator - Level Control | N |
| AP04-PC02 | MC | Level | Separator | Separator - Level Control | N |
| AP04-PC03 | MC | Level | Separator | Separator - Level Control | N |
| AP04-PC04 | MC | Level | Separator | Separator - Level Control | Y |
| AP05-PC01 | MC | Level | Separator | Separator - Level Control | N |
| AP05-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| CW01-PC01 | RM | Pressure | Wellhead | ESD | Y |
| CW01-PC02 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW01-PC03 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC04 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC05 | RM | Temperature | Process Heater | Process Heater | Y |
| CW01-PC11 | RM | Pressure | Wellhead | ESD | Y |
| CW01-PC12 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW01-PC13 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC14 | RM | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| CW01-PC15 | RM | Temperature | Process Heater | Process Heater | Y |
| CW01-PC21 | RM | Pressure | Wellhead | ESD | Y |
| CW01-PC22 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW01-PC23 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC24 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC25 | RM | Temperature | Process Heater | Process Heater | Y |
| CW01-PC31 | RM | Pressure | Wellhead | ESD | Y |
| CW01-PC32 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW01-PC33 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC34 | RM | Level | Separator | Separator - Level Control | Y |
| CW01-PC35 | RM | Temperature | Process Heater | Process Heater | Y |
| CW02-PC01 | RM | Pressure | Wellhead | ESD | Y |
| CW02-PC02 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW02-PC03 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC04 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC05 | RM | Temperature | Process Heater | Process Heater | Y |
| CW02-PC11 | RM | Pressure | Wellhead | ESD | Y |
| CW02-PC12 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW02-PC13 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC14 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC15 | RM | Temperature | Process Heater | Process Heater | Y |
| CW02-PC21 | RM | Pressure | Wellhead | ESD | Y |
| CW02-PC22 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW02-PC23 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC24 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC25 | RM | Temperature | Process Heater | Process Heater | Y |
| CW02-PC31 | RM | Pressure | Wellhead | ESD | Y |
| CW02-PC32 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| CW02-PC33 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC34 | RM | Level | Separator | Separator - Level Control | Y |
| CW02-PC35 | RM | Temperature | Process Heater | Process Heater | Y |
| CZ01-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ01-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ02-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ02-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ03-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ03-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ04-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ04-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ05-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ05-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ05-PC03 | GC | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| CZ06-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ06-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ06-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| CZ07-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ07-PC02 | GC | Pressure | Plunger Lift | Plunger Lift | Y |
| CZ08-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ08-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| CZ09-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ09-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| CZ10-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| CZ11-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| DL01-PC01 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC02 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC03 | RM | Temperature | Process Heater | Process Heater | Y |
| DL01-PC04 | RM | Level | Wellhead | ESD | Y |
| DL01-PC05 | RM | Temperature | Process Heater | Process Heater | Y |
| DL01-PC11 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC12 | RM | Level | Wellhead | ESD | Y |
| DL01-PC13 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC14 | RM | Level | Wellhead | ESD | Y |
| DL01-PC15 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC21 | RM | Level | Wellhead | ESD | Y |
| DL01-PC22 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC23 | RM | Level | Wellhead | ESD | Y |
| DL01-PC24 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC25 | RM | Level | Wellhead | ESD | Y |
| DL01-PC31 | RM | Temperature | Process Heater | Process Heater | Y |
| DL01-PC32 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC33 | RM | Level | Wellhead | ESD | Y |
| DL01-PC34 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC35 | RM | Level | Wellhead | ESD | Y |
| DL01-PC41 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC42 | RM | Level | Wellhead | ESD | Y |
| DL01-PC43 | RM | Level | Separator | Separator - Level Control | Y |
| DL01-PC44 | RM | Level | Wellhead | ESD | Y |
| DL01-PC45 | RM | Temperature | Flare | Other | N |
| DL02-PC01 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC02 | RM | Level | Wellhead | ESD | Y |
| DL02-PC03 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC04 | RM | Level | Wellhead | ESD | Y |
| DL02-PC05 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC11 | RM | Level | Wellhead | ESD | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| DL02-PC12 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC13 | RM | Level | Wellhead | ESD | Y |
| DL02-PC14 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC15 | RM | Level | Wellhead | ESD | Y |
| DL02-PC21 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC22 | RM | Level | Wellhead | ESD | Y |
| DL02-PC23 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC24 | RM | Level | Wellhead | ESD | Y |
| DL02-PC25 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC31 | RM | Level | Wellhead | ESD | Y |
| DL02-PC32 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC33 | RM | Level | Wellhead | ESD | Y |
| DL02-PC34 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC35 | RM | Level | Wellhead | ESD | Y |
| DL02-PC41 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC42 | RM | Level | Wellhead | ESD | Y |
| DL02-PC43 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC44 | RM | Level | Wellhead | ESD | Y |
| DL02-PC45 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC51 | RM | Level | Wellhead | ESD | Y |
| DL02-PC52 | RM | Level | Separator | Separator - Level Control | Y |
| DL02-PC53 | RM | Level | Wellhead | ESD | Y |
| DL02-PC54 | RM | Temperature | Process Heater | Separator - Other | Y |
| DL02-PC55 | RM | Temperature | Process Heater | Separator - Other | Y |
| DL02-PC61 | RM | Temperature | Process Heater | Separator - Other | Y |
| DL02-PC62 | RM | Temperature | Flare | Other | Y |
| GZ01-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC05 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC11 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC12 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC13 | GC | Level | Separator | Separator - Level Control | Y |
| GZ01-PC14 | GC | Pressure | Wellhead | ESD | Y |
| GZ01-PC15 | GC | Pressure | Wellhead | ESD | Y |
| GZ01-PC21 | GC | Pressure | Wellhead | ESD | Y |
| GZ01-PC22 | GC | Pressure | Wellhead | ESD | Y |
| GZ02-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| GZ02-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| GZ02-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| GZ02-PC04 | GC | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|--------------------|---------------------------|-------------------|
| GZ02-PC05 | GC | Level | Compressor | Other | N |
| GZ02-PC11 | GC | Level | Compressor | Compressor | N |
| GZ02-PC12 | GC | Level | Compressor | Compressor | N |
| GZ02-PC13 | GC | Level | Compressor | Compressor | N |
| GZ02-PC14 | GC | Pressure | Compressor | Compressor | N |
| GZ02-PC15 | GC | Level | Compressor | Compressor | N |
| GZ02-PC21 | GC | Level | Compressor | Compressor | N |
| GZ02-PC22 | GC | Pressure | Wellhead | ESD | Y |
| GZ02-PC23 | GC | Pressure | Wellhead | ESD | Y |
| GZ02-PC24 | GC | Pressure | Compressor | Compressor | N |
| GZ03-PC01 | GC | Level | Compressor | Compressor | N |
| GZ03-PC02 | GC | Level | Compressor | Compressor | N |
| GZ03-PC03 | GC | Level | Compressor | Compressor | N |
| GZ03-PC04 | GC | Level | Compressor | Other | N |
| GZ03-PC05 | GC | Pressure | Compressor | Compressor | N |
| GZ03-PC11 | GC | Pressure | Wellhead | ESD | Y |
| GZ03-PC12 | GC | Pressure | Wellhead | ESD | Y |
| GZ03-PC13 | GC | Level | Separator | Separator - Level Control | N |
| GZ03-PC14 | GC | Level | Separator | Separator - Level Control | N |
| GZ03-PC15 | GC | Level | Separator | Separator - Level Control | N |
| GZ03-PC21 | GC | Level | Separator | Separator - Level Control | Y |
| GZ03-PC22 | GC | Level | Separator | Separator - Level Control | Y |
| GZ03-PC23 | GC | Level | Separator | Separator - Level Control | Y |
| GZ03-PC24 | GC | Level | Separator | Separator - Level Control | Y |
| GZ03-PC25 | GC | Pressure | Wellhead | ESD | N |
| GZ03-PC31 | GC | Level | Dehydration System | Separator - Level Control | N |
| GZ03-PC32 | GC | Level | Dehydration System | Dehydration System | N |
| GZ03-PC33 | GC | Level | Dehydration System | Dehydration System | N |
| GZ03-PC34 | GC | Temperature | Dehydration System | Dehydration System | N |
| GZ03-PC35 | GC | Temperature | Dehydration System | Dehydration System | N |
| GZ03-PC41 | GC | Level | Dehydration System | Other | N |
| GZ03-PC42 | GC | Pressure | Sales | Other | N |
| GZ04-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| GZ04-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| GZ04-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| GZ04-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| GZ04-PC05 | GC | Pressure | Wellhead | ESD | Y |
| GZ04-PC11 | GC | Pressure | Wellhead | ESD | Y |
| LB01-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB01-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB02-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB02-PC02 | GC | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| LB02-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| LB02-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| LB03-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB03-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB04-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB04-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB04-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| LB04-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| LB05-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB05-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB05-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| LB05-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC05 | GC | Level | Separator | Separator - Level Control | Y |
| LB06-PC11 | GC | Level | Separator | Separator - Level Control | Y |
| LB07-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| LB07-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| LB07-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| LB07-PC04 | GC | Level | Separator | Separator - Level Control | Y |
| OF01-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF02-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF03-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF04-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF05-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF06-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF07-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF08-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF08-PC02 | AP | Pressure | Plunger Lift | Plunger Lift | Y |
| OF09-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF10-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF11-PC01 | AP | Pressure | Wellhead | Separator - Other | Y |
| OF11-PC02 | AP | Level | Separator | Separator - Level Control | Y |
| OF11-PC03 | AP | Level | Separator | Separator - Level Control | Y |
| OF11-PC04 | AP | Pressure | Wellhead | Separator - Other | Y |
| RB01-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| RB01-PC02 | GC | Level | Separator | Separator - Level Control | Y |
| RB01-PC03 | GC | Level | Separator | Separator - Level Control | Y |
| RB01-PC04 | GC | Pressure | Separator | Separator - Other | N |
| RB01-PC05 | GC | Level | Separator | Separator - Level Control | N |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|--------------------|---------------------------|-------------------|
| RB01-PC11 | GC | Level | Separator | Separator - Level Control | N |
| RB01-PC12 | GC | Level | Separator | Separator - Level Control | N |
| RB01-PC13 | GC | Level | Dehydration System | Dehydration System | N |
| RB01-PC14 | GC | Level | Dehydration System | Dehydration System | N |
| RB01-PC15 | GC | Level | Dehydration System | Dehydration System | N |
| RB01-PC21 | GC | Temperature | Dehydration System | Dehydration System | N |
| RB01-PC23 | GC | Pressure | Dehydration System | Other | N |
| RB01-PC24 | GC | Level | Dehydration System | Separator - Level Control | N |
| RB01-PC25 | GC | Level | Flare | Other | N |
| RB01-PC34 | GC | Level | Separator | Separator - Level Control | Y |
| RB02-PC01 | GC | Level | Separator | Separator - Level Control | Y |
| RB02-PC02 | GC | Level | Dehydration System | Dehydration System | Y |
| RB02-PC03 | GC | Temperature | Dehydration System | Dehydration System | Y |
| RB02-PC05 | GC | Level | Dehydration System | Dehydration System | Y |
| RB02-PC11 | GC | Level | Dehydration System | Dehydration System | Y |
| RB02-PC12 | GC | Level | Dehydration System | Other | Y |
| RQ01-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| RQ02-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| RQ02-PC02 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| RQ03-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| RQ04-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| RQ05-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| RQ05-PC02 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| RQ05-PC03 | MC | Level | Separator | Separator - Level Control | Y |
| RQ05-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| RQ06-PC01 | MC | Temperature | Process Heater | Process Heater | Y |
| RQ06-PC02 | MC | Temperature | Process Heater | Process Heater | Y |
| RQ06-PC03 | MC | Level | Separator | Separator - Level Control | Y |
| RQ06-PC04 | MC | Level | Separator | Separator - Level Control | Y |
| RQ07-PC01 | MC | Temperature | Process Heater | Process Heater | Y |
| RQ07-PC02 | MC | Temperature | Process Heater | Process Heater | Y |
| RQ07-PC03 | MC | Level | Separator | Separator - Level Control | Y |
| RQ07-PC04 | MC | Level | Separator | Separator - Level Control | Y |
| RQ07-PC05 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| VF01-PC01 | AP | Level | Wellhead | ESD | Y |
| VF01-PC02 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC03 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC04 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC05 | AP | Level | Wellhead | ESD | Y |
| VF01-PC11 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC12 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC13 | AP | Temperature | Process Heater | Process Heater | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|---------------------------|-------------------|
| VF01-PC14 | AP | Level | Wellhead | ESD | Y |
| VF01-PC15 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC21 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC22 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC23 | AP | Level | Wellhead | ESD | Y |
| VF01-PC24 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC25 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC31 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC32 | AP | Level | Wellhead | ESD | Y |
| VF01-PC33 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC34 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC35 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC41 | AP | Level | Wellhead | ESD | Y |
| VF01-PC42 | AP | Level | Separator | Separator - Level Control | Y |
| VF01-PC43 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC44 | AP | Temperature | Process Heater | Process Heater | Y |
| VF01-PC45 | AP | Pressure | Wellhead | Other | Y |
| VF01-PC51 | AP | Pressure | Wellhead | Other | Y |
| VF01-PC52 | AP | Pressure | Wellhead | Other | Y |
| VF01-PC53 | AP | Pressure | Wellhead | Other | Y |
| VF01-PC54 | AP | Pressure | Wellhead | Other | Y |
| VF01-PC55 | AP | Pressure | Wellhead | Other | Y |
| VF02-PC01 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC02 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC03 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC04 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC05 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC11 | AP | Level | Separator | Separator - Level Control | Y |
| VF02-PC12 | AP | Temperature | Process Heater | Process Heater | Y |
| XQ01-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ01-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ01-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ01-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ02-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ02-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ02-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ02-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ03-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ03-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ03-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ03-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ04-PC01 | MC | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|--------------------|---------------------------|-------------------|
| XQ04-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ04-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ04-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ05-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ05-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ05-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ05-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ06-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ06-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ06-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ06-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| XQ07-PC01 | MC | Level | Separator | Separator - Level Control | Y |
| XQ07-PC02 | MC | Level | Separator | Separator - Level Control | Y |
| XQ07-PC03 | MC | Temperature | Process Heater | Process Heater | Y |
| XQ07-PC04 | MC | Pressure | Plunger Lift | Plunger Lift | Y |
| ZW01-PC01 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC02 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC03 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC04 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC05 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW01-PC11 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW01-PC12 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC13 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC14 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC15 | RM | Level | Separator | Separator - Level Control | Y |
| ZW01-PC21 | RM | Level | Process Heater | Process Heater | Y |
| ZW01-PC22 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC23 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC24 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW01-PC25 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW01-PC31 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| ZW01-PC32 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC33 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW01-PC34 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW01-PC35 | RM | Temperature | Process Heater | Process Heater | Y |
| ZW02-PC01 | RM | Level | Separator | Separator - Level Control | Y |
| ZW02-PC02 | RM | Level | Separator | Separator - Level Control | Y |
| ZW02-PC03 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW02-PC04 | RM | Temperature | Dehydration System | Dehydration System | Y |
| ZW02-PC12 | RM | Pressure | Plunger Lift | Plunger Lift | Y |
| ZW03-PC01 | RM | Level | Separator | Separator - Level Control | Y |
| ZW03-PC02 | RM | Level | Separator | Separator - Level Control | Y |

| Device Identifier | Region | Controller application | Basic application | Detailed application | Single Well (Y/N) |
|-------------------|--------|------------------------|-------------------|----------------------|-------------------|
| ZW03-PC03 | RM | Pressure | Plunger Lift | Plunger Lift | Y |

Table S4-2 – Device classification, based on field characterization by site operator (On/OFF or throttle), time series characterization (Intermittent-vent, Continuous-vent, Intermittent-vent*, or Continuous-vent*, and EPA classification provided by the companies.

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| AA01-PC04 | On/Off | intermittent-vent | intermittent |
| AA01-PC05 | Throttle | intermittent-vent | intermittent |
| AA01-PC06 | On/Off | intermittent-vent | intermittent |
| AA01-PC07 | Throttle | intermittent-vent | intermittent |
| AA01-PC08 | On/Off | intermittent-vent | intermittent |
| AA01-PC09 | Throttle | intermittent-vent | intermittent |
| AA01-PC11 | Throttle | intermittent-vent | intermittent |
| AA02-PC04 | On/Off | continuous-vent | intermittent |
| AA02-PC05 | On/Off | intermittent-vent | intermittent |
| AA02-PC06 | On/Off | continuous-vent * | intermittent |
| AA02-PC07 | On/Off | continuous-vent * | intermittent |
| AA02-PC08 | Throttle | continuous-vent | intermittent |
| AA02-PC09 | On/Off | continuous-vent | intermittent |
| AP01-PC01 | On/Off | intermittent-vent | intermittent |
| AP01-PC02 | On/Off | intermittent-vent | intermittent |
| AP01-PC03 | On/Off | intermittent-vent | intermittent |
| AP01-PC04 | On/Off | intermittent-vent | intermittent |
| AP01-PC05 | On/Off | intermittent-vent | intermittent |
| AP01-PC12 | On/Off | intermittent-vent * | intermittent |
| AP02-PC01 | On/Off | intermittent-vent | intermittent |
| AP02-PC02 | On/Off | intermittent-vent | intermittent |
| AP02-PC03 | On/Off | intermittent-vent | intermittent |
| AP02-PC04 | On/Off | intermittent-vent | intermittent |
| AP03-PC01 | On/Off | intermittent-vent | intermittent |
| AP03-PC02 | On/Off | intermittent-vent | intermittent |
| AP04-PC01 | On/Off | intermittent-vent | intermittent |
| AP04-PC02 | On/Off | intermittent-vent | intermittent |
| AP04-PC03 | On/Off | intermittent-vent | intermittent |
| AP04-PC04 | On/Off | intermittent-vent | intermittent |
| AP05-PC01 | On/Off | intermittent-vent | intermittent |
| AP05-PC02 | On/Off | intermittent-vent | intermittent |
| CW01-PC01 | On/Off | intermittent-vent | low bleed |
| CW01-PC02 | On/Off | intermittent-vent | low bleed |
| CW01-PC03 | On/Off | intermittent-vent | low bleed |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| CW01-PC04 | On/Off | intermittent-vent | low bleed |
| CW01-PC05 | On/Off | intermittent-vent | low bleed |
| CW01-PC11 | On/Off | intermittent-vent | low bleed |
| CW01-PC12 | On/Off | intermittent-vent | low bleed |
| CW01-PC13 | On/Off | intermittent-vent | low bleed |
| CW01-PC14 | On/Off | intermittent-vent | low bleed |
| CW01-PC15 | On/Off | intermittent-vent | low bleed |
| CW01-PC21 | On/Off | intermittent-vent | low bleed |
| CW01-PC22 | On/Off | intermittent-vent | low bleed |
| CW01-PC23 | On/Off | intermittent-vent | low bleed |
| CW01-PC24 | On/Off | intermittent-vent | low bleed |
| CW01-PC25 | On/Off | intermittent-vent | low bleed |
| CW01-PC31 | On/Off | intermittent-vent | low bleed |
| CW01-PC32 | On/Off | intermittent-vent | low bleed |
| CW01-PC33 | On/Off | intermittent-vent | low bleed |
| CW01-PC34 | On/Off | intermittent-vent | low bleed |
| CW01-PC35 | On/Off | intermittent-vent | low bleed |
| CW02-PC01 | On/Off | intermittent-vent | intermittent |
| CW02-PC02 | On/Off | intermittent-vent | intermittent |
| CW02-PC03 | On/Off | intermittent-vent | intermittent |
| CW02-PC04 | On/Off | intermittent-vent | intermittent |
| CW02-PC05 | On/Off | intermittent-vent | intermittent |
| CW02-PC11 | On/Off | intermittent-vent | intermittent |
| CW02-PC12 | On/Off | intermittent-vent | intermittent |
| CW02-PC13 | On/Off | intermittent-vent | intermittent |
| CW02-PC14 | On/Off | intermittent-vent | intermittent |
| CW02-PC15 | On/Off | intermittent-vent | intermittent |
| CW02-PC21 | On/Off | intermittent-vent | intermittent |
| CW02-PC22 | On/Off | intermittent-vent | intermittent |
| CW02-PC23 | On/Off | intermittent-vent | intermittent |
| CW02-PC24 | On/Off | intermittent-vent | intermittent |
| CW02-PC25 | On/Off | intermittent-vent | intermittent |
| CW02-PC31 | On/Off | intermittent-vent | intermittent |
| CW02-PC32 | On/Off | intermittent-vent | intermittent |
| CW02-PC33 | On/Off | continuous-vent * | intermittent |
| CW02-PC34 | On/Off | intermittent-vent | intermittent |
| CW02-PC35 | On/Off | intermittent-vent | intermittent |
| CZ01-PC01 | On/Off | intermittent-vent | not classified |
| CZ01-PC02 | On/Off | intermittent-vent | not classified |
| CZ02-PC01 | On/Off | continuous-vent * | not classified |
| CZ02-PC02 | On/Off | intermittent-vent | not classified |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| CZ03-PC01 | Throttle | intermittent-vent | not classified |
| CZ03-PC02 | On/Off | intermittent-vent | not classified |
| CZ04-PC01 | On/Off | intermittent-vent | not classified |
| CZ04-PC02 | On/Off | intermittent-vent | not classified |
| CZ05-PC01 | On/Off | continuous-vent | not classified |
| CZ05-PC02 | On/Off | intermittent-vent | not classified |
| CZ05-PC03 | On/Off | intermittent-vent | not classified |
| CZ06-PC01 | Throttle | continuous-vent | not classified |
| CZ06-PC02 | On/Off | continuous-vent | not classified |
| CZ06-PC03 | Throttle | intermittent-vent | not classified |
| CZ07-PC01 | On/Off | intermittent-vent | not classified |
| CZ07-PC02 | On/Off | intermittent-vent | not classified |
| CZ08-PC01 | Throttle | continuous-vent | low bleed |
| CZ08-PC02 | Throttle | intermittent-vent * | low bleed |
| CZ09-PC01 | On/Off | continuous-vent | low bleed |
| CZ09-PC02 | Throttle | continuous-vent | low bleed |
| CZ10-PC01 | On/Off | intermittent-vent * | low bleed |
| CZ11-PC01 | Throttle | intermittent-vent * | low bleed |
| DL01-PC01 | On/Off | intermittent-vent | not classified |
| DL01-PC02 | On/Off | intermittent-vent | not classified |
| DL01-PC03 | On/Off | intermittent-vent | not classified |
| DL01-PC04 | On/Off | continuous-vent * | not classified |
| DL01-PC05 | On/Off | intermittent-vent | not classified |
| DL01-PC11 | On/Off | intermittent-vent | not classified |
| DL01-PC12 | On/Off | intermittent-vent | not classified |
| DL01-PC13 | On/Off | intermittent-vent | not classified |
| DL01-PC14 | On/Off | intermittent-vent | not classified |
| DL01-PC15 | On/Off | intermittent-vent | not classified |
| DL01-PC21 | On/Off | intermittent-vent | not classified |
| DL01-PC22 | On/Off | intermittent-vent | not classified |
| DL01-PC23 | On/Off | intermittent-vent * | not classified |
| DL01-PC24 | On/Off | continuous-vent | not classified |
| DL01-PC25 | On/Off | intermittent-vent | not classified |
| DL01-PC31 | On/Off | intermittent-vent | not classified |
| DL01-PC32 | On/Off | intermittent-vent | not classified |
| DL01-PC33 | On/Off | intermittent-vent | not classified |
| DL01-PC34 | On/Off | intermittent-vent | not classified |
| DL01-PC35 | On/Off | intermittent-vent | not classified |
| DL01-PC41 | On/Off | intermittent-vent | not classified |
| DL01-PC42 | On/Off | intermittent-vent | not classified |
| DL01-PC43 | On/Off | intermittent-vent | not classified |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| DL01-PC44 | On/Off | intermittent-vent | not classified |
| DL01-PC45 | On/Off | intermittent-vent | not classified |
| DL02-PC01 | On/Off | intermittent-vent | not classified |
| DL02-PC02 | On/Off | intermittent-vent | not classified |
| DL02-PC03 | On/Off | intermittent-vent | not classified |
| DL02-PC04 | On/Off | intermittent-vent | not classified |
| DL02-PC05 | On/Off | intermittent-vent | not classified |
| DL02-PC11 | On/Off | intermittent-vent | not classified |
| DL02-PC12 | On/Off | intermittent-vent | not classified |
| DL02-PC13 | On/Off | intermittent-vent | not classified |
| DL02-PC14 | On/Off | intermittent-vent * | not classified |
| DL02-PC15 | On/Off | intermittent-vent * | not classified |
| DL02-PC21 | On/Off | intermittent-vent | not classified |
| DL02-PC22 | On/Off | intermittent-vent | not classified |
| DL02-PC23 | On/Off | intermittent-vent | not classified |
| DL02-PC24 | On/Off | intermittent-vent | not classified |
| DL02-PC25 | On/Off | continuous-vent * | not classified |
| DL02-PC31 | On/Off | intermittent-vent | not classified |
| DL02-PC32 | On/Off | intermittent-vent | not classified |
| DL02-PC33 | On/Off | intermittent-vent * | not classified |
| DL02-PC34 | On/Off | intermittent-vent | not classified |
| DL02-PC35 | On/Off | intermittent-vent | not classified |
| DL02-PC41 | On/Off | intermittent-vent | not classified |
| DL02-PC42 | On/Off | intermittent-vent | not classified |
| DL02-PC43 | On/Off | intermittent-vent | not classified |
| DL02-PC44 | On/Off | intermittent-vent | not classified |
| DL02-PC45 | On/Off | intermittent-vent | not classified |
| DL02-PC51 | On/Off | intermittent-vent | not classified |
| DL02-PC52 | On/Off | intermittent-vent | not classified |
| DL02-PC53 | On/Off | intermittent-vent | not classified |
| DL02-PC54 | On/Off | intermittent-vent | not classified |
| DL02-PC55 | On/Off | intermittent-vent | not classified |
| DL02-PC61 | On/Off | intermittent-vent | not classified |
| DL02-PC62 | On/Off | intermittent-vent | not classified |
| GZ01-PC01 | On/Off | intermittent-vent | intermittent |
| GZ01-PC02 | On/Off | intermittent-vent | intermittent |
| GZ01-PC03 | On/Off | intermittent-vent | intermittent |
| GZ01-PC04 | On/Off | intermittent-vent | intermittent |
| GZ01-PC05 | On/Off | intermittent-vent | intermittent |
| GZ01-PC11 | On/Off | intermittent-vent | intermittent |
| GZ01-PC12 | On/Off | intermittent-vent | intermittent |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| GZ01-PC13 | On/Off | intermittent-vent | intermittent |
| GZ01-PC14 | On/Off | intermittent-vent | intermittent |
| GZ01-PC15 | On/Off | intermittent-vent | intermittent |
| GZ01-PC21 | On/Off | intermittent-vent | intermittent |
| GZ01-PC22 | On/Off | intermittent-vent | intermittent |
| GZ02-PC01 | Throttle | intermittent-vent | intermittent |
| GZ02-PC02 | Throttle | intermittent-vent | intermittent |
| GZ02-PC03 | Throttle | intermittent-vent | intermittent |
| GZ02-PC04 | Throttle | intermittent-vent | intermittent |
| GZ02-PC05 | On/Off | intermittent-vent | intermittent |
| GZ02-PC11 | On/Off | intermittent-vent | intermittent |
| GZ02-PC12 | On/Off | continuous-vent | intermittent |
| GZ02-PC13 | On/Off | intermittent-vent | intermittent |
| GZ02-PC14 | Throttle | continuous-vent | intermittent |
| GZ02-PC15 | On/Off | intermittent-vent | intermittent |
| GZ02-PC21 | Throttle | intermittent-vent | intermittent |
| GZ02-PC22 | On/Off | intermittent-vent | intermittent |
| GZ02-PC23 | On/Off | intermittent-vent | intermittent |
| GZ02-PC24 | On/Off | intermittent-vent | intermittent |
| GZ03-PC01 | On/Off | continuous-vent * | intermittent |
| GZ03-PC02 | On/Off | intermittent-vent * | intermittent |
| GZ03-PC03 | On/Off | intermittent-vent | intermittent |
| GZ03-PC04 | On/Off | intermittent-vent | intermittent |
| GZ03-PC05 | Throttle | intermittent-vent * | intermittent |
| GZ03-PC11 | On/Off | intermittent-vent | intermittent |
| GZ03-PC12 | On/Off | intermittent-vent | intermittent |
| GZ03-PC13 | Throttle | continuous-vent | intermittent |
| GZ03-PC14 | On/Off | intermittent-vent * | intermittent |
| GZ03-PC15 | On/Off | intermittent-vent | intermittent |
| GZ03-PC21 | On/Off | intermittent-vent | intermittent |
| GZ03-PC22 | On/Off | continuous-vent | intermittent |
| GZ03-PC23 | On/Off | intermittent-vent | intermittent |
| GZ03-PC24 | On/Off | continuous-vent | intermittent |
| GZ03-PC25 | On/Off | intermittent-vent | intermittent |
| GZ03-PC31 | On/Off | intermittent-vent | intermittent |
| GZ03-PC32 | Throttle | intermittent-vent | intermittent |
| GZ03-PC33 | Throttle | intermittent-vent | intermittent |
| GZ03-PC34 | On/Off | intermittent-vent | intermittent |
| GZ03-PC35 | On/Off | intermittent-vent | intermittent |
| GZ03-PC41 | On/Off | intermittent-vent | intermittent |
| GZ03-PC42 | Throttle | intermittent-vent | intermittent |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| GZ04-PC01 | On/Off | intermittent-vent | intermittent |
| GZ04-PC02 | Throttle | continuous-vent * | intermittent |
| GZ04-PC03 | On/Off | intermittent-vent * | intermittent |
| GZ04-PC04 | Throttle | intermittent-vent | intermittent |
| GZ04-PC05 | On/Off | intermittent-vent | intermittent |
| GZ04-PC11 | On/Off | intermittent-vent | intermittent |
| LB01-PC01 | On/Off | intermittent-vent | not classified |
| LB01-PC02 | On/Off | intermittent-vent | not classified |
| LB02-PC01 | On/Off | intermittent-vent | not classified |
| LB02-PC02 | On/Off | intermittent-vent | not classified |
| LB02-PC03 | On/Off | intermittent-vent | not classified |
| LB02-PC04 | On/Off | intermittent-vent | not classified |
| LB03-PC01 | On/Off | intermittent-vent * | not classified |
| LB03-PC02 | On/Off | intermittent-vent | not classified |
| LB04-PC01 | On/Off | intermittent-vent | not classified |
| LB04-PC02 | On/Off | intermittent-vent * | not classified |
| LB04-PC03 | On/Off | intermittent-vent | not classified |
| LB04-PC04 | On/Off | intermittent-vent | not classified |
| LB05-PC01 | On/Off | intermittent-vent * | not classified |
| LB05-PC02 | On/Off | intermittent-vent | not classified |
| LB05-PC03 | On/Off | intermittent-vent * | not classified |
| LB05-PC04 | On/Off | intermittent-vent | not classified |
| LB06-PC01 | On/Off | intermittent-vent | not classified |
| LB06-PC02 | On/Off | intermittent-vent | not classified |
| LB06-PC03 | On/Off | intermittent-vent | not classified |
| LB06-PC04 | On/Off | intermittent-vent | not classified |
| LB06-PC05 | On/Off | intermittent-vent | not classified |
| LB06-PC11 | On/Off | intermittent-vent | not classified |
| LB07-PC01 | On/Off | intermittent-vent | not classified |
| LB07-PC02 | On/Off | continuous-vent * | not classified |
| LB07-PC03 | On/Off | intermittent-vent | not classified |
| LB07-PC04 | On/Off | intermittent-vent | not classified |
| OF01-PC01 | On/Off | intermittent-vent * | not classified |
| OF02-PC01 | On/Off | intermittent-vent | not classified |
| OF03-PC01 | On/Off | intermittent-vent | not classified |
| OF04-PC01 | On/Off | intermittent-vent | not classified |
| OF05-PC01 | On/Off | intermittent-vent | not classified |
| OF06-PC01 | On/Off | intermittent-vent | not classified |
| OF07-PC01 | On/Off | continuous-vent * | not classified |
| OF08-PC01 | On/Off | intermittent-vent | not classified |
| OF08-PC02 | On/Off | intermittent-vent | not classified |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| OF09-PC01 | On/Off | intermittent-vent | not classified |
| OF10-PC01 | On/Off | continuous-vent | not classified |
| OF11-PC01 | On/Off | intermittent-vent * | not classified |
| OF11-PC02 | Throttle | continuous-vent * | not classified |
| OF11-PC03 | Throttle | intermittent-vent | not classified |
| OF11-PC04 | Throttle | intermittent-vent | not classified |
| RB01-PC01 | On/Off | intermittent-vent | not classified |
| RB01-PC02 | On/Off | intermittent-vent | not classified |
| RB01-PC03 | On/Off | intermittent-vent | not classified |
| RB01-PC04 | Throttle | continuous-vent | not classified |
| RB01-PC05 | On/Off | intermittent-vent | not classified |
| RB01-PC11 | On/Off | intermittent-vent | not classified |
| RB01-PC12 | On/Off | intermittent-vent | not classified |
| RB01-PC13 | On/Off | continuous-vent | not classified |
| RB01-PC14 | On/Off | intermittent-vent * | not classified |
| RB01-PC15 | On/Off | intermittent-vent | not classified |
| RB01-PC21 | Throttle | continuous-vent | not classified |
| RB01-PC23 | Throttle | continuous-vent | not classified |
| RB01-PC24 | On/Off | intermittent-vent | not classified |
| RB01-PC25 | On/Off | intermittent-vent | not classified |
| RB01-PC34 | On/Off | continuous-vent | not classified |
| RB02-PC01 | On/Off | intermittent-vent | not classified |
| RB02-PC02 | On/Off | intermittent-vent | not classified |
| RB02-PC03 | Throttle | continuous-vent * | not classified |
| RB02-PC05 | On/Off | intermittent-vent | not classified |
| RB02-PC11 | On/Off | intermittent-vent | not classified |
| RB02-PC12 | On/Off | intermittent-vent | not classified |
| RQ01-PC01 | Throttle | intermittent-vent | not classified |
| RQ02-PC01 | Throttle | continuous-vent | not classified |
| RQ02-PC02 | On/Off | intermittent-vent | not classified |
| RQ03-PC01 | Throttle | continuous-vent | not classified |
| RQ04-PC01 | Throttle | intermittent-vent | not classified |
| RQ05-PC01 | Throttle | intermittent-vent | not classified |
| RQ05-PC02 | On/Off | intermittent-vent | not classified |
| RQ05-PC03 | Throttle | continuous-vent | not classified |
| RQ05-PC04 | On/Off | intermittent-vent | not classified |
| RQ06-PC01 | On/Off | intermittent-vent | not classified |
| RQ06-PC02 | On/Off | intermittent-vent | not classified |
| RQ06-PC03 | Throttle | intermittent-vent | not classified |
| RQ06-PC04 | Throttle | intermittent-vent | not classified |
| RQ07-PC01 | On/Off | intermittent-vent | not classified |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| RQ07-PC02 | On/Off | intermittent-vent | not classified |
| RQ07-PC03 | Throttle | continuous-vent | not classified |
| RQ07-PC04 | Throttle | continuous-vent | not classified |
| RQ07-PC05 | On/Off | intermittent-vent | not classified |
| VF01-PC01 | On/Off | continuous-vent | not classified |
| VF01-PC02 | On/Off | intermittent-vent | not classified |
| VF01-PC03 | On/Off | intermittent-vent | not classified |
| VF01-PC04 | On/Off | intermittent-vent | not classified |
| VF01-PC05 | On/Off | continuous-vent | not classified |
| VF01-PC11 | On/Off | intermittent-vent | not classified |
| VF01-PC12 | On/Off | intermittent-vent | not classified |
| VF01-PC13 | On/Off | intermittent-vent | not classified |
| VF01-PC14 | On/Off | intermittent-vent | not classified |
| VF01-PC15 | On/Off | intermittent-vent | not classified |
| VF01-PC21 | On/Off | intermittent-vent | not classified |
| VF01-PC22 | On/Off | continuous-vent | not classified |
| VF01-PC23 | On/Off | intermittent-vent | not classified |
| VF01-PC24 | On/Off | intermittent-vent | not classified |
| VF01-PC25 | On/Off | intermittent-vent | not classified |
| VF01-PC31 | On/Off | intermittent-vent | not classified |
| VF01-PC32 | On/Off | intermittent-vent | not classified |
| VF01-PC33 | On/Off | intermittent-vent | not classified |
| VF01-PC34 | On/Off | intermittent-vent | not classified |
| VF01-PC35 | On/Off | intermittent-vent | not classified |
| VF01-PC41 | On/Off | intermittent-vent | not classified |
| VF01-PC42 | On/Off | intermittent-vent | not classified |
| VF01-PC43 | On/Off | intermittent-vent | not classified |
| VF01-PC44 | On/Off | intermittent-vent | not classified |
| VF01-PC45 | On/Off | continuous-vent | not classified |
| VF01-PC51 | On/Off | continuous-vent | not classified |
| VF01-PC52 | On/Off | intermittent-vent | not classified |
| VF01-PC53 | On/Off | intermittent-vent * | not classified |
| VF01-PC54 | On/Off | intermittent-vent * | not classified |
| VF01-PC55 | On/Off | intermittent-vent | not classified |
| VF02-PC01 | On/Off | intermittent-vent | not classified |
| VF02-PC02 | On/Off | intermittent-vent | low bleed |
| VF02-PC03 | On/Off | intermittent-vent | low bleed |
| VF02-PC04 | On/Off | intermittent-vent | low bleed |
| VF02-PC05 | On/Off | intermittent-vent | low bleed |
| VF02-PC11 | On/Off | intermittent-vent | low bleed |
| VF02-PC12 | On/Off | intermittent-vent | low bleed |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| XQ01-PC01 | On/Off | intermittent-vent | intermittent |
| XQ01-PC02 | On/Off | intermittent-vent | intermittent |
| XQ01-PC03 | Throttle | intermittent-vent | intermittent |
| XQ01-PC04 | On/Off | continuous-vent * | high bleed |
| XQ02-PC01 | On/Off | intermittent-vent | intermittent |
| XQ02-PC02 | On/Off | intermittent-vent | intermittent |
| XQ02-PC03 | Throttle | intermittent-vent | intermittent |
| XQ02-PC04 | On/Off | continuous-vent | high bleed |
| XQ03-PC01 | On/Off | continuous-vent | high bleed |
| XQ03-PC02 | On/Off | continuous-vent | high bleed |
| XQ03-PC03 | Throttle | intermittent-vent | intermittent |
| XQ03-PC04 | On/Off | continuous-vent | high bleed |
| XQ04-PC01 | On/Off | intermittent-vent | intermittent |
| XQ04-PC02 | On/Off | continuous-vent | high bleed |
| XQ04-PC03 | Throttle | intermittent-vent | intermittent |
| XQ04-PC04 | On/Off | continuous-vent * | intermittent |
| XQ05-PC01 | On/Off | intermittent-vent | intermittent |
| XQ05-PC02 | On/Off | continuous-vent | high bleed |
| XQ05-PC03 | Throttle | intermittent-vent | intermittent |
| XQ05-PC04 | On/Off | intermittent-vent | intermittent |
| XQ06-PC01 | On/Off | continuous-vent | intermittent |
| XQ06-PC02 | On/Off | continuous-vent | intermittent |
| XQ06-PC03 | Throttle | intermittent-vent | intermittent |
| XQ06-PC04 | On/Off | intermittent-vent | intermittent |
| XQ07-PC01 | On/Off | intermittent-vent | intermittent |
| XQ07-PC02 | On/Off | intermittent-vent | intermittent |
| XQ07-PC03 | Throttle | intermittent-vent | intermittent |
| XQ07-PC04 | On/Off | intermittent-vent | intermittent |
| ZW01-PC01 | On/Off | continuous-vent * | not classified |
| ZW01-PC02 | On/Off | intermittent-vent | not classified |
| ZW01-PC03 | On/Off | intermittent-vent | not classified |
| ZW01-PC04 | On/Off | intermittent-vent | not classified |
| ZW01-PC05 | On/Off | intermittent-vent | not classified |
| ZW01-PC11 | On/Off | intermittent-vent | not classified |
| ZW01-PC12 | On/Off | intermittent-vent | not classified |
| ZW01-PC13 | On/Off | continuous-vent * | not classified |
| ZW01-PC14 | On/Off | intermittent-vent | not classified |
| ZW01-PC15 | On/Off | intermittent-vent | not classified |
| ZW01-PC21 | On/Off | intermittent-vent | not classified |
| ZW01-PC22 | On/Off | intermittent-vent | not classified |
| ZW01-PC23 | On/Off | intermittent-vent | not classified |

| Device Identifier | Field Characterization of Device service | Classification based on time series ¹ | Company classification into EPA categories ² |
|-------------------|--|--|---|
| ZW01-PC24 | On/Off | intermittent-vent | not classified |
| ZW01-PC25 | On/Off | intermittent-vent | not classified |
| ZW01-PC31 | On/Off | intermittent-vent | not classified |
| ZW01-PC32 | On/Off | intermittent-vent | not classified |
| ZW01-PC33 | On/Off | intermittent-vent | not classified |
| ZW01-PC34 | On/Off | intermittent-vent | not classified |
| ZW01-PC35 | On/Off | intermittent-vent | not classified |
| ZW02-PC01 | On/Off | continuous-vent | not classified |
| ZW02-PC02 | On/Off | intermittent-vent | not classified |
| ZW02-PC03 | On/Off | intermittent-vent | not classified |
| ZW02-PC04 | On/Off | intermittent-vent | not classified |
| ZW02-PC12 | On/Off | intermittent-vent | not classified |
| ZW03-PC01 | On/Off | intermittent-vent | not classified |
| ZW03-PC02 | On/Off | continuous-vent * | not classified |
| ZW03-PC03 | On/Off | intermittent-vent | not classified |

(1) Classification based on time series: *Intermittent-vent*: Clear actuation pattern, returning to zero between actuations. *Continuous-vent*: Non-zero, no temporal variability. A (*) Indicates that the study team made classification based on best judgment due to ambiguity from the time series.

(2) *Intermittent, Low bleed or High bleed*, for sites where all devices had the same classification (non-ambiguous). *Not classified* for sites where companies reported more than one device type.

Table S4-3 – For each device, the manufacturer and model are classified into blinded bins. The table shows measured tubing diameter and tubing length (from the controller to the valve it controls), supply gas pressure, as well as gas hydrocarbon composition for the well each device is servicing.

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| AA01-PC04 | Q01 | 29 | 0.25 | 94 | 81.85 | 8.72 | 3.86 | 2.47 |
| AA01-PC05 | Q01 | 30 | 0.25 | 94 | 81.85 | 8.72 | 3.86 | 2.47 |
| AA01-PC06 | Q01 | 0 | 0.25 | 94 | 81.42 | 8.79 | 4.02 | 2.69 |
| AA01-PC07 | Q01 | 0 | 0.25 | 94 | 81.42 | 8.79 | 4.02 | 2.69 |
| AA01-PC08 | Q01 | 28 | 0.25 | 94 | 78.32 | 8.87 | 4.44 | 3.05 |
| AA01-PC09 | Q01 | 30 | 0.25 | 94 | 78.32 | 8.87 | 4.44 | 3.05 |
| AA01-PC11 | I01 | 34 | 0.25 | 15 | 81.85 | 8.72 | 3.86 | 2.47 |
| AA02-PC04 | H01 | 11 | 0.25 | 6 | 80.53 | 8.79 | 4.10 | 2.74 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| AA02-PC05 | L01 | 29 | 0.25 | 32 | 80.53 | 8.79 | 4.10 | 2.74 |
| AA02-PC06 | L01 | 29 | 0.25 | 39 | 80.53 | 8.79 | 4.10 | 2.74 |
| AA02-PC07 | L01 | 29 | 0.25 | 41 | 80.53 | 8.79 | 4.10 | 2.74 |
| AA02-PC08 | I01 | 60 | 0.375 | 23 | 80.53 | 8.79 | 4.10 | 2.74 |
| AA02-PC09 | L01 | 29 | 0.25 | 19 | 80.53 | 8.79 | 4.10 | 2.74 |
| AP01-PC01 | N01 | 30 | 0.375 | 180 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP01-PC02 | N01 | 30 | 0.375 | 50 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP01-PC03 | N01 | 30 | 0.375 | 50 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP01-PC04 | N01 | 30 | 0.375 | 60 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP01-PC05 | N01 | 30 | 0.375 | 60 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP01-PC12 | I02 | 11 | 0.375 | 25 | 66.43 | 14.72 | 10.54 | 5.88 |
| AP02-PC01 | I02 | 22 | 0.375 | 90 | 68.85 | 14.18 | 9.90 | 4.86 |
| AP02-PC02 | I02 | 20 | 0.375 | 90 | 70.63 | 13.28 | 9.05 | 4.85 |
| AP02-PC03 | I02 | 24 | 0.375 | 75 | 72.66 | 12.24 | 8.36 | 4.40 |
| AP02-PC04 | I02 | 55 | 0.375 | 45 | 70.05 | 12.41 | 9.96 | 4.87 |
| AP03-PC01 | I02 | 30 | 0.375 | 55 | 64.46 | 15.11 | 11.39 | 6.86 |
| AP03-PC02 | I02 | 30 | 0.375 | 50 | 68.26 | 13.28 | 10.21 | 6.25 |
| AP04-PC01 | I02 | 32 | 0.375 | 25 | 65.35 | 13.15 | 11.62 | 7.04 |
| AP04-PC02 | I02 | 23 | 0.375 | 40 | 66.28 | 14.46 | 9.79 | 6.61 |
| AP04-PC03 | I02 | 32 | 0.375 | 65 | 62.75 | 13.93 | 12.76 | 7.82 |
| AP04-PC04 | I02 | 30 | 0.375 | 55 | 59.63 | 16.87 | 14.22 | 7.25 |
| AP05-PC01 | I02 | 34 | 0.375 | 25 | 70.86 | 14.03 | 7.87 | 5.14 |
| AP05-PC02 | I02 | 32 | 0.375 | 70 | 70.86 | 14.03 | 7.87 | 5.14 |
| CW01-PC01 | F01 | 20 | 0.375 | 45 | 81.26 | 7.76 | 3.90 | 2.87 |
| CW01-PC02 | B01 | 20 | 0.375 | 130 | 81.26 | 7.76 | 3.90 | 2.87 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| CW01-PC03 | Q02 | 22 | 0.375 | 30 | 81.26 | 7.76 | 3.90 | 2.87 |
| CW01-PC04 | Q02 | 18 | 0.375 | 30 | 81.26 | 7.76 | 3.90 | 2.87 |
| CW01-PC05 | I05 | 20 | 0.375 | 28 | 81.26 | 7.76 | 3.90 | 2.87 |
| CW01-PC11 | F01 | 25 | 0.375 | 45 | 81.58 | 8.25 | 3.75 | 2.71 |
| CW01-PC12 | B01 | 25 | 0.375 | 130 | 81.58 | 8.25 | 3.75 | 2.71 |
| CW01-PC13 | Q02 | 25 | 0.375 | 30 | 81.58 | 8.25 | 3.75 | 2.71 |
| CW01-PC14 | Q02 | 30 | 0.375 | 30 | 81.58 | 8.25 | 3.75 | 2.71 |
| CW01-PC15 | I05 | 25 | 0.375 | 28 | 81.58 | 8.25 | 3.75 | 2.71 |
| CW01-PC21 | F01 | 18 | 0.375 | 45 | 84.18 | 7.69 | 2.84 | 1.85 |
| CW01-PC22 | B01 | 18 | 0.375 | 130 | 84.18 | 7.69 | 2.84 | 1.85 |
| CW01-PC23 | Q02 | 18 | 0.375 | 30 | 84.18 | 7.69 | 2.84 | 1.85 |
| CW01-PC24 | Q02 | 18 | 0.375 | 30 | 84.18 | 7.69 | 2.84 | 1.85 |
| CW01-PC25 | I05 | 18 | 0.375 | 28 | 84.18 | 7.69 | 2.84 | 1.85 |
| CW01-PC31 | F01 | 20 | 0.375 | 45 | 81.69 | 7.79 | 3.77 | 2.60 |
| CW01-PC32 | B01 | 20 | 0.375 | 130 | 81.69 | 7.79 | 3.77 | 2.60 |
| CW01-PC33 | Q02 | 22 | 0.375 | 30 | 81.69 | 7.79 | 3.77 | 2.60 |
| CW01-PC34 | Q02 | 22 | 0.375 | 30 | 81.69 | 7.79 | 3.77 | 2.60 |
| CW01-PC35 | I05 | 22 | 0.375 | 28 | 81.69 | 7.79 | 3.77 | 2.60 |
| CW02-PC01 | F01 | 20 | 0.375 | 45 | 81.80 | 8.12 | 4.39 | 2.63 |
| CW02-PC02 | B01 | 20 | 0.375 | 130 | 81.80 | 8.12 | 4.39 | 2.63 |
| CW02-PC03 | Q02 | 20 | 0.375 | 30 | 81.80 | 8.12 | 4.39 | 2.63 |
| CW02-PC04 | Q02 | 19 | 0.375 | 30 | 81.80 | 8.12 | 4.39 | 2.63 |
| CW02-PC05 | I05 | 20 | 0.375 | 28 | 81.80 | 8.12 | 4.39 | 2.63 |
| CW02-PC11 | F01 | 15 | 0.375 | 45 | 80.64 | 7.81 | 4.41 | 3.51 |
| CW02-PC12 | B01 | 15 | 0.375 | 130 | 80.64 | 7.81 | 4.41 | 3.51 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| CW02-PC13 | Q02 | 16 | 0.375 | 30 | 80.64 | 7.81 | 4.41 | 3.51 |
| CW02-PC14 | Q02 | 16 | 0.375 | 30 | 80.64 | 7.81 | 4.41 | 3.51 |
| CW02-PC15 | I05 | 16 | 0.375 | 28 | 80.64 | 7.81 | 4.41 | 3.51 |
| CW02-PC21 | F01 | 20 | 0.375 | 45 | 82.36 | 7.66 | 3.78 | 2.60 |
| CW02-PC22 | B01 | 20 | 0.375 | 130 | 82.36 | 7.66 | 3.78 | 2.60 |
| CW02-PC23 | Q02 | 22 | 0.375 | 30 | 82.36 | 7.66 | 3.78 | 2.60 |
| CW02-PC24 | Q02 | 22 | 0.375 | 30 | 82.36 | 7.66 | 3.78 | 2.60 |
| CW02-PC25 | I05 | 22 | 0.375 | 28 | 82.36 | 7.66 | 3.78 | 2.60 |
| CW02-PC31 | F01 | 19 | 0.375 | 30 | 82.02 | 7.89 | 4.01 | 2.48 |
| CW02-PC32 | B01 | 19 | 0.375 | 130 | 82.02 | 7.89 | 4.01 | 2.48 |
| CW02-PC33 | Q02 | 19 | 0.375 | 30 | 82.02 | 7.89 | 4.01 | 2.48 |
| CW02-PC34 | Q02 | 20 | 0.375 | 30 | 82.02 | 7.89 | 4.01 | 2.48 |
| CW02-PC35 | I05 | 19 | 0.375 | 28 | 82.02 | 7.89 | 4.01 | 2.48 |
| CZ01-PC01 | M01 | 32.5 | 0.375 | 40 | 90.81 | 3.25 | 0.99 | 2.26 |
| CZ01-PC02 | E01 | 20 | 0.375 | 11 | 90.81 | 3.25 | 0.99 | 2.26 |
| CZ02-PC01 | J01 | 17 | 0.25 | 54 | 91.13 | 2.89 | 0.91 | 2.26 |
| CZ02-PC02 | E01 | 20 | 0.25 | 32 | 91.13 | 2.89 | 0.91 | 2.26 |
| CZ03-PC01 | A01 | 27 | 0.5 | 37 | 93.33 | 2.04 | 0.51 | 1.26 |
| CZ03-PC02 | E01 | 20 | 0.375 | 13 | 93.33 | 2.04 | 0.51 | 1.26 |
| CZ04-PC01 | M01 | 11 | 0.375 | 43 | 91.72 | 2.82 | 0.79 | 1.89 |
| CZ04-PC02 | E01 | 20 | 0.375 | 10 | 91.72 | 2.82 | 0.79 | 1.89 |
| CZ05-PC01 | A01 | 29 | 0.375 | 45 | 93.76 | 1.87 | 0.46 | 1.14 |
| CZ05-PC02 | E01 | 20 | 0.375 | 19 | 93.76 | 1.87 | 0.46 | 1.14 |
| CZ05-PC03 | A01 | 29 | 0.375 | 18 | 93.76 | 1.87 | 0.46 | 1.14 |
| CZ06-PC01 | G01 | 6 | 0.25 | 73 | 94.07 | 1.84 | 0.42 | 0.92 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| CZ06-PC02 | E01 | 20 | 0.375 | 17 | 94.07 | 1.84 | 0.42 | 0.92 |
| CZ06-PC03 | G01 | 6 | 0.25 | 39 | 94.07 | 1.84 | 0.42 | 0.92 |
| CZ07-PC01 | A01 | 20 | 0.375 | 38 | 93.29 | 2.10 | 0.54 | 1.20 |
| CZ07-PC02 | E01 | 27.5 | 0.375 | 27 | 93.29 | 2.10 | 0.54 | 1.20 |
| CZ08-PC01 | M01 | 11 | 0.375 | 77 | 96.14 | 0.76 | 0.11 | 0.20 |
| CZ08-PC02 | M01 | 19 | 0.375 | 77 | 97.58 | 0.78 | 0.08 | 0.15 |
| CZ09-PC01 | M01 | 19 | 0.375 | 52 | 96.07 | 0.70 | 0.06 | 0.10 |
| CZ09-PC02 | M01 | 9 | 0.375 | 40 | 96.07 | 0.70 | 0.06 | 0.10 |
| CZ10-PC01 | M01 | 13 | 0.375 | 40 | 96.10 | 0.69 | 0.09 | 0.19 |
| CZ11-PC01 | M01 | 23 | 0.375 | 43 | 95.81 | 0.86 | 0.11 | 0.20 |
| DL01-PC01 | Q02 | 15 | 0.375 | 40 | 90.57 | 4.93 | 1.37 | 1.14 |
| DL01-PC02 | Q02 | 12 | 0.375 | 40 | 90.57 | 4.93 | 1.37 | 1.14 |
| DL01-PC03 | I05 | 30 | 0.375 | 90 | 90.57 | 4.93 | 1.37 | 1.14 |
| DL01-PC04 | F01 | 27 | 0.375 | 90 | 90.57 | 4.93 | 1.37 | 1.14 |
| DL01-PC05 | I05 | 25 | 0.375 | 90 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC11 | M01 | 30 | 0.375 | 25 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC12 | F01 | 27 | 0.375 | 160 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC13 | M01 | 35 | 0.375 | 25 | 90.10 | 5.08 | 1.39 | 1.08 |
| DL01-PC14 | F01 | 30 | 0.375 | 160 | 90.10 | 5.08 | 1.39 | 1.08 |
| DL01-PC15 | M01 | 35 | 0.375 | 25 | 91.00 | 4.16 | 1.04 | 0.88 |
| DL01-PC21 | F01 | 35 | 0.375 | 160 | 91.00 | 4.16 | 1.04 | 0.88 |
| DL01-PC22 | M01 | 30 | 0.375 | 25 | 90.65 | 4.82 | 1.32 | 1.12 |
| DL01-PC23 | F01 | 30 | 0.375 | 160 | 90.65 | 4.82 | 1.32 | 1.12 |
| DL01-PC24 | M01 | 38 | 0.375 | 25 | 89.35 | 5.19 | 1.39 | 1.18 |
| DL01-PC25 | F01 | 28 | 0.375 | 160 | 89.35 | 5.19 | 1.39 | 1.18 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| DL01-PC31 | I05 | 25 | 0.375 | 90 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC32 | M01 | 28 | 0.375 | 25 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC33 | F01 | 28 | 0.375 | 160 | 90.84 | 4.92 | 1.43 | 1.16 |
| DL01-PC34 | M01 | 26 | 0.375 | 25 | 90.88 | 4.82 | 1.35 | 1.16 |
| DL01-PC35 | F01 | 25 | 0.375 | 160 | 90.88 | 4.82 | 1.35 | 1.16 |
| DL01-PC41 | M01 | 28 | 0.375 | 25 | 89.68 | 5.11 | 1.38 | 1.11 |
| DL01-PC42 | F01 | 28 | 0.375 | 160 | 89.68 | 5.11 | 1.38 | 1.11 |
| DL01-PC43 | M01 | 29 | 0.375 | 25 | 89.35 | 5.30 | 1.44 | 1.03 |
| DL01-PC44 | F01 | 28 | 0.375 | 160 | 89.35 | 5.30 | 1.44 | 1.03 |
| DL01-PC45 | I05 | 25 | 0.375 | 45 | 89.35 | 5.30 | 1.44 | 1.03 |
| DL02-PC01 | M03 | 28 | 0.375 | 25 | 90.36 | 4.93 | 1.30 | 1.03 |
| DL02-PC02 | F01 | 28 | 0.375 | 160 | 90.36 | 4.93 | 1.30 | 1.03 |
| DL02-PC03 | M03 | 22 | 0.375 | 25 | 90.51 | 5.03 | 1.37 | 1.09 |
| DL02-PC04 | F01 | 25 | 0.375 | 160 | 90.51 | 5.03 | 1.37 | 1.09 |
| DL02-PC05 | M03 | 26 | 0.375 | 25 | 90.51 | 5.03 | 1.37 | 1.09 |
| DL02-PC11 | F01 | 25 | 0.375 | 160 | 90.51 | 5.03 | 1.37 | 1.09 |
| DL02-PC12 | M03 | 24 | 0.375 | 25 | 90.39 | 4.99 | 1.34 | 1.03 |
| DL02-PC13 | F01 | 25 | 0.375 | 160 | 90.39 | 4.99 | 1.34 | 1.03 |
| DL02-PC14 | M03 | 26 | 0.375 | 25 | 90.47 | 5.19 | 1.47 | 1.11 |
| DL02-PC15 | F01 | 25 | 0.375 | 160 | 90.47 | 5.19 | 1.47 | 1.11 |
| DL02-PC21 | M03 | 26 | 0.375 | 25 | 90.20 | 4.98 | 1.30 | 1.04 |
| DL02-PC22 | F01 | 27 | 0.375 | 160 | 90.20 | 4.98 | 1.30 | 1.04 |
| DL02-PC23 | M03 | 26 | 0.375 | 25 | 90.00 | 5.03 | 1.35 | 0.88 |
| DL02-PC24 | F01 | 26 | 0.375 | 160 | 90.00 | 5.03 | 1.35 | 0.88 |
| DL02-PC25 | M03 | 26 | 0.375 | 25 | 90.21 | 5.10 | 1.40 | 1.04 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| DL02-PC31 | F01 | 27 | 0.375 | 160 | 90.21 | 5.10 | 1.40 | 1.04 |
| DL02-PC32 | M03 | 26 | 0.375 | 25 | 89.80 | 5.15 | 1.31 | 0.97 |
| DL02-PC33 | F01 | 26 | 0.375 | 160 | 89.80 | 5.15 | 1.31 | 0.97 |
| DL02-PC34 | M03 | 28 | 0.375 | 25 | 90.38 | 5.08 | 1.38 | 0.84 |
| DL02-PC35 | F01 | 28 | 0.375 | 160 | 90.38 | 5.08 | 1.38 | 0.84 |
| DL02-PC41 | M03 | 30 | 0.375 | 25 | 90.06 | 4.97 | 1.28 | 0.82 |
| DL02-PC42 | F01 | 28 | 0.375 | 160 | 90.06 | 4.97 | 1.28 | 0.82 |
| DL02-PC43 | M03 | 28 | 0.375 | 25 | 90.27 | 4.78 | 1.20 | 1.50 |
| DL02-PC44 | F01 | 28 | 0.375 | 160 | 90.27 | 4.78 | 1.20 | 1.50 |
| DL02-PC45 | M03 | 28 | 0.375 | 25 | 90.38 | 4.96 | 1.32 | 0.97 |
| DL02-PC51 | F01 | 26 | 0.375 | 160 | 90.38 | 4.96 | 1.32 | 0.97 |
| DL02-PC52 | M03 | 28 | 0.375 | 25 | 89.67 | 5.07 | 1.17 | 0.81 |
| DL02-PC53 | F01 | 28 | 0.375 | 160 | 89.67 | 5.07 | 1.17 | 0.81 |
| DL02-PC54 | I05 | 25 | 0.375 | 90 | 90.20 | 4.98 | 1.30 | 1.04 |
| DL02-PC55 | I05 | 28 | 0.375 | 90 | 90.20 | 4.98 | 1.30 | 1.04 |
| DL02-PC61 | I05 | 25 | 0.375 | 90 | 90.20 | 4.98 | 1.30 | 1.04 |
| DL02-PC62 | I05 | 25 | 0.375 | 45 | 90.20 | 4.98 | 1.30 | 1.04 |
| GZ01-PC01 | J01 | 23 | 0.375 | 47 | 97.40 | 0.52 | 0.11 | 0.21 |
| GZ01-PC02 | J01 | 22 | 0.375 | 47 | 97.40 | 0.52 | 0.11 | 0.21 |
| GZ01-PC03 | J01 | 26 | 0.375 | 184 | 97.42 | 0.52 | 0.11 | 0.15 |
| GZ01-PC04 | J01 | 26 | 0.375 | 47 | 97.42 | 0.52 | 0.11 | 0.15 |
| GZ01-PC05 | J01 | 20 | 0.375 | 184 | 97.32 | 0.52 | 0.11 | 0.25 |
| GZ01-PC11 | J01 | 23 | 0.375 | 47 | 97.32 | 0.52 | 0.11 | 0.25 |
| GZ01-PC12 | J01 | 25 | 0.375 | 184 | 97.29 | 0.55 | 0.12 | 0.28 |
| GZ01-PC13 | J01 | 23 | 0.375 | 47 | 97.29 | 0.55 | 0.12 | 0.28 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| GZ01-PC14 | K01 | 30 | 0.375 | NA | 97.40 | 0.52 | 0.11 | 0.21 |
| GZ01-PC15 | K01 | 30 | 0.375 | NA | 97.42 | 0.52 | 0.11 | 0.15 |
| GZ01-PC21 | K01 | 30 | 0.375 | NA | 97.32 | 0.52 | 0.11 | 0.25 |
| GZ01-PC22 | K01 | 30 | 0.375 | NA | 97.29 | 0.55 | 0.12 | 0.28 |
| GZ02-PC01 | M01 | 29 | 0.375 | 127 | 97.35 | 0.51 | 0.10 | 0.21 |
| GZ02-PC02 | M01 | 28 | 0.375 | 35 | 97.35 | 0.51 | 0.10 | 0.21 |
| GZ02-PC03 | M01 | 30 | 0.375 | 127 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC04 | M01 | 31 | 0.375 | 35 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC05 | H01 | NA | 0.375 | NA | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC11 | J01 | 30 | 0.375 | 110 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC12 | J01 | 28 | 0.375 | 120 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC13 | J01 | 30 | 0.375 | 135 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC14 | I01 | 42 | 0.375 | 36 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC15 | M01 | NA | 0.375 | 20 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC21 | M01 | 20 | 0.25 | 120 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC22 | K01 | 3 | 0.375 | 3600 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ02-PC23 | K01 | 3 | 0.375 | 3600 | 97.35 | 0.51 | 0.10 | 0.21 |
| GZ02-PC24 | I01 | 300 | 0.375 | 25 | 97.42 | 0.51 | 0.09 | 0.12 |
| GZ03-PC01 | L01 | 30 | 0.25 | 26 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC02 | L01 | 30 | 0.25 | 26 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC03 | L01 | 30 | 0.25 | 26 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC04 | H01 | NA | 0.25 | 8 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC05 | I01 | 32 | 0.375 | 36 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC11 | K01 | 37 | 0.375 | 5400 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC12 | K01 | 37 | 0.375 | 5400 | 97.16 | 0.33 | 0.03 | 0.08 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| GZ03-PC13 | M01 | 26 | 0.375 | 93 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC14 | M01 | 27 | 0.375 | 70 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC15 | M01 | 25 | 0.375 | 55 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC21 | M01 | 27 | 0.375 | 84 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC22 | M01 | 7 | 0.375 | 47 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC23 | M01 | 32 | 0.375 | 29 | 97.36 | 0.30 | 0.03 | 0.04 |
| GZ03-PC24 | M01 | 1 | 0.375 | 47 | 97.36 | 0.30 | 0.03 | 0.04 |
| GZ03-PC25 | K01 | 31 | 0.375 | 66 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC31 | M04 | 25 | 0.375 | 95 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC32 | M03 | 26 | 0.25 | 28 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC33 | M03 | 29 | 0.25 | 86 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC34 | I05 | NA | 0.375 | 40 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC35 | I05 | 29 | 0.375 | 31 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC41 | H01 | 32 | 0.25 | 8 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ03-PC42 | I01 | 36 | 0.375 | 20 | 97.16 | 0.33 | 0.03 | 0.08 |
| GZ04-PC01 | M01 | 27 | 0.375 | 94 | 90.83 | 0.22 | 0.01 | 0.07 |
| GZ04-PC02 | M01 | 25 | 0.6 | 32 | 90.83 | 0.22 | 0.01 | 0.07 |
| GZ04-PC03 | M01 | 30 | 0.375 | 25 | 97.44 | 0.23 | 0.02 | 0.02 |
| GZ04-PC04 | M01 | 30 | 0.375 | 94 | 97.44 | 0.23 | 0.02 | 0.02 |
| GZ04-PC05 | K01 | 30 | 0.375 | 5400 | 90.83 | 0.22 | 0.01 | 0.07 |
| GZ04-PC11 | K01 | 32 | 0.375 | 3600 | 97.44 | 0.23 | 0.02 | 0.02 |
| LB01-PC01 | M03 | 30 | 0.375 | 400 | 80.52 | 10.62 | 3.62 | 3.61 |
| LB01-PC02 | M03 | 30 | 0.375 | 292 | 80.52 | 10.62 | 3.62 | 3.61 |
| LB02-PC01 | M01 | 30 | 0.375 | 85 | 80.41 | 10.77 | 3.56 | 3.48 |
| LB02-PC02 | M01 | 30 | 0.375 | 80 | 80.41 | 10.77 | 3.56 | 3.48 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| LB02-PC03 | M01 | 30 | 0.375 | 80 | 80.41 | 10.77 | 3.56 | 3.48 |
| LB02-PC04 | M01 | 30 | 0.375 | 80 | 80.41 | 10.77 | 3.56 | 3.48 |
| LB03-PC01 | M01 | 30 | 0.375 | 73 | 79.46 | 10.95 | 4.15 | 4.05 |
| LB03-PC02 | M01 | 30 | 0.375 | 48 | 79.46 | 10.95 | 4.15 | 4.05 |
| LB04-PC01 | M03 | 30 | 0.375 | 90 | 79.15 | 11.16 | 4.26 | 3.94 |
| LB04-PC02 | M03 | 30 | 0.375 | 85 | 79.15 | 11.16 | 4.26 | 3.94 |
| LB04-PC03 | M03 | 30 | 0.375 | 93 | 78.53 | 11.43 | 4.43 | 4.45 |
| LB04-PC04 | M03 | 30 | 0.375 | 83 | 78.53 | 11.43 | 4.43 | 4.45 |
| LB05-PC01 | M03 | 30 | 0.375 | 390 | 87.73 | 3.07 | 0.81 | 0.99 |
| LB05-PC02 | M03 | 30 | 0.375 | 328 | 87.73 | 3.07 | 0.81 | 0.99 |
| LB05-PC03 | M03 | 25 | 0.375 | 387 | 87.73 | 3.07 | 0.81 | 0.99 |
| LB05-PC04 | M03 | 25 | 0.375 | 352 | 87.73 | 3.07 | 0.81 | 0.99 |
| LB06-PC01 | M03 | 32 | 0.375 | 408 | 81.15 | 11.16 | 3.75 | 2.65 |
| LB06-PC02 | M03 | 32 | 0.375 | 301 | 81.15 | 11.16 | 3.75 | 2.65 |
| LB06-PC03 | M03 | 32 | 0.375 | 427 | 80.67 | 11.27 | 3.88 | 2.92 |
| LB06-PC04 | M03 | 28 | 0.375 | 300 | 80.67 | 11.27 | 3.88 | 2.92 |
| LB06-PC05 | M03 | 30 | 0.375 | 427 | 81.44 | 11.10 | 3.66 | 2.50 |
| LB06-PC11 | M03 | 30 | 0.375 | 300 | 81.44 | 11.10 | 3.66 | 2.50 |
| LB07-PC01 | M03 | 24 | 0.375 | 85 | 79.04 | 11.45 | 4.24 | 3.97 |
| LB07-PC02 | M03 | 24 | 0.375 | 85 | 79.04 | 11.45 | 4.24 | 3.97 |
| LB07-PC03 | J01 | 28 | 0.375 | 85 | 79.31 | 11.34 | 4.14 | 3.99 |
| LB07-PC04 | M03 | 28 | 0.375 | 85 | 79.31 | 11.34 | 4.14 | 3.99 |
| OF01-PC01 | I03 | 14 | 0.25 | 34 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF02-PC01 | I03 | 20 | 0.25 | 35 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF03-PC01 | I03 | 30 | 0.25 | 38 | 96.34 | 2.96 | 0.43 | 0.22 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| OF04-PC01 | I03 | 18 | 0.25 | 50 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF05-PC01 | I03 | 30 | 0.25 | 39 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF06-PC01 | I03 | 16 | 0.25 | 39 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF07-PC01 | I03 | 22 | 0.375 | 88 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF08-PC01 | I03 | 27 | 0.25 | 110 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF08-PC02 | E01 | NA | 0.25 | 20 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF09-PC01 | I03 | 14 | 0.25 | 25 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF10-PC01 | I03 | 23 | 0.25 | 20 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF11-PC01 | I03 | 29 | 0.25 | 23 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF11-PC02 | M01 | 40 | 0.375 | 120 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF11-PC03 | M01 | 40 | 0.375 | 92 | 96.34 | 2.96 | 0.43 | 0.22 |
| OF11-PC04 | I01 | 40 | 0.375 | 18 | 96.34 | 2.96 | 0.43 | 0.22 |
| RB01-PC01 | M03 | 10 | 0.25 | 1 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC02 | M03 | 32 | 0.375 | 140 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC03 | M03 | 32 | 0.375 | 140 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC04 | M05 | 30 | 0.375 | 15 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC05 | M01 | 35 | 0.375 | 45 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC11 | M01 | 32 | 0.375 | 70 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC12 | M01 | 32 | 0.375 | 180 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC13 | M01 | 25 | 0.375 | 100 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC14 | M01 | 19 | 0.375 | 60 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC15 | M01 | 32 | 0.375 | NA | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC21 | I05 | 10 | 0.25 | 100 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC23 | M05 | 30 | 0.375 | 30 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC24 | M01 | 32 | 0.375 | 30 | 82.19 | 8.47 | 3.85 | 3.33 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| RB01-PC25 | H01 | 52 | 0.375 | 1 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB01-PC34 | M01 | 32 | 0.375 | 140 | 82.19 | 8.47 | 3.85 | 3.33 |
| RB02-PC01 | M01 | 32 | 0.375 | 75 | 72.35 | 14.60 | 7.40 | 3.44 |
| RB02-PC02 | M01 | 29 | 0.25 | 25 | 72.35 | 14.60 | 7.40 | 3.44 |
| RB02-PC03 | I05 | 14 | 0.25 | 35 | 72.35 | 14.60 | 7.40 | 3.44 |
| RB02-PC05 | M01 | 30 | 0.25 | 100 | 72.35 | 14.60 | 7.40 | 3.44 |
| RB02-PC11 | M01 | 30 | 0.25 | 100 | 72.35 | 14.60 | 7.40 | 3.44 |
| RB02-PC12 | M01 | 32 | 0.25 | NA | 72.35 | 14.60 | 7.40 | 3.44 |
| RQ01-PC01 | Q02 | 24 | 0.25 | 70 | 86.88 | 6.48 | 2.83 | 2.48 |
| RQ02-PC01 | Q02 | 23 | 0.25 | 32 | 86.22 | 6.43 | 2.86 | 3.21 |
| RQ02-PC02 | O01 | 30 | 0.375 | 102 | 86.22 | 6.43 | 2.86 | 3.21 |
| RQ03-PC01 | Q02 | 22 | 0.375 | 40 | 85.61 | 6.43 | 2.84 | 3.80 |
| RQ04-PC01 | Q02 | 20 | 0.25 | 28 | 86.24 | 6.45 | 2.84 | 3.16 |
| RQ05-PC01 | Q02 | 21 | 0.375 | 34 | 88.27 | 6.12 | 2.86 | 1.52 |
| RQ05-PC02 | O01 | 30 | 0.375 | 34 | 88.27 | 6.12 | 2.86 | 1.52 |
| RQ05-PC03 | G01 | 22 | 0.375 | 38 | 87.71 | 6.11 | 3.20 | 1.76 |
| RQ05-PC04 | O01 | 30 | 0.375 | 0 | 87.71 | 6.11 | 3.20 | 1.76 |
| RQ06-PC01 | I05 | 8 | 0.25 | 32 | 84.16 | 8.24 | 3.97 | 1.61 |
| RQ06-PC02 | I05 | 8 | 0.25 | 47 | 84.16 | 8.24 | 3.97 | 1.61 |
| RQ06-PC03 | M03 | 27 | 0.25 | 38 | 84.16 | 8.24 | 3.97 | 1.61 |
| RQ06-PC04 | M03 | 29 | 0.25 | 27 | 84.16 | 8.24 | 3.97 | 1.61 |
| RQ07-PC01 | I05 | 18 | 0.25 | 65 | 77.73 | 9.13 | 6.59 | 4.32 |
| RQ07-PC02 | I05 | 18 | 0.25 | 55 | 77.73 | 9.13 | 6.59 | 4.32 |
| RQ07-PC03 | G01 | 22 | 0.25 | 36 | 77.73 | 9.13 | 6.59 | 4.32 |
| RQ07-PC04 | G01 | 21 | 0.25 | 25 | 77.73 | 9.13 | 6.59 | 4.32 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| RQ07-PC05 | P01 | 25 | 0.375 | 0 | 77.73 | 9.13 | 6.59 | 4.32 |
| VF01-PC01 | F01 | 95 | 0.375 | 140 | 97.49 | 2.02 | 0.06 | 0.00 |
| VF01-PC02 | M02 | 40 | 0.375 | 90 | 97.49 | 2.02 | 0.06 | 0.00 |
| VF01-PC03 | I04 | 21 | 0.25 | 27 | 97.49 | 2.02 | 0.06 | 0.00 |
| VF01-PC04 | I04 | 21 | 0.25 | 40 | 97.49 | 2.02 | 0.06 | 0.00 |
| VF01-PC05 | F01 | 61 | 0.25 | 134 | 97.63 | 1.95 | 0.05 | 0.00 |
| VF01-PC11 | M02 | 38 | 0.375 | 90 | 97.63 | 1.95 | 0.05 | 0.00 |
| VF01-PC12 | I04 | 23 | 0.25 | 15 | 97.63 | 1.95 | 0.05 | 0.00 |
| VF01-PC13 | I04 | 22 | 0.25 | 41 | 97.63 | 1.95 | 0.05 | 0.00 |
| VF01-PC14 | F01 | 50 | 0.375 | 95 | 97.61 | 2.01 | 0.06 | 0.00 |
| VF01-PC15 | M02 | 35 | 0.375 | 90 | 97.61 | 2.01 | 0.06 | 0.00 |
| VF01-PC21 | I04 | 7 | 0.25 | 26 | 97.61 | 2.01 | 0.06 | 0.00 |
| VF01-PC22 | I04 | 7 | 0.25 | 45 | 97.61 | 2.01 | 0.06 | 0.00 |
| VF01-PC23 | F01 | 86 | 0.375 | 110 | 97.74 | 1.82 | 0.04 | 0.00 |
| VF01-PC24 | M02 | 34 | 0.375 | 100 | 97.74 | 1.82 | 0.04 | 0.00 |
| VF01-PC25 | I04 | 15 | 0.375 | 32 | 97.74 | 1.82 | 0.04 | 0.00 |
| VF01-PC31 | I04 | 15 | 0.375 | 45 | 97.74 | 1.82 | 0.04 | 0.00 |
| VF01-PC32 | F01 | 25 | 0.375 | 98 | 97.63 | 2.01 | 0.05 | 0.00 |
| VF01-PC33 | M02 | 40 | 0.375 | 90 | 97.63 | 2.01 | 0.05 | 0.00 |
| VF01-PC34 | I04 | 14 | 0.25 | 25 | 97.63 | 2.01 | 0.05 | 0.00 |
| VF01-PC35 | I04 | 14 | 0.25 | 40 | 97.63 | 2.01 | 0.05 | 0.00 |
| VF01-PC41 | F01 | 89 | 0.375 | 84 | 97.68 | 1.89 | 0.05 | 0.00 |
| VF01-PC42 | M02 | 36 | 0.375 | 85 | 97.68 | 1.89 | 0.05 | 0.00 |
| VF01-PC43 | I04 | 17 | 0.25 | 26 | 97.68 | 1.89 | 0.05 | 0.00 |
| VF01-PC44 | I04 | 17 | 0.25 | 40 | 97.68 | 1.89 | 0.05 | 0.00 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| VF01-PC45 | C01 | 27 | 0.375 | 28 | 97.49 | 2.02 | 0.06 | 0.00 |
| VF01-PC51 | C01 | 18 | 0.375 | 28 | 97.63 | 1.95 | 0.05 | 0.00 |
| VF01-PC52 | C01 | 30 | 0.375 | 28 | 97.61 | 2.01 | 0.06 | 0.00 |
| VF01-PC53 | C01 | 25 | 0.375 | 28 | 97.74 | 1.82 | 0.04 | 0.00 |
| VF01-PC54 | C01 | 25 | 0.375 | 28 | 97.63 | 2.01 | 0.05 | 0.00 |
| VF01-PC55 | C01 | 30 | 0.375 | 28 | 97.68 | 1.89 | 0.05 | 0.00 |
| VF02-PC01 | F03 | 25 | 0.375 | 110 | 96.90 | 2.66 | 0.10 | 0.00 |
| VF02-PC02 | F03 | 30 | 0.375 | 110 | 96.94 | 2.59 | 0.09 | 0.00 |
| VF02-PC03 | F03 | 30 | 0.375 | 110 | 96.81 | 2.68 | 0.09 | 0.00 |
| VF02-PC04 | F03 | 30 | 0.375 | 110 | 96.98 | 2.56 | 0.08 | 0.00 |
| VF02-PC05 | F03 | 28 | 0.375 | 110 | 97.02 | 2.66 | 0.09 | 0.00 |
| VF02-PC11 | F03 | 31 | 0.375 | 110 | 96.93 | 2.61 | 0.09 | 0.00 |
| VF02-PC12 | I05 | 31 | 0.375 | 331 | 96.98 | 2.56 | 0.08 | 0.00 |
| XQ01-PC01 | Q02 | 27 | 0.25 | 30 | 88.21 | 6.64 | 1.98 | 1.46 |
| XQ01-PC02 | Q02 | 24 | 0.25 | 30 | 88.21 | 6.64 | 1.98 | 1.46 |
| XQ01-PC03 | I05 | 15 | 0.25 | 40 | 88.21 | 6.64 | 1.98 | 1.46 |
| XQ01-PC04 | F02 | 15 | 0.375 | 25 | 88.21 | 6.64 | 1.98 | 1.46 |
| XQ02-PC01 | G01 | 28 | 0.25 | 35 | 86.45 | 7.49 | 2.61 | 1.90 |
| XQ02-PC02 | G01 | 28 | 0.25 | 35 | 86.45 | 7.49 | 2.61 | 1.90 |
| XQ02-PC03 | I05 | 18 | 0.25 | 45 | 86.45 | 7.49 | 2.61 | 1.90 |
| XQ02-PC04 | F02 | 18 | 0.375 | 15 | 86.45 | 7.49 | 2.61 | 1.90 |
| XQ03-PC01 | Q02 | 23 | 0.25 | 30 | 90.85 | 5.17 | 1.28 | 1.04 |
| XQ03-PC02 | Q02 | 23 | 0.25 | 30 | 90.85 | 5.17 | 1.28 | 1.04 |
| XQ03-PC03 | I05 | 22 | 0.25 | 20 | 90.85 | 5.17 | 1.28 | 1.04 |
| XQ03-PC04 | F02 | 22 | 0.375 | 35 | 90.85 | 5.17 | 1.28 | 1.04 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| XQ04-PC01 | Q02 | 25 | 0.25 | 38 | 89.49 | 5.33 | 2.32 | 2.27 |
| XQ04-PC02 | Q02 | 28 | 0.25 | 38 | 89.49 | 5.33 | 2.32 | 2.27 |
| XQ04-PC03 | I05 | 15 | 0.25 | 15 | 89.49 | 5.33 | 2.32 | 2.27 |
| XQ04-PC04 | D01 | 15 | 0.375 | 10 | 89.49 | 5.33 | 2.32 | 2.27 |
| XQ05-PC01 | Q02 | 25 | 0.25 | 35 | 90.16 | 5.38 | 2.11 | 1.75 |
| XQ05-PC02 | Q02 | 27 | 0.25 | 35 | 90.16 | 5.38 | 2.11 | 1.75 |
| XQ05-PC03 | I05 | 17 | 0.25 | 12 | 90.16 | 5.38 | 2.11 | 1.75 |
| XQ05-PC04 | D01 | 17 | 0.375 | 10 | 90.16 | 5.38 | 2.11 | 1.75 |
| XQ06-PC01 | G01 | 28 | 0.25 | 38 | 89.14 | 5.48 | 2.41 | 2.45 |
| XQ06-PC02 | G01 | 28 | 0.25 | 38 | 89.14 | 5.48 | 2.41 | 2.45 |
| XQ06-PC03 | I05 | 28 | 0.25 | 30 | 89.14 | 5.48 | 2.41 | 2.45 |
| XQ06-PC04 | D01 | 28 | 0.375 | 10 | 89.14 | 5.48 | 2.41 | 2.45 |
| XQ07-PC01 | G01 | 60 | 0.25 | 38 | 91.62 | 4.41 | 1.72 | 1.59 |
| XQ07-PC02 | G01 | 60 | 0.25 | 38 | 91.62 | 4.41 | 1.72 | 1.59 |
| XQ07-PC03 | I05 | 60 | 0.25 | 30 | 91.62 | 4.41 | 1.72 | 1.59 |
| XQ07-PC04 | D01 | 60 | 0.375 | 10 | 91.62 | 4.41 | 1.72 | 1.59 |
| ZW01-PC01 | Q02 | 28 | 0.375 | 42 | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC02 | Q02 | 27 | 0.375 | 52 | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC03 | I05 | 14 | 0.375 | NA | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC04 | I05 | 14 | 0.375 | NA | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC05 | I05 | 12 | 0.375 | NA | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC11 | I05 | 12 | 0.375 | NA | 90.61 | 5.09 | 2.00 | 1.62 |
| ZW01-PC12 | Q02 | 25 | 0.375 | 42 | 90.87 | 5.24 | 1.80 | 1.25 |
| ZW01-PC13 | Q02 | 25 | 0.375 | 52 | 90.87 | 5.24 | 1.80 | 1.25 |
| ZW01-PC14 | Q02 | 25 | 0.375 | 42 | 90.87 | 5.24 | 1.80 | 1.25 |

| Device Identifier | Manufacturer and Model | Supply gas pressure (psig) | Tubing Diameter (in) | Tubing Length (in) | % of C1 in gas (%mol) ¹ | % of C2 in gas (%mol) ¹ | % of C3 in gas (%mol) ¹ | % of C4+ in gas (%mol) ¹ |
|-------------------|------------------------|----------------------------|----------------------|--------------------|------------------------------------|------------------------------------|------------------------------------|-------------------------------------|
| ZW01-PC15 | Q02 | 25 | 0.375 | 52 | 90.87 | 5.24 | 1.80 | 1.25 |
| ZW01-PC21 | Q02 | 40 | 0.375 | 22 | 90.87 | 5.24 | 1.80 | 1.25 |
| ZW01-PC22 | I05 | 15 | 0.375 | NA | 90.87 | 5.24 | 1.80 | 1.25 |
| ZW01-PC23 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC24 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC25 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC31 | B01 | 22 | 0.375 | 60 | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC32 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC33 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC34 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW01-PC35 | I05 | 15 | 0.375 | NA | 90.03 | 5.89 | 2.03 | 1.25 |
| ZW02-PC01 | Q02 | 25 | 0.375 | 30 | 89.65 | 5.68 | 2.22 | 1.59 |
| ZW02-PC02 | Q02 | 25 | 0.375 | 35 | 89.65 | 5.68 | 2.22 | 1.59 |
| ZW02-PC03 | I05 | 60 | 0.375 | NA | 89.65 | 5.68 | 2.22 | 1.59 |
| ZW02-PC04 | I05 | 60 | 0.375 | NA | 89.65 | 5.68 | 2.22 | 1.59 |
| ZW02-PC12 | B01 | 25 | 0.375 | 52 | 89.65 | 5.68 | 2.22 | 1.59 |
| ZW03-PC01 | Q02 | 25 | 0.375 | 26 | 91.22 | 4.94 | 1.81 | 1.25 |
| ZW03-PC02 | Q02 | 25 | 0.375 | 40 | 91.22 | 4.94 | 1.81 | 1.25 |
| ZW03-PC03 | F01 | 25 | 0.375 | 50 | 91.22 | 4.94 | 1.81 | 1.20 |

(1) Total may not sum to 100% due to nitrogen, CO₂, and other species in the gas.

Table S4-4 – Average measured emission rates for each device (whole gas and methane).

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| AA01-PC04 | 7.595 | not measured | 7.595 | 6.216 | c |
| AA01-PC05 | 0 | not measured | 0.000 | 0.000 | |
| AA01-PC06 | 1.602 | not measured | 1.602 | 1.304 | c |
| AA01-PC07 | 0.013 | not measured | 0.013 | 0.011 | |
| AA01-PC08 | 1.741 | not measured | 1.741 | 1.363 | c |
| AA01-PC09 | 0.035 | not measured | 0.035 | 0.027 | c |
| AA01-PC11 | 0.279 | not measured | 0.279 | 0.228 | c |
| AA02-PC04 | 13.597 | not measured | 13.597 | 10.950 | |
| AA02-PC05 | 2.514 | not measured | 2.514 | 2.025 | c |
| AA02-PC06 | 4.926 | not measured | 4.926 | 3.967 | |
| AA02-PC07 | 1.186 | not measured | 1.186 | 0.955 | |
| AA02-PC08 | 111.413 | not measured | 111.413 | 89.718 | |
| AA02-PC09 | 7.766 | not measured | 7.766 | 6.254 | |
| AP01-PC01 | 1.027 | not measured | 1.027 | 0.682 | c |
| AP01-PC02 | 0.001 | not measured | 0.001 | 0.000 | c |
| AP01-PC03 | 0.036 | not measured | 0.036 | 0.024 | |
| AP01-PC04 | 0.003 | not measured | 0.003 | 0.002 | |
| AP01-PC05 | 0.001 | not measured | 0.001 | 0.001 | |
| AP01-PC12 | 25.559 | not measured | 25.559 | 16.980 | |
| AP02-PC01 | 0.028 | not measured | 0.028 | 0.020 | |
| AP02-PC02 | 0.112 | not measured | 0.112 | 0.079 | c |
| AP02-PC03 | 0.002 | 0.000 | 0.002 | 0.002 | |
| AP02-PC04 | 0.032 | not measured | 0.032 | 0.022 | c |
| AP03-PC01 | 0 | not measured | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| AP03-PC02 | 0 | not measured | 0.000 | 0.000 | |
| AP04-PC01 | 0.004 | not measured | 0.004 | 0.002 | |
| AP04-PC02 | 0.111 | 0.000 | 0.111 | 0.074 | c |
| AP04-PC03 | 0.036 | 0.007 | 0.036 | 0.023 | c |
| AP04-PC04 | 0.001 | not measured | 0.001 | 0.001 | |
| AP05-PC01 | 0.169 | 0.197 | 0.169 | 0.120 | c |
| AP05-PC02 | 0 | not measured | 0.000 | 0.000 | |
| CW01-PC01 | not measured | 0.000 | 0.000 | 0.000 | |
| CW01-PC02 | 0 | not measured | 0.000 | 0.000 | |
| CW01-PC03 | 0 | not measured | 0.000 | 0.000 | |
| CW01-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| CW01-PC05 | 0.008 | not measured | 0.008 | 0.007 | a |
| CW01-PC11 | 0.022 | not measured | 0.022 | 0.018 | c, d |
| CW01-PC12 | 0.034 | not measured | 0.034 | 0.028 | a |
| CW01-PC13 | 0.235 | not measured | 0.235 | 0.192 | |
| CW01-PC14 | 0.031 | not measured | 0.031 | 0.025 | a |
| CW01-PC15 | 0 | not measured | 0.000 | 0.000 | |
| CW01-PC21 | 0 | 0.002 | 0.000 | 0.000 | |
| CW01-PC22 | 0 | not measured | 0.000 | 0.000 | |
| CW01-PC23 | 1.377 | not measured | 1.377 | 1.159 | c |
| CW01-PC24 | 0 | not measured | 0.000 | 0.000 | a |
| CW01-PC25 | 0.003 | not measured | 0.003 | 0.003 | a |
| CW01-PC31 | 0 | not measured | 0.000 | 0.000 | a |
| CW01-PC32 | 0.102 | not measured | 0.102 | 0.083 | b, c |
| CW01-PC33 | 0 | not measured | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| CW01-PC34 | 0 | not measured | 0.000 | 0.000 | a |
| CW01-PC35 | 0.622 | not measured | 0.622 | 0.508 | a, b |
| CW02-PC01 | not measured | 0.082 | 0.082 | 0.067 | |
| CW02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| CW02-PC03 | 0 | not measured | 0.000 | 0.000 | |
| CW02-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| CW02-PC05 | 0.004 | not measured | 0.004 | 0.003 | a |
| CW02-PC11 | not measured | 0.000 | 0.000 | 0.000 | |
| CW02-PC12 | 0 | not measured | 0.000 | 0.000 | |
| CW02-PC13 | 0 | not measured | 0.000 | 0.000 | |
| CW02-PC14 | 0 | not measured | 0.000 | 0.000 | a |
| CW02-PC15 | 0.002 | not measured | 0.002 | 0.002 | a |
| CW02-PC21 | not measured | 0.000 | 0.000 | 0.000 | |
| CW02-PC22 | 0.003 | not measured | 0.003 | 0.003 | a |
| CW02-PC23 | 0 | not measured | 0.000 | 0.000 | a |
| CW02-PC24 | 0 | 0.142 | 0.000 | 0.000 | |
| CW02-PC25 | 0 | not measured | 0.000 | 0.000 | |
| CW02-PC31 | not measured | 0.000 | 0.000 | 0.000 | |
| CW02-PC32 | 0.529 | not measured | 0.529 | 0.434 | |
| CW02-PC33 | 7.821 | not measured | 7.821 | 6.415 | |
| CW02-PC34 | 0 | not measured | 0.000 | 0.000 | a |
| CW02-PC35 | 0.010 | not measured | 0.010 | 0.008 | a |
| CZ01-PC01 | 0.243 | not measured | 0.243 | 0.221 | a |
| CZ01-PC02 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ02-PC01 | 118.497 | not measured | 118.497 | 107.983 | a |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| CZ02-PC02 | not measured | 0.580 | 0.580 | 0.528 | |
| CZ03-PC01 | 0.006 | not measured | 0.006 | 0.005 | a |
| CZ03-PC02 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ04-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| CZ04-PC02 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ05-PC01 | 40.400 | not measured | 40.400 | 37.880 | a |
| CZ05-PC02 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ05-PC03 | 0 | not measured | 0.000 | 0.000 | |
| CZ06-PC01 | not measured | 51.231 | 51.231 | 48.192 | |
| CZ06-PC02 | not measured | 50.714 | 50.714 | 47.705 | |
| CZ06-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ07-PC01 | 0.007 | not measured | 0.007 | 0.006 | a |
| CZ07-PC02 | not measured | 0.000 | 0.000 | 0.000 | |
| CZ08-PC01 | 60.099 | not measured | 60.099 | 57.783 | a |
| CZ08-PC02 | 21.578 | not measured | 21.578 | 21.056 | |
| CZ09-PC01 | 149.678 | not measured | 149.678 | 143.801 | a |
| CZ09-PC02 | 44.871 | not measured | 44.871 | 43.109 | |
| CZ10-PC01 | 43.173 | not measured | 43.173 | 41.489 | a |
| CZ11-PC01 | 22.183 | not measured | 22.183 | 21.253 | a |
| DL01-PC01 | 0.065 | not measured | 0.065 | 0.059 | |
| DL01-PC02 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC03 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC04 | not measured | 1.461 | 1.461 | 1.323 | |
| DL01-PC05 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC11 | 0 | not measured | 0.000 | 0.000 | a |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| DL01-PC12 | 0.502 | not measured | 0.502 | 0.456 | d |
| DL01-PC13 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC14 | 0.595 | not measured | 0.595 | 0.536 | d |
| DL01-PC15 | 5.386 | not measured | 5.386 | 4.902 | a |
| DL01-PC21 | 0.980 | not measured | 0.980 | 0.892 | c, d |
| DL01-PC22 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC23 | 1.574 | not measured | 1.574 | 1.427 | c, d |
| DL01-PC24 | 19.759 | not measured | 19.759 | 17.656 | a |
| DL01-PC25 | 0 | not measured | 0.000 | 0.000 | |
| DL01-PC31 | 0 | not measured | 0.000 | 0.000 | |
| DL01-PC32 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC33 | 0.114 | not measured | 0.114 | 0.104 | d |
| DL01-PC34 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC35 | 0 | not measured | 0.000 | 0.000 | |
| DL01-PC41 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC42 | 0.489 | not measured | 0.489 | 0.438 | d |
| DL01-PC43 | 0 | not measured | 0.000 | 0.000 | a |
| DL01-PC44 | 0.502 | not measured | 0.502 | 0.449 | d |
| DL01-PC45 | not measured | 0.000 | 0.000 | 0.000 | |
| DL02-PC01 | 0.005 | not measured | 0.005 | 0.004 | a |
| DL02-PC02 | 0.465 | not measured | 0.465 | 0.420 | d |
| DL02-PC03 | 0.008 | 59.833 | 0.008 | 0.007 | a |
| DL02-PC04 | 0.007 | not measured | 0.007 | 0.006 | d |
| DL02-PC05 | 0.007 | not measured | 0.007 | 0.006 | a |
| DL02-PC11 | 0.528 | 0.881 | 0.528 | 0.478 | d |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| DL02-PC12 | 0.008 | not measured | 0.008 | 0.007 | a |
| DL02-PC13 | 0 | 3.537 | 0.000 | 0.000 | |
| DL02-PC14 | 13.760 | not measured | 13.760 | 12.449 | a |
| DL02-PC15 | 1.360 | 0.696 | 1.360 | 1.230 | c, d |
| DL02-PC21 | 0.005 | 13.328 | 0.005 | 0.004 | a |
| DL02-PC22 | 0 | not measured | 0.000 | 0.000 | |
| DL02-PC23 | 0.005 | not measured | 0.005 | 0.004 | a |
| DL02-PC24 | 0 | not measured | 0.000 | 0.000 | |
| DL02-PC25 | 5.137 | not measured | 5.137 | 4.634 | a |
| DL02-PC31 | 0 | 0.507 | 0.000 | 0.000 | |
| DL02-PC32 | 0.004 | not measured | 0.004 | 0.004 | a |
| DL02-PC33 | 1.783 | not measured | 1.783 | 1.601 | d |
| DL02-PC34 | 0.005 | 9.214 | 0.005 | 0.004 | a |
| DL02-PC35 | 1.207 | not measured | 1.207 | 1.091 | c, d |
| DL02-PC41 | 0.006 | not measured | 0.006 | 0.005 | a |
| DL02-PC42 | 0.504 | 0.001 | 0.504 | 0.454 | d |
| DL02-PC43 | 0.007 | not measured | 0.007 | 0.007 | a |
| DL02-PC44 | 0 | 1.244 | 0.000 | 0.000 | |
| DL02-PC45 | 0.005 | 0.007 | 0.005 | 0.005 | a |
| DL02-PC51 | 0 | not measured | 0.000 | 0.000 | |
| DL02-PC52 | 0.004 | not measured | 0.004 | 0.003 | a |
| DL02-PC53 | 0 | not measured | 0.000 | 0.000 | |
| DL02-PC54 | 0.004 | not measured | 0.004 | 0.004 | |
| DL02-PC55 | 0 | not measured | 0.000 | 0.000 | a |
| DL02-PC61 | 0.002 | not measured | 0.002 | 0.002 | a |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| DL02-PC62 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ01-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| GZ01-PC02 | 0 | not measured | 0.000 | 0.000 | |
| GZ01-PC03 | 0 | not measured | 0.000 | 0.000 | a |
| GZ01-PC04 | 0 | not measured | 0.000 | 0.000 | |
| GZ01-PC05 | 0 | not measured | 0.000 | 0.000 | a |
| GZ01-PC11 | 0 | not measured | 0.000 | 0.000 | |
| GZ01-PC12 | 0 | not measured | 0.000 | 0.000 | a |
| GZ01-PC13 | 0 | not measured | 0.000 | 0.000 | |
| GZ01-PC14 | not measured | 0.042 | 0.042 | 0.041 | |
| GZ01-PC15 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ01-PC21 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ01-PC22 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ02-PC01 | 0 | 0.000 | 0.000 | 0.000 | a |
| GZ02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| GZ02-PC03 | 0 | not measured | 0.000 | 0.000 | a |
| GZ02-PC04 | 0 | not measured | 0.000 | 0.000 | |
| GZ02-PC05 | 0 | not measured | 0.000 | 0.000 | a |
| GZ02-PC11 | 0 | not measured | 0.000 | 0.000 | a |
| GZ02-PC12 | 57.949 | not measured | 57.949 | 56.454 | |
| GZ02-PC13 | 0 | not measured | 0.000 | 0.000 | |
| GZ02-PC14 | not measured | 43.288 | 43.288 | 42.171 | |
| GZ02-PC15 | 0 | not measured | 0.000 | 0.000 | |
| GZ02-PC21 | 0 | not measured | 0.000 | 0.000 | a |
| GZ02-PC22 | not measured | 0.000 | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| GZ02-PC23 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ02-PC24 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ03-PC01 | 3.664 | not measured | 3.664 | 3.560 | |
| GZ03-PC02 | 32.606 | not measured | 32.606 | 31.680 | |
| GZ03-PC03 | 0 | not measured | 0.000 | 0.000 | a |
| GZ03-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| GZ03-PC05 | not measured | 0.013 | 0.013 | 0.013 | |
| GZ03-PC11 | not measured | 0.024 | 0.024 | 0.024 | |
| GZ03-PC12 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ03-PC13 | 34.132 | not measured | 34.132 | 33.163 | |
| GZ03-PC14 | 6.122 | not measured | 6.122 | 5.948 | a |
| GZ03-PC15 | 0 | 0.052 | 0.000 | 0.000 | |
| GZ03-PC21 | 0 | not measured | 0.000 | 0.000 | a |
| GZ03-PC22 | 37.673 | not measured | 37.673 | 36.603 | a |
| GZ03-PC23 | 0.024 | not measured | 0.024 | 0.024 | c |
| GZ03-PC24 | 6.647 | not measured | 6.647 | 6.471 | |
| GZ03-PC25 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ03-PC31 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ03-PC32 | 0 | not measured | 0.000 | 0.000 | a |
| GZ03-PC33 | 0.002 | not measured | 0.002 | 0.002 | a |
| GZ03-PC34 | 0 | not measured | 0.000 | 0.000 | a |
| GZ03-PC35 | 0 | not measured | 0.000 | 0.000 | |
| GZ03-PC41 | 0 | not measured | 0.000 | 0.000 | |
| GZ03-PC42 | not measured | 0.000 | 0.000 | 0.000 | |
| GZ04-PC01 | 5.504 | not measured | 5.504 | 4.999 | c |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| GZ04-PC02 | 6.009 | not measured | 6.009 | 5.458 | a,b |
| GZ04-PC03 | 32.670 | not measured | 32.670 | 31.834 | |
| GZ04-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| GZ04-PC05 | not measured | 0.142 | 0.142 | 0.129 | |
| GZ04-PC11 | not measured | 0.012 | 0.012 | 0.012 | |
| LB01-PC01 | 40.155 | not measured | 40.155 | 32.333 | a, c |
| LB01-PC02 | 8.774 | not measured | 8.774 | 7.065 | c |
| LB02-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| LB02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| LB02-PC03 | 0.001 | not measured | 0.001 | 0.000 | a |
| LB02-PC04 | 0 | not measured | 0.000 | 0.000 | |
| LB03-PC01 | 50.071 | 55.301 | 50.071 | 39.786 | a |
| LB03-PC02 | 0.273 | not measured | 0.273 | 0.217 | |
| LB04-PC01 | 26.212 | not measured | 26.212 | 20.748 | a, c |
| LB04-PC02 | 9.820 | not measured | 9.820 | 7.773 | |
| LB04-PC03 | 19.116 | not measured | 19.116 | 15.012 | a, c |
| LB04-PC04 | 9.701 | not measured | 9.701 | 7.619 | c |
| LB05-PC01 | 68.606 | not measured | 68.606 | 60.188 | a |
| LB05-PC02 | 0 | not measured | 0.000 | 0.000 | |
| LB05-PC03 | 78.556 | not measured | 78.556 | 68.916 | a |
| LB05-PC04 | 0 | not measured | 0.000 | 0.000 | |
| LB06-PC01 | 3.475 | not measured | 3.475 | 2.820 | a, c |
| LB06-PC02 | 6.630 | not measured | 6.630 | 5.380 | c |
| LB06-PC03 | 7.691 | not measured | 7.691 | 6.204 | a, c |
| LB06-PC04 | 0 | not measured | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| LB06-PC05 | 22.456 | 20.773 | 22.456 | 18.287 | a, c |
| LB06-PC11 | 0.288 | not measured | 0.288 | 0.235 | c |
| LB07-PC01 | 36.294 | 51.347 | 36.294 | 28.685 | a, c |
| LB07-PC02 | 64.752 | not measured | 64.752 | 51.178 | |
| LB07-PC03 | 3.293 | not measured | 3.293 | 2.612 | a, c |
| LB07-PC04 | 26.980 | 33.879 | 26.980 | 21.399 | |
| OF01-PC01 | 7.125 | not measured | 7.125 | 6.864 | |
| OF02-PC01 | 0 | not measured | 0.000 | 0.000 | |
| OF03-PC01 | 1.556 | not measured | 1.556 | 1.499 | c |
| OF04-PC01 | 0 | not measured | 0.000 | 0.000 | |
| OF05-PC01 | 1.607 | not measured | 1.607 | 1.548 | c |
| OF06-PC01 | 0 | not measured | 0.000 | 0.000 | |
| OF07-PC01 | 6.615 | not measured | 6.615 | 6.373 | |
| OF08-PC01 | 0 | not measured | 0.000 | 0.000 | |
| OF08-PC02 | 0 | not measured | 0.000 | 0.000 | |
| OF09-PC01 | 0 | not measured | 0.000 | 0.000 | |
| OF10-PC01 | 2.696 | not measured | 2.696 | 2.597 | |
| OF11-PC01 | 6.589 | not measured | 6.589 | 6.347 | |
| OF11-PC02 | 2.821 | not measured | 2.821 | 2.717 | |
| OF11-PC03 | 0 | not measured | 0.000 | 0.000 | |
| OF11-PC04 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC01 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC02 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC03 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC04 | 7.787 | not measured | 7.787 | 6.400 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| RB01-PC05 | 0.123 | not measured | 0.123 | 0.101 | |
| RB01-PC11 | 0.199 | not measured | 0.199 | 0.163 | |
| RB01-PC12 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC13 | 17.226 | not measured | 17.226 | 14.159 | |
| RB01-PC14 | 4.163 | 0.194 | 4.163 | 3.422 | |
| RB01-PC15 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC21 | 15.169 | not measured | 15.169 | 12.468 | |
| RB01-PC23 | 19.824 | not measured | 19.824 | 16.294 | |
| RB01-PC24 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC25 | 0 | not measured | 0.000 | 0.000 | |
| RB01-PC34 | 16.795 | not measured | 16.795 | 13.804 | |
| RB02-PC01 | 0 | 6.664 | 0.000 | 0.000 | |
| RB02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| RB02-PC03 | 9.578 | not measured | 9.578 | 6.930 | |
| RB02-PC05 | 7.949 | not measured | 7.949 | 5.751 | c |
| RB02-PC11 | 0.002 | not measured | 0.002 | 0.001 | |
| RB02-PC12 | 0.004 | not measured | 0.004 | 0.003 | |
| RQ01-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| RQ02-PC01 | 6.316 | not measured | 6.316 | 5.446 | a |
| RQ02-PC02 | 0.001 | not measured | 0.001 | 0.001 | |
| RQ03-PC01 | 19.088 | NA | 19.088 | 16.341 | a |
| RQ04-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| RQ05-PC01 | 0 | not measured | 0.000 | 0.000 | |
| RQ05-PC02 | 0.008 | 0.515 | 0.008 | 0.007 | a |
| RQ05-PC03 | 17.390 | not measured | 17.390 | 15.253 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| RQ05-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| RQ06-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| RQ06-PC02 | 0 | not measured | 0.000 | 0.000 | |
| RQ06-PC03 | 0 | 0.000 | 0.000 | 0.000 | a |
| RQ06-PC04 | 0 | not measured | 0.000 | 0.000 | |
| RQ07-PC01 | 0 | not measured | 0.000 | 0.000 | |
| RQ07-PC02 | 0 | not measured | 0.000 | 0.000 | |
| RQ07-PC03 | 18.241 | 20.992 | 18.241 | 14.179 | a |
| RQ07-PC04 | 9.078 | not measured | 9.078 | 7.056 | a |
| RQ07-PC05 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC01 | 2.347 | not measured | 2.347 | 2.288 | |
| VF01-PC02 | 0.003 | not measured | 0.003 | 0.003 | a |
| VF01-PC03 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC04 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC05 | 5.387 | not measured | 5.387 | 5.259 | a |
| VF01-PC11 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC12 | 0.001 | not measured | 0.001 | 0.001 | a |
| VF01-PC13 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC14 | 0.001 | not measured | 0.001 | 0.001 | a |
| VF01-PC15 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC21 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC22 | 16.807 | not measured | 16.807 | 16.405 | |
| VF01-PC23 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC24 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC25 | 0 | not measured | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| VF01-PC31 | 0.001 | not measured | 0.001 | 0.001 | a |
| VF01-PC32 | 0.001 | not measured | 0.001 | 0.001 | a |
| VF01-PC33 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC34 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC35 | 0.001 | not measured | 0.001 | 0.001 | a |
| VF01-PC41 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC42 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC43 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC44 | 0 | not measured | 0.000 | 0.000 | |
| VF01-PC45 | 8.505 | not measured | 8.505 | 8.291 | |
| VF01-PC51 | 11.023 | not measured | 11.023 | 10.761 | a |
| VF01-PC52 | 0 | not measured | 0.000 | 0.000 | a |
| VF01-PC53 | 9.645 | not measured | 9.645 | 9.427 | |
| VF01-PC54 | 4.544 | not measured | 4.544 | 4.436 | |
| VF01-PC55 | 0.002 | not measured | 0.002 | 0.002 | a |
| VF02-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| VF02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| VF02-PC03 | 1.119 | not measured | 1.119 | 1.083 | a |
| VF02-PC04 | 0 | not measured | 0.000 | 0.000 | |
| VF02-PC05 | 0 | not measured | 0.000 | 0.000 | a |
| VF02-PC11 | 0 | not measured | 0.000 | 0.000 | |
| VF02-PC12 | 0 | not measured | 0.000 | 0.000 | |
| XQ01-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| XQ01-PC02 | 0 | not measured | 0.000 | 0.000 | |
| XQ01-PC03 | not measured | 0.000 | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| XQ01-PC04 | 37.374 | 0.125 | 37.374 | 32.969 | a |
| XQ02-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| XQ02-PC02 | 0 | 0.000 | 0.000 | 0.000 | |
| XQ02-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ02-PC04 | 14.982 | not measured | 14.982 | 12.952 | a |
| XQ03-PC01 | 14.955 | not measured | 14.955 | 13.587 | a |
| XQ03-PC02 | 16.531 | not measured | 16.531 | 15.019 | |
| XQ03-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ03-PC04 | 14.500 | not measured | 14.500 | 13.174 | a |
| XQ04-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| XQ04-PC02 | 37.406 | not measured | 37.406 | 33.473 | |
| XQ04-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ04-PC04 | not measured | 2.866 | 2.866 | 2.564 | |
| XQ05-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| XQ05-PC02 | 24.085 | not measured | 24.085 | 21.714 | |
| XQ05-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ05-PC04 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ06-PC01 | 20.160 | not measured | 20.160 | 17.970 | a |
| XQ06-PC02 | 11.918 | not measured | 11.918 | 10.623 | |
| XQ06-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ06-PC04 | not measured | 0.149 | 0.149 | 0.133 | |
| XQ07-PC01 | 0 | not measured | 0.000 | 0.000 | a |
| XQ07-PC02 | 0 | not measured | 0.000 | 0.000 | |
| XQ07-PC03 | not measured | 0.000 | 0.000 | 0.000 | |
| XQ07-PC04 | not measured | 1.752 | 1.752 | 1.605 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| ZW01-PC01 | 6.149 | not measured | 6.149 | 5.572 | |
| ZW01-PC02 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC03 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC04 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC05 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC11 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC12 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC13 | 2.664 | not measured | 2.664 | 2.421 | |
| ZW01-PC14 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC15 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC21 | 3.058 | not measured | 3.058 | 2.779 | c |
| ZW01-PC22 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC23 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC24 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC25 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC31 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC32 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC33 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC34 | 0 | not measured | 0.000 | 0.000 | |
| ZW01-PC35 | 0 | not measured | 0.000 | 0.000 | |
| ZW02-PC01 | 11.284 | not measured | 11.284 | 10.116 | |
| ZW02-PC02 | 0 | not measured | 0.000 | 0.000 | |
| ZW02-PC03 | 0 | not measured | 0.000 | 0.000 | |
| ZW02-PC04 | 0 | not measured | 0.000 | 0.000 | |
| ZW02-PC12 | 0 | not measured | 0.000 | 0.000 | |

| Device Identifier | Supply Gas meter - avg. emission rate whole gas (scf/h) | Hi Flow® - avg. emission rate whole gas (scf/h) | Whole gas flow rate used in data analysis (scf/h) | Methane flow rate used in data analysis (scf/h) | Flags |
|-------------------|---|---|---|---|-------|
| ZW03-PC01 | 0 | not measured | 0.000 | 0.000 | |
| ZW03-PC02 | 3.590 | not measured | 3.590 | 3.275 | |
| ZW03-PC03 | 0 | not measured | 0 | 0 | |

Flags:

a: Correction factor was applied to account for the condensation of an oily substance on the sensor of the measuring instrument. Post-field work testing of the Fox A supply gas meter indicated that its readings were 34% lower than the Fox C supply gas meter while the two meters were reading similarly before deployment into the field. Inter-comparisons with HiFlow® measurements indicated that the deposition on the sensor likely occurred between measurements LB06-PC05 and LB07-PC01, which occurred on subsequent days. To account for the oily deposition, all supply gas meter A measurements starting with LB07-PC01 were multiplied by 1.52 $[1/(1-0.34)]$ to correct for the oily substance.

b: Rapid peak in time series attributed to voltage surge associated with vehicle, which was the source of power for the supply gas meters used in the study, being turned on/off rather than with a pneumatic controller actuation.

c: Devices used in volume per actuation analysis for the “zero” pattern emissions.

d: Some ESDs exhibited spikes in emission rate that may not have been actual device actuations but may be related to pressure changes in the supply gas to the device

Table S4-5 –Total measurement time, number of actuations, and frequency of actuations.

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| AA01-PC04 | 15.4 | 51 | 3.3 |
| AA01-PC05 | 109.2 | 0 | no actuations |
| AA01-PC06 | 23.0 | 24 | 1.0 |
| AA01-PC07 | 18.7 | 1 | 0.1 |
| AA01-PC08 | 15.2 | 10 | 0.7 |
| AA01-PC09 | 15.7 | 2 | 0.1 |
| AA01-PC11 | 14.3 | 2 | 0.1 |
| AA02-PC04 | 11.0 | 0 | no actuations |
| AA02-PC05 | 14.8 | 2 | 0.1 |
| AA02-PC06 | 15.7 | 1 | 0.1 |
| AA02-PC07 | 18.0 | 4 | 0.2 |
| AA02-PC08 | 10.3 | 0 | no actuations |
| AA02-PC09 | 11.2 | 0 | no actuations |
| AP01-PC01 | 15.7 | 12 | 0.8 |
| AP01-PC02 | 14.3 | 0 | no actuations |
| AP01-PC03 | 53.1 | 0 | no actuations |
| AP01-PC04 | 15.0 | 0 | no actuations |
| AP01-PC05 | 15.0 | 0 | no actuations |
| AP01-PC12 | 15.0 | 78 | 5.2 |
| AP02-PC01 | 15.1 | 4 | 0.3 |
| AP02-PC02 | 15.4 | 10 | 0.6 |
| AP02-PC03 | 16.0 | 0 | no actuations |
| AP02-PC04 | 15.0 | 7 | 0.5 |
| AP03-PC01 | 16.7 | 0 | no actuations |
| AP03-PC02 | 16.1 | 0 | no actuations |
| AP04-PC01 | 16.0 | 0 | no actuations |
| AP04-PC02 | 16.6 | 35 | 2.1 |
| AP04-PC03 | 13.5 | 5 | 0.4 |
| AP04-PC04 | 15.1 | 0 | no actuations |
| AP05-PC01 | 23.9 | 6 | 0.3 |
| AP05-PC02 | 14.0 | 0 | no actuations |
| CW01-PC01 | 15.0 | 0 | no actuations |
| CW01-PC02 | 15.0 | 0 | no actuations |
| CW01-PC03 | 15.7 | 0 | no actuations |
| CW01-PC04 | 15.5 | 0 | no actuations |
| CW01-PC05 | 15.6 | 0 | no actuations |
| CW01-PC11 | 19.5 | 2 | 0.1 |
| CW01-PC12 | 14.8 | 1 | 0.1 |
| CW01-PC13 | 15.5 | 1 | 0.1 |
| CW01-PC14 | 15.7 | 1 | 0.1 |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| CW01-PC15 | 15.0 | 0 | no actuations |
| CW01-PC21 | 14.7 | 0 | no actuations |
| CW01-PC22 | 15.7 | 0 | no actuations |
| CW01-PC23 | 15.7 | 21 | 1.3 |
| CW01-PC24 | 15.8 | 0 | no actuations |
| CW01-PC25 | 15.6 | 0 | no actuations |
| CW01-PC31 | 15.3 | 0 | no actuations |
| CW01-PC32 | 18.5 | 0 | no actuations |
| CW01-PC33 | 15.3 | 0 | no actuations |
| CW01-PC34 | 15.4 | 0 | no actuations |
| CW01-PC35 | 18.5 | 0 | no actuations |
| CW02-PC01 | 15.0 | 0 | no actuations |
| CW02-PC02 | 15.3 | 0 | no actuations |
| CW02-PC03 | 14.6 | 0 | no actuations |
| CW02-PC04 | 14.5 | 0 | no actuations |
| CW02-PC05 | 15.4 | 0 | no actuations |
| CW02-PC11 | 15.0 | 0 | no actuations |
| CW02-PC12 | 15.4 | 0 | no actuations |
| CW02-PC13 | 16.8 | 0 | no actuations |
| CW02-PC14 | 16.9 | 0 | no actuations |
| CW02-PC15 | 15.5 | 0 | no actuations |
| CW02-PC21 | 15.0 | 0 | no actuations |
| CW02-PC22 | 15.3 | 0 | no actuations |
| CW02-PC23 | 15.3 | 0 | no actuations |
| CW02-PC24 | 15.2 | 0 | no actuations |
| CW02-PC25 | 15.2 | 0 | no actuations |
| CW02-PC31 | 15.0 | 0 | no actuations |
| CW02-PC32 | 16.3 | 3 | 0.2 |
| CW02-PC33 | 20.2 | 1 | 0.0 |
| CW02-PC34 | 20.2 | 0 | no actuations |
| CW02-PC35 | 16.3 | 0 | no actuations |
| CZ01-PC01 | 14.9 | 1 | 0.1 |
| CZ01-PC02 | 15.0 | 0 | no actuations |
| CZ02-PC01 | 15.2 | 0 | no actuations |
| CZ02-PC02 | 15.0 | 1 | 0.7 |
| CZ03-PC01 | 16.4 | 0 | no actuations |
| CZ03-PC02 | 15.0 | 0 | no actuations |
| CZ04-PC01 | 16.1 | 0 | no actuations |
| CZ04-PC02 | 15.0 | 0 | no actuations |
| CZ05-PC01 | 15.3 | 0 | no actuations |
| CZ05-PC02 | 15.0 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| CZ05-PC03 | 15.3 | 0 | no actuations |
| CZ06-PC01 | 15.0 | 0 | no actuations |
| CZ06-PC02 | 15.0 | 0 | no actuations |
| CZ06-PC03 | 15.0 | 0 | no actuations |
| CZ07-PC01 | 16.2 | 0 | no actuations |
| CZ07-PC02 | 15.0 | 0 | no actuations |
| CZ08-PC01 | 15.1 | 0 | no actuations |
| CZ08-PC02 | 16.1 | 3 | 0.2 |
| CZ09-PC01 | 15.1 | 0 | no actuations |
| CZ09-PC02 | 15.2 | 0 | no actuations |
| CZ10-PC01 | 29.5 | 2 | 0.1 |
| CZ11-PC01 | 15.7 | 0 | no actuations |
| DL01-PC01 | 15.0 | 1 | 0.1 |
| DL01-PC02 | 15.0 | 0 | no actuations |
| DL01-PC03 | 14.9 | 0 | no actuations |
| DL01-PC04 | 15.0 | 0 | no actuations |
| DL01-PC05 | 14.4 | 0 | no actuations |
| DL01-PC11 | 14.8 | 0 | no actuations |
| DL01-PC12 | 14.7 | 1 | 0.1 |
| DL01-PC13 | 14.9 | 0 | no actuations |
| DL01-PC14 | 14.8 | 1 | 0.1 |
| DL01-PC15 | 14.9 | 1 | 0.1 |
| DL01-PC21 | 14.8 | 7 | 0.5 |
| DL01-PC22 | 14.7 | 0 | no actuations |
| DL01-PC23 | 14.7 | 7 | 0.5 |
| DL01-PC24 | 15.5 | 0 | no actuations |
| DL01-PC25 | 15.5 | 0 | no actuations |
| DL01-PC31 | 14.5 | 0 | no actuations |
| DL01-PC32 | 15.0 | 0 | no actuations |
| DL01-PC33 | 15.0 | 1 | 0.1 |
| DL01-PC34 | 15.2 | 0 | no actuations |
| DL01-PC35 | 15.2 | 0 | no actuations |
| DL01-PC41 | 15.7 | 0 | no actuations |
| DL01-PC42 | 15.7 | 1 | 0.1 |
| DL01-PC43 | 14.9 | 0 | no actuations |
| DL01-PC44 | 14.9 | 1 | 0.1 |
| DL01-PC45 | 15.0 | 0 | no actuations |
| DL02-PC01 | 14.9 | 0 | no actuations |
| DL02-PC02 | 14.9 | 1 | 0.1 |
| DL02-PC03 | 14.9 | 0 | no actuations |
| DL02-PC04 | 14.9 | 1 | 0.1 |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| DL02-PC05 | 14.9 | 0 | no actuations |
| DL02-PC11 | 14.8 | 1 | 0.1 |
| DL02-PC12 | 15.2 | 0 | no actuations |
| DL02-PC13 | 15.3 | 0 | no actuations |
| DL02-PC14 | 14.8 | 30 | 2.0 |
| DL02-PC15 | 14.9 | 30 | 2.0 |
| DL02-PC21 | 16.1 | 0 | no actuations |
| DL02-PC22 | 16.0 | 0 | no actuations |
| DL02-PC23 | 15.0 | 0 | no actuations |
| DL02-PC24 | 14.7 | 0 | no actuations |
| DL02-PC25 | 15.3 | 0 | no actuations |
| DL02-PC31 | 15.2 | 0 | no actuations |
| DL02-PC32 | 14.9 | 0 | no actuations |
| DL02-PC33 | 14.8 | 33 | 2.2 |
| DL02-PC34 | 15.2 | 0 | no actuations |
| DL02-PC35 | 15.1 | 11 | 0.7 |
| DL02-PC41 | 14.7 | 0 | no actuations |
| DL02-PC42 | 14.7 | 1 | 0.1 |
| DL02-PC43 | 15.0 | 0 | no actuations |
| DL02-PC44 | 15.0 | 0 | no actuations |
| DL02-PC45 | 14.9 | 0 | no actuations |
| DL02-PC51 | 14.9 | 0 | no actuations |
| DL02-PC52 | 15.1 | 0 | no actuations |
| DL02-PC53 | 15.1 | 0 | no actuations |
| DL02-PC54 | 14.6 | 0 | no actuations |
| DL02-PC55 | 14.6 | 0 | no actuations |
| DL02-PC61 | 14.5 | 0 | no actuations |
| DL02-PC62 | 15.0 | 0 | no actuations |
| GZ01-PC01 | 15.3 | 0 | no actuations |
| GZ01-PC02 | 15.7 | 0 | no actuations |
| GZ01-PC03 | 15.2 | 0 | no actuations |
| GZ01-PC04 | 15.1 | 0 | no actuations |
| GZ01-PC05 | 15.4 | 0 | no actuations |
| GZ01-PC11 | 15.3 | 0 | no actuations |
| GZ01-PC12 | 14.6 | 0 | no actuations |
| GZ01-PC13 | 14.4 | 0 | no actuations |
| GZ01-PC14 | 15.0 | 0 | no actuations |
| GZ01-PC15 | 15.0 | 0 | no actuations |
| GZ01-PC21 | 15.0 | 0 | no actuations |
| GZ01-PC22 | 15.0 | 0 | no actuations |
| GZ02-PC01 | 14.6 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| GZ02-PC02 | 14.5 | 0 | no actuations |
| GZ02-PC03 | 14.8 | 0 | no actuations |
| GZ02-PC04 | 15.6 | 0 | no actuations |
| GZ02-PC05 | 15.0 | 0 | no actuations |
| GZ02-PC11 | 15.2 | 0 | no actuations |
| GZ02-PC12 | 15.2 | 0 | no actuations |
| GZ02-PC13 | 15.0 | 0 | no actuations |
| GZ02-PC14 | 15.0 | 0 | no actuations |
| GZ02-PC15 | 15.1 | 0 | no actuations |
| GZ02-PC21 | 15.3 | 0 | no actuations |
| GZ02-PC22 | 15.0 | 0 | no actuations |
| GZ02-PC23 | 15.0 | 0 | no actuations |
| GZ02-PC24 | 15.0 | 0 | no actuations |
| GZ03-PC01 | 15.2 | 2 | 0.1 |
| GZ03-PC02 | 15.5 | 2 | 0.1 |
| GZ03-PC03 | 15.5 | 0 | no actuations |
| GZ03-PC04 | 15.2 | 0 | no actuations |
| GZ03-PC05 | 15.0 | 0 | no actuations |
| GZ03-PC11 | 15.0 | 0 | no actuations |
| GZ03-PC12 | 15.0 | 0 | no actuations |
| GZ03-PC13 | 17.6 | 0 | no actuations |
| GZ03-PC14 | 17.6 | 0 | no actuations |
| GZ03-PC15 | 14.9 | 0 | no actuations |
| GZ03-PC21 | 90.5 | 0 | no actuations |
| GZ03-PC22 | 15.0 | 0 | no actuations |
| GZ03-PC23 | 90.4 | 14 | 0.2 |
| GZ03-PC24 | 15.2 | 0 | no actuations |
| GZ03-PC25 | 15.0 | 0 | no actuations |
| GZ03-PC31 | 15.0 | 0 | no actuations |
| GZ03-PC32 | 14.9 | 0 | no actuations |
| GZ03-PC33 | 14.9 | 0 | no actuations |
| GZ03-PC34 | 14.9 | 0 | no actuations |
| GZ03-PC35 | 14.9 | 0 | no actuations |
| GZ03-PC41 | 15.1 | 0 | no actuations |
| GZ03-PC42 | 15.0 | 0 | no actuations |
| GZ04-PC01 | 16.0 | 2 | 0.1 |
| GZ04-PC02 | 16.0 | 0 | no actuations |
| GZ04-PC03 | 17.8 | 5 | 0.3 |
| GZ04-PC04 | 17.9 | 0 | no actuations |
| GZ04-PC05 | 15.0 | 0 | no actuations |
| GZ04-PC11 | 15.0 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| LB01-PC01 | 15.0 | 4 | 0.3 |
| LB01-PC02 | 15.0 | 3 | 0.2 |
| LB02-PC01 | 15.0 | 0 | no actuations |
| LB02-PC02 | 15.0 | 0 | no actuations |
| LB02-PC03 | 15.0 | 0 | no actuations |
| LB02-PC04 | 15.0 | 0 | no actuations |
| LB03-PC01 | 15.0 | 8 | 0.5 |
| LB03-PC02 | 15.2 | 1 | 0.1 |
| LB04-PC01 | 15.0 | 5 | 0.3 |
| LB04-PC02 | 15.0 | 6 | 0.4 |
| LB04-PC03 | 20.2 | 8 | 0.4 |
| LB04-PC04 | 20.2 | 2 | 0.1 |
| LB05-PC01 | 15.1 | 11 | 0.7 |
| LB05-PC02 | 15.1 | 0 | no actuations |
| LB05-PC03 | 15.5 | 15 | 1.0 |
| LB05-PC04 | 15.5 | 0 | no actuations |
| LB06-PC01 | 15.0 | 4 | 0.3 |
| LB06-PC02 | 15.0 | 2 | 0.1 |
| LB06-PC03 | 15.2 | 11 | 0.7 |
| LB06-PC04 | 15.2 | 0 | no actuations |
| LB06-PC05 | 15.7 | 14 | 0.9 |
| LB06-PC11 | 15.7 | 6 | 0.4 |
| LB07-PC01 | 15.0 | 15 | 1.0 |
| LB07-PC02 | 15.0 | 15 | 1.0 |
| LB07-PC03 | 18.1 | 14 | 0.8 |
| LB07-PC04 | 21.1 | 2 | 0.1 |
| OF01-PC01 | 15.0 | 23 | 1.5 |
| OF02-PC01 | 14.9 | 0 | no actuations |
| OF03-PC01 | 15.0 | 154 | 10.3 |
| OF04-PC01 | 15.0 | 0 | no actuations |
| OF05-PC01 | 15.4 | 6 | 0.4 |
| OF06-PC01 | 15.0 | 0 | no actuations |
| OF07-PC01 | 15.0 | 98 | 6.5 |
| OF08-PC01 | 15.2 | 0 | no actuations |
| OF08-PC02 | 15.0 | 0 | no actuations |
| OF09-PC01 | 15.1 | 0 | no actuations |
| OF10-PC01 | 15.1 | 0 | no actuations |
| OF11-PC01 | 22.7 | 10 | 0.4 |
| OF11-PC02 | 14.9 | 0 | no actuations |
| OF11-PC03 | 15.7 | 0 | no actuations |
| OF11-PC04 | 15.3 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| RB01-PC01 | 15.0 | 0 | no actuations |
| RB01-PC02 | 11.0 | 0 | no actuations |
| RB01-PC03 | 15.0 | 0 | no actuations |
| RB01-PC04 | 14.9 | 0 | no actuations |
| RB01-PC05 | 18.0 | 0 | no actuations |
| RB01-PC11 | 18.0 | 1 | 0.1 |
| RB01-PC12 | 16.0 | 0 | no actuations |
| RB01-PC13 | 14.9 | 0 | no actuations |
| RB01-PC14 | 16.9 | 8 | 0.5 |
| RB01-PC15 | 15.0 | 0 | no actuations |
| RB01-PC21 | 15.0 | 0 | no actuations |
| RB01-PC23 | 15.0 | 0 | no actuations |
| RB01-PC24 | 15.0 | 0 | no actuations |
| RB01-PC25 | 15.0 | 0 | no actuations |
| RB01-PC34 | 15.0 | 0 | no actuations |
| RB02-PC01 | 15.0 | 0 | no actuations |
| RB02-PC02 | 15.8 | 0 | no actuations |
| RB02-PC03 | 15.0 | 0 | no actuations |
| RB02-PC05 | 15.0 | 5 | 0.3 |
| RB02-PC11 | 15.0 | 0 | no actuations |
| RB02-PC12 | 15.0 | 0 | no actuations |
| RQ01-PC01 | 15.1 | 0 | no actuations |
| RQ02-PC01 | 16.2 | 0 | no actuations |
| RQ02-PC02 | 16.1 | 0 | no actuations |
| RQ03-PC01 | 20.4 | 0 | no actuations |
| RQ04-PC01 | 39.9 | 0 | no actuations |
| RQ05-PC01 | 20.2 | 0 | no actuations |
| RQ05-PC02 | 20.3 | 1 | 0.0 |
| RQ05-PC03 | 14.8 | 0 | no actuations |
| RQ05-PC04 | 15.0 | 0 | no actuations |
| RQ06-PC01 | 14.8 | 0 | no actuations |
| RQ06-PC02 | 15.0 | 0 | no actuations |
| RQ06-PC03 | 15.9 | 0 | no actuations |
| RQ06-PC04 | 15.8 | 0 | no actuations |
| RQ07-PC01 | 15.1 | 0 | no actuations |
| RQ07-PC02 | 15.0 | 0 | no actuations |
| RQ07-PC03 | 16.1 | 0 | no actuations |
| RQ07-PC04 | 15.2 | 0 | no actuations |
| RQ07-PC05 | 15.2 | 0 | no actuations |
| VF01-PC01 | 15.7 | 0 | no actuations |
| VF01-PC02 | 15.8 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| VF01-PC03 | 15.3 | 0 | no actuations |
| VF01-PC04 | 15.4 | 0 | no actuations |
| VF01-PC05 | 15.2 | 0 | no actuations |
| VF01-PC11 | 15.2 | 0 | no actuations |
| VF01-PC12 | 15.8 | 0 | no actuations |
| VF01-PC13 | 15.9 | 0 | no actuations |
| VF01-PC14 | 14.1 | 0 | no actuations |
| VF01-PC15 | 14.1 | 0 | no actuations |
| VF01-PC21 | 15.2 | 0 | no actuations |
| VF01-PC22 | 15.2 | 0 | no actuations |
| VF01-PC23 | 15.2 | 0 | no actuations |
| VF01-PC24 | 15.2 | 0 | no actuations |
| VF01-PC25 | 15.2 | 0 | no actuations |
| VF01-PC31 | 15.2 | 0 | no actuations |
| VF01-PC32 | 15.0 | 0 | no actuations |
| VF01-PC33 | 16.1 | 0 | no actuations |
| VF01-PC34 | 15.1 | 0 | no actuations |
| VF01-PC35 | 15.1 | 0 | no actuations |
| VF01-PC41 | 17.1 | 0 | no actuations |
| VF01-PC42 | 17.1 | 0 | no actuations |
| VF01-PC43 | 14.9 | 0 | no actuations |
| VF01-PC44 | 14.9 | 0 | no actuations |
| VF01-PC45 | 14.5 | 0 | no actuations |
| VF01-PC51 | 14.5 | 0 | no actuations |
| VF01-PC52 | 15.2 | 0 | no actuations |
| VF01-PC53 | 15.2 | 1 | 0.1 |
| VF01-PC54 | 16.0 | 1 | 0.1 |
| VF01-PC55 | 16.0 | 0 | no actuations |
| VF02-PC01 | 15.3 | 0 | no actuations |
| VF02-PC02 | 15.3 | 0 | no actuations |
| VF02-PC03 | 15.0 | 1 | 0.1 |
| VF02-PC04 | 15.0 | 0 | no actuations |
| VF02-PC05 | 14.6 | 0 | no actuations |
| VF02-PC11 | 14.6 | 0 | no actuations |
| VF02-PC12 | 15.0 | 0 | no actuations |
| XQ01-PC01 | 15.0 | 0 | no actuations |
| XQ01-PC02 | 15.0 | 0 | no actuations |
| XQ01-PC03 | 15.0 | 0 | no actuations |
| XQ01-PC04 | 15.3 | 3 | 0.2 |
| XQ02-PC01 | 15.9 | 0 | no actuations |
| XQ02-PC02 | 15.9 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| XQ02-PC03 | 15.0 | 0 | no actuations |
| XQ02-PC04 | 14.0 | 0 | no actuations |
| XQ03-PC01 | 15.0 | 0 | no actuations |
| XQ03-PC02 | 15.0 | 0 | no actuations |
| XQ03-PC03 | 15.0 | 0 | no actuations |
| XQ03-PC04 | 15.0 | 0 | no actuations |
| XQ04-PC01 | 15.9 | 0 | no actuations |
| XQ04-PC02 | 15.9 | 0 | no actuations |
| XQ04-PC03 | 15.0 | 0 | no actuations |
| XQ04-PC04 | 15.0 | 0 | no actuations |
| XQ05-PC01 | 15.0 | 0 | no actuations |
| XQ05-PC02 | 15.0 | 0 | no actuations |
| XQ05-PC03 | 15.0 | 0 | no actuations |
| XQ05-PC04 | 15.0 | 0 | no actuations |
| XQ06-PC01 | 15.0 | 0 | no actuations |
| XQ06-PC02 | 15.0 | 0 | no actuations |
| XQ06-PC03 | 15.0 | 0 | no actuations |
| XQ06-PC04 | 15.0 | 0 | no actuations |
| XQ07-PC01 | 17.0 | 0 | no actuations |
| XQ07-PC02 | 17.0 | 0 | no actuations |
| XQ07-PC03 | 15.0 | 0 | no actuations |
| XQ07-PC04 | 15.0 | 1 | 0.7 |
| ZW01-PC01 | 15.3 | 0 | no actuations |
| ZW01-PC02 | 15.0 | 0 | no actuations |
| ZW01-PC03 | 15.0 | 0 | no actuations |
| ZW01-PC04 | 15.3 | 0 | no actuations |
| ZW01-PC05 | 15.4 | 0 | no actuations |
| ZW01-PC11 | 14.9 | 0 | no actuations |
| ZW01-PC12 | 22.0 | 0 | no actuations |
| ZW01-PC13 | 15.0 | 0 | no actuations |
| ZW01-PC14 | 15.5 | 0 | no actuations |
| ZW01-PC15 | 14.9 | 0 | no actuations |
| ZW01-PC21 | 15.0 | 4 | 0.3 |
| ZW01-PC22 | 14.8 | 0 | no actuations |
| ZW01-PC23 | 14.9 | 0 | no actuations |
| ZW01-PC24 | 15.0 | 0 | no actuations |
| ZW01-PC25 | 14.9 | 0 | no actuations |
| ZW01-PC31 | 15.0 | 0 | no actuations |
| ZW01-PC32 | 15.0 | 0 | no actuations |
| ZW01-PC33 | 14.9 | 0 | no actuations |
| ZW01-PC34 | 14.9 | 0 | no actuations |

| Device Identifier | Total measured time (min) | # of actuations* | frequency of actuations (#/min) |
|-------------------|---------------------------|------------------|---------------------------------|
| ZW01-PC35 | 15.1 | 0 | no actuations |
| ZW02-PC01 | 15.0 | 0 | no actuations |
| ZW02-PC02 | 14.9 | 0 | no actuations |
| ZW02-PC03 | 15.0 | 0 | no actuations |
| ZW02-PC04 | 15.0 | 0 | no actuations |
| ZW02-PC12 | 15.0 | 0 | no actuations |
| ZW03-PC01 | 15.0 | 0 | no actuations |
| ZW03-PC02 | 15.0 | 0 | no actuations |
| ZW03-PC03 | 15.0 | 0 | no actuations |

*Note that a report of no actuations does not necessarily indicate no emissions; a continuous vent device may have emissions with no identifiable actuation

S5. Estimates of emissions from devices with no emissions detected during 15 minute sampling period

The data set includes 241 devices (64%) for which no emissions were detected over a 15 minute sampling period (136 devices) or that had flow below the instrument measurement threshold that was indistinguishable from instrument noise (105 devices). Even though no actuations were detected on these devices during the sampling period, for some of these devices, actuations and the associated emissions per actuation may have been observed if the sampling period had been extended. Not detecting emissions from infrequently actuating devices would be an issue for any finite sampling time; in this work, the approach that was taken was to sample for a 15 minute period, then to estimate potential emissions from infrequently actuating devices. Estimates of the potential emissions from infrequently actuating devices were determined by estimating actuation frequency and volume.

$$\text{Estimated emissions} = \text{actuation frequency (min}^{-1}\text{)} * \text{actuation volume (scf)}$$

It is assumed, in these estimates, that all of these devices for which emissions are estimated are intermittent vent controllers, rather than continuous vent controllers, since the measured emission rates included zero values.

The actuation frequencies and emissions per actuation were estimated based on data for controllers with well-defined actuation patterns. A well-defined actuation pattern exhibited intermittent emissions patterns, returned to a zero emissions baseline between actuations, and had two or more actuations during the 15 minute sampling period. Average actuation volumes for controllers in eight types of service are provided in Table S5-1.

Table S5-1. Counts of devices and average emissions per actuation for controllers in eight application categories; note that for ESDs, the emissions measured during the sampling were device leak rates rather than device actuations.

| Application | Devices with no emissions detected during sampling period | Devices with well-defined actuations | Average volume per actuation for “Actuating” Devices (scf) |
|---------------------------|---|--------------------------------------|--|
| Separator - Level Control | 109 | 26 | 0.349 |
| ESD | 31 | 5 | 0.026 |
| Plunger Lift | 20 | 1 | 0.048 |
| Process Heater | 40 | 1 | 0.191 |
| Other | 10 | 0 | Assumed average from all other devices (0.271) |
| Separator - Other | 9 | 2 | 0.070 |
| Compressor | 7 | 2 | 0.158 |
| Dehydration System | 15 | 1 | 0.398 |

Table S5-1 provides estimates of actuation volumes, categorized by application. Actuation frequency could be estimated using a variety of approaches. An upper bound on the emission rate could be estimated by assuming that all devices for which no emissions were observed over 15 minutes of sampling actually had actuations that occurred immediately before and

immediately after the sampling period (4 actuations per hour, a frequency of 0.067 min^{-1}). This scenario is improbable, nevertheless, it does provide an upper bound. Assuming that devices with no measured emissions actuated every 15 minutes, and had the actuation volumes, consistent with application type, reported in Table S5-1, increases the overall population average emissions by 11% (from 5.52 scf/h to 6.13 scf/h whole gas). As the assumed actuation frequency decreases, the estimated additional emissions decrease, as shown in Figure S5-1. If a 3 hour period between actuations is assumed (0.0055 min^{-1}), the study average emissions rate per device increases by less than 1%.

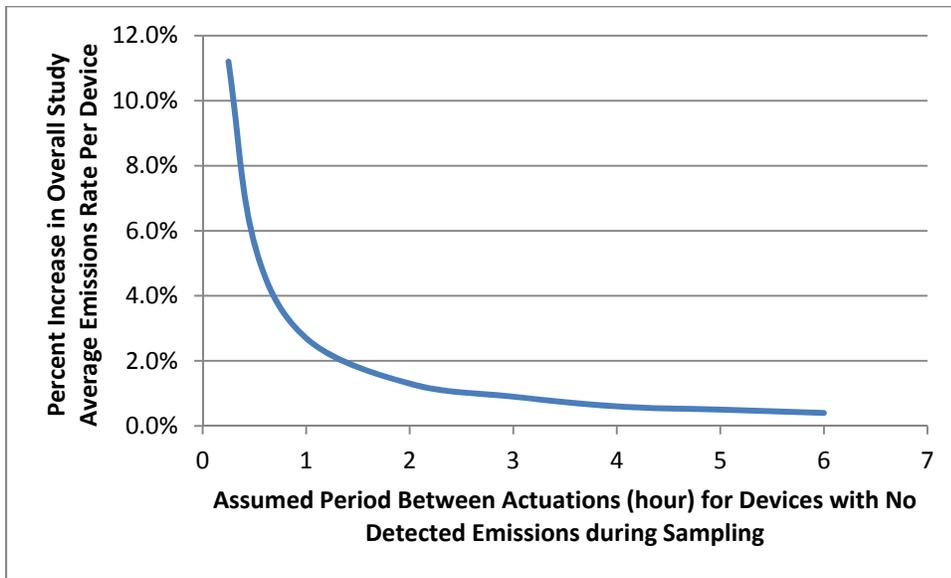


Figure S5-1. Sensitivity of study-average emissions rate per device to the assumed period between actuations.

For some application categories, specifically level control of separators, actuation frequencies, for devices with no actuations detected over 15 minutes of sampling, can be estimated based on the data from devices with observed actuations. Separator level controllers were both the largest category of pneumatic devices measured in this study (50% of total devices) and the largest category of devices with no measured emissions over a 15 minute sampling period (45%). For this category of devices, the actuation frequencies for all intermittent vent controllers with a period between actuations of less than 7.5 minutes (at least two actuations in 15 minutes of observation, 21% of the intermittent vent separator level controllers) are shown in Figure S5-2. The most conservative estimate of the range of periods between actuations for separator level controllers would be a linear extrapolation of the subset of devices with a periodicity of less than 7.5 minutes (Figure S5-2).

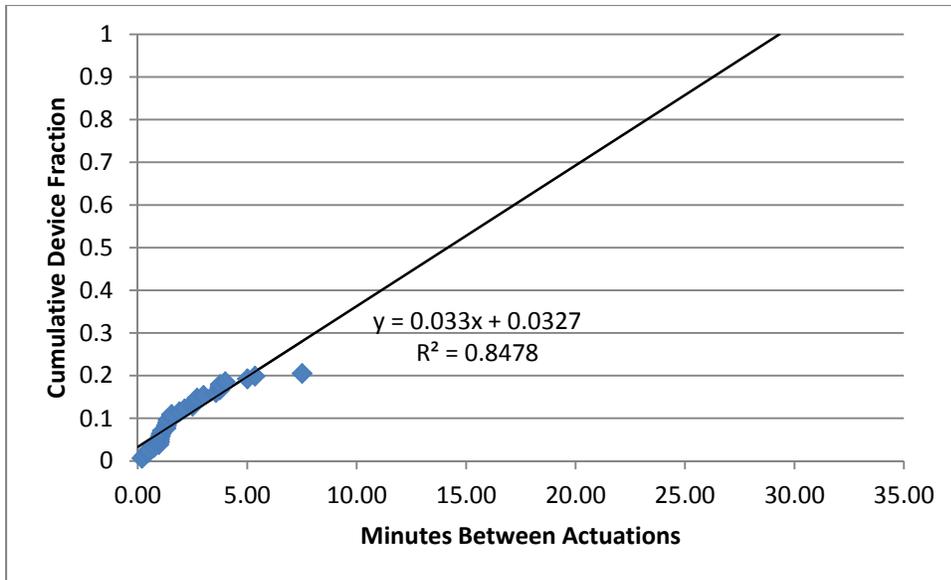


Figure S5-2. Period between actuations for separator level controllers with intermittent vent emissions patterns.

A linear extrapolation of the actuation frequency for separator level controllers with two or more actuations in the sample period to the overall population of separator level controllers indicated that all separator level controllers would undergo an actuation within 30 minutes. Assuming that the minutes between actuations for the separator level controllers for which no emissions were detected during sampling were evenly spaced between 15 minutes and 30 minutes, the increase in the overall study-average per device emissions rate for all devices in all applications would be between 5.1% (assuming that the actual emissions rate from all non-separator level controllers for which no emissions were detected during sampling were negligible) and 8.9% (assuming that all devices without detected emissions during sampling and that were not in separator level controller applications actuated every 15 minutes). This approach likely under-estimates the time between actuations for separator level controllers (over-estimates the frequency). Based on the linear extrapolation shown in Figure S5-2, 25% of devices in separator level control applications would be expected to have actuations between 7.5 minutes to 15 minutes. For devices sampled in the study, only 6% of level controllers on separators recorded a single actuation during a 15 minute sample time or had a periodicity in this range due to two actuations during a sample time longer than 15 minutes. Adjusting the slope of the linear interpolation to fit the data collected between 7.5 and 15 minutes changes the slope to 0.008 and would indicate that all devices would actuate within 121 minutes. Separator level controller emissions would be estimated to increase by 2.9% under this assumption. Under this revised linear interpolation, the estimated average emissions per device from the overall study population could increase between 2.1% and 5.9%, again depending on the frequency assumed for controllers not in separator level control service.

Overall, the study average emission rate for controllers would be expected to increase by 2%-6% if the measurement period had been extended indefinitely. This estimate is based on data for controllers in separator level control service, the most common type of service observed in the study, and a type of service that is likely to result in regular actuations.

S6. Numbers of controllers per well

In this work, a total of 65 sites were visited. The 65 sites had 377 pneumatic controllers on which measurements were performed and 53 for which either time constraints or equipment failure led to no sample being collected. The 65 sites with 430 controllers had 161 wells, for an average of 2.7 devices per well. The median value was 2.0 controllers per well with 25th and 75th percentile values of 1 and 4 controllers per well. The minimum value was 0.4 devices per well, and the maximum value was 11 devices per well. The distribution is shown in Figure S6-1. Table S6-1 provides counts of controllers and wells at individual sites.

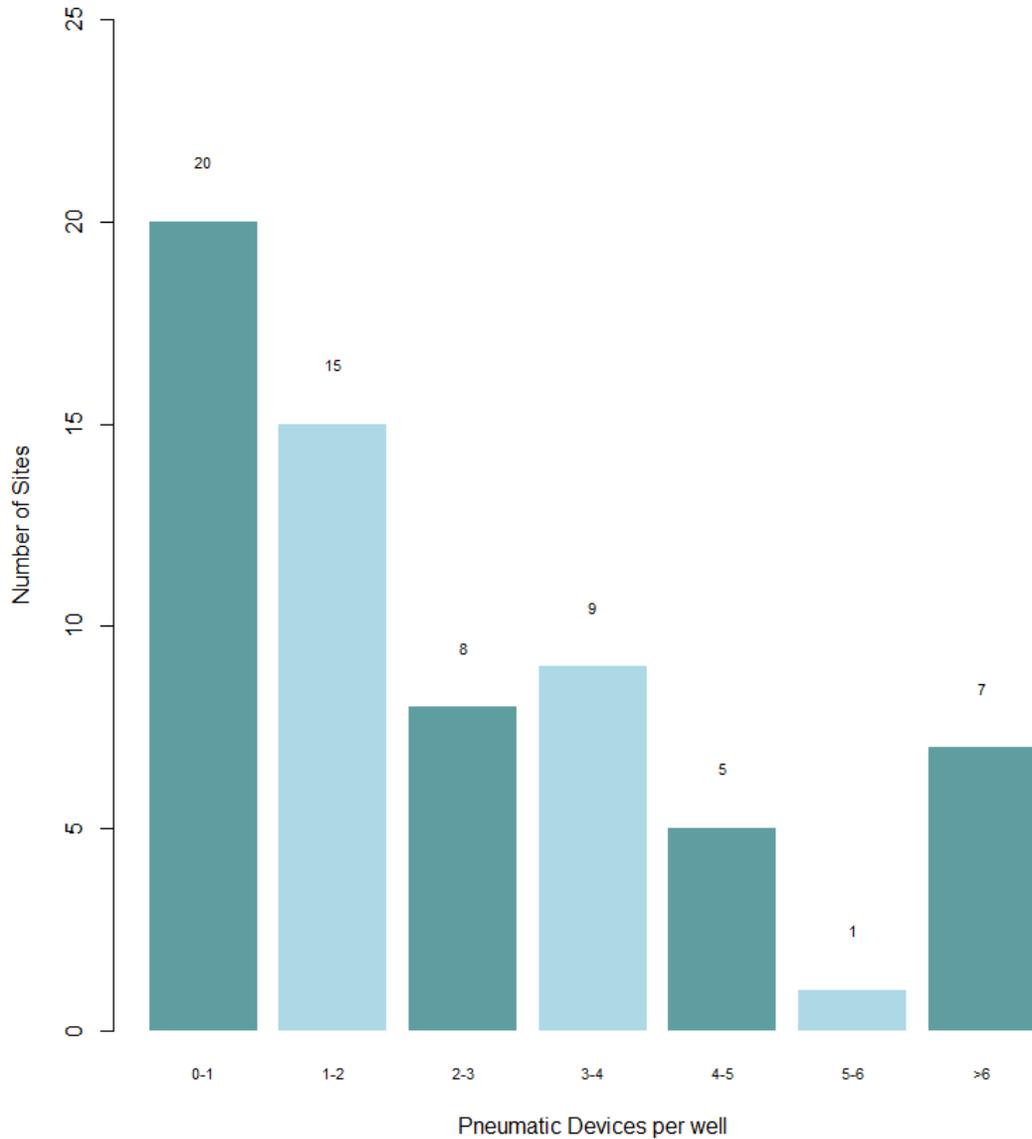


Figure S6-1. Distribution of number of pneumatic devices per well for production sites sampled by the study team.

Table S6-1 Number of pneumatic devices and wells for sites sampled in this work.

| Site Identifier | Count of Measured Pneumatic Devices | Count of Not measured Pneumatic Devices: | Total Pneumatic Devices | Count of wells | Devices/well |
|-----------------|-------------------------------------|--|-------------------------|----------------|--------------|
| AA01 | 7 | 22 | 29 | 3 | 9.7 |
| AA02 | 6 | 14 | 20 | 2 | 10.0 |
| AP01 | 6 | 0 | 6 | 16 | 0.4 |
| AP02 | 4 | 0 | 4 | 10 | 0.4 |
| AP03 | 2 | 0 | 2 | 3 | 0.7 |
| AP04 | 4 | 0 | 4 | 8 | 0.5 |
| AP05 | 2 | 0 | 2 | 4 | 0.5 |
| CW01 | 20 | 0 | 20 | 4 | 5.0 |
| CW02 | 20 | 0 | 20 | 4 | 5.0 |
| CZ01 | 2 | 0 | 2 | 1 | 2.0 |
| CZ02 | 2 | 0 | 2 | 1 | 2.0 |
| CZ03 | 2 | 0 | 2 | 1 | 2.0 |
| CZ04 | 2 | 0 | 2 | 1 | 2.0 |
| CZ05 | 3 | 0 | 3 | 1 | 3.0 |
| CZ06 | 3 | 0 | 3 | 1 | 3.0 |
| CZ07 | 2 | 0 | 2 | 1 | 2.0 |
| CZ08 | 2 | 1 | 3 | 3 | 1.0 |
| CZ09 | 2 | 0 | 2 | 1 | 2.0 |
| CZ10 | 1 | 0 | 1 | 1 | 1.0 |
| CZ11 | 1 | 0 | 1 | 1 | 1.0 |
| DL01 | 25 | 0 | 25 | 10 | 2.5 |
| DL02 | 32 | 0 | 32 | 14 | 2.3 |
| GZ01 | 12 | 0 | 12 | 4 | 3.0 |
| GZ02 | 14 | 0 | 14 | 2 | 7.0 |
| GZ03 | 22 | 0 | 22 | 2 | 11.0 |
| GZ04 | 6 | 0 | 6 | 2 | 3.0 |
| LB01 | 2 | 0 | 2 | 1 | 2.0 |
| LB02 | 4 | 0 | 4 | 2 | 2.0 |
| LB03 | 2 | 0 | 2 | 1 | 2.0 |
| LB04 | 4 | 0 | 4 | 2 | 2.0 |
| LB05 | 4 | 2 | 6 | 2 | 3.0 |
| LB06 | 6 | 3 | 9 | 3 | 3.0 |
| LB07 | 4 | 0 | 4 | 2 | 2.0 |
| OF01 | 1 | 0 | 1 | 1 | 1.0 |
| OF02 | 1 | 0 | 1 | 1 | 1.0 |
| OF03 | 1 | 0 | 1 | 1 | 1.0 |
| OF04 | 1 | 0 | 1 | 1 | 1.0 |
| OF05 | 1 | 0 | 1 | 1 | 1.0 |

| Site Identifier | Count of Measured Pneumatic Devices | Count of Not measured Pneumatic Devices: | Total Pneumatic Devices | Count of wells | Devices/well |
|-----------------|-------------------------------------|--|-------------------------|----------------|--------------|
| OF06 | 1 | 0 | 1 | 1 | 1.0 |
| OF07 | 1 | 0 | 1 | 1 | 1.0 |
| OF08 | 2 | 0 | 2 | 1 | 2.0 |
| OF09 | 1 | 0 | 1 | 1 | 1.0 |
| OF10 | 1 | 0 | 1 | 1 | 1.0 |
| OF11 | 4 | 0 | 4 | 1 | 4.0 |
| RB01 | 15 | 0 | 15 | 3 | 5.0 |
| RB02 | 6 | 1 | 7 | 1 | 7.0 |
| RQ01 | 1 | 0 | 1 | 1 | 1.0 |
| RQ02 | 2 | 0 | 2 | 1 | 2.0 |
| RQ03 | 1 | 0 | 1 | 1 | 1.0 |
| RQ04 | 1 | 0 | 1 | 1 | 1.0 |
| RQ05 | 4 | 0 | 4 | 2 | 2.0 |
| RQ06 | 4 | 0 | 4 | 1 | 4.0 |
| RQ07 | 5 | 0 | 5 | 1 | 5.0 |
| VF01 | 30 | 0 | 30 | 6 | 5.0 |
| VF02 | 7 | 0 | 7 | 6 | 1.2 |
| XQ01 | 4 | 0 | 4 | 1 | 4.0 |
| XQ02 | 4 | 0 | 4 | 1 | 4.0 |
| XQ03 | 4 | 0 | 4 | 1 | 4.0 |
| XQ04 | 4 | 0 | 4 | 1 | 4.0 |
| XQ05 | 4 | 0 | 4 | 1 | 4.0 |
| XQ06 | 4 | 0 | 4 | 1 | 4.0 |
| XQ07 | 4 | 0 | 4 | 1 | 4.0 |
| ZW01 | 20 | 5 | 25 | 3 | 8.3 |
| ZW02 | 5 | 1 | 6 | 1 | 6.0 |
| ZW03 | 3 | 4 | 7 | 1 | 7.0 |

S7. Estimates of emissions from pneumatic controllers in the United States

National emissions are estimated by multiplying an average emission measurement by the number of times that emission occurs on the national scale. Emission measurements are often referred to as an “emission factor” or EF, and the data used to scale up the emissions is called the activity factor (AF). Emissions are calculated as:

$$EF_i * AF_i = ER_i \quad (\text{Equation S7-1})$$

where:

EF_i = Emission Factor for region i

AF_i = Activity Factor for region i

ER_i = resulting Emission Rate total for region i

For this work, the activity factors are national estimates of the number of pneumatic controllers. Emission factors are based on average emissions per controller measured in this work. Four combinations of activity factors and emission factors are used to calculate national emission estimates (Table S7-1); these scenarios illustrate the uncertainty in national emission estimates that arise due to uncertainties in activity factors.

Table S7-1. National emission estimates, assuming various activity factor scenarios

| Activity Factor | Emission Factor | National emission estimate |
|---|--|-----------------------------------|
| Number of controllers in EPA 2012 Greenhouse Gas National Emission Inventory, 477,606 controllers | Average emission rate for all controllers measured in this work, 4.9 scf methane/h | 394 Gg/y 20.5 bcf/y |
| Number of controllers in EPA 2012 Greenhouse Gas National Emission Inventory, 477,606 controllers | Average emission rate for controllers measured in this work, not including Emergency Shut Down controllers in the average, 5.5 scf methane/h | 442 Gg/y 23.0 bcf/y |
| Number of wells in EPA 2012 Greenhouse Gas National Emission Inventory, 470,913 wells, with 75% of the wells assumed to have 2.7 pneumatic controllers per well, as observed in this work | Average emission rate for all controllers measured in this work, 4.9 scf methane/h | 786 Gg/y 40.9 bcf/y |
| Number of wells in EPA 2012 Greenhouse Gas National Emission Inventory, 470,913 wells, with all of the wells assumed to have 2.7 pneumatic controllers per well, as observed in this work | Average emission rate for all controllers measured in this work, 4.9 scf methane/h | 1050 Gg/y 54.6 bcf/y |

The range of estimates (394-1050 Gg/y) in Table S7-1 indicates the extent of variability in national emission estimates due to uncertainties in activity data and does not include uncertainty due associated with the emission factors derived from measurements. In the absence of

additional activity data, a central estimate will be assumed to be a mid-point between the second and third scenarios, approximately 600 Gg/yr, equivalent to a scenario in which approximately 75% of wells have pneumatic (as opposed to mechanical) controllers, and approximately 75% of controllers are inventoried as having emissions. These scenarios were selected since at least some of the participants in this study have significant numbers of wells with no pneumatic controllers, and because at least some of the participants do not inventory devices, such as Emergency Shut Down controllers, that are not expected to actuate. If the central estimate and range of emission estimates are added to the emission estimates for liquid unloadings reported by Allen, et al. (2014) and other source categories reported by Allen, et al (2013), total emissions from the natural gas production sector are 2185 Gg (reported to three significant figures as 2180 Gg), as shown in Table S7-2 and Figure S7-1.

Table S7-2. National emission estimates for the Natural Gas Production sector, based on this work for pneumatic controllers, Allen, et al. (2014) for liquid unloadings and Allen, et al. (2013) for other sources

| Category | Emission Estimates Allen, et al (2014) and 2012 EPA NEI Activity Data Gg methane/yr | 2012 National Emission Inventory Estimates Gg methane/yr | Emission Estimates As reported in Allen, et al (2013) Gg methane/yr |
|--|---|--|---|
| Completion flowbacks and workovers from wells with hydraulic fracturing ¹ | 24 ¹ | 217 | 18 (5-27) ¹ (completions) 143 (workovers) |
| Chemical Pumps ² | 73 ² | 65 | 68 (35-100) ² |
| Equipment leaks ³ | 307 ³ | 191 (est. ⁴) | 291 (186-396) ³ |
| Pneumatic Controllers | 600 (394-1050) | 334 | 580 (518-826) |
| Unloadings (non plunger lift) | 80 (50-160) | 155 | 149 |
| Unloadings (plunger lift) | 190 (110-290) | 119 | 108 |
| Other Sources, not measured in Allen, et al., 2013 | 911 | 911 | 891-930 |
| TOTAL methane, Gg | 2185 | 1992 | 2300 |

¹The estimate of 18 Gg for completion flowbacks in Allen, et al. (2013) was based on 8077 well completions, with hydraulic fracturing, in 2011. If this is scaled up to the 10,664 completions and workovers (with hydraulic fracturing) reported in the 2012 NEI, the estimate becomes 24 Gg.

²The estimate of 68 Gg for pneumatic pumps in Allen, et al. (2013) was based on a pump count of 35,013 in 2011. If this is scaled up to the pump count of 37,477 reported in the 2012 NEI, the estimate becomes 73 Gg.

³The estimate of 291 Gg for equipment leaks in Allen, et al. (2013) was based on a well count of 446,745 in 2011. If this is scaled up to the well count of 470,913 reported in the 2012 NEI, the estimate becomes 307 Gg.

⁴Equipment leak emissions from the source categories measured by Allen, et al. (2013) are not all separately reported in the GHG NEI; estimate based on the mid-point of the range reported by Allen, et al. (2013).

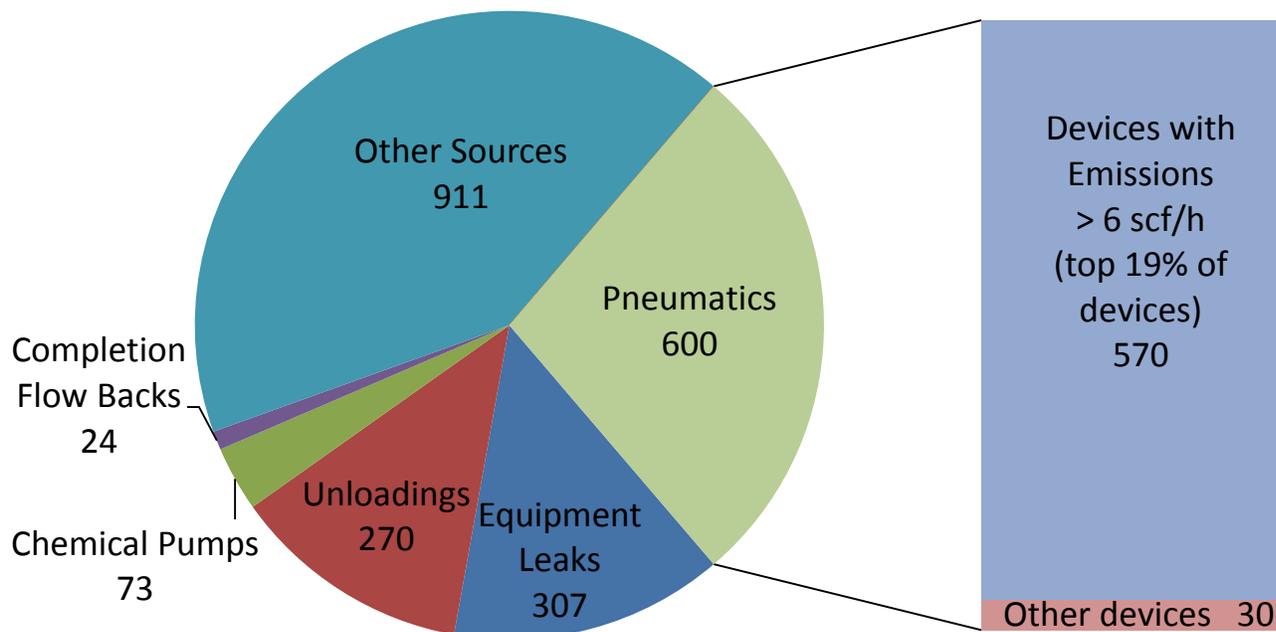


Figure S7-1. Distribution of emissions, by source category in the Natural Gas Production Sector, based on this work.

The total estimated methane emissions from natural gas production (2180 Gg/yr), based on updated estimates for pneumatic controllers and liquid unloadings, is within 10 percent of the emissions estimate in the 2012 GHG NEI (1992 Gg/yr). A larger estimate for pneumatic controller emissions than in the 2012 GHG NEI is balanced by a lower estimate for completion flowback emissions than in the 2012 GHG NEI, resulting in total emissions that are very nearly equal. This result is similar to the comparison reported by Allen, et al. (2013), where total estimated emissions of 2300 Gg/yr was within 10% of the 2011 GHG NEI (as reported in 2013) of 2545 Gg/yr. As in this work, a larger estimate for pneumatic controller emissions than in the 2011 GHG NEI was balanced by a lower estimate for completion flowback emissions than in the 2011 GHG NEI.

The methane emissions reported in Table S7-2 can also be expressed as a percentage of natural gas production. If the 2180 Gg of methane emissions is normalized by total U.S. natural gas gross withdrawals of 29.54 trillion scf (including oil and coal bed, gas, and shale, onshore and offshore) reported by the Energy Information Administration for 2012 (<http://www.eia.gov/naturalgas/>), methane emissions in the production sector are 0.38% (volume basis) of natural gas gross withdrawals. If it is assumed that the natural gas is 78.8% methane, the methane emissions are 0.48% of methane withdrawals. Allen, et al. (2013) reported these percentages as 0.42% and 0.53% based on 2300 Gg of methane emissions and 2011 natural gas gross withdrawals of 28.5 trillion scf. The differences in percentages between this work and

Allen, et al. (2013) are due to both increased withdrawals and decreased emission estimates in the GHG NEI for source categories not measured in this work.

Allen, D.T.; Torres, V.M.; Thomas, J.; Sullivan, D.; Harrison, M.; Hendler, A.; Herndon, S.C.; Kolb, C.E.; Fraser, M.P.; Hill, A.D.; Lamb, B.K.; Miskimins, J.; Sawyer, R.F.; Seinfeld, J.H. Measurements of Methane Emissions at Natural Gas Production Sites in the United States, *Proc. Natl. Acad. Sci. U.S.A.* **2013**, *110*, 17768-17773.

Allen, D.T.; Pacsi, A.; Sullivan, D.; Zavala-Araiza, D.; Harrison, M.; Keen, K.; Fraser, M.; Hill, A.D.; Lamb, B.K.; Sawyer, R.F.; Seinfeld, J.H. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings, submitted to *Environmental Science & Technology* (2014).

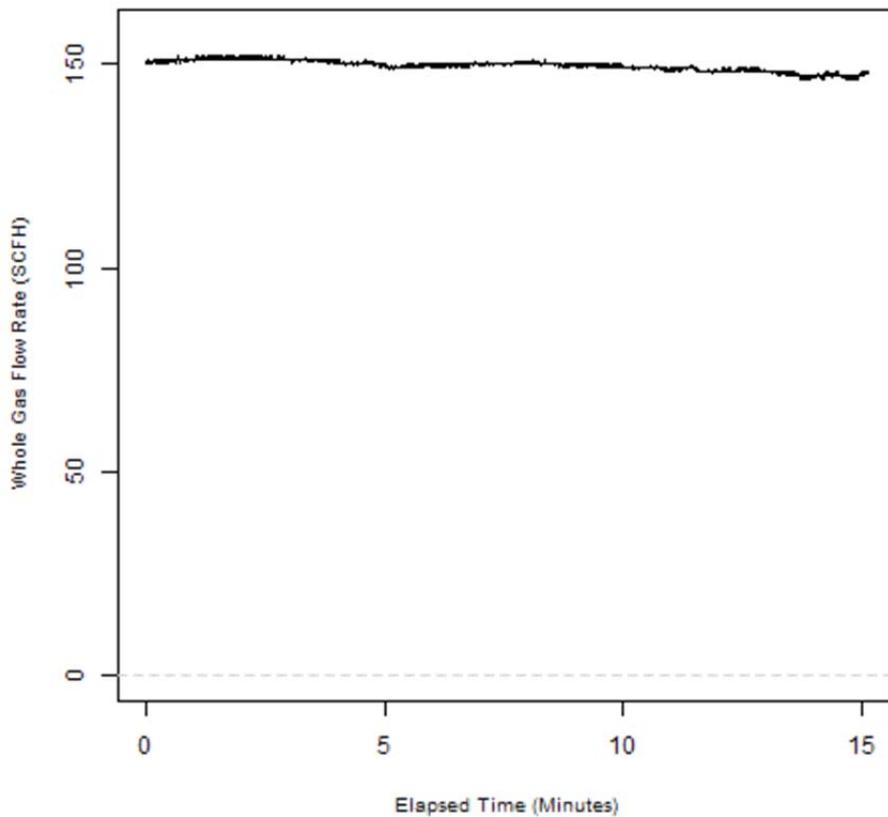
S8. Summary of data on 40 highest emitting devices

Controller characteristics and time series for measured emissions are reported for the 40 devices with the highest measured emission rates. This information was reviewed by technical experts on pneumatic controller operation to assess whether controllers were operating properly. While these 40 controllers were not removed from operation and subjected to a rigorous performance analysis, the data that were collected may reveal some features of operation. For example, if a device had very high rates of nearly continuous emissions, larger than would be expected for the device design and supply gas pressure, it could be hypothesized that the controller/control valve system had a leak. If a device with intermittent actuation emissions, which appeared to be an intermittent vent controller, did not return to zero flow between actuations, it could be hypothesized that the barrier between the supply gas and the controller was not closing completely. It is important to recognize that these are hypotheses, based on expert opinion. The controllers are categorized, based on these hypotheses, as having “equipment issues” or “operating as expected”.

CZ09-PC01 [1] Region: GC

Device characteristics:

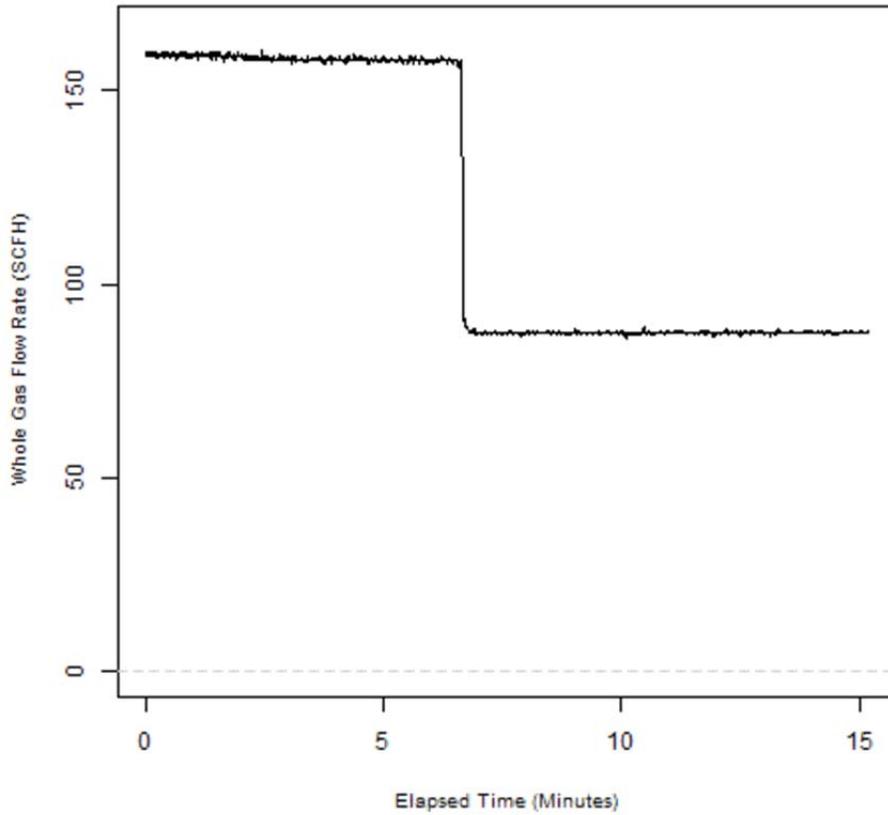
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 149.7 scf/h |
| Avg. Emission rate (methane): | 143.8 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 19 psig |
| Assessment of controller operation: | equipment issues |



CZ02-PC01 [2] Region: GC

Device characteristics:

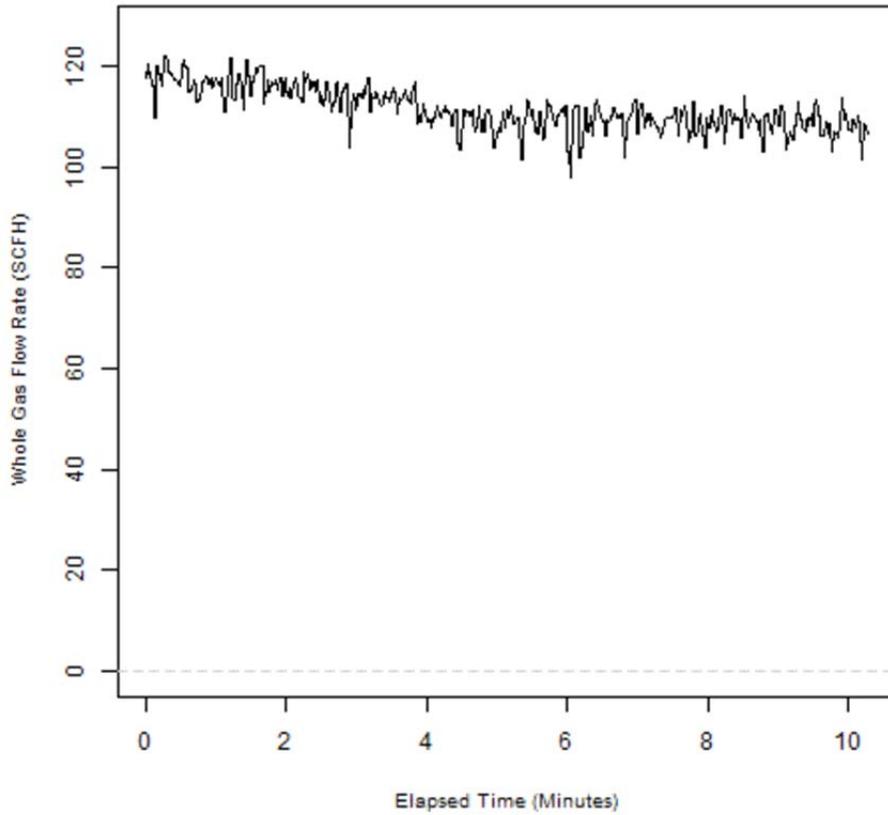
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 118.5 scf/h |
| Avg. Emission rate (methane): | 108.0 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | J01 |
| Supply pressure: | 17 psig |
| Assessment of controller operation: | equipment issues |



AA02-PC08 [3] Region: MC

Device characteristics:

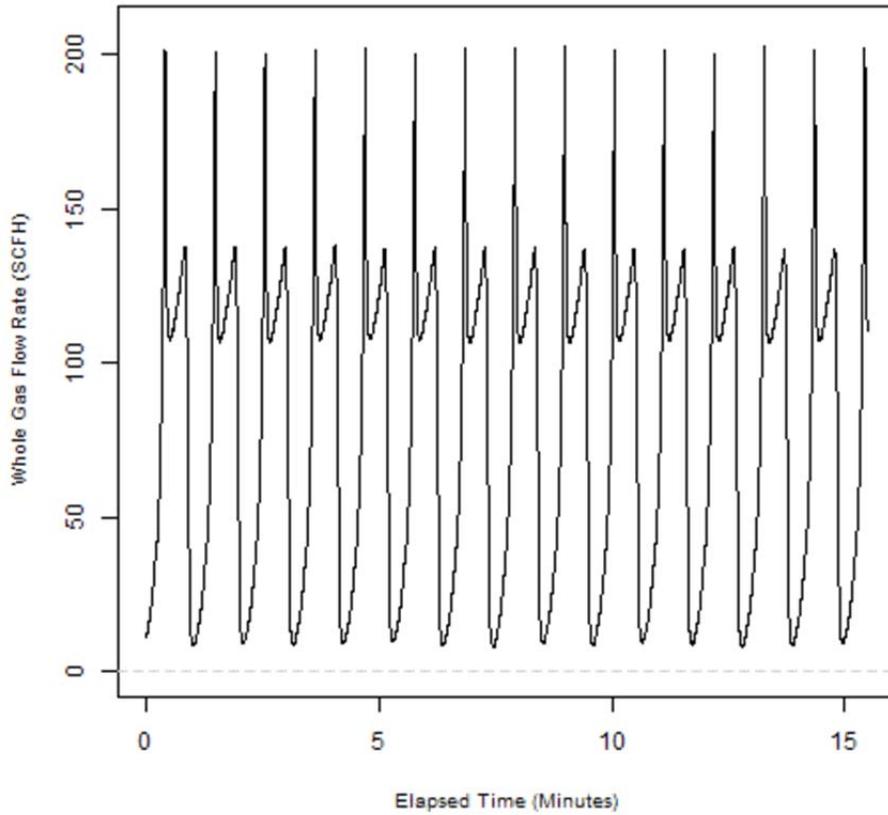
| | |
|-------------------------------------|-----------------------------------|
| Avg. Emission rate (whole gas): | 111.4 scf/h |
| Avg. Emission rate (methane): | 89.7 scf/h |
| Controller application: | Pressure |
| Basic Application: | Compressor |
| Detailed Application: | Compressor - Suction Feed Control |
| Manufacturer/Model (blinded): | I01 |
| Supply pressure: | 60 psig |
| Assessment of controller operation: | equipment issues |



LB05-PC03 [4] Region: GC

Device characteristics:

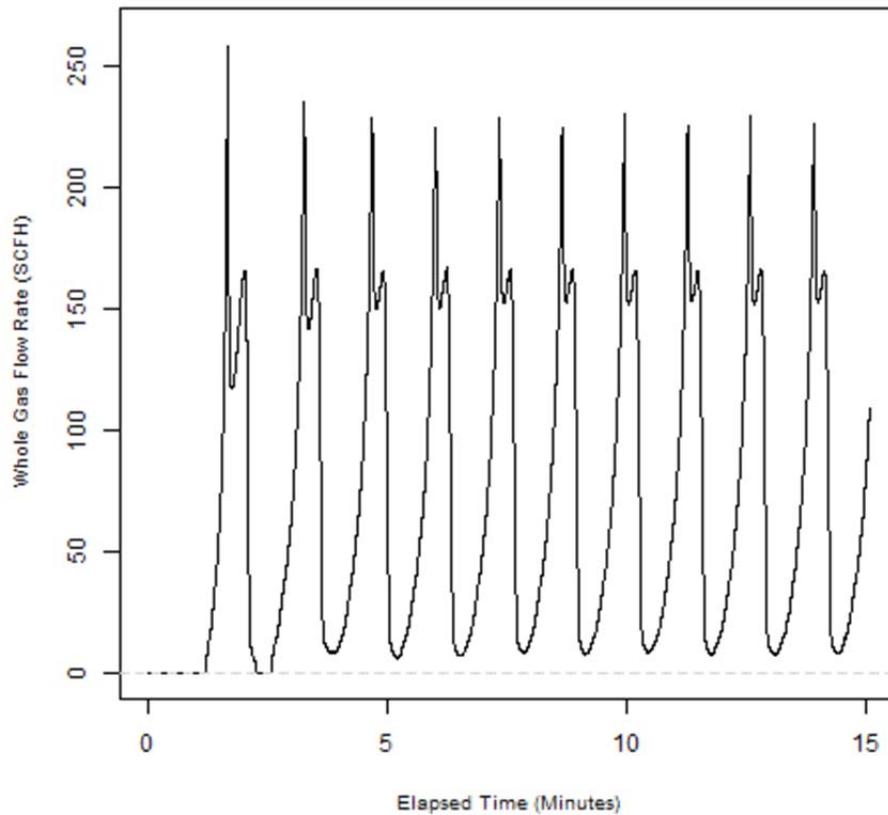
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 78.6 scf/h |
| Avg. Emission rate (methane): | 68.9 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 25 psig |
| Assessment of controller operation: | equipment issues |



LB05-PC01 [5] Region: GC

Device characteristics:

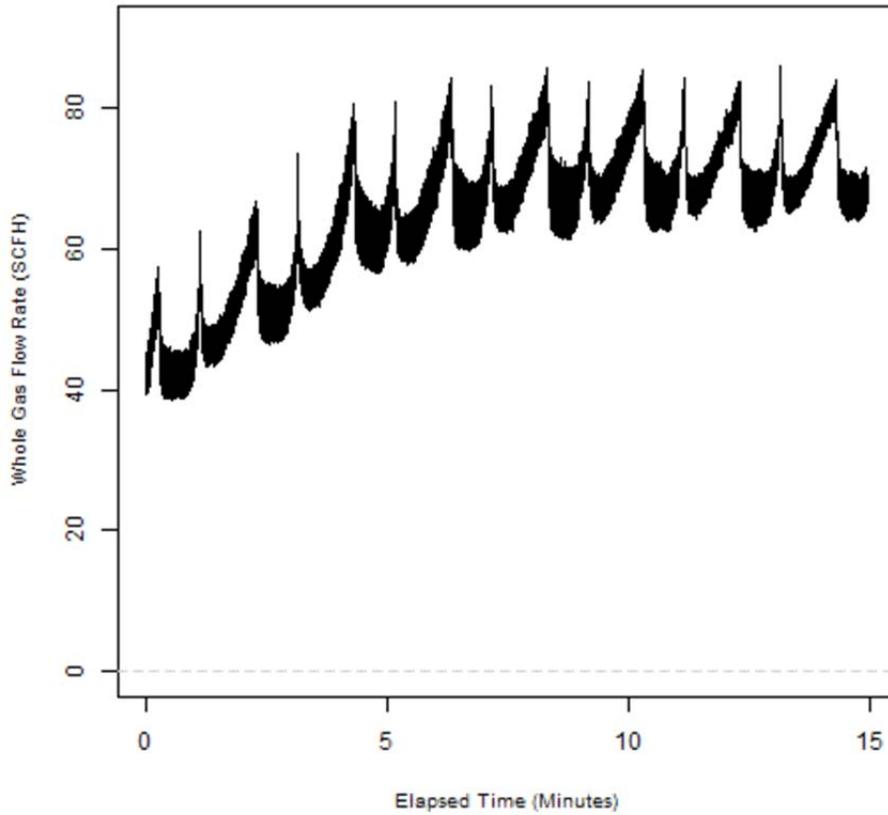
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 68.6 scf/h |
| Avg. Emission rate (methane): | 60.2 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | equipment issues |



LB07-PC02 [6] Region: GC

Device characteristics:

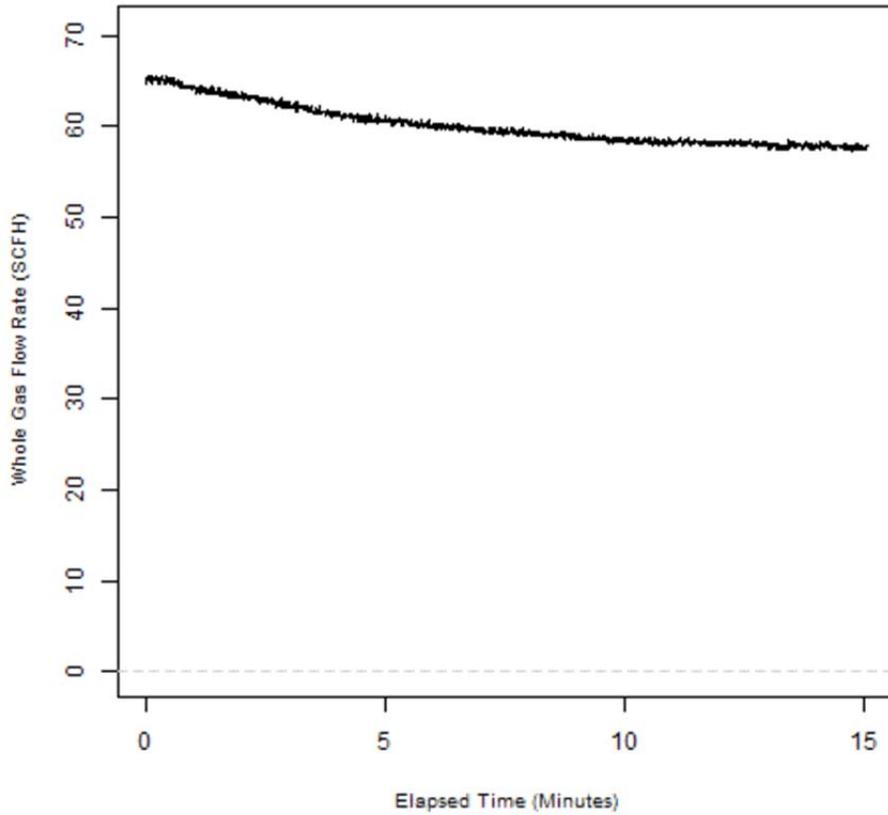
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 64.8 scf/h |
| Avg. Emission rate (methane): | 51.2 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 24 psig |
| Assessment of controller operation: | equipment issues |



CZ08-PC01 [7] Region: GC

Device characteristics:

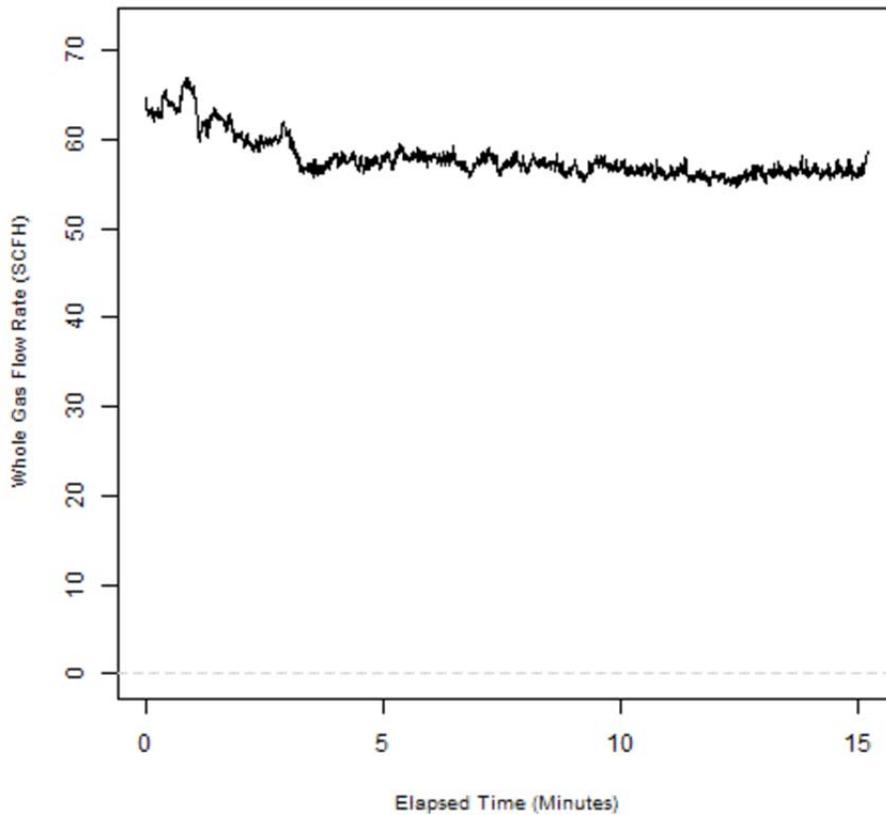
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 60.1 scf/h |
| Avg. Emission rate (methane): | 57.8 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 11 psig |
| Assessment of controller operation: | equipment issues |



GZ02-PC12 [8] Region: GC

Device characteristics:

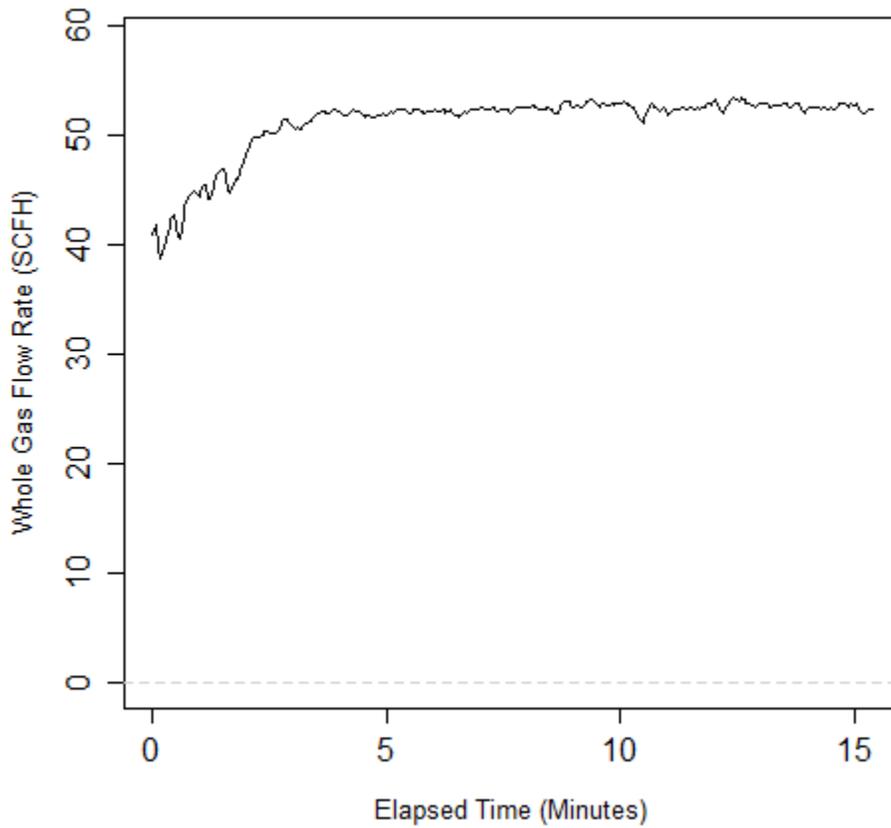
| | |
|-------------------------------------|---|
| Avg. Emission rate (whole gas): | 57.9 scf/h |
| Avg. Emission rate (methane): | 56.5 scf/h |
| Controller application: | Level |
| Basic Application: | Compressor |
| Detailed Application: | Compressor - Liquid Level Control (Stage 2) |
| Manufacturer/Model (blinded): | J01 |
| Supply pressure: | 28 psig |
| Assessment of controller operation: | equipment issues |



CZ06-PC01 [9] Region: GC

Device characteristics:

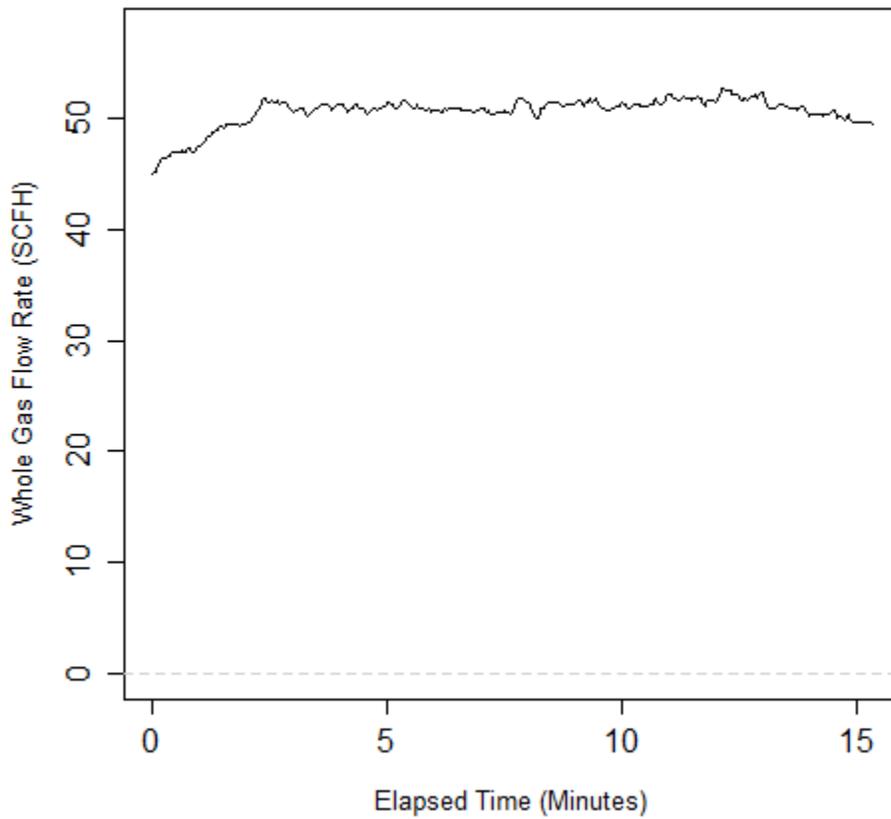
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 51.2 scf/h |
| Avg. Emission rate (methane): | 48.2 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | G01 |
| Supply pressure: | 6 psig |
| Assessment of controller operation: | operating as expected |



CZ06-PC02 [10] Region: GC

Device characteristics:

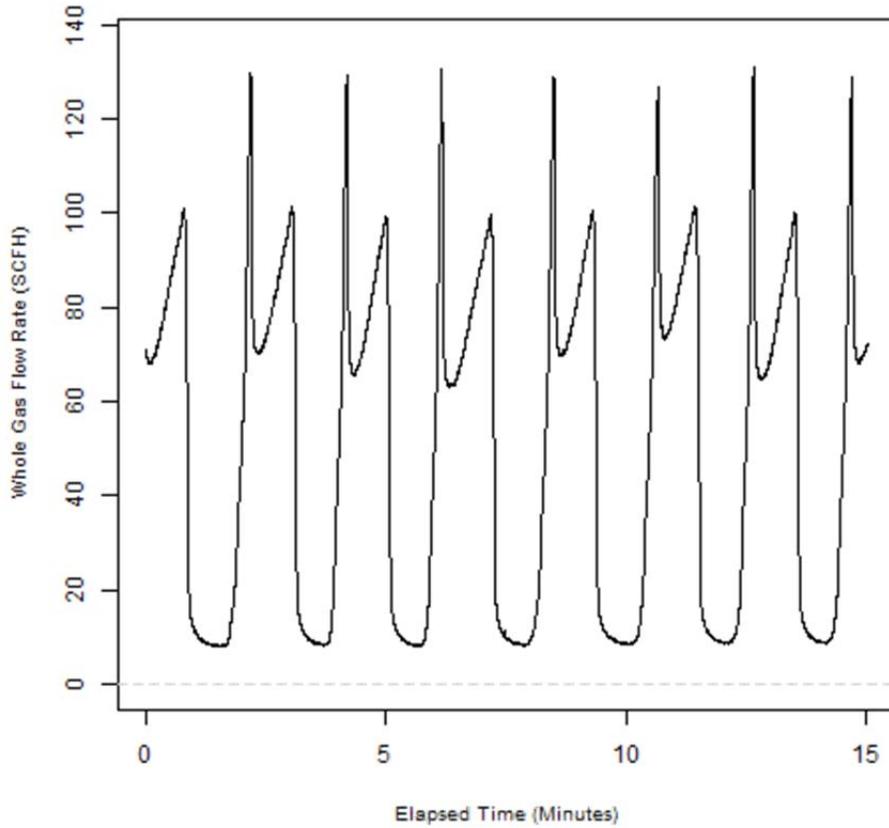
| | |
|-------------------------------------|------------------|
| Avg. Emission rate (whole gas): | 50.7 scf/h |
| Avg. Emission rate (methane): | 47.7 scf/h |
| Controller application: | Pressure |
| Basic Application: | Plunger Lift |
| Detailed Application: | Plunger Lift |
| Manufacturer/Model (blinded): | E01 |
| Supply pressure: | 20 psig |
| Assessment of controller operation: | equipment issues |



LB03-PC01 [11] Region: GC

Device characteristics:

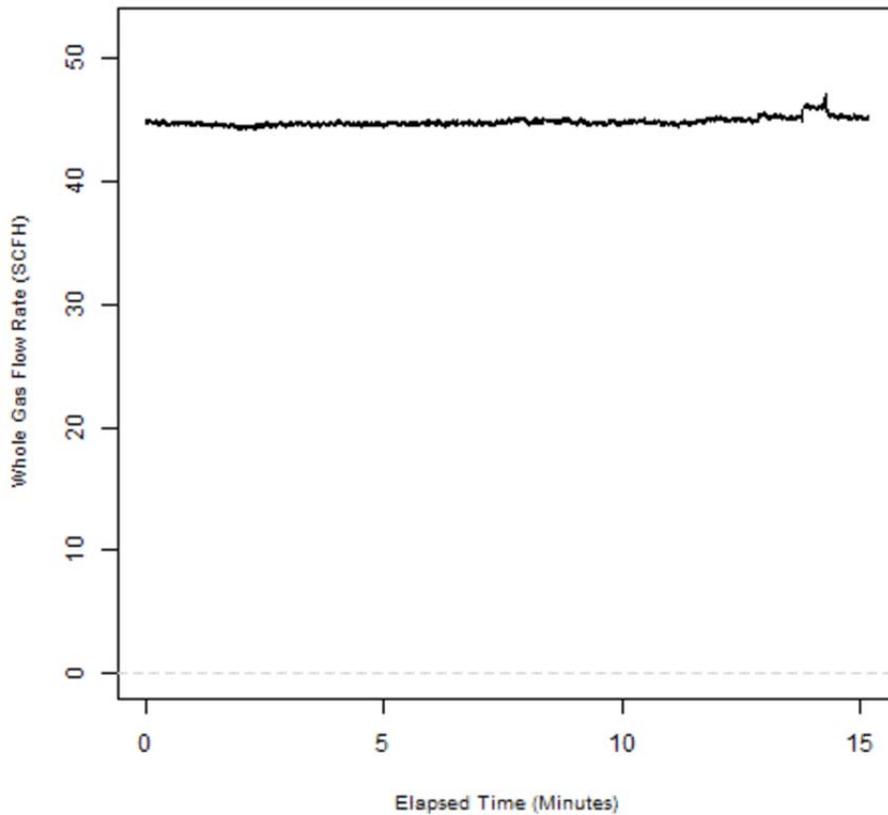
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 50.0 scf/h |
| Avg. Emission rate (methane): | 39.7 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | equipment issues |



CZ09-PC02 [12] Region: GC

Device characteristics:

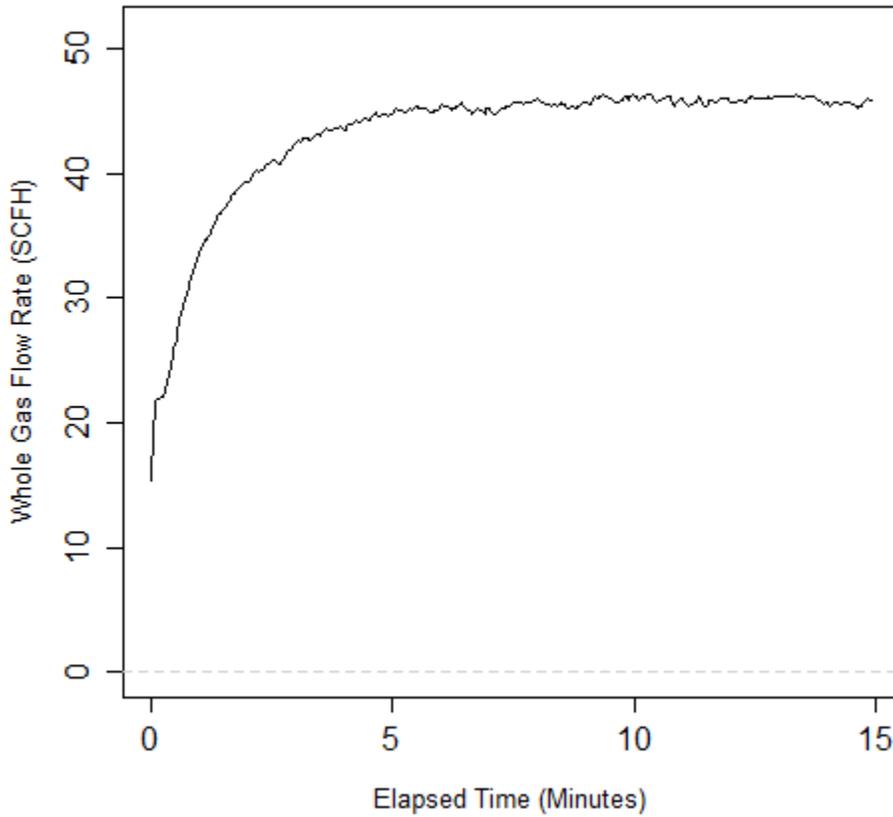
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 44.9 scf/h |
| Avg. Emission rate (methane): | 43.1 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 9 psig |
| Assessment of controller operation: | equipment issues |



GZ02-PC14 [13] Region: GC

Device characteristics:

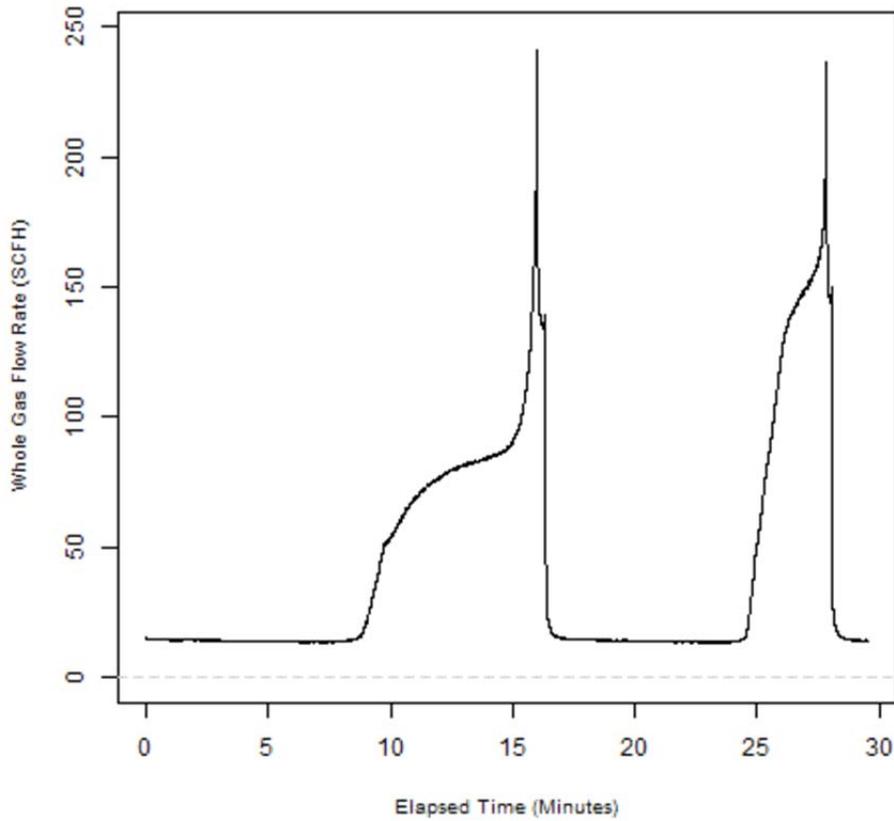
| | |
|-------------------------------------|-----------------------------------|
| Avg. Emission rate (whole gas): | 43.3 scf/h |
| Avg. Emission rate (methane): | 42.2 scf/h |
| Controller application: | Pressure |
| Basic Application: | Compressor |
| Detailed Application: | Compressor - Suction Feed Control |
| Manufacturer/Model (blinded): | I01 |
| Supply pressure: | 42 psig |
| Assessment of controller operation: | equipment issues |



CZ10-PC01 [14] Region: GC

Device characteristics:

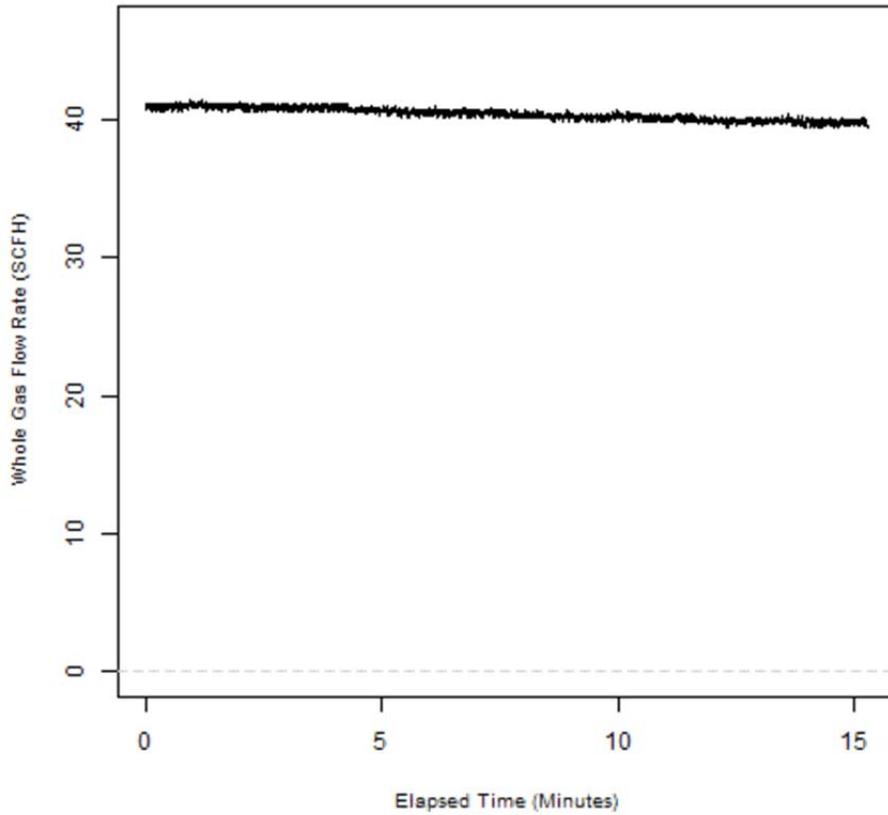
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 43.2 scf/h |
| Avg. Emission rate (methane): | 41.5 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 13 psig |
| Assessment of controller operation: | equipment issues |



CZ05-PC01 [15] Region: GC

Device characteristics:

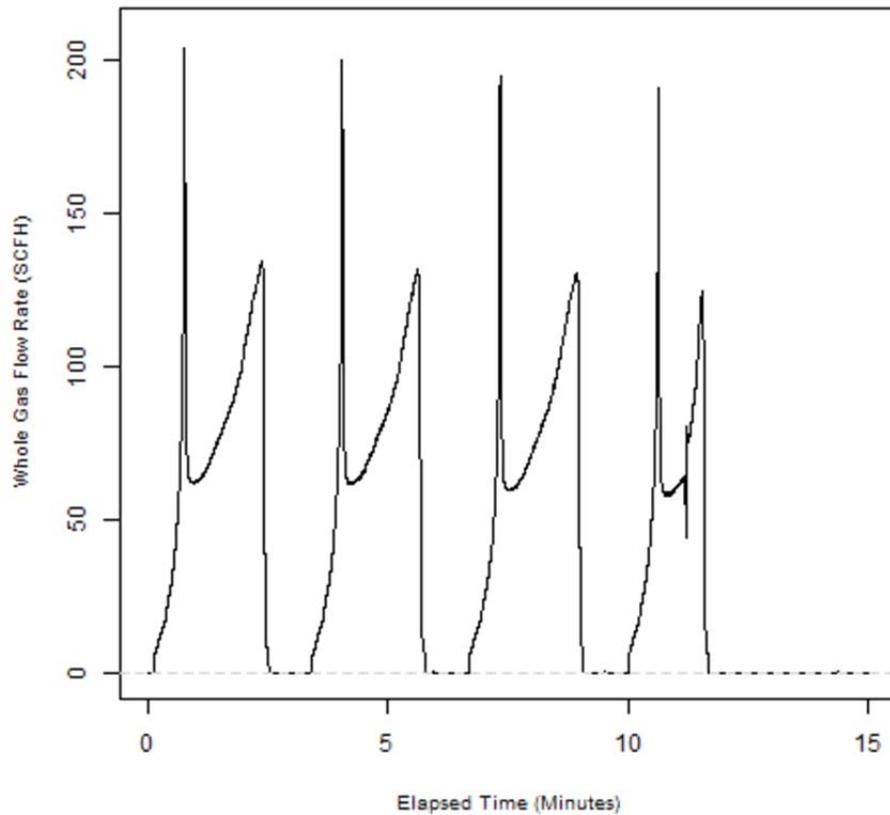
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 40.4 scf/h |
| Avg. Emission rate (methane): | 37.9 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | A01 |
| Supply pressure: | 29 psig |
| Assessment of controller operation: | equipment issues |



LB01-PC01 [16] Region: GC

Device characteristics:

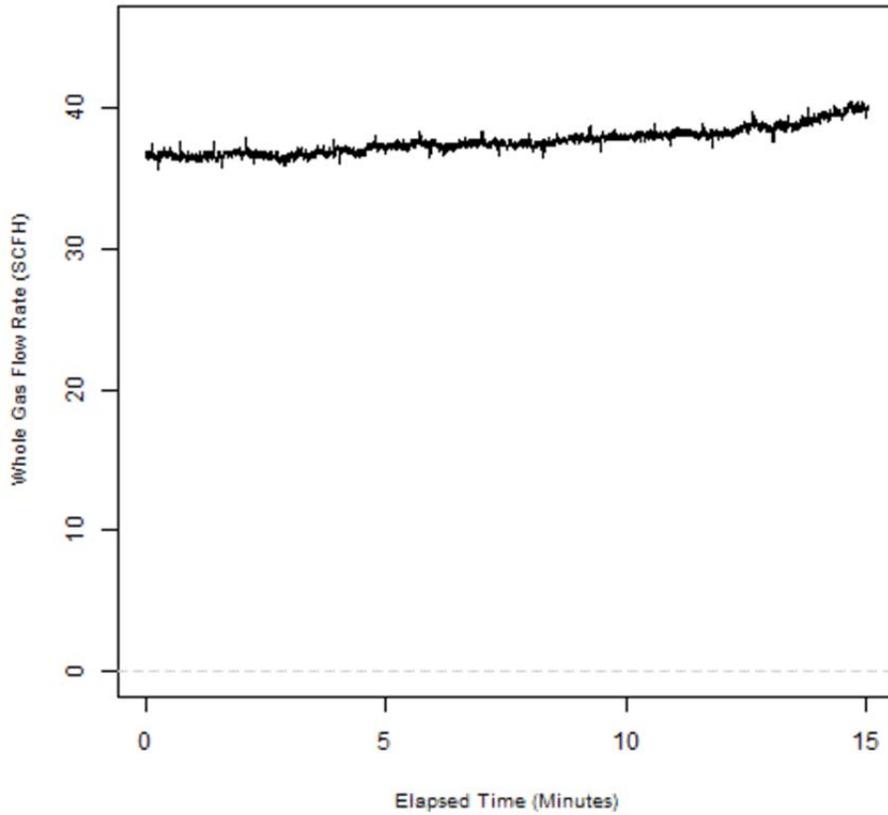
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 40.2 scf/h |
| Avg. Emission rate (methane): | 32.3 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



GZ03-PC22 [17] Region: GC

Device characteristics:

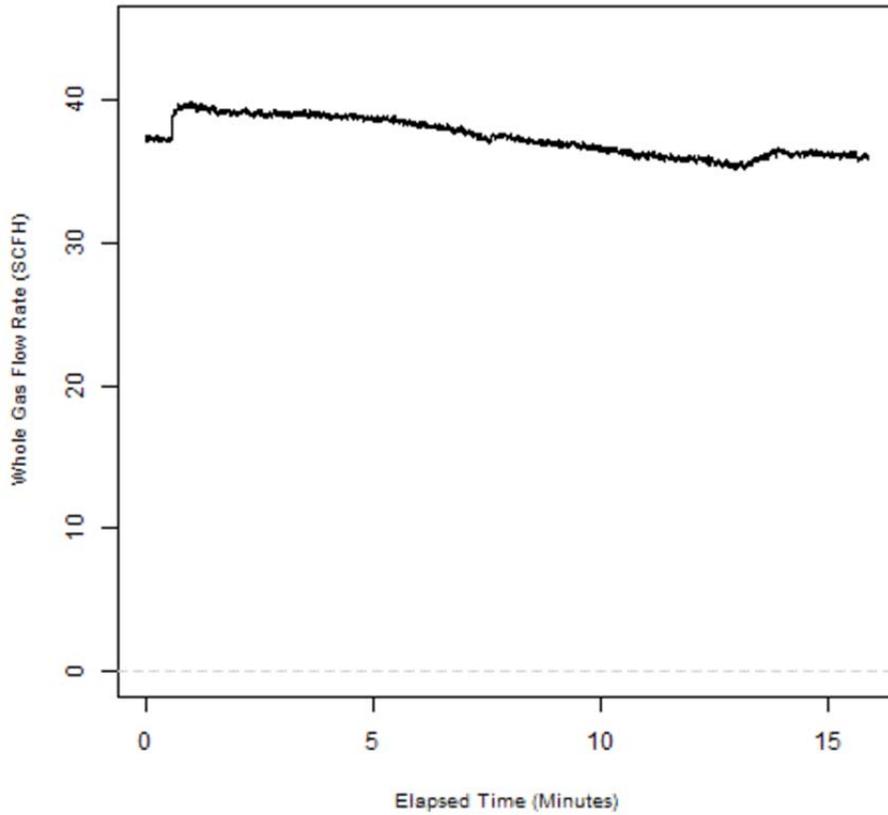
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 37.7 scf/h |
| Avg. Emission rate (methane): | 36.6 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 7 psig |
| Assessment of controller operation: | equipment issues |



XQ04-PC02 [18] Region: MC

Device characteristics:

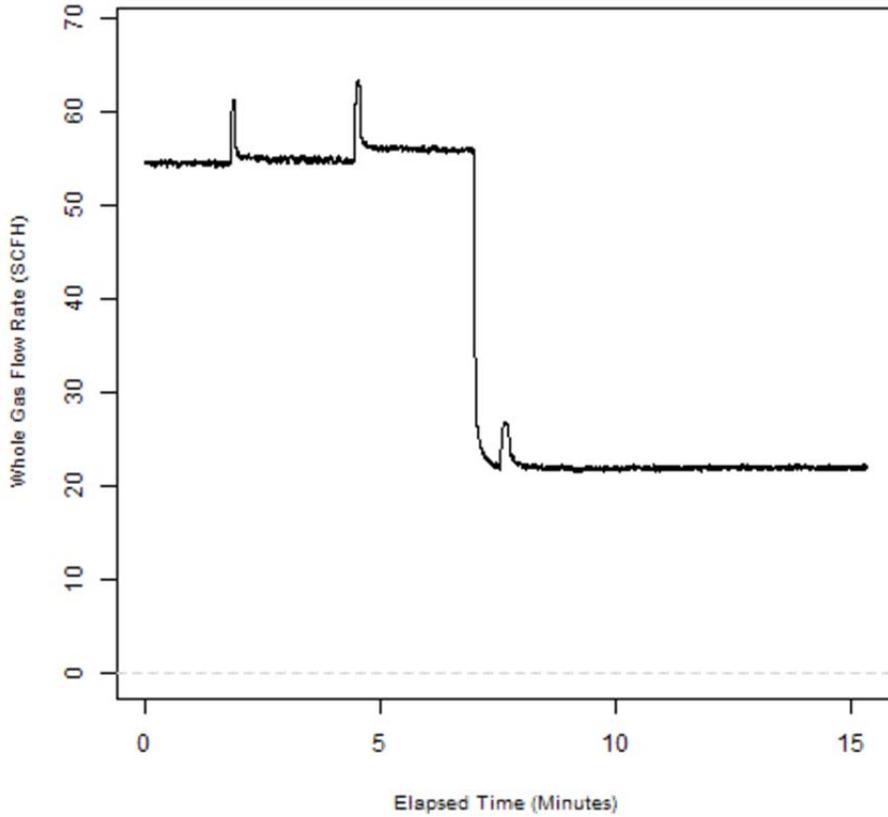
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 37.4 scf/h |
| Avg. Emission rate (methane): | 33.5 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | Q02 |
| Supply pressure: | 28 psig |
| Assessment of controller operation: | equipment issues |



XQ01-PC04 [19] Region: MC

Device characteristics:

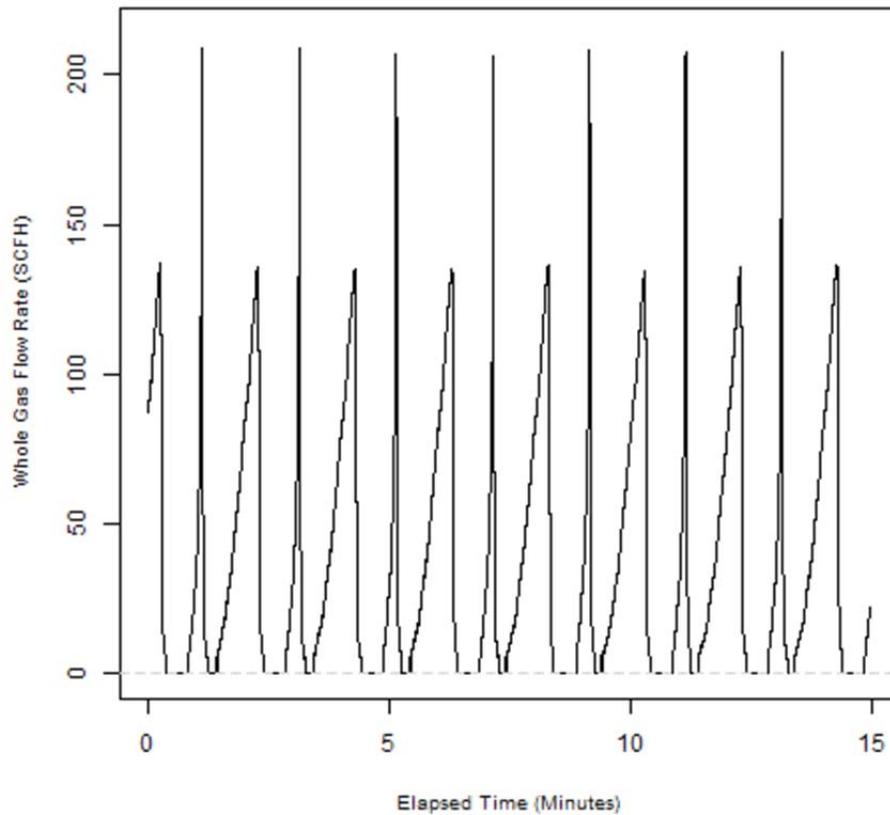
| | |
|-------------------------------------|------------------|
| Avg. Emission rate (whole gas): | 37.4 scf/h |
| Avg. Emission rate (methane): | 33.0 scf/h |
| Controller application: | Pressure |
| Basic Application: | Plunger Lift |
| Detailed Application: | Plunger Lift |
| Manufacturer/Model (blinded): | F02 |
| Supply pressure: | 15 psig |
| Assessment of controller operation: | equipment issues |



LB07-PC01 [20] Region: GC

Device characteristics:

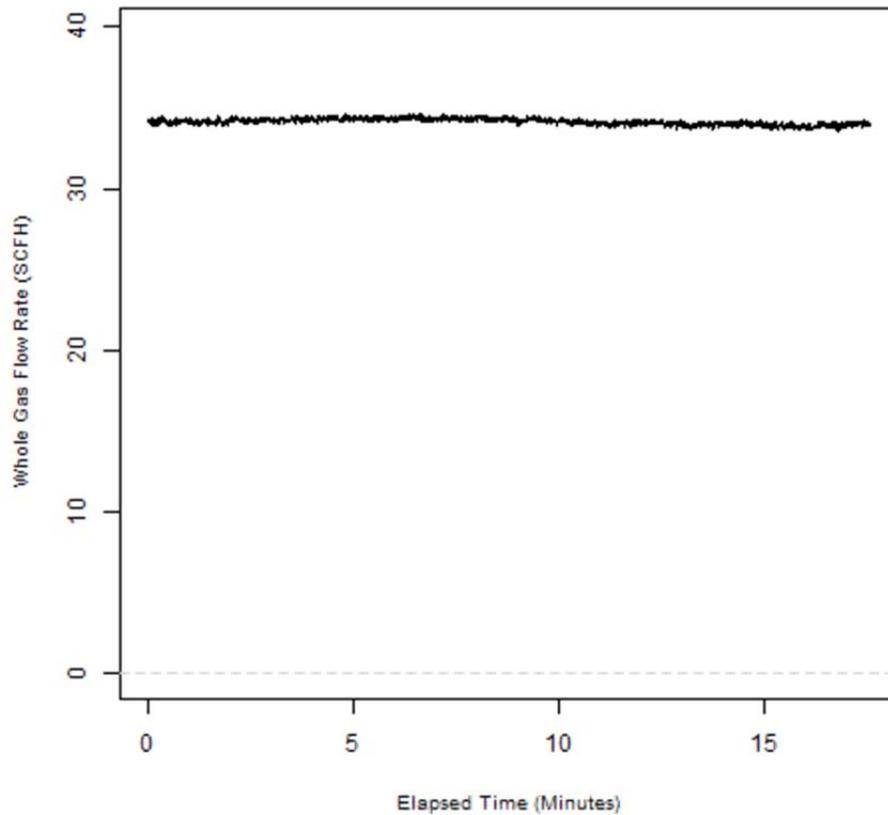
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 36.3 scf/h |
| Avg. Emission rate (methane): | 28.7 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 24 psig |
| Assessment of controller operation: | operating as expected |



GZ03-PC13 [21] Region: GC

Device characteristics:

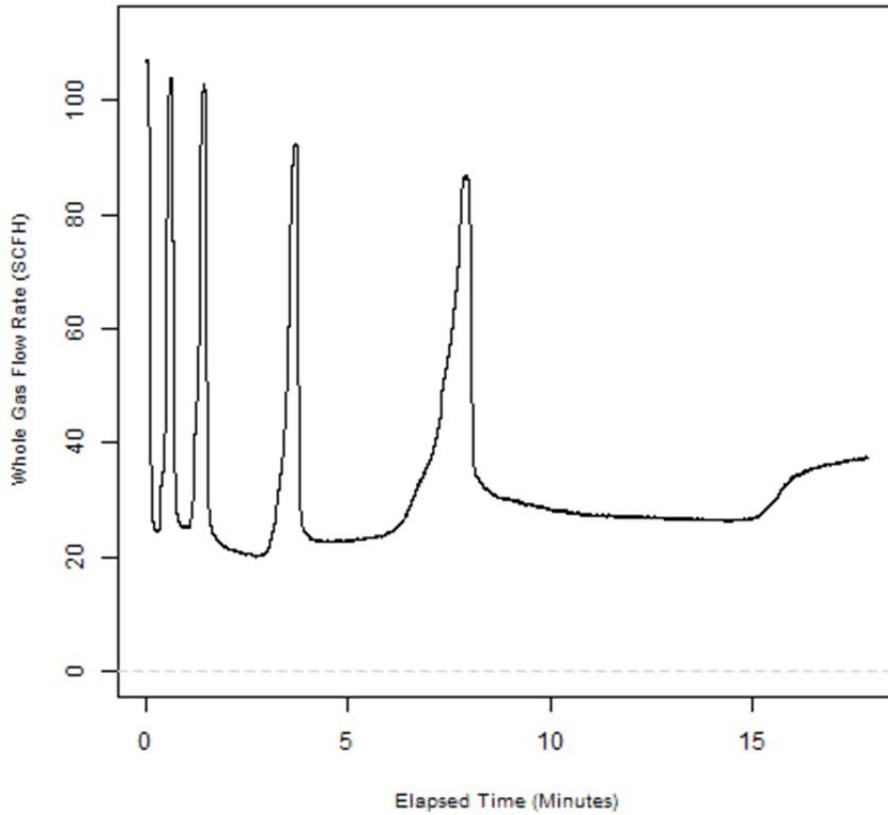
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 34.1 scf/h |
| Avg. Emission rate (methane): | 33.2 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 26 psig |
| Assessment of controller operation: | equipment issues |



GZ04-PC03 [22] Region: GC

Device characteristics:

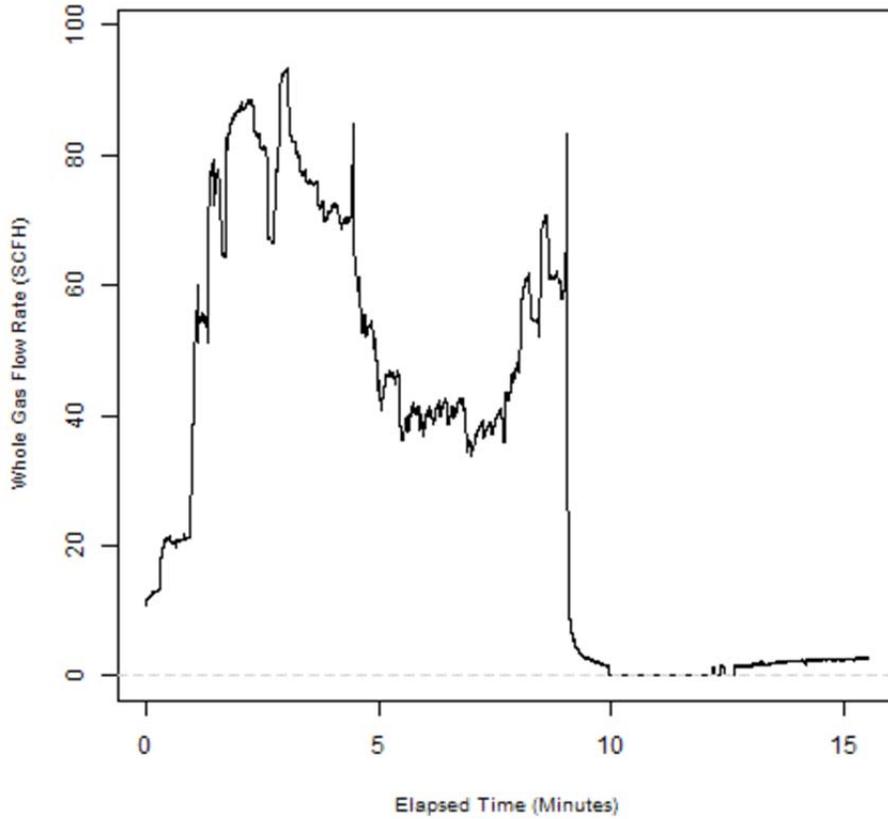
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 32.7 scf/h |
| Avg. Emission rate (methane): | 31.8 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | equipment issues |



GZ03-PC02 [23] Region: GC

Device characteristics:

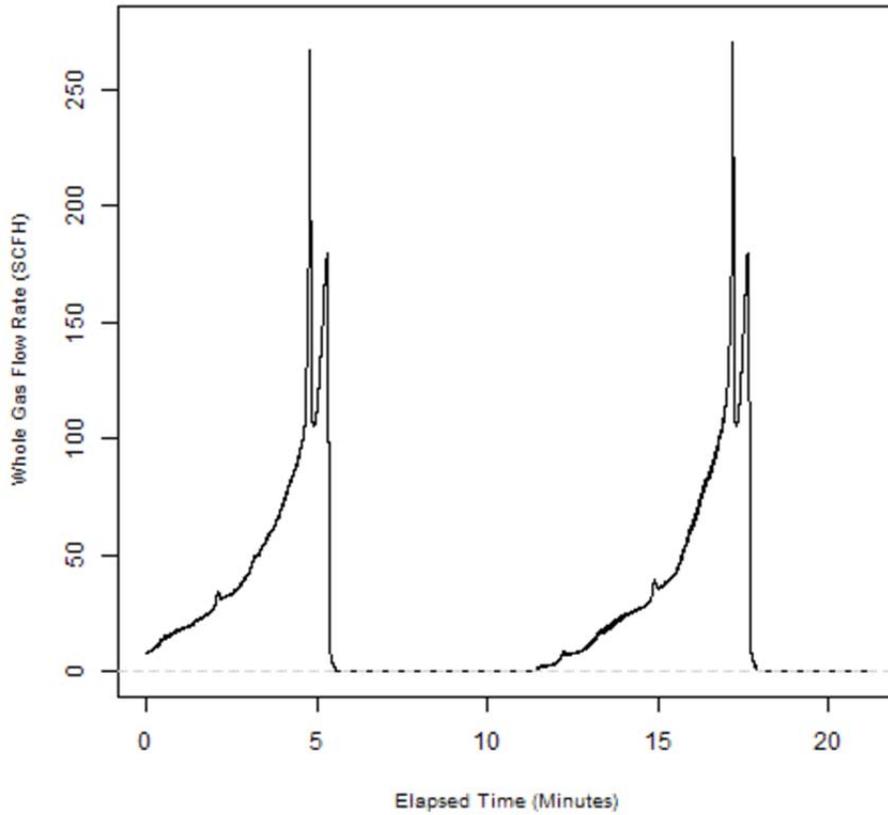
| | |
|-------------------------------------|---|
| Avg. Emission rate (whole gas): | 32.6 scf/h |
| Avg. Emission rate (methane): | 31.7 scf/h |
| Controller application: | Level |
| Basic Application: | Compressor |
| Detailed Application: | Compressor - Liquid Level Control (Stage 2) |
| Manufacturer/Model (blinded): | L01 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



LB07-PC04 [24] Region: GC

Device characteristics:

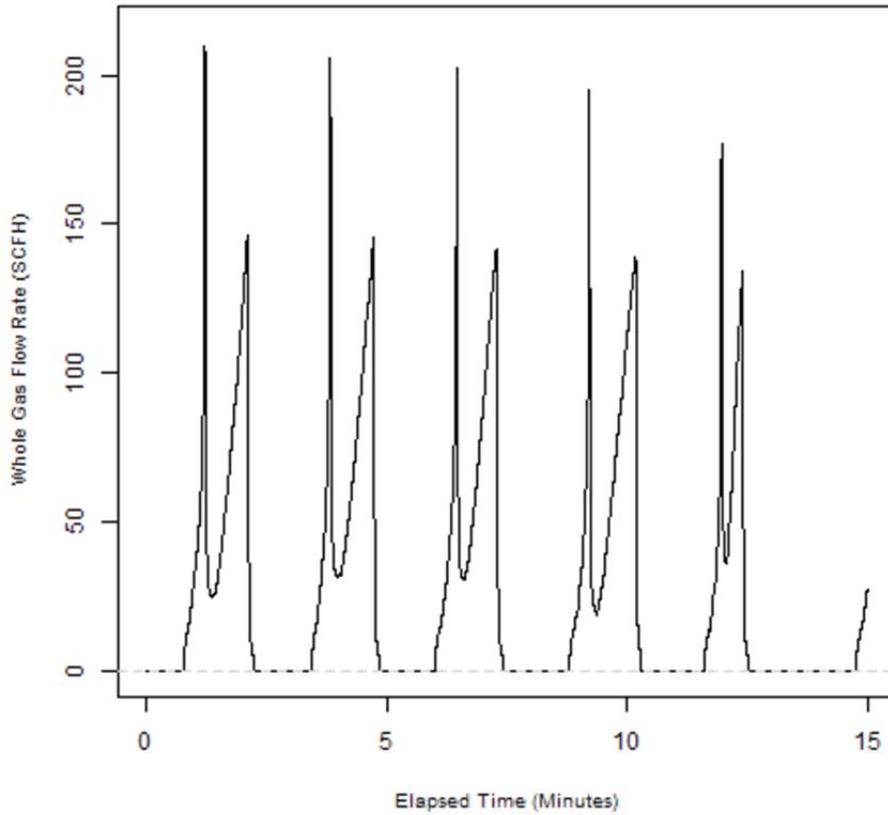
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 27.0 scf/h |
| Avg. Emission rate (methane): | 21.4 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 28 psig |
| Assessment of controller operation: | equipment issues |



LB04-PC01 [25] Region: GC

Device characteristics:

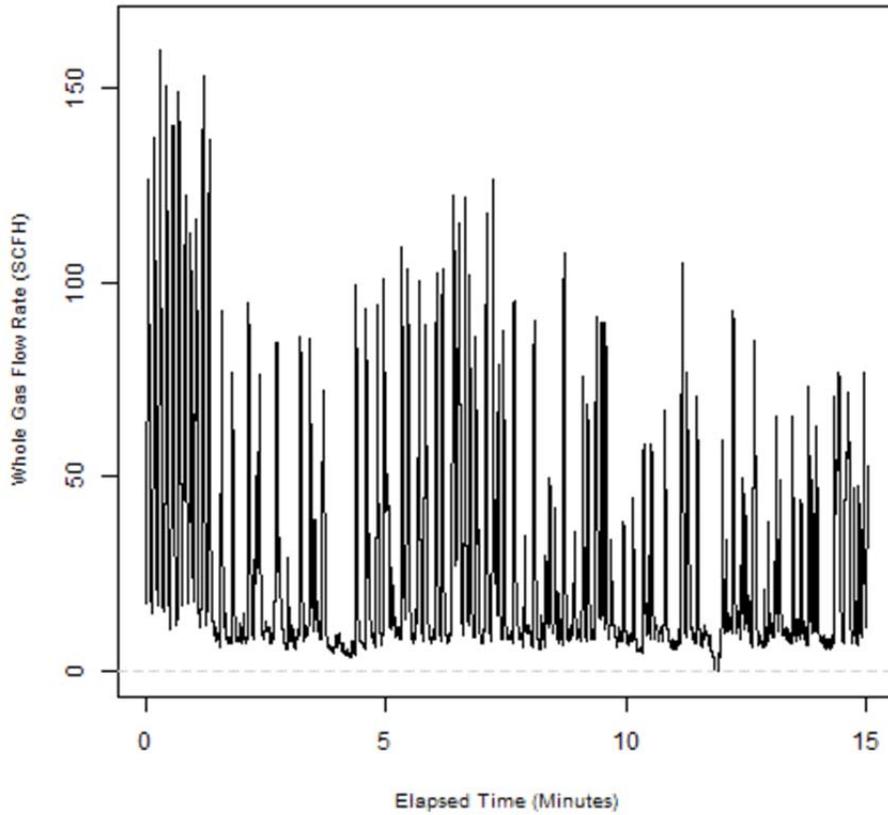
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 26.2 scf/h |
| Avg. Emission rate (methane): | 20.7 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



AP01-PC12 [26] Region: MC

Device characteristics:

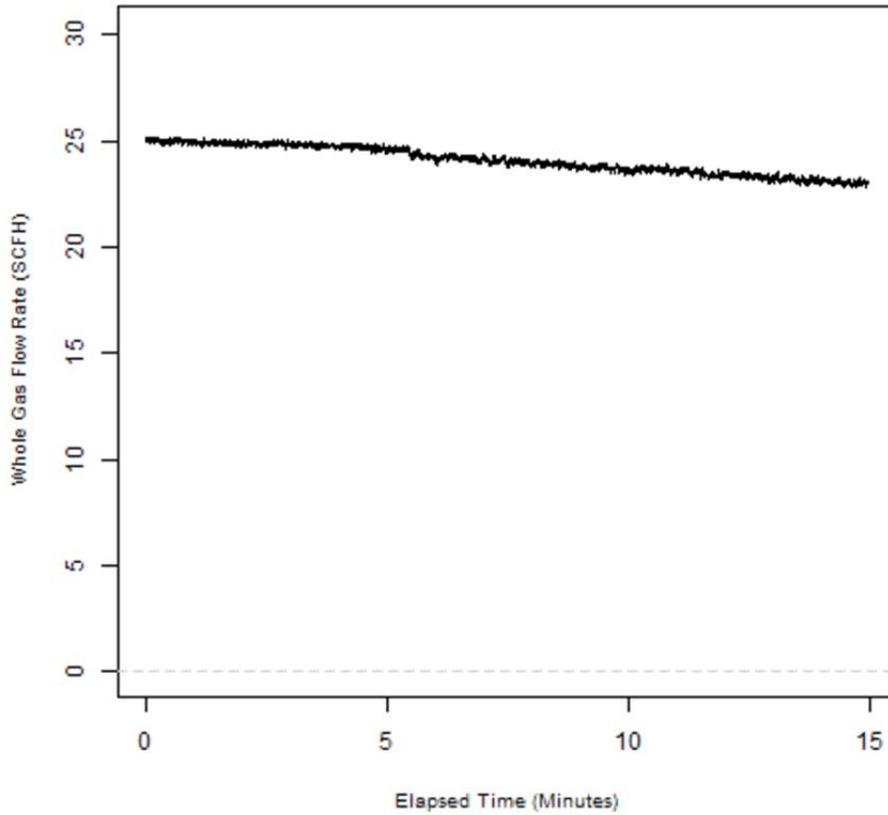
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 25.6 scf/h |
| Avg. Emission rate (methane): | 17.0 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | I02 |
| Supply pressure: | 11 psig |
| Assessment of controller operation: | equipment issues |



XQ05-PC02 [27] Region: MC

Device characteristics:

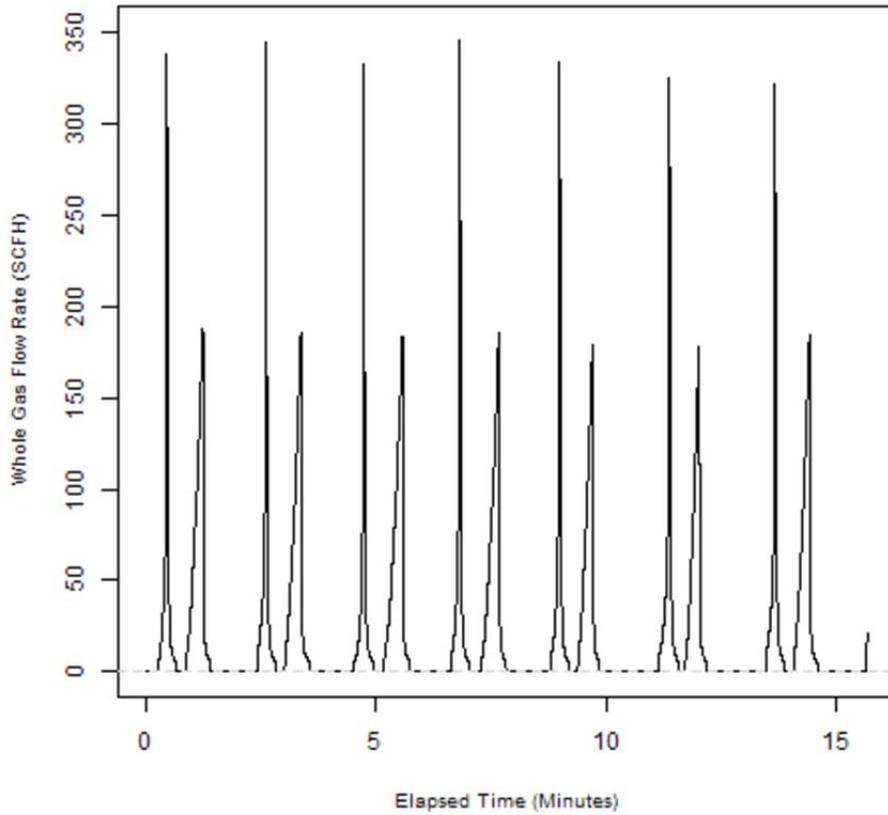
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 24.1 scf/h |
| Avg. Emission rate (methane): | 21.7 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | Q02 |
| Supply pressure: | 27 psig |
| Assessment of controller operation: | operating as expected |



LB06-PC05 [28] Region: GC

Device characteristics:

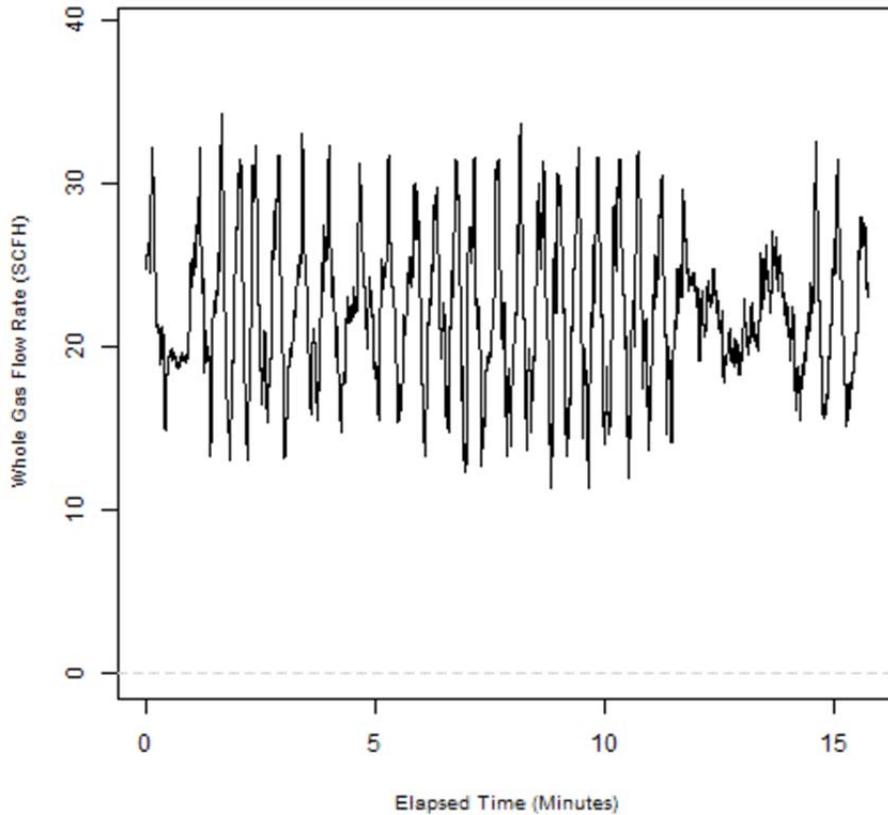
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 22.5 scf/h |
| Avg. Emission rate (methane): | 18.3 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



CZ11-PC01 [29] Region: GC

Device characteristics:

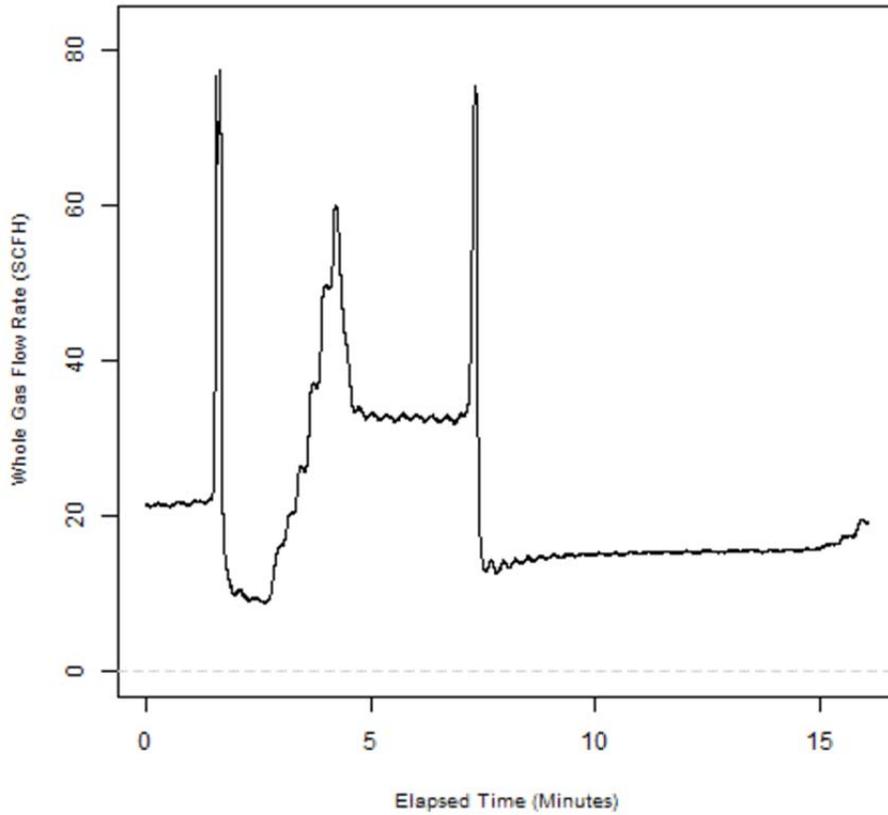
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 22.2 scf/h |
| Avg. Emission rate (methane): | 21.3 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 23 psig |
| Assessment of controller operation: | equipment issues |



CZ08-PC02 [30] Region: GC

Device characteristics:

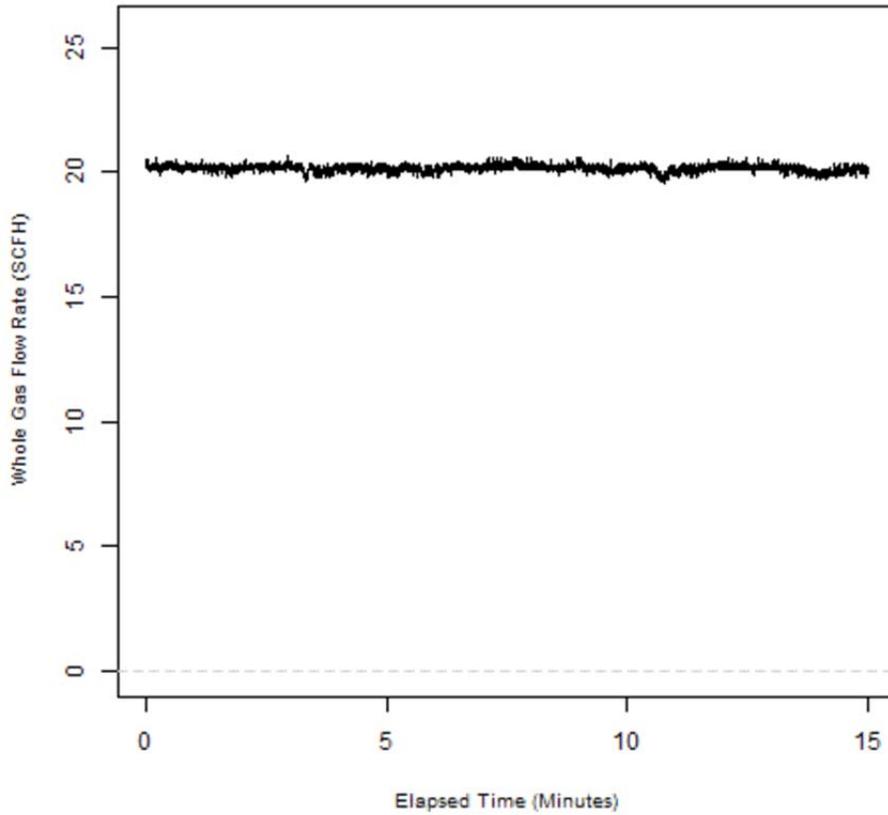
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 21.6 scf/h |
| Avg. Emission rate (methane): | 21.1 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 19 psig |
| Assessment of controller operation: | equipment issues |



XQ06-PC01 [31] Region: MC

Device characteristics:

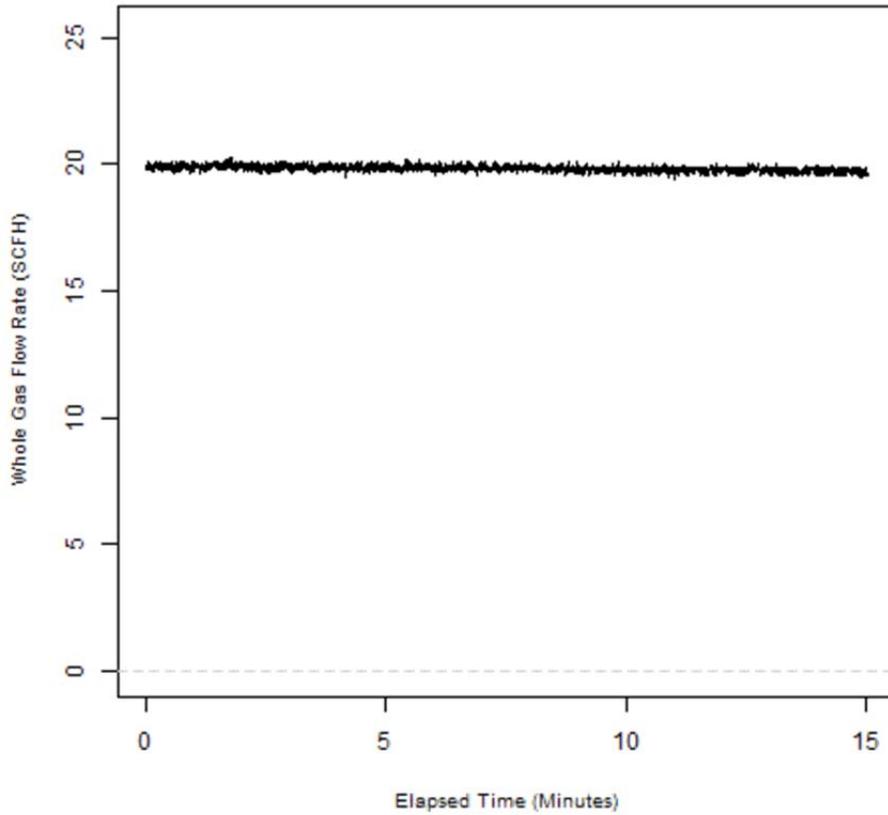
| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 20.2 scf/h |
| Avg. Emission rate (methane): | 18.0 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | G01 |
| Supply pressure: | 28 psig |
| Assessment of controller operation: | operating as expected |



RB01-PC23 [32] Region: GC

Device characteristics:

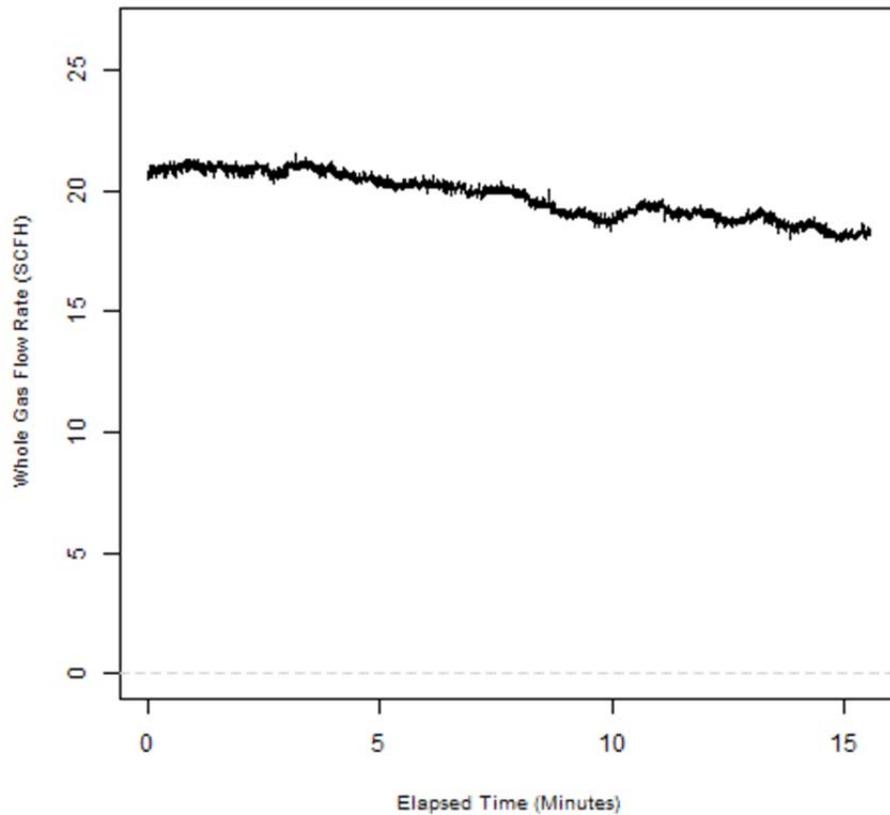
| | |
|-------------------------------------|-----------------------|
| Avg. Emission rate (whole gas): | 19.8 scf/h |
| Avg. Emission rate (methane): | 16.3 scf/h |
| Controller application: | Pressure |
| Basic Application: | Dehydration System |
| Detailed Application: | Site Gas Feed Control |
| Manufacturer/Model (blinded): | M05 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



DL01-PC24 [33] Region: RM

Device characteristics:

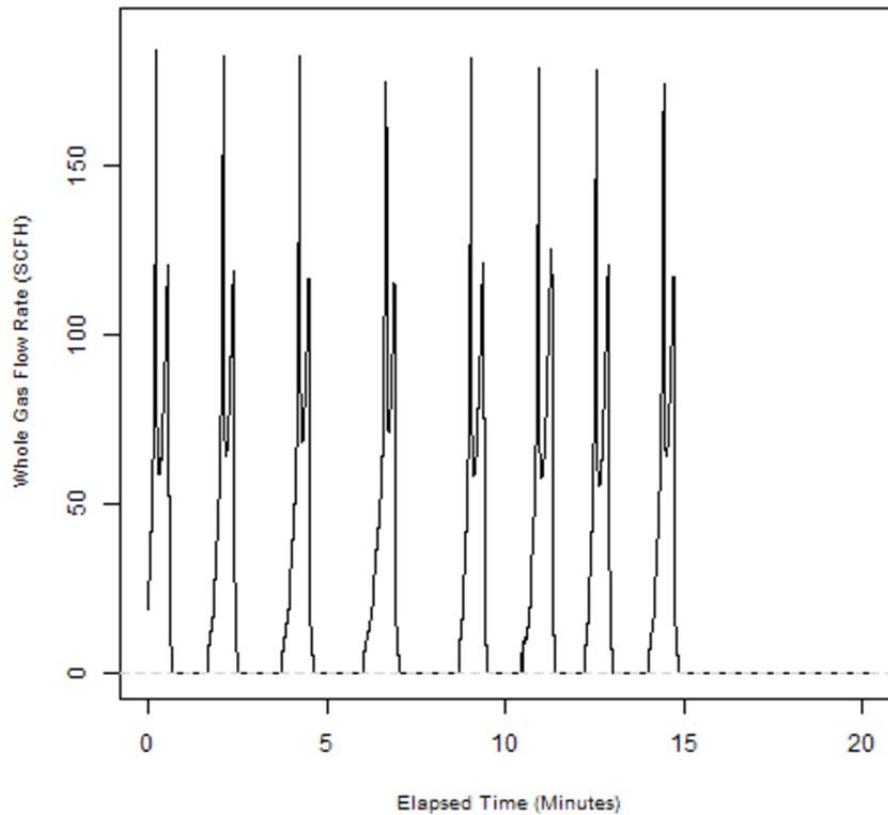
| | |
|-------------------------------------|----------------------------------|
| Avg. Emission rate (whole gas): | 19.8 scf/h |
| Avg. Emission rate (methane): | 17.7 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Liquid Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 38 psig |
| Assessment of controller operation: | equipment issues |



LB04-PC03 [34] Region: GC

Device characteristics:

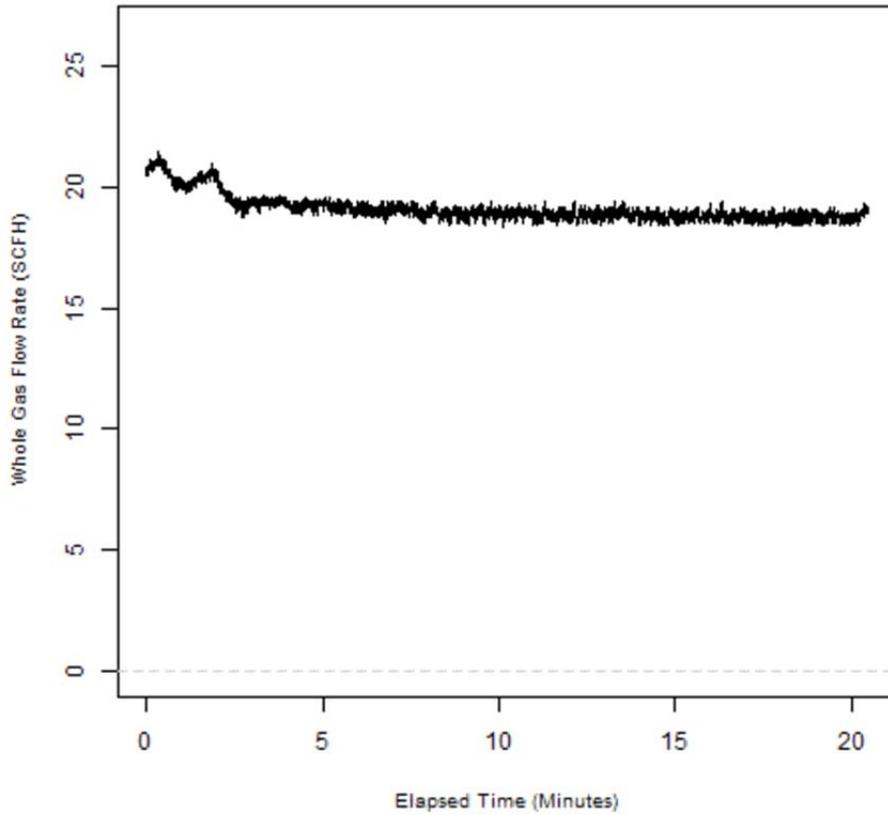
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 19.1 scf/h |
| Avg. Emission rate (methane): | 15.0 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | M03 |
| Supply pressure: | 30 psig |
| Assessment of controller operation: | operating as expected |



RQ03-PC01 [35] Region: MC

Device characteristics:

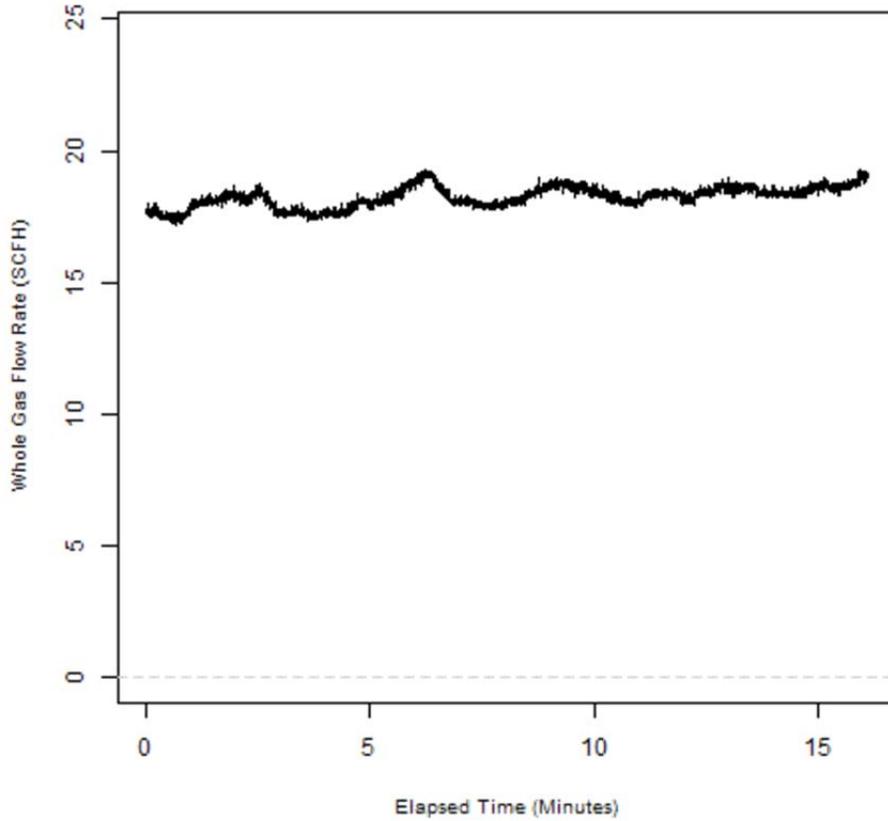
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 19.1 scf/h |
| Avg. Emission rate (methane): | 16.3 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | Q02 |
| Supply pressure: | 22 psig |
| Assessment of controller operation: | operating as expected |



RQ07-PC03 [36] Region: MC

Device characteristics:

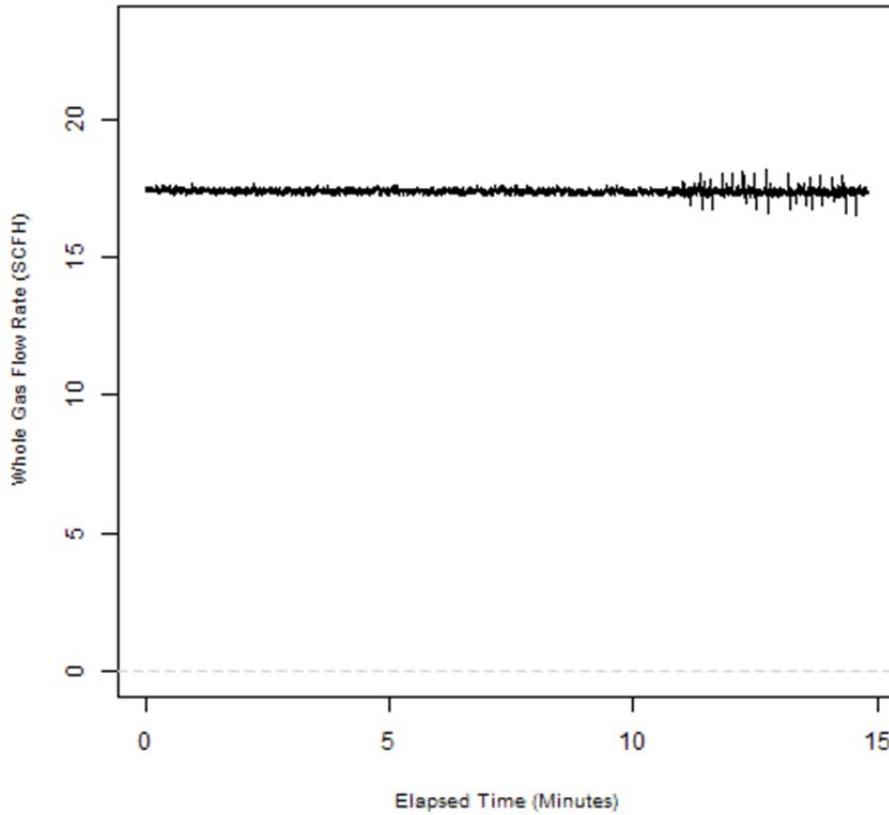
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 18.2 scf/h |
| Avg. Emission rate (methane): | 14.2 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | G01 |
| Supply pressure: | 22 psig |
| Assessment of controller operation: | operating as expected |



RQ05-PC03 [37] Region: MC

Device characteristics:

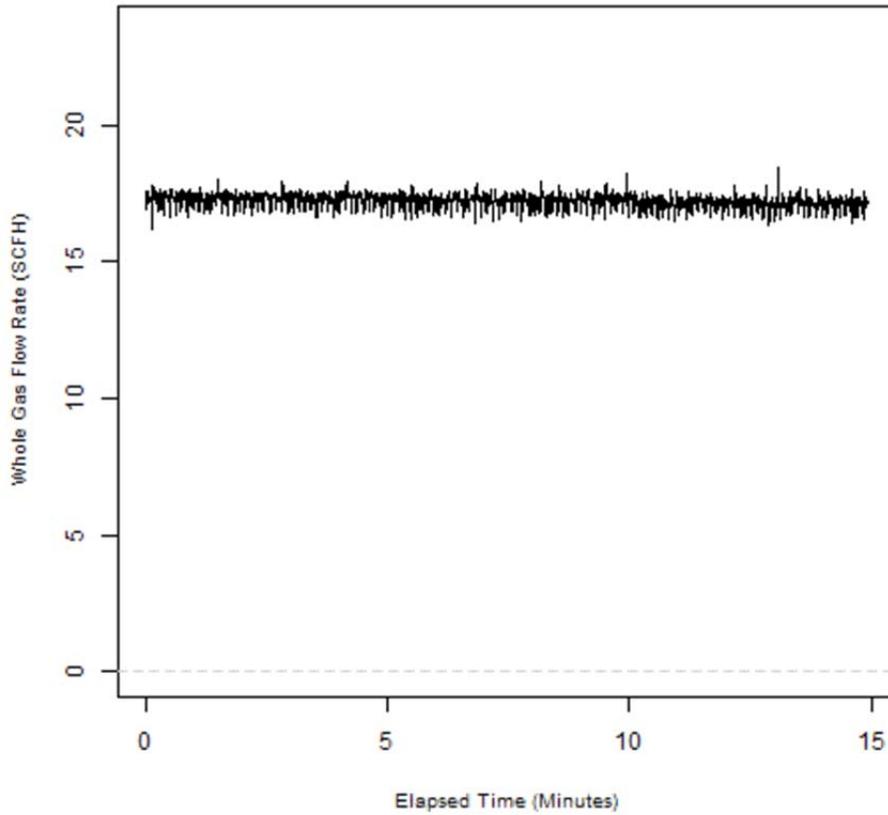
| | |
|-------------------------------------|-------------------------------|
| Avg. Emission rate (whole gas): | 17.4 scf/h |
| Avg. Emission rate (methane): | 15.3 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Oil Level Control |
| Manufacturer/Model (blinded): | G01 |
| Supply pressure: | 22 psig |
| Assessment of controller operation: | equipment issues |



RB01-PC13 [38] Region: GC

Device characteristics:

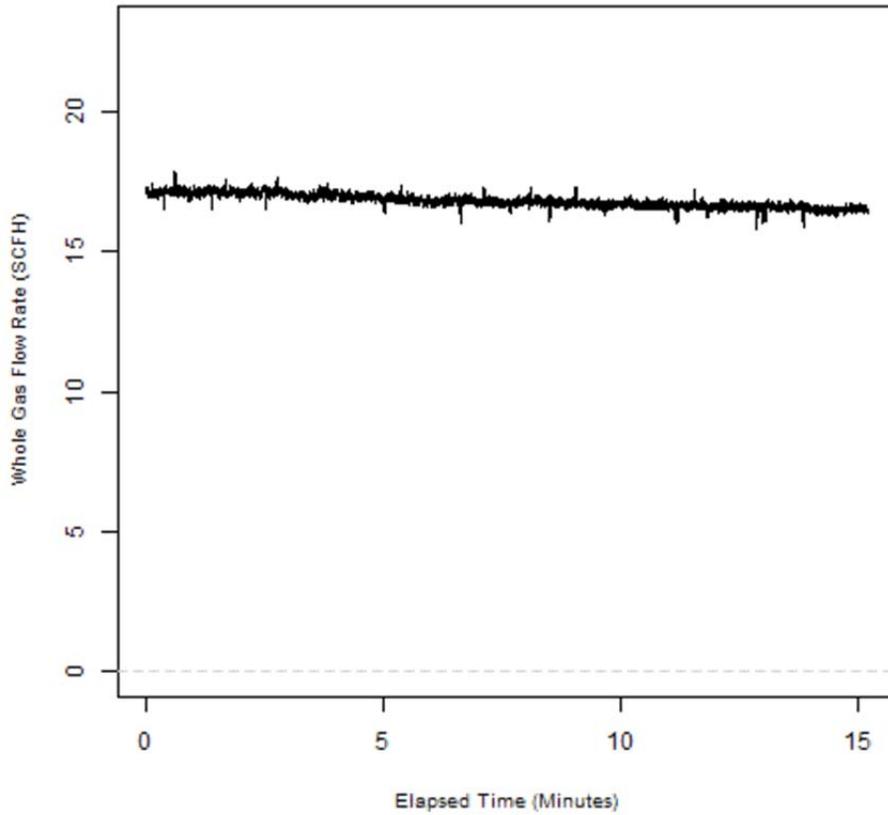
| | |
|-------------------------------------|-------------------------------------|
| Avg. Emission rate (whole gas): | 17.2 scf/h |
| Avg. Emission rate (methane): | 14.2 scf/h |
| Controller application: | Level |
| Basic Application: | Dehydration System |
| Detailed Application: | Contact Tower- Liquid Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 25 psig |
| Assessment of controller operation: | equipment issues |



VF01-PC22 [39] Region: AP

Device characteristics:

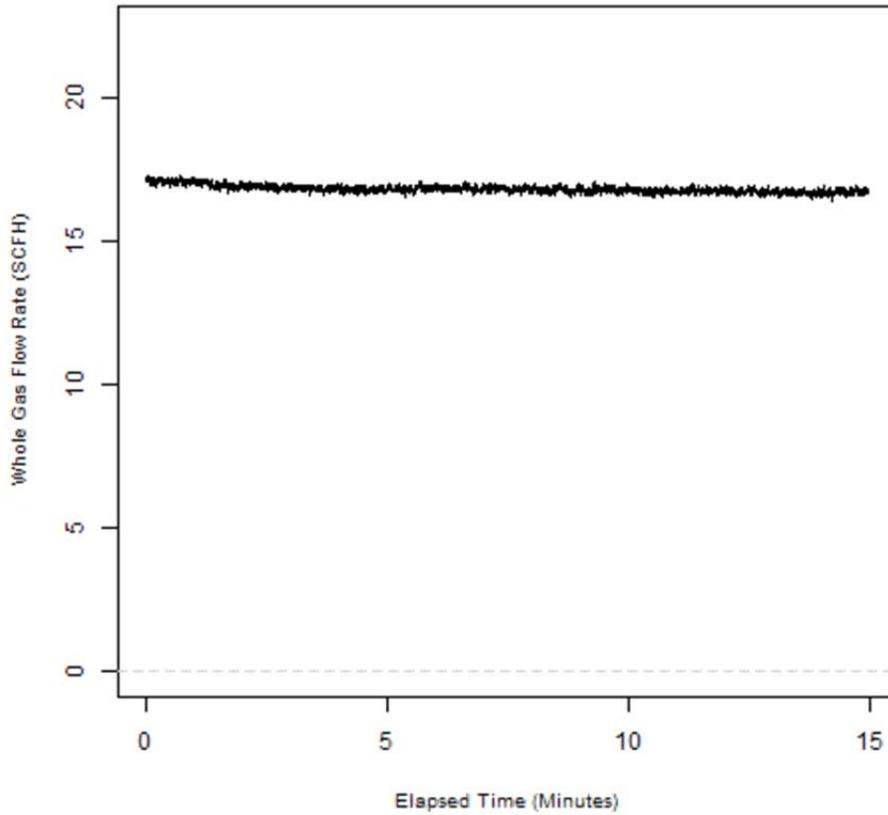
| | |
|-------------------------------------|----------------------------|
| Avg. Emission rate (whole gas): | 16.8 scf/h |
| Avg. Emission rate (methane): | 16.4 scf/h |
| Controller application: | Temperature |
| Basic Application: | Process Heater |
| Detailed Application: | Gas Flow to Process Heater |
| Manufacturer/Model (blinded): | I04 |
| Supply pressure: | 7 psig |
| Assessment of controller operation: | equipment issues |



RB01-PC34 [40] Region: GC

Device characteristics:

| | |
|-------------------------------------|---------------------------------|
| Avg. Emission rate (whole gas): | 16.8 scf/h |
| Avg. Emission rate (methane): | 13.8 scf/h |
| Controller application: | Level |
| Basic Application: | Separator |
| Detailed Application: | Separator - Water Level Control |
| Manufacturer/Model (blinded): | M01 |
| Supply pressure: | 32 psig |
| Assessment of controller operation: | equipment issues |



Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers

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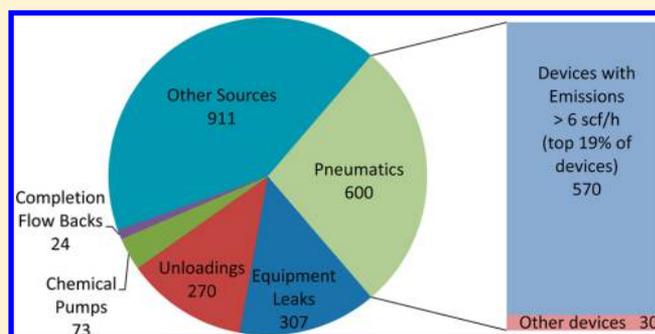
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Supporting Information

ABSTRACT: Emissions from 377 gas actuated (pneumatic) controllers were measured at natural gas production sites and a small number of oil production sites, throughout the United States. A small subset of the devices (19%), with whole gas emission rates in excess of 6 standard cubic feet per hour (scf/h), accounted for 95% of emissions. More than half of the controllers recorded emissions of 0.001 scf/h or less during 15 min of measurement. Pneumatic controllers in level control applications on separators and in compressor applications had higher emission rates than controllers in other types of applications. Regional differences in emissions were observed, with the lowest emissions measured in the Rocky Mountains and the highest emissions in the Gulf Coast. Average methane emissions per controller reported in this work are 17% higher than the average emissions per controller in the 2012 EPA greenhouse gas national emission inventory (2012 GHG NEI, released in 2014); the average of 2.7 controllers per well observed in this work is higher than the 1.0 controllers per well reported in the 2012 GHG NEI.



INTRODUCTION

Natural gas production in the United States is increasing; the U.S. Energy Information Administration projects that by 2040, total natural gas production in the United States will increase by 40%.¹ With increased production, natural gas is displacing other fuels,² and this fuel switching has implications for greenhouse gas emissions.

Natural gas may have a lower greenhouse gas footprint than other, more carbon intensive, fossil fuels (coal and petroleum), since the carbon dioxide emissions associated with natural gas combustion are less than those associated with the combustion of coal and petroleum. For example, for identical heat releases on combustion, natural gas generates less than half of the carbon dioxide emissions of a typical coal.³ The greenhouse gas benefits of natural gas relative to other fossil fuels may be eroded, however, by natural gas leaks in the supply chain. Methane, the principal component of natural gas, is a potent, but short-lived greenhouse gas. Because one kg of methane emissions is equivalent to between 28 and 120 kg of CO₂ emissions, depending on the time scale over which impacts are

assessed (100-year to immediate time horizons),^{4,5} methane emissions in the natural gas supply chain amounting to more than a few percent of natural gas use can change the greenhouse gas footprint of natural gas, relative to other fossil fuels.^{5–9} Thus, to characterize the greenhouse gas footprint of natural gas, it is important to determine the magnitude of methane emissions in the natural gas supply chain.¹⁰

Methane emissions in the natural gas supply chain have been estimated using two basic approaches, commonly referred to as top-down and bottom-up approaches. Top-down approaches for estimating methane emissions from the natural gas supply chain involve measuring ambient concentrations of methane near emission sources. These concentrations can be measured using fixed ground monitors,^{11,12} mobile and vehicle mounted ground monitors,^{13,14} aircraft based instruments^{15–17} or

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Table 1. Sample Population, Categorized by Controller Application and Region (AP= Appalachian; GC = Gulf Coast; MC = Mid-Continent; RM = Rocky Mountain)

| region | separator | number of controllers sampled, categorized by application | | | | | | | | total |
|--------|-----------|---|------------|----------|--------------|--------------------|-------|-------|-----|-------|
| | | process heater | compressor | wellhead | plunger lift | dehydration system | flare | sales | | |
| AP | 14 | 13 | 0 | 24 | 1 | 0 | 0 | 0 | 52 | |
| GC | 73 | 0 | 13 | 11 | 7 | 17 | 1 | 1 | 123 | |
| MC | 48 | 11 | 7 | 0 | 11 | 0 | 0 | 0 | 77 | |
| RM | 51 | 21 | 0 | 32 | 11 | 8 | 2 | 0 | 125 | |
| total | 186 | 45 | 20 | 67 | 30 | 25 | 3 | 1 | 377 | |

satellite instruments.¹⁸ Brandt et al.¹⁹ and Miller et al.²⁰ have summarized recent top-down estimates of methane emissions and conclude that top-down emission estimates are generally higher than current bottom-up inventories of methane emissions, and some of this difference may be due to methane emissions from the natural gas supply chain. However, these analyses do not reveal which of the many potential sources of methane emissions along the natural gas supply chain might be incorrectly estimated.

Complementing top-down measurements, bottom-up measurements of methane emissions are made directly at the emission sources. In this approach, emission measurements are made at a representative sample of sources; the measurements from the sample population are then extrapolated to larger regional or national populations. The advantage of “bottom-up” approaches is that they can gather much more detail about the emission sources, and therefore can identify which source categories, among many, are responsible for emissions. For example, Allen, et al.²¹ concluded that emissions from well completion flowbacks are overestimated, while emissions from pneumatic controllers may be underestimated, in current inventories of emissions. Both top-down and bottom-up approaches can contribute to an improved understanding of methane emissions from the natural gas supply chain. The work reported here uses bottom-up measurements to improve understanding of emissions from pneumatic controllers on natural gas production sites.

Pneumatic controllers use gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures, and pressures. When a pneumatic controller identifies the need to change liquid level, pressure, temperature or flow, it will open or close a control valve in order to return to a desired set point. The opening and closing of the valve can occur either through discrete (on/off) changes, or through changes that are proportional in magnitude to the deviation from the set point (throttling). Controllers can deliver this type of service (on/off and throttling) through either continuously venting or intermittent venting of gas. Thus, controllers can be grouped into four categories, depending on the type of service (on/off or throttling) and the type of venting (continuous or intermittent). In estimating emissions, the U.S. EPA uses the categories of low continuous bleed (<6 scf/h of gas vented), high continuous bleed (>6 standard cubic feet per hour (scf/h) of gas vented) and intermittent controllers.²² Finally, controllers can also be categorized based on equipment manufacturer, model number, and the type of application (e.g., separator level control) in which they are used. In this work, the primary categorization of controllers will be as either continuous vent or intermittent vent based on the pattern observed during measurement; data on applications, service

types, and EPA categorization for the controllers sampled in this work are provided in Supporting Information (SI).

The U.S. EPA²² reports 477 606 pneumatic controllers are in use at natural gas production sites in the United States. These controllers are estimated to emit 334 Gg/yr of methane (17.4 billion cubic feet (bcf) methane), for an average of 0.7 Mg device⁻¹ yr⁻¹ or 4.2 scf/h methane device⁻¹. These estimated emissions from pneumatic controllers have been based on relatively limited measurements;²³ recent field measurements have suggested that these emissions may be understated.

Allen et al.²¹ made measurements of emissions from 305 pneumatic controllers on well sites in the United States where the wells had been hydraulically fractured. Average emissions were 10.5 scf/h of methane, approximately double the average emission rate per device in the current EPA national emission inventory. Measurements of emissions from 581 pneumatic controllers, made in British Columbia and Alberta, averaged 9.2 scf/h of whole gas,²⁴ an emission rate similar to that reported by Allen et al.²¹ In both of these studies, emissions from controllers exhibited wide ranges. In both sets of measurements, a small subset of controllers accounted for most of the emissions.

While the measurements at hydraulically fractured gas wells in the United States²¹ and the measurements in British Columbia and Alberta²⁴ recorded emissions higher than the average emissions per device in the EPA national emission inventory, the sampled populations for these two sets of measurements were not necessarily broadly representative of U.S. national populations of pneumatic controllers. The measurements reported by Allen et al.²¹ were made exclusively in shale gas production regions, and at sites where the wells had been hydraulically fractured. Many of the sites were recently completed wells, which initially tend to have higher liquid production rates, and therefore may have more frequent actuation of certain types of pneumatic devices than the average for the entire population of gas wells in the United States, leading to potentially higher emissions. The Canadian measurements²⁴ were made exclusively in one production region and on devices with manufacturer specified emission rates in excess of 4.2 scf/h.

The goals of the work presented here were (i) to measure emissions from pneumatic controllers at a wider population of wells, geographically distributed across the United States, including conventional gas wells, shale gas wells and a limited number of oil wells, and (ii) to characterize the features of the controllers with high emissions, which previous work^{21,24} has found to be the major contributor to emissions.

■ MATERIALS AND METHODS

Sampled Population. A total of 377 pneumatic controllers were sampled at 65 sites (some with multiple wells) throughout the United States (an average of 5.8 pneumatic controllers per

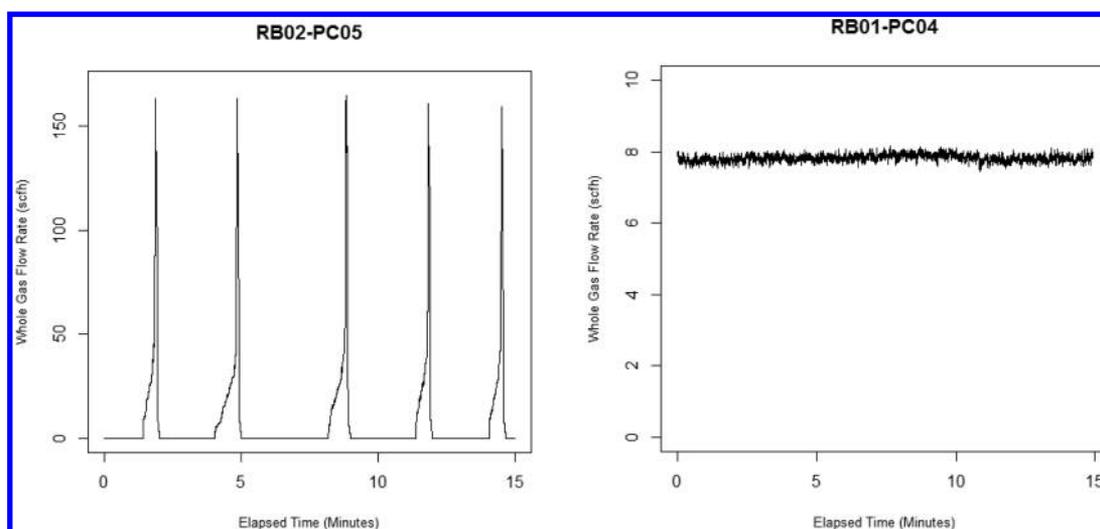


Figure 1. Representative time series for supply gas measurements for intermittent vent (left) and continuous vent (right) controllers; the intermittent vent controller (RB02-PC05) had a total of five actuations during the sampling period and an average emission rate, over the 15 min period of 7.9 scf/h; the continuous vent controller (RB01-PC04) had nearly constant emissions of 8.0 scf/h.

site, 2.7 controllers per well). Measurements were made primarily at natural gas production sites (351 of 377 controllers), and at a limited number of oil sites (26 controllers). Because the definitions of oil and gas wells vary, largely depending on gas to oil production ratios, the data will be treated as a single set. Sampling sites were selected from well sites owned by companies participating in the study using a process designed to yield a random sampling of participant sites (see SI, Section S1). For each well site that was visited, all controllers on the site were sampled using supply gas meters, unless operating conditions, safety issues or other factors prevented sampling. A total of 333 controllers had measurements made using the supply gas meters; 97 controllers could not be measured using the supply gas meter; of the 97 that were not sampled with the supply gas meter, 44 were sampled using exhaust gas measurements, leading to a total of 377 controllers in the sampled population. The applications that the controllers were used in (e.g., separator level control, compressor pressure control) are shown in Table 1. Details of the regions, device types, associated well types, operating methods and other characteristics of each of the 377 controllers sampled in this work are provided in SI, Section S4.

Emission Measurement Methods. Emissions from pneumatic controllers can be determined either by measuring the supply of gas entering the controller or by measuring the gas discharged from the controller. Both approaches were used in this work, and since there is no accumulation of gas in the controller, both measurement approaches should lead to equivalent measurements, if there are no leaks in the equipment downstream of the controller.

Measurements of the gas entering the controller were made by one of three Fox flow meters (model #FT2A); flow meters were inserted into the supply gas line for the controller. This supply gas measurement was the primary measurement method used in this work, and was used to measure emission rates on 333 of the 377 controllers in the sample population (the remainder were sampled by measuring gas emitted by the controller using a HiFlow Sampler described later in this section, see SI for comparisons between the supply gas and exhaust gas measurements). The flow meters reported flows at a sampling frequency of 10 Hz. Two of the Fox model #FT2A

instruments (labeled A and C in this study) had a range of operation of 0–300 scf/h, with a precision of $\pm 1\%$ of flow, and the third Fox model #FT2A (labeled B in this study) had a range of operation of 0–1200 scf/h, with a precision of $\pm 1\%$ of flow. The Fox model #FT2A instruments A and C were used whenever possible because of their greater absolute precision, however, if any instantaneous reading on the A or C Fox model #FT2A was greater than 300 scf/h, the measurement on the pneumatic device was repeated with the B meter to ensure that high leak rates were measured accurately. This happened only once during the measurement campaign, and for this single controller, the flow exceeded 300 scf/h only during a few seconds when the flow from an actuation was peaking (average whole gas flow rate over 15 min of sampling was 3.06 scf/h, a value lower than the average emissions per controller in the sampled population). A repeat test with the B instrument did not detect any actuations.

For each controller measurement using the supply gas flow meter, a site operator depressurized and disconnected the controller supply gas line; the flow meter was inserted and the system was reconnected, repressurized, and allowed to stabilize for several minutes before measurements began. Once the system had stabilized, measurements were made for approximately 15 min. Longer sampling times may have allowed a more complete measurement of emission rates from devices with relatively fewer controller actuations, but would have limited the number of controllers that could be sampled. Figure 1 shows representative 15 min emission time series for pneumatic controllers measured using the supply gas measurement.

All three Fox flow meters were calibrated by the instrument manufacturer and in laboratory testing, using methane. The instruments measure flow based on a thermal conductivity measurement. In this work, since gas composition information was available for each site where measurements were made, site specific correction factors were employed to estimate methane and whole gas emission rates. The method is described in SI Section S2. Results in this work are reported as both methane and whole gas emission rates, based on site specific gas composition data.

For some pneumatic controllers, it was not possible or safe to disrupt the supply gas to insert the supply gas flow meter, so exhaust gas measurements were used as the primary measurement on that subset of devices. Exhaust gas flow rate was measured using a Hi Flow instrument similar to that described by Allen et al.²¹ Briefly, the Hi Flow Sampler is a portable, intrinsically safe, battery-powered instrument that has been used for several decades in measuring emissions of methane in the natural gas supply chain.^{25–27} An emission source is enclosed, using attachments that come with the instrument; leak rate is measured by drawing air from the enclosure, through the sampler, at a high flow rate (up to 8–10 cfm) to capture all the gas emitted by the component, along with a certain amount of entrained surrounding air. By accurately measuring the flow rate of the sampled stream and the background corrected natural gas concentration within the sampled stream, the gas leak rate is calculated. Methane is measured, at concentrations less than approximately 5%, by a catalytic oxidizer unit coupled with a thermal conductivity detector. At methane concentrations greater than approximately 5%, concentrations are measured directly using a thermal conductivity detector. The instrument was calibrated using pure methane and a mixture containing 2.5% methane. The instrument reading based on the methane calibration was corrected for gas composition using site specific gas composition data and laboratory data, as described in SI Section S2. The commercial Hi Flow instrument is designed primarily to measure methane leaks that have a relatively steady flow and flow rates are not normally automatically recorded at high frequency. For this work, the instrument software was modified by the manufacturer to output data every 2–3 s. A 0.3–0.5 Hz reporting frequency was selected based on residence times expected in the leak enclosures at the maximum flow rate of the Hi Flow device (at a 10 cubic feet per minute sample flow, gas in a 1 ft³ sample enclosure has a residence time of 6 s). As with the in-line supply gas measurement, Hi Flow data were collected for approximately 15 min for each controller. A time series from the Hi Flow device, along with a parallel measurement made using a supply gas meter, is shown in Figure 2. The Hi Flow device, because it entrains ambient air in a long sample loop, dampens some of the peak rate. Therefore, the Hi Flow is not able to resolve high frequency actuations as well as the in-line supply measurement. For 24 controller measurements, both supply gas and Hi Flow measurements were made to compare the two measurement methods (for these controllers, the supply gas flow was treated as the primary measurement). The detailed results are provided in SI Section S3. To summarize, 11 of the 24 simultaneous measurements had emissions of less than 0.005 scfh (46%), as recorded by the in-line supply gas meter (the primary measurement device). For five devices which had an average emission rate greater than 6 scfh (measured by the supply gas meter) the supply gas meter to Hi Flow measurement ratio was between 0.7 and 1.1.

RESULTS AND DISCUSSION

Methane emissions from 377 controllers were measured in this work and details of each of the individual measurements are available in SI Section S4. A relatively small subset of devices accounts for a majority of the emissions. At the high end of the emission rate distribution, 20 percent of devices accounted for 96% of whole gas and methane emissions. The 19% of devices that had emissions in excess of 6 standard cubic feet whole gas

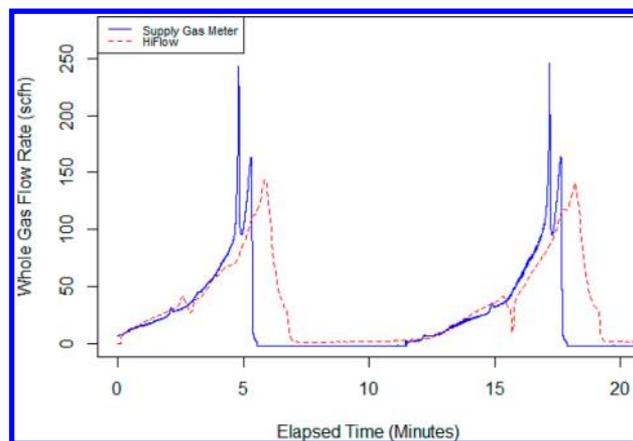


Figure 2. Comparison of supply gas meter (blue line) and Hi Flow measurements (red line) for device LB07-PC04, which was a water level control on a separator. The average emission rate measured by the supply gas meter was 27.0 scf/h as compared to 33.9 scf/h measured by the Hi Flow. Note that the time lag, longer period of emission detection, and the reduced maximum flow rate associated with the Hi Flow measurement is expected because of the dilution that occurs with ambient air in the exhaust enclosure and the flow through the instrument.

per hour (scf/h) accounted for 95% of all whole gas and methane emissions. At the low emission rate end of the distribution, more than half (51%) of the controllers had an emissions rate less than 0.001 scf/h over the 15 min sampling period; 62% had an emissions rate less than 0.01 scf/h over the 15 min sampling period.

The average emission rate for the 377 devices is 5.5 scf/h of whole gas (4.9 scf/h of methane), however, this average emission may be influenced by the estimated emission rates for devices that had no emissions over the 15 min sampling period. If the devices with no emissions detected over 15 min are assigned the lowest emission rate detected (0.001–0.01 scf/h), there is no change in the average emission rate. However, using this minimum detection limit approach may underestimate potential emissions for devices that had little to no detectable emissions over 15 min. Some of these devices may have relatively infrequent actuations that were not sampled. In principle, any device actuating less than four times per hour may not have been detected over a 15 min sampling period. To estimate the emissions from devices with no emissions detected over a 15 min sampling period, the average emission per actuation was calculated for controllers in each application. The average emissions per actuation were multiplied by an estimated frequency of actuation. For example, for separator level controllers, the average volume per actuation was estimated by averaging observed volumes per actuation for separator level controllers; the average frequency of actuation for devices, for which no actuations were observed, was estimated by extrapolating observed actuation frequency data for controllers in separator level control service. A variety of assumptions can be made in extrapolating actuation frequencies. Details of a variety of approaches are available in SI Section S5. Using a variety of approaches, the estimated average emissions associated with devices with no emissions recorded over a 15 min sampling increases the population average emissions by 2–11%. Because this increase is relatively small, for clarity, all of the data reported in this work are based on

Table 2. Whole Gas Emissions from Controllers (scf/h), Categorized by Region and Application^a

| region | all devices | average whole gas emission rates from controllers (scf/h), categorized by the application | | | | | | | | |
|---------|-------------|---|----------------|------------|----------|--------------|--------------------|-------|-------|----------------------|
| | | separator | process heater | compressor | wellhead | plunger lift | dehydration system | flare | sales | avg. w/o compressors |
| AP | 1.7 | 0.3 | 1.3 | | 2.8 | 0.0 | | | | 1.7 |
| GC | 11.9 | 16.3 | | 10.6 | 0.0 | 7.3 | 4.3 | 0.0 | 0.0 | 12.0 |
| MC | 5.8 | 4.9 | 0.0 | 20.2 | | 6.5 | | | | 4.4 |
| RM | 0.8 | 1.5 | 0.2 | | 0.4 | 0.1 | 0.0 | 0.0 | | 0.8 |
| average | 5.5 | 8.1 | 0.5 | 14.0 | 1.2 | 4.1 | 3.0 | 0.0 | 0.0 | 5.0 |

^aNumbers of devices sampled in each category are reported in Table 1.

actual measurements, not including additions to the emissions for devices with low (0.001–0.01 scf/h) observed emissions.

To estimate an uncertainty bound on the overall average, a bootstrapping process was used.²⁸ In the bootstrapping procedure, the original data set of 377 devices was recreated by making 377 random device selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence interval for the average whole gas emission estimate of 5.5 scf/h is 4.0–7.2 scf/h, where the bounds represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. Similarly, the 95% confidence interval for the average methane emissions estimate of 4.9 scf/h is 3.6–6.5 scf/h.

The measurements showed significant variations among regions, the controller application, and whether the device was continuous vent or intermittent vent. Table 2 summarizes the distribution of emission rates among controllers in various applications, and shows the regional distribution of controller emissions. Measurements made on pneumatics in service on compressors had average emission rates of 14.0 scf/h (12.4 scf/h methane), compared to an average whole gas emission rate of 5.5 scf/h (4.9 scf/h methane) for all devices. Devices in use for level control on separators averaged 8.1 scf whole gas/h (7.1 scf methane/h). Overall, 76% of devices measured with whole gas emission rates greater than 6 scf/h were in service on compressors or as level controllers on separators. Emission rates for continuous vent controllers (57 devices, average emissions of 24.1 scf/h whole gas, 21.8 scf/h methane) were higher than for intermittent vent devices (2.2 scf/h whole gas, 1.9 scf/h methane).

In addition to varying by application and controller type (continuous vent or intermittent vent), emissions also varied by region. Emissions were highest in the Gulf Coast and Mid-Continent regions and were lowest in the Rocky Mountain and Appalachian regions (see SI, Section S4, for geographical boundaries of regions). Controllers on compressors, with high average emissions, were only observed on sampling sites in the Gulf Coast and Mid-Continent regions, so some of the regional differences can be attributed to the presence of compressors. As shown in Table 2, however, if average emissions by region are recalculated without including controllers associated with compressors, the Gulf Coast and Mid-Continent regions still had average emissions greater than those observed in the Rocky Mountain and Appalachian regions.

Another factor that may account for regional differences in emission rates is frequency of actuation. For example, controllers on separators in the Gulf Coast could actuate more frequently due to higher liquid production rates, which could explain higher emission rates in that region. However, the frequencies of actuation for the devices in Gulf Coast were similar to those in most other regions, indicating a larger

emission per actuation for the devices in the Gulf Coast, rather than more frequent actuation. In contrast, the Appalachians showed a considerably higher frequency of actuations and a smaller emission rate, indicating a smaller emission per actuation for those devices (Table 3). Thus, regional differences

Table 3. Frequency of Actuations and Emissions from Intermittent Vent Controllers Where Actuations Were Observed, Categorized by Region

| region | count of devices | frequency of actuations (#/min) | avg. emission rate (scf/h) |
|--------|------------------|---------------------------------|----------------------------|
| AP | 8 | 2.42 | 4.85 |
| GC | 30 | 0.37 | 20.5 |
| MC | 17 | 0.93 | 5.05 |
| RM | 25 | 0.43 | 1.72 |
| total | 80 | average: 0.73 | average: 9.76 |

in pneumatic controller emission rates cannot be completely explained by frequency of actuation of controllers, or by controllers associated with compressors and separator level control (Table 2); much of the difference may be due to differences in controller type (continuous vent vs intermittent vent) among regions. Continuous vent devices, with average whole gas emissions of 24.1 scf/h, were 21% of the controllers in the Gulf Coast and Mid-Continent regions, but only 9% in the Appalachian and Rocky Mountain regions.

This data set of emissions from pneumatic devices has elements that are similar to and different from the previous data sets reported for the United States,²¹ and for British Columbia and Alberta.²⁴ The primary similarity is that all three data sets indicate that a small population of devices dominates total emissions. In this work, 19% of devices with emissions greater than 6 scf/h of whole gas account for 95% of the whole gas and methane emissions. In the previous measurements reported by Allen et al.,²¹ 20% of devices account for 80% of the whole gas emissions and 41% of devices with emissions greater than 6 scf/h of whole gas, account for 90% of the whole gas emissions (88% of the methane emissions). In the measurements for British Columbia and Alberta²⁴ (referred to here as the British Columbia data), which were restricted to pneumatic devices with manufacturer reported bleed rates greater than 4.2 scf/h, 44% of devices with emissions greater than 6 scf/h accounted for 91% of emissions. Both the British Columbia data and the measurements reported in this work had large numbers of devices for which no emissions were detected during the sampling period. For the British Columbia data (again, focused on devices with manufacturer reported bleed rates in excess of 4.2 cfh), 31% of measurements had no detectable emissions over a 30 min sampling period; in this work 62% of devices had emissions less than 0.01 scf/h over the 15 min sampling period.

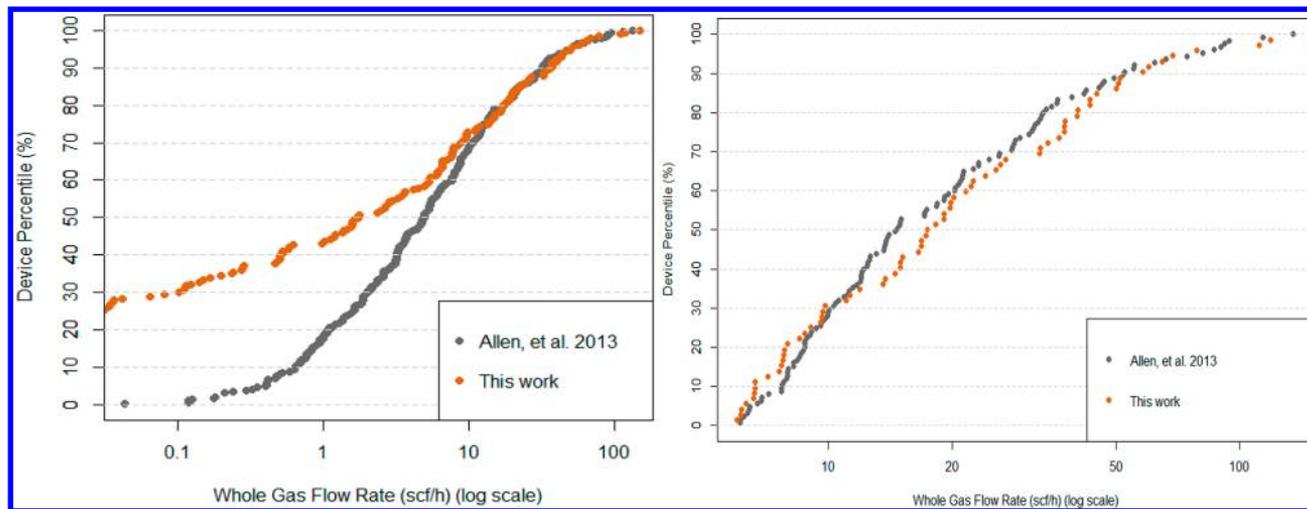


Figure 3. Distributions of emissions for subsets of controllers (38% of devices measured in this work) venting greater than 0.01 scf/h (left) and subsets of controllers venting greater than 6 scf/h of whole gas (right) as reported in this work (the 19% of devices that account for 95% of emissions) and Allen et al.²¹

The overall average emission rates reported in this work are lower than the previous data sets reported by Allen et al.²¹ for the United States, and for British Columbia and Alberta.²⁴ For the British Columbia data this can be attributed to the sampling design for that data set, which selected devices with manufacturer reported bleed rates in excess of 4.2 scf/h. These controller types tend to be found in particular applications. When the emissions from the British Columbia data set are compared to the emissions reported in this work, for devices in similar applications, the results are in reasonable agreement. For example, for the separator controllers that were the most frequent application observed in this work, the British Columbia data report an average emissions rate of approximately 7.8 scf/h (level control) while the average for this work was 8.1 scf/h (separator application).

The lower average emission rates reported in this work, compared to those reported by Allen et al.²¹ is primarily due to the number of controllers with no emissions detected over the sampling period. Figure 3 compares emission rates for controllers sampled in this work, with emissions rates reported by Allen et al.²¹ The results show reasonable agreement between the two studies for controllers with emissions above 6 scf/h. These controllers accounted for 95% of the emissions in this work and 90% of the emissions in the sample reported by Allen et al. (2013).

The primary reason for the differences in the average emission rates reported in this work and in Allen et al.²¹ is the higher percentage of low emission devices (<0.01 scf/h) observed in this work. This could be due to multiple factors. In this work, all controllers on-site were sampled, regardless of whether they would be reported through emission inventories. For example, emergency shut-down (ESD) controllers represented 12% of the sampled population in this work. These controllers do not have planned actuations, so they would not have been sampled in the work of Allen et al.,²¹ and they may or may not be included in controller counts in national emission inventories. In addition, in the work of Allen et al.²¹ about 40% of the inventoried controllers on sites were sampled; while these were intended to be selected randomly from inventoried controllers, there may have been an

unintentional bias toward devices that were observed, with an infrared camera, to have emissions.

Implications for National Emission Estimates. As shown in Table 4, if regional average emission rates determined

Table 4. National Emission Estimates, Based on Regional Device Counts for Pneumatic Controllers and Regional Average Emissions Measured in This Work

| region | count of devices | avg. emission rate whole gas(scfh) | avg. emission rate methane (scfh) | regional emissions (Gg/yr) |
|-----------------|------------------|------------------------------------|-----------------------------------|----------------------------|
| AP | 77 261 | 1.70 | 1.65 | 21.5 |
| GC | 53 436 | 11.80 | 10.61 | 95.4 |
| MC ^a | 222 684 | 5.80 | 4.87 | 182.5 |
| RM ^b | 124 225 | 0.75 | 0.67 | 14.0 |
| total | 477 606 | | | 313.4 |

^aMC totals include equipment counts for Mid-Continent and Southwest regions reported in the 2012 EPA GHG NEI. ^bRM totals include equipment counts for Rocky Mountain and West Coast regions reported in the 2012 EPA GHG NEI.

in this work are multiplied by regional controller counts reported in the 2012 EPA national greenhouse gas emission inventory (2012 GHG NEI, released in 2014), the national methane emission estimate for pneumatic controllers in natural gas service is 313 Gg/yr (within 10% of the 2012 GHG NEI estimate of 334 Gg). If the national average of the emission rates measured in this work (5.5 scf/h of whole gas, or 4.9 scf/h of methane) is multiplied by the total national equipment count in the 2012 GHG NEI (477 606 controllers) the national methane emission estimate is 394 Gg/yr, 17% higher than the 2012 GHG NEI estimate of 334 Gg. Adding an additional 2–11% to the estimated emission totals to account for potential emissions from controllers that had less than 0.01 scf/h of emissions over 15 min, would only slightly change these comparisons with the 2012 GHG NEI. This estimate may represent a lower bound on national emissions, however, since the average emissions per controller observed in this work includes some low- or nonemitting devices, such as ESD controllers, that may not be included in the count of national controllers. If the average emissions per controller from this

work were recalculated with ESD controllers excluded, the average emissions would increase by approximately 15% (see SI, Section S7).

The inclusion or exclusion of ESD controllers in national pneumatic controller counts is just one part of the uncertainty associated with the total count of controllers. The average number of controllers per well observed in this work (2.7 controllers per well) was higher than the average number of controllers per well (1.0 controllers per well) reported in the 2012 GHG NEI, potentially indicating an under-count of controllers in the GHG NEI. Some of the difference between the controllers per well observed in this work and the average pneumatic controllers per well in the GHG NEI is due to wells that use mechanical or other nonpneumatic controllers; as an example of how an alternative controller count could influence national emission estimates, if 75% of wells in the United States have an average of 2.7 pneumatic controllers per well (the remainder having nonpneumatic controllers), and if 75% of the controllers on well sites are inventoried as having emissions, the total count of pneumatic controllers would double the level in the current inventory, roughly doubling emissions to 600 Gg (see SI). It was beyond the scope of this work to develop new national pneumatic controller counts, but the data reported here indicate that this is a topic that merits attention.

Characteristics of High Emitting Devices. Because average emissions are strongly influenced by the highest emitting devices, the characteristics of the 40 controllers with highest emissions rates were examined in detail by experts in pneumatic device operation. These characterizations included the service type, region of use, device type, the numbers of actuations and other temporal features of the emission time series. Based on these analyses, many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design. For example, some devices not designed to bleed continuously had continuous emissions. This could be the result of a defect in the system, such as a crack or hole in the end-device's (control valve's) diaphragm actuator, or a defect in the controller itself, such as fouling or wear. No additional troubleshooting analysis was performed on these high emitters, so the actual root causes are not known with certainty. The results, however, do indicate that some of the high emissions were caused by repairable issues. Details are provided in the SI (Section S8).

■ ASSOCIATED CONTENT

● Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at <http://pubs.acs.org/>.

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Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agency's Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including

Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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Corrections

PERSPECTIVE

Correction for “Theory of mass-independent fractionation of isotopes, phase space accessibility, and a role of isotopic symmetry,” by Rudolph A. Marcus, which appeared in issue 44, October 29, 2013, of *Proc Natl Acad Sci USA* (110:17703–17707; first published June 28, 2013; 10.1073/pnas.1213080110).

The author notes that, on page 1, middle column, lines 11–16 “Fewer accidental resonances mean less energy sharing and so less statistical behavior with a consequence that they are in equilibrium with the population of accessible states of O_3^* at low pressures, as discussed later.” should instead appear as “Fewer accidental resonances mean less energy sharing and so less statistical behavior with a consequence of a shorter lifetime of O_3^* at low pressures, as discussed later.”

On page 2, middle column, first full paragraph, lines 11–14 “This major difference in the pressure effect indicates a difference in the role of the collisions in these two distant phenomena.” should instead appear as “This major difference in the pressure effect indicates a difference in the role of the collisions in these two distinct phenomena.”

On page 3, middle column, first paragraph, lines 4–7 “The overall deviation from statistical theory for the recombination rate constant was (N. Ghaderi) perhaps a factor of 2.” should instead appear as “The overall deviation from statistical theory for the recombination rate constant was (N. Ghaderi) less than a factor of 2.”

On page 3, middle column, first full paragraph, lines 22–26 “Any chaos in the form of higher-order resonances within a volume element h^N would be coarse grained and so presumably contribute to quantum chaos.” should instead appear as “Any chaos in the form of higher-order resonances within a volume element h^N would be coarse grained and so presumably not contribute to quantum chaos.”

Both the online article and the print article have been corrected.

www.pnas.org/cgi/doi/10.1073/pnas.1315099110

ENVIRONMENTAL SCIENCES

Correction for “Measurements of methane emissions at natural gas production sites in the United States,” by David T. Allen, Vincent M. Torres, James Thomas, David W. Sullivan, Matthew Harrison, Al Hendler, Scott C. Herndon, Charles E. Kolb, Matthew P. Fraser, A. Daniel Hill, Brian K. Lamb, Jennifer Miskimins, Robert F. Sawyer, and John H. Seinfeld, which appeared in issue 44, October 29, 2013, of *Proc Natl Acad Sci USA* (110:17768–17773; first published September 16, 2013; 10.1073/pnas.1304880110).

The authors note that upon publication their conflict of interest statement was not complete. The updated disclosure statement is as follows, “Jennifer Miskimins holds a joint appointment with Barree & Associates and the Colorado School of Mines. She has also served as an advisor to Nexen in 2012. David T. Allen served as a consultant for the Eastern Research Group and ExxonMobil in 2012, and is the current chair of the Science Advisory Board for the EPA. John H. Seinfeld has served as a consultant for Shell in 2012. David T. Allen, Matthew Harrison, Charles E. Kolb, and Robert F. Sawyer variously serve as members of scientific advisory panels for projects supported by Environmental Defense Fund and companies involved in the natural gas supply chain. These projects are led at Colorado State University (on natural gas gathering and processing), Washington State University (on local distribution of natural gas), and the University of West Virginia (on CNG fueling and use in heavy duty vehicles).”

Both the online article and print article have been corrected.

www.pnas.org/cgi/doi/10.1073/pnas.1318658110

PHYSIOLOGY

Correction for “mitoBK_{Ca} is encoded by the *Kcnma1* gene, and a splicing sequence defines its mitochondrial location,” by Harpreet Singh, Rong Lu, Jean C. Bopassa, Andrea L. Meredith, Enrico Stefani, and Ligia Toro, which appeared in issue 26, June 25, 2013, of *Proc Natl Acad Sci USA* (110:10836–10841; first published June 10, 2013; 10.1073/pnas.1302028110).

PNAS notes that a conflict of interest statement was omitted during publication. PNAS declares that “The editor, Ramon Latorre, is a recent coauthor with the authors of this publication, having published a paper with them in 2012.”

Additionally, the authors note:

“Although Figs. 1 and S1 display the same sequence template, the analyses of LC/MS/MS data were performed against the respective databases, rat for Fig. 1, and mouse for Fig. S1. Sequence

alignment of rat (NCBI:Q62976.3; UniProtKB: Q62976-1 V.3, which differs by 3 amino acids near the N terminus with that of Figs. 1 and S1) and mouse (NCBI: NP_001240298.1) isoforms show 98.9% amino acid identity with differences circumscribed to the extreme N and C termini. Peptides identified by LC/MS/MS have the exact sequence in rat and mouse as shown in Figs. 1 and S1.”

“In published Fig. 7, panels *E* and *F* show slices of the same heart in each condition; to better display the infarcted vs. healthy portions, these images were scaled to approximately the same size. We noticed that some data points in panel *G* were slightly moved during figure preparation. The revised Fig. 7 now shows heart slices at their original magnification (*E* and *F*) and the correct panel *G*. The corrected figure and its legend appear below.”

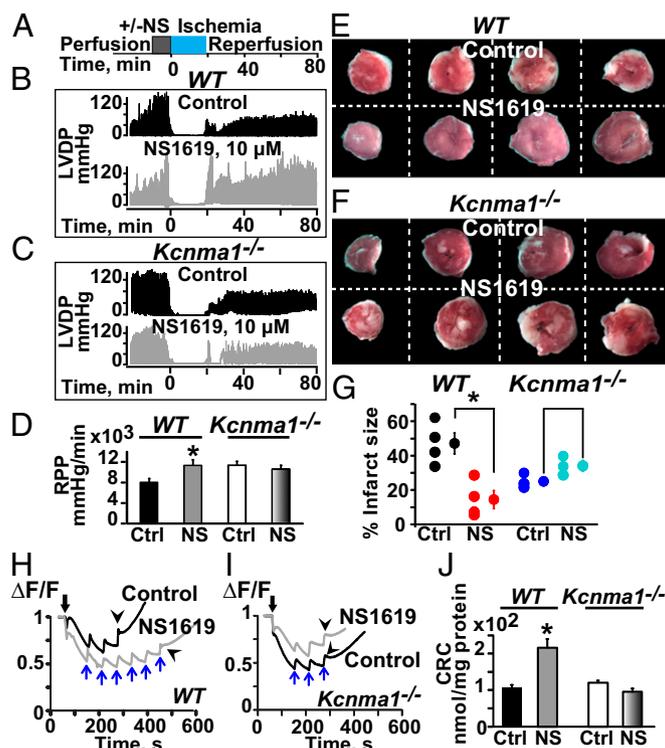


Fig. 7. BK_{Ca} protects the heart from ischemic injury. (A) Ischemia/reperfusion protocol. (B and C) Function traces of hearts preconditioned with vehicle (DMSO, control) or with NS1619 (10 μM) in WT and *Kcnma1*^{-/-} mice. (D) NS1619 significantly improved mean RPP in WT but not in *Kcnma1*^{-/-} mice. (E and G) WT hearts preconditioned with NS1619 exhibited less infarct size (white) compared with the control. (F and G) In *Kcnma1*^{-/-}, infarct size was not reduced with NS1619. (H–J) Mitochondrial Ca²⁺ uptake. NS1619 preconditioning increased the amount of Ca²⁺ needed to induce a large Ca²⁺ release in WT but not in *Kcnma1*^{-/-} samples. Black arrows, addition of mitochondria. Blue arrows, 40 nmol Ca²⁺ pulses. Arrowheads, massive release of Ca²⁺. **P* < 0.05 vs. control (Ctrl); CRC, Ca²⁺ retention capacity.

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Measurements of methane emissions at natural gas production sites in the United States

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Engineering estimates of methane emissions from natural gas production have led to varied projections of national emissions. This work reports direct measurements of methane emissions at 190 onshore natural gas sites in the United States (150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 workovers). For well completion flowbacks, which clear fractured wells of liquid to allow gas production, methane emissions ranged from 0.01 Mg to 17 Mg (mean = 1.7 Mg; 95% confidence bounds of 0.67–3.3 Mg), compared with an average of 81 Mg per event in the 2011 EPA national emission inventory from April 2013. Emission factors for pneumatic pumps and controllers as well as equipment leaks were both comparable to and higher than estimates in the national inventory. Overall, if emission factors from this work for completion flowbacks, equipment leaks, and pneumatic pumps and controllers are assumed to be representative of national populations and are used to estimate national emissions, total annual emissions from these source categories are calculated to be 957 Gg of methane (with sampling and measurement uncertainties estimated at ± 200 Gg). The estimate for comparable source categories in the EPA national inventory is $\sim 1,200$ Gg. Additional measurements of unloadings and workovers are needed to produce national emission estimates for these source categories. The 957 Gg in emissions for completion flowbacks, pneumatics, and equipment leaks, coupled with EPA national inventory estimates for other categories, leads to an estimated 2,300 Gg of methane emissions from natural gas production (0.42% of gross gas production).

greenhouse gas emissions | hydraulic fracturing

Methane is the primary component of natural gas and is also a greenhouse gas (GHG). In the US national inventories of GHG emissions for 2011, released by the Environmental Protection Agency (EPA) in April 2013 (1), 2,545 Gg of CH₄ emissions have been attributed to natural gas production activities. These published estimates of CH₄ emissions from the US natural gas industry are primarily based on engineering estimates along with average emission factors developed in the early 1990s (2, 3). During the past two decades, however, natural gas production processes have changed significantly, so the emission factors from the 1990s may not reflect current practices. This work presents direct measurements of methane emissions from multiple sources at onshore natural gas production sites incorporating operational practices that have been adopted or become more prevalent since the 1990s.

Horizontal drilling and hydraulic fracturing are among the practices that have become more widely used over the past two decades. During hydraulic fracturing, materials that typically consist of water, sand and additives, are injected at high pressure into low-permeability formations. The injection of the hydraulic fracturing fluids creates channels for flow in the formations (often shale formations), allowing methane and other hydrocarbon gases

and liquids in the formation to migrate to the production well. The well and formation is partially cleared of liquids in a process referred to as a completion flowback, after which the well is placed into production. Production of natural gas from shale formations (shale gas) accounts for 30% of US natural gas production, and this percentage is projected to grow to more than 50% by 2040 (4).

Multiple analyses of the environmental implications of gas production using hydraulic fracturing have been performed, including assessments of water contamination (5–8), criteria air pollutant and air toxics releases (9–11), and greenhouse gas emissions (11–18). Greenhouse gas emission analyses have generally been based on either engineering estimates of emissions or measurements made 100 m to a kilometer downwind of the well site. This work reports direct on-site measurements of methane emissions from natural gas production in shale gas production regions.

Significance

This work reports direct measurements of methane emissions at 190 onshore natural gas sites in the United States. The measurements indicate that well completion emissions are lower than previously estimated; the data also show emissions from pneumatic controllers and equipment leaks are higher than Environmental Protection Agency (EPA) national emission projections. Estimates of total emissions are similar to the most recent EPA national inventory of methane emissions from natural gas production. These measurements will help inform policymakers, researchers, and industry, providing information about some of the sources of methane emissions from the production of natural gas, and will better inform and advance national and international scientific and policy discussions with respect to natural gas development and use.

Author contributions: D.T.A. and M.H. designed research; D.T.A., V.M.T., J.T., D.W.S., M.H., A.H., and S.C.H. performed research; C.E.K., M.P.F., A.D.H., B.K.L., J.M., R.F.S., and J.H.S. analyzed data; and D.T.A. wrote the paper.

Conflict of interest statement: J.M. holds a joint appointment with Barree & Associates and the Colorado School of Mines. She has also served as an advisor to Nexen in 2012. D.T.A. served as a consultant for the Eastern Research Group and ExxonMobil in 2012, and is the current chair of the Science Advisory Board for the EPA. J.H.S. has served as a consultant for Shell in 2012. D.T.A., M.H., C.E.K., and R.F.S. variously serve as members of scientific advisory panels for projects supported by Environmental Defense Fund and companies involved in the natural gas supply chain. These projects are led at Colorado State University (on natural gas gathering and processing), Washington State University (on local distribution of natural gas), and the University of West Virginia (on CNG fueling and use in heavy duty vehicles).

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Methane emissions were measured directly at 190 natural gas production sites in the Gulf Coast, Midcontinent, Rocky Mountain, and Appalachian production regions of the United States. The sites included 150 production sites with 489 wells, all of which were hydraulically fractured. In addition to the 150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 well workovers were sampled; the sites were operated by nine different companies. The types of sources that were targeted for measurement account for approximately two-thirds of methane emissions from all onshore and offshore natural gas production, as estimated in the 2011 national greenhouse gas emission inventory (1). A summary of the scope of the study, along with a rationale for the inclusion or exclusion of sources for direct measurement efforts, is provided in *SI Appendix*. Sampling was conducted from May 2012 through December 2012 at sites throughout the United States (see *SI Appendix* for a map and for the number of sampling sites in each region). All nine companies that participated in the study provided sites for sampling, and at least three companies provided sites in each of the regions (*SI Appendix*).

The data presented in this report represent hundreds of measurements of methane emissions from several types of onshore natural gas production activities; however, the sites sampled still represent a small fraction of the total number of sites nationwide (Table 1). This dataset is designed to be representative of the participating companies' activities and practices, but not necessarily all activities and practices. Multiple methods were used to minimize the potential for bias in the sample set, as described in *SI Appendix*.

Results

Emission measurements were performed for 27 well completion flowbacks, 9 liquids unloadings, 4 well workovers, and 150 production sites with 489 hydraulically fractured wells (Table 1 and *SI Appendix*). Data are summarized here for the well completion flowbacks, liquids unloading, and production site emissions. *SI Appendix* provides additional details. The data on well workovers, collected for workovers without hydraulic fracturing, are not presented because the data set was small and emission estimates for workovers without fracturing represent less than 0.1% of national emission estimates.

Well Completion Flowbacks. After a well is drilled, the well is "completed." Completion is the process of making a well ready for continuous production. Specifically, after drilling and fracturing, before natural gas production can begin, the well must be cleaned of sand and liquid of various types that had been injected into the well. The recovery of these liquids is referred to as a flowback, and gas, including methane, can be dissolved or entrained in the flowback liquids. Some of the methane in the liquids can be sent to sales or emission control devices, but some can be emitted.

Measurements were made of methane emissions during 27 completion flowback events. Emissions data for each of the 27

events is provided in *SI Appendix*. Five of the flowbacks were in the Appalachian region, seven in the Gulf Coast region, five in the Midcontinent region, and 10 in the Rocky Mountain region. The durations of the completions ranged from 5 to 339 h (2 wk). Measured methane emissions over an entire completion flowback event ranged from less than 0.01 Mg to more than 17 Mg, with an average value of 1.7 Mg and a 95% confidence interval of 0.67–3.3 Mg. Measurement and sampling uncertainty are included in the confidence interval; uncertainties due to a limited sample size dominate the overall uncertainty estimate. Methods for determining the confidence intervals are described in *SI Appendix*.

The completions with the lowest emissions were those in which the flowback from the well was sent immediately, at the start of the completion, to a separator, and all of the gases from the separator were sent to sales. The only emissions from these completions were from methane dissolved in liquids (mostly water) sent from the separator to a vented tank. The completion flowback with the highest total emissions, 17 Mg, was the longest in duration (339 h) and had initial flowback into a vented tank with very high methane concentrations. Some of the other relatively high emission completion flowbacks (~3 Mg to 6 Mg of methane) involved large amounts of flared gas (up to 130 Mg of methane to the flare, which was assumed to combust the methane at 98% efficiency, *SI Appendix*). Another completion with emissions of 4 Mg of methane was one in which all gases, for the entire event, were vented to the atmosphere. This type of venting for the entire duration of the completion was observed in 9 of the 27 completions. However, the nine completions of this type showed a wide range of emissions (4 Mg of methane for one completion and 0.5 Mg of methane for another completion of this type for an adjacent well).

These data provide extensive measurements on methane emissions from well completions that can be used in national emission estimates. Current national inventories of methane emissions have been assembled, based on simple engineering models of the completion process. In the most recent EPA national greenhouse gas emission inventory (2011 inventory, released April 2013) (1), 8,077 well completions with hydraulic fracturing are estimated to result in 654 Gg per year of emissions, for an average of 81 Mg of methane per completion flowback (compared with 1.7 Mg per flowback for the events reported here). To understand the reasons for the much lower emissions per event reported in this work, it is useful to define a potential emission for each flowback. The potential of a flowback to emit is defined here, and in the EPA national inventory (1), as the methane that would be emitted if all of the methane leaving the wellhead during the flowback were vented to the atmosphere. Potential emissions for the wells in this work ranged from 0.2 Mg to more than 1 Gg methane, with an average of 124 Mg. The average from the EPA national inventory is slightly higher at 151 Mg. Net emissions are calculated, in the EPA national inventory, by reducing potential emissions by estimates of methane captured or controlled

Table 1. Comparison of sample set size to emission source populations

| Source | No. of events/locations sampled | Total no. of events/locations |
|--------------------|---------------------------------|-------------------------------|
| Well completions | 27 | 8,077* |
| Gas well unloading | 9 | 35,828 [†] |
| Well workovers | 4 | 1782 (11,663) [‡] |
| Wells | 489 | 446,745 [§] |

*Completions, with hydraulic fracturing reported in the 2011 National GHG Emission Inventory (1).

[†]Wells without plunger lift that have unloading events (the type of event sampled in this work) reported in the 2011 National GHG Emission Inventory (1).

[‡]Workover events with (and without) hydraulic fracturing reported in the 2011 National GHG Emission Inventory (1).

[§]Gas wells with and without hydraulic fracturing reported in the 2011 National GHG Emission Inventory (1); 513,000 on-shore natural gas wells are reported by the Energy Information Administration (20); see *SI Appendix*.

because of regulatory or voluntary emission reductions. In the current national inventory, emission reductions are roughly one-half of potential emissions (*SI Appendix*). In this work, net or measured emissions for the total of all 27 completions are 98% less than potential emissions. This large difference between the net emissions measured in this work and the net emissions estimated in the national inventory is due to several factors. First, consistent with emerging regulatory requirements (21) and improved operating practices, 67% of the wells sent methane to sales or control devices. Second, for those wells with methane capture or control, 99% of the potential emissions were captured or controlled. Finally, the wells with uncontrolled releases had much lower than average potential to emit. Of the nine wells in this work that had uncontrolled venting of methane, the average potential to emit was 0.83 Mg, which is 0.55% of the average potential to emit in the national inventory. The relative importance of these factors is discussed in *SI Appendix*.

Unloadings. Gas wells often produce liquid hydrocarbons and water along with natural gas. In most new wells, the velocity of natural gas up the production tubing of the well is sufficient to lift any produced water out of the well with the gas. As gas production declines, the velocity may no longer be sufficient to lift the liquids, which begin to accumulate in the wellbore and eventually restrict gas flow from the producing formation. Liquids accumulation therefore needs to be removed to allow the well to continue to produce gas at optimal rates.

There are multiple methods of unloading a gas well, some of which do not result in emissions. In this work, sampling was performed for unloadings in which an operator manually bypasses the well's separator. Unlike automated plunger lift methods, these manual unloading events could be scheduled, allowing the study team adequate time to install measurement equipment. As the flow to the separator, which typically operates at pressures of multiple atmospheres, is bypassed, flow is diverted to an atmospheric pressure tank. This diversion allows the well to flow to a lower pressure destination (the atmospheric pressure tank, rather than the pressurized separator). This lower pressure end point allows more gas to flow, increasing velocity in the production tubing and lifting the liquids out of the well. Gas is discharged from the tanks through the tank vent, unless the tanks have an emissions control system such as a combustor.

The nine unloading events reported in this work were varied in their characteristics. Methane emissions ranged from less than 0.02 Mg to 3.7 Mg. Some unloadings lasted 2 h (or more) and had relatively uninterrupted flow. Other unloadings were as short as 10–15 min with uninterrupted flow, and still others had intermittent flow for short periods and periods of no flow for much of the unloading period. Some of the wells sampled only unloaded once over the current life of the well, whereas others were unloaded monthly. The average emission per unloading event was 1.1 Mg of methane (95% confidence limits of 0.32–2.0 Mg). If the emissions per event for each well are multiplied by the event frequency (events per year) reported by the well operators, the average emission per well per year was 5.8 Mg (an average of 5.9 events per unloaded well per year). The sampled population reflected a wide range of emission rates, with a population of high emitting wells and a population of low emitting wells. When emissions are averaged per event, emissions from four of the nine events contribute more than 95% of the total emissions. *SI Appendix* provides more information about individual unloading events.

Because the characteristics of the unloading events sampled in this work are highly variable, and because the number of events sampled is small, extrapolating the results to larger populations should be done with caution. One source of data on larger populations of wells with unloadings, to which the population sampled in this work can be compared, is a survey reported by

the American Petroleum Institute and America's Natural Gas Alliance (API/ANGA) (22). In this survey, more than 20 companies provided data and well characteristics for 40,000–60,000 wells (with the number in the sample depending on the type of emission event). These API/ANGA data were used by the EPA to arrive at 2011 national inventory emission estimates for 35,828 wells without plunger lift and 22,866 with plunger lift, which vent for unloading. Unloading emissions for the wells in the API/ANGA survey were estimated based on well characteristics such as well bore volume, well pressure, venting time, and gas production rate (3). For the unloading events without plunger lift, 100 of the 2,901 wells (3%) in the survey account for 50% of the estimated emissions. Ninety percent of the estimated emissions in the API/ANGA survey are due to one-half of the wells. Because a small population of wells (3%) accounts for one-half of the emissions, if this relatively small population of high emitting wells is not adequately sampled, it is not possible to accurately estimate national emissions. The wells sampled in this work unloaded relatively infrequently. In contrast, some wells in the API/ANGA survey, including some of the highest emitting wells, unload with a daily or weekly frequency. An average frequency of unloading for the wells in the API/ANGA survey is 32.57 events per year, compared with an average observed in this work of 5.9.

Because a small number of unloading events accounts for a large fraction of emissions in the API/ANGA survey (22), and because some of these wells had frequencies of unloading higher than any of the events observed in this work, the sample set of nine events reported in this work is not sufficient for accurately estimating emissions from unloading at a national scale. Nevertheless, the data reported here provide valuable insights for the design of future sampling campaigns.

One important result from the measurements reported here is that current EPA estimation methods overpredict measured emissions. If the emission estimation method (3) used in the API/ANGA survey is applied to the events sampled in this work, estimates are 5 times higher than measured emissions. Estimates of the emissions for the nine events are 5.2 Mg per event versus measured emissions of 1.1 Mg per event. Emissions were overestimated for every event. The percentage by which emissions are overestimated increases as emissions per event decrease (*SI Appendix*). Possible causes of the overestimate include the assumptions in the estimation method that the entire well bore volume is released in an unloading and that the gas flow during an unloading is continuous.

Overall, the implication of all of these issues is a large uncertainty bound in the national emissions from gas well unloading. If the per well annual emissions from this work are used, a national emission estimate based on counts of wells that undergo unloading is in reasonable agreement with emissions in the EPA national inventory (1). In contrast, another estimate of unloading emissions, based on the per event emissions observed in this work and an estimate of national unloading events (22), would lead to a national estimate five times the estimate based on well counts. This estimate is not supported by the available data, given that the national event count is dominated by high frequency unloading events and the wells observed here unloaded far less frequently with much higher emission estimates per event. A lower estimate of unloading emissions could be suggested based on national well counts, emission estimates, and the finding that emission estimation methods, used in many EPA inventory estimates, overestimate observations made in this work by a factor of 5. All of these methods, however, assume a single scalar value represents a wide range of unloadings; the data presented in this work and in the API/ANGA survey (22) suggest that refined emission estimation methods, taking into account well and unloading characteristics, will be required. Additional measurements of unloading emissions are needed, both to resolve the

Table 2. National emission estimates for the natural gas production sector, based on this work and the 2011 national inventory

| Category | 2011 EPA GHG inventory net emissions,* Gg of methane/yr | Emission estimates from this report, [†] Gg of methane/yr | Comments |
|---|---|--|--|
| Sources with emissions measurements from this work used to generate national emission estimates | | | |
| Completion flowbacks from wells with hydraulic fracturing | 654* | 18 [‡] (5–27) [§] | Decrease in national emission estimate |
| Chemical pumps | 34* | 68 (35–100) [§] | Increase in national emission estimate |
| Pneumatic controllers | 355* | 580 [‡] (518–826) [§] | Increase in national emission estimate; if national emission factors derived from this work are used, this estimate becomes 790 Gg (<i>SI Appendix</i>) |
| Equipment leaks | 172–211** [¶] | 291 [‡] (186–396) [§] | Increase in national emission estimate; this comparison is based on equivalent categories of equipment, not all equipment leaks [¶] (<i>SI Appendix</i>) |
| Subtotal, national emissions, estimated based on this work | 1215–1254 ^{†#} | 957 ± 200 [#] | Decrease of ~250 Gg for national emission estimate |
| Sources with limited measurements; national emissions not estimated | | | |
| Unloadings (nonplunger lift) | 149* (EPA inventory) | | Highly diverse events; small data set collected in this work; preliminary national emission estimates have a broad range of values (25–206 Gg; see text) |
| Workovers (without hydraulic fracturing) | 0.3* (EPA inventory) | | Measurements in this work included only one recompletion and three swabbing events (see text) |
| Other sources, not measured in this work | | | |
| Unloadings (plunger lift) | 108* (EPA inventory) | | No measurements made in this work |
| Workovers (with hydraulic fracturing) | 143* (EPA inventory) | | No measurements made in this work; equipment configurations are similar to completion flowbacks for wells with hydraulic fracturing; if emissions per event are comparable to completion flowbacks, current inventories may overestimate emissions |
| Other sources, not measured in this work | 891–930** [¶] (EPA inventory) | | Includes potential emissions of sources not measured less prorated regulatory and voluntary emission reductions* |
| Total methane, Gg | 2,545 | 2,300 | Decrease of ~250 Gg for estimate |
| Methane emissions,**% [percent of gross gas production] | 0.47% [0.59%] | 0.42% [0.53%] | Brackets: gross gas emitted/gross gas produced (assuming produced gas is 78.8% methane) |

*Emissions from EPA national inventory are based on reported potential emissions less reductions; when reductions are reported for combined source categories, identical percentage reductions of potential emissions are assumed to apply across source categories (*SI Appendix, section S5*).

[†]Emission factors used to estimate national inventories are designed to be representative of the participating companies' activities and practices, but not necessarily all activities and practices.

[‡]National emissions based on a regionally weighted average (*SI Appendix, section S5*).

[§]Ranges are based on 95% confidence bounds of emission factors; activity factors are identical to those used in EPA inventory. Uncertainties in activity factors (e.g., device counts) are not included. Uncertainties associated with whether regional or national averaging is performed are included in the uncertainty estimate (*SI Appendix, section S5.4*).

[¶]Sampling in this work included compressors on well sites, but not all gathering compressors. Well site and gathering compressors are combined in the national inventory. Range reported for national inventory for equipment leaks and "other" sources reflect uncertainty in attributing compressor emissions from national inventory to a specific source category.

[#]Uncertainty bound assumes uncertainties for completion flowbacks, pneumatic pumps and controllers and leaks are independent, and consequently, the combined uncertainty is the square root of the sum of the squares of the individual uncertainties.

**US total gross gas production (oil and coal bed, gas, and shale, onshore and offshore): 547,000 Gg.

differences between estimates and measurements and to better characterize the population of wells with unloading emissions.

Finally, it is also clear from the data that properly accounting for unloading emissions will be important in reconciling emission inventories with regional ambient measurements. Average methane emission rates for a single unloading ranged from roughly 100 g/min to in excess of 30,000 g/min. These rates are much larger than emission rates for production sites (typically tens of grams of methane per minute per well) or from completions (typically a few hundred grams per event per minute). At these emission rates, a single unloading event could, during the short period that it is occurring, result in emissions that are the equivalent of just a few wells in routine production to the equivalent of up to several thousand wells in routine production. Therefore, reconciliation between instantaneous ambient measurements and emission inventories will need to carefully represent the emissions from unloadings.

Well Sites in Routine Production. A well site contains one or more wellheads and may contain separators, pneumatic controllers, water tanks, hydrocarbon tanks (oil or condensate), and possibly other devices such as dehydrators, compressors, and flares. In this work, measurements were made from pneumatic controllers and pumps, because these devices release methane as part of their routine operation, and from equipment leaks detected by using an infrared camera (*SI Appendix*) at well sites.

Emissions for equipment on well sites, in routine production, that were targeted for measurements had much narrower uncertainty bounds than well completion flowbacks or well unloadings. Emissions from pneumatic chemical injection pumps measured in this work averaged 3.7 ± 1.6 g of methane per minute per pump, 9% lower than the EPA emission factor (*SI Appendix, section S2*). Intermittent and low bleed pneumatic devices measured in this work averaged 5.9 ± 2.4 and 1.7 ± 1.0 g

Table 3. Measurement methods used in the study

| Source | Direct measurement methods | Mobile downwind sampling |
|--------------------|---|---|
| Well completions | Measurements from flowback tanks made by using enclosures and temporary stacks with measurements of flow rate and composition | Downwind tracer ratio methods: Metered release of C ₂ H ₂ and N ₂ O on site and downwind measurements of methane to C ₂ H ₂ and methane to N ₂ O concentration ratios |
| Gas well unloading | Temporary stack with measurements of flow rate and composition | |
| Well workovers | Measurements from flowback tanks made by using enclosures and temporary stacks with measurements of flow rate and composition | |
| Production sites | Infrared (FLIR) camera surveys of sites and flow rate measurements using a HiFlow device | Metered release of C ₂ H ₂ and N ₂ O on site and downwind measurements of methane to C ₂ H ₂ and methane to N ₂ O concentration ratios |

of natural gas per device per minute, 29% and 270% higher than EPA emission factors, respectively (*SI Appendix, section S2*). No high bleed pneumatic devices were identified at the sampling sites, and the average emission rate for the population of pneumatic controllers sampled in this work was 3.36 ± 0.65 g of methane per min (3.8 ± 0.69 g of natural gas per min). Equipment leaks measured in this work averaged 1.23 ± 0.44 g of methane per minute per well, which can be compared with an EPA estimate of potential emissions (no regulatory or voluntary emission reductions) of 1.37–1.67, derived from EPA’s inventory for similar equipment types (wellheads, separators, heaters, meters/piping, and dehydrator fugitives), with the range reflecting whether small compressors are added to the comparison (*SI Appendix, section S5*). Comparing to net emissions is challenging because EPA does not assign emission reductions to specific equipment categories. Additional information is provided in *SI Appendix*.

There was significant geographical variability in the emissions rates from pneumatic pumps and controllers, but these regional differences were not as pronounced for equipment leaks. Emissions per pump from the Gulf Coast are statistically significantly different and roughly an order of magnitude higher than from pumps in the Midcontinent. Emissions per controller from the Gulf Coast are highest and are statistically significantly different from controller emissions in the Rocky Mountain and Appalachian regions. Emissions per controller in the Rocky Mountain region are lowest and an order of magnitude less than the national average (*SI Appendix*).

Implications for National Emission Estimates. If the average emissions reported in this work for well completion flowbacks, pneumatic devices, and equipment leaks are assumed to be representative of national populations and are applied to national counts of completions, pneumatic devices, and wells in EPA’s national inventory, emissions from these source categories would be calculated as 957 Gg (with sampling and measurement uncertainties estimated at ± 200 Gg), compared with 1,211–1,250 Gg methane per year in the 2011 EPA national inventory (1) for the same source categories. A large emissions decrease associated with completion flowbacks is partially offset by emission increases from pneumatic controllers and equipment leaks. Reasons for these differences are described in *SI Appendix*.

The estimated uncertainty in the national emission estimates based on this work is $\sim 20\%$ (200 Gg). The sources of uncertainty include measurement uncertainty, uncertainty introduced by the selection of sites, and uncertainty due to choices in performing regional or national averaging of equipment counts and emission factors. These components of the quantified uncertainty are described in *SI Appendix*. The uncertainty estimate does not

include factors such as uncertainty in national counts of wells or equipment and the issue of whether the companies that provided sampling sites are representative of the national population.

The 957 ± 200 Gg in emissions for completion flowbacks, pneumatics, and equipment leaks, coupled with national inventory estimates for other categories, leads to an estimated 2,300 Gg of methane emissions from natural gas production (0.42% of gross gas production). A summary is provided in Table 2, and details of the calculations are available in *SI Appendix*.

Total emissions estimated based on measurements in this work (2,300 Gg) are comparable with the most recent EPA national GHG inventory (2,545 Gg in the 2011 inventory, released in April 2013) (1). Table 2 also compares emissions in specific source categories, estimated based on the measurements made in this work, to EPA estimates of the same categories in the national inventory (1). For some emission categories, such as completion flowbacks and pneumatic controllers, conclusions can be drawn from the comparisons. Specifically, measured emissions from completion flowbacks are roughly 600 Gg lower than the completion flowback emissions in the current inventory; measured emissions from pneumatic controllers are 150–500 Gg higher than in the current inventory. For other emission categories, such as equipment leaks and pneumatic pumps, however, drawing conclusions is more difficult. For these source categories, the national inventory reports potential emissions for each category, but aggregates emission reductions, creating uncertainty in the net emissions in these categories (see *SI Appendix, section S5.5* for more details).

It should also be noted that the national inventory has changed in recent years based on evolving regulations (21) and understanding of emission sources. In this work, comparisons are made to the most recent release of the inventory (2011 final version, released in April 2013) and back casts to previous years by using consistent calculation methodologies. Emissions were estimated as 2,545 Gg in 2011, compared with 2,948 Gg in 2009 and 2,724 Gg in 2010. The work presented here suggests practices such as combusting or capturing emissions from completion flowbacks, as required by New Source Performance Standards subpart OOOO and the revised National Emission Standards for Hazardous Air Pollutants subpart HH (21), are resulting in reduced methane emissions. Other source categories require more data to produce national emission estimates, and adjustments in the inventory may emerge as more emission measurements are performed. Emission estimates may be adjusted downward if workovers with hydraulic fracturing are found to have emissions per event that are similar to completion flowbacks and may be adjusted either upward or downward as more emissions data are collected for liquids unloading or pneumatic devices.

Finally, an emissions intensity of 0.42% is reported in Table 2. The intensity expresses a methane emission per unit of gross gas production. This intensity should be interpreted with caution, because it includes only production operations and implicitly attributes all methane emissions from natural gas wells to natural gas production, although natural gas wells produce substantial amounts of natural gas liquids and oil. The intensity is reported here because it facilitates comparisons with other analyses that have appeared in the literature (23).

Methods

Multiple independent and complementary techniques were used to measure methane emissions. The primary procedures involved direct measurements of CH₄ emissions at their source. A variety of different procedures were used for direct source measurements, depending on the type of source being sampled and the type of natural gas production equipment being used. Table 3 summarizes the direct source methods used in the study; detailed descriptions of the methods are provided in *SI Appendix*.

In addition to direct source measurements, tracer ratio measurements, designed to estimate the total methane emissions from a site, were made at 20% of the well completion flowbacks and 13% of the production sites. The tracer release method was developed in the 1990s to quantify methane emissions from a wide range of natural gas system components (24, 25). Sites for tracer releases were selected for their steady, moderate winds and downwind access. Measurements for sites without downwind access could not be made. Table 3 also summarizes these measurement methods, which are described in detail in *SI Appendix*. In brief, tracer compounds were released at a known rate on-site; downwind measurements of methane (minus

background) and the tracer (minus background) were assumed to be equal to the ratio of emission rates, allowing methane emissions to be estimated. These measurements were performed for a subset of the sampling locations that had relatively open terrain and steady winds, producing well-defined emission plumes downwind of the sites. The tracer studies allowed for an independent measurement of emissions that were also measured by using direct source methods. For completion flowbacks, emission estimates based on the downwind measurements were generally within a factor of 2 of the direct source measurements, supporting the conclusion that emissions from completion flowbacks are roughly 97% below the most recent national estimates and that emissions from completion flowbacks without methane control or recovery equipment, observed in this work, are well below the average potential emissions in current national inventories (1). For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements. Tracer study results are summarized in *SI Appendix*.

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Proposed Short-Lived Climate Pollutant Reduction Strategy

April 2016



California Environmental Protection Agency

 **Air Resources Board**

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Table of Contents

| | |
|---|----|
| EXECUTIVE SUMMARY..... | 1 |
| I. Introduction: Showing the Way to 2°C..... | 13 |
| A. Significant Benefits from Accelerated Action to Cut SLCP Emissions | 15 |
| B. Building on California’s Air Quality and Climate Leadership | 17 |
| C. Purpose of SLCP Reduction Strategy..... | 18 |
| D. Achieving Science-Based Targets | 19 |
| E. Coordinating Research Efforts Related to SLCPs | 20 |
| F. Process for Developing the SLCP Reduction Strategy | 21 |
| II. California’s Approach to Reducing SLCP Emissions..... | 23 |
| A. Prioritize Actions with Diverse Benefits..... | 23 |
| B. Put Organic Waste to Beneficial Use..... | 24 |
| C. Identify Practical Solutions to Overcome Barriers..... | 25 |
| D. Invest in SLCP Emission Reductions and Communities..... | 27 |
| E. Advance the Science of SLCP Sources and Emissions..... | 28 |
| F. Need for Focused SLCP Programs..... | 29 |
| III. Latest Understanding of Science on SLCPs..... | 31 |
| A. Black Carbon | 36 |
| B. Methane..... | 37 |
| C. Fluorinated Gases (Hydrofluorocarbons)..... | 38 |
| IV. Reducing Black Carbon Emissions..... | 40 |
| A. Anthropogenic (Non-Forest) Sources of Black Carbon Emissions..... | 40 |
| 1. Progress to Date..... | 41 |
| 2. Recommended Actions to Further Reduce Non-Forest Black Carbon Emissions | 47 |
| B. Forest-Related Sources of Black Carbon Emissions | 48 |
| 1. Progress to Date..... | 50 |
| 2. Recommended Actions to Reduce Wildfire Risk and Black Carbon Emissions | 53 |
| V. Reducing Methane Emissions | 58 |
| A. Progress to Date | 58 |
| B. Recommended Actions to Further Reduce Methane Emissions..... | 63 |
| 1. Dairy Manure | 64 |
| 2. Dairy and Livestock Enteric Fermentation | 69 |

| | |
|---|-----|
| 3. Landfills | 71 |
| 4. Wastewater Treatment and other Miscellaneous Sources | 75 |
| 5. Oil and Gas | 76 |
| VI. Reducing HFC Emissions..... | 81 |
| A. Progress to Date..... | 82 |
| B. Recommended Actions to Further Reduce HFC Emissions | 85 |
| C. Sulfuryl Fluoride..... | 90 |
| VII. Achieving Success | 92 |
| A. Integrate and Coordinate Planning | 92 |
| B. Enable Local and Regional Leadership | 93 |
| C. Investments | 95 |
| D. Coordinate with Subnational, Federal, and International Partners..... | 97 |
| VIII. Evaluations..... | 100 |
| A. Economic Assessment of Measures in the Proposed Strategy..... | 100 |
| 1. Residential Wood Combustion Black Carbon Emission Reductions | 102 |
| 2. Methane Emission Reductions from Dairy Manure | 106 |
| 3. Methane Emission Reductions from Diversion of Landfill Organic Waste | 113 |
| 4. Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Regulation | 118 |
| 5. Hydrofluorocarbon (HFC) Emission Reductions..... | 119 |
| B. Public Health Assessment | 121 |
| C. Environmental Justice and Disadvantaged Communities | 125 |
| D. Environmental Analysis..... | 127 |
| IX. Next Steps..... | 129 |

Appendices

Appendix A: California SLCP Emissions

Appendix B: Research Related to Mitigation Measures

Appendix C: Draft Environmental Analysis for the Proposed SLCP Reduction Strategy

Appendix D: Supporting Documentation for the Economic Assessment of Measures in the Proposed Strategy

EXECUTIVE SUMMARY

Eureka! Synonymous with discovery and opportunity, California represents an ideal; a state of mind—stunning scenery, recreational opportunities, a thriving economy and a culturally diverse people. However, climate change is threatening this ideal, and our very way of life. It is clear that the impacts of climate change are already upon us. California continues to suffer through historic temperatures, persistent droughts, and more intense and frequent wildfires. Each year seems to bring a new global temperature record, and new evidence suggests sea levels are rising much faster than predicted. What was once, and remains, a generational problem of greenhouse gas (GHG) balance in the atmosphere has now become an immediate threat to our California lifestyle.

The only practical way to rapidly reduce the impacts of climate change is to employ strategies built on the tremendous body of science. The science unequivocally underscores the need to immediately reduce emissions of short-lived climate pollutants (SLCPs), which include black carbon (soot), methane (CH₄), and fluorinated gases (F-gases, including hydrofluorocarbons, or HFCs). They are powerful climate forcers and harmful air pollutants that have an outsized impact on climate change in the near term, compared to longer-lived GHGs, such as carbon dioxide (CO₂). SLCPs are estimated to be responsible for about 40 percent of current net climate forcing. Action to reduce these powerful “super pollutants” today will provide immediate benefits as the effects of our policies to reduce long-lived GHGs further unfold.



While we must continue to steadily reduce CO₂ emissions for long-term climate stability, we also need a global commitment and near-term actions to dramatically reduce SLCP emissions over the next 10–15 years. Deploying existing technologies and resource management strategies globally to reduce SLCP emissions can cut the expected rate of global warming in half and keep average warming below the dangerous 2°C threshold at least through 2050. We can slow sea level rise significantly, reduce disruption of historic rainfall patterns, and boost agricultural productivity by reducing crop losses to air pollution. Cutting global SLCP emissions immediately will slow climate feedback mechanisms in the Arctic and elsewhere that would otherwise further accelerate global warming and make climate change far more difficult to solve and far more costly to live with – as more resources would be required for disaster relief, conflict management, and adaptation. Most importantly, we can dramatically reduce global air pollution, saving millions of lives each year. Many of these benefits will primarily accrue in regions and populations disproportionately impacted by climate change, including the developing world.

Using cost-effective and available technologies and strategies, worldwide anthropogenic sources of SLCP emissions can be largely controlled by 2030 and the global benefits of a collective commitment to substantially reduce SLCP emissions would be profound. Leading efforts by California, the United States, Mexico, Norway, Europe, the Arctic Council, and several countries and non-governmental entities acting through the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants (CCAC) are already targeting SLCPs. Many other countries included SLCP emissions in their commitments made at the Paris climate conference, or are targeting them through separate policies to improve air quality and promote sustainable agriculture and transportation, among other efforts.



California's seminal Global Warming Solutions Act, AB 32 (Nuñez, Chapter 488, Statutes of 2006), charges the California Air Resources Board (ARB or Board) with achieving and maintaining a statewide GHG emission limit, while seeking continuing GHG emission reductions. SLCP emission reductions are critical to achieving this mandate. California is committed to taking further action to reduce SLCP emissions by 2030. Senate Bill 605 (Lara, Chapter 523, Statutes of 2014) requires the ARB to develop a plan to reduce emissions of SLCPs. Additionally, Governor Brown has identified reductions of SLCP emissions as one of "five pillars" to meet an overarching goal to reduce California's GHG emissions by 40 percent below 1990 levels by 2030. This proposed SLCP Reduction Strategy (Proposed Strategy) was developed pursuant to SB 605 and lays out a range of options to accelerate SLCP emission reductions in California, including regulations, incentives, and other market-supporting activities. Governor Brown's 2016-2017 Proposed Budget includes \$215 million from Cap-and-Trade expenditures specifically targeting SLCP emission reductions. These include \$40 million for black carbon residential woodsmoke reductions, \$20 million for HFC reductions from refrigerants, \$100 million for waste diversion, \$20 million for Healthy Soils, and \$35 million for dairy digester development.

An Opportunity for California

Historic action is not enough. Many opportunities to reduce emissions of SLCPs still exist, and California is doubling down on its efforts to control these emissions from all sources. A dedicated commitment, as described in this Proposed Strategy, to achieve sustainable reductions in SLCP emissions in California will provide significant benefits throughout the State.

In this Proposed Strategy, we outline SLCP emission reduction actions that provide a wide array of climate, health, and economic benefits throughout the State. The State's organic waste should be put to beneficial use, such as for soil amendments/compost,

electrical generation, transportation fuel, and pipeline-injected renewable natural gas. Practical solutions must be developed and implemented to overcome barriers to waste gas utilization for pipeline injection and grid interconnection. Additional data on SLCP sources must be collected in order to improve California's SLCP emission inventory and better understand potential mitigation measures. Finally, the State should provide incentives to accelerate market transitions to cleaner technologies that foster significant system-wide solutions to cut emissions of SLCPs. Many of the sources and sectors responsible for SLCP emissions are concentrated in communities with high levels of pollution or unemployment, which could especially benefit from targeted investments to improve public health and boost economic growth.

In the coming years, many billions of dollars in public and private investments are anticipated to support efforts to reduce SLCP and CO₂ emissions and support our agricultural and waste sectors, build sustainable freight systems, encourage low-Global Warming Potential (GWP) refrigerants and grow healthy forests. These investments will strengthen the State as a whole and the communities where they occur. Many of the benefits will accrue in the Central Valley, rural parts of the State, or other areas disproportionately impacted by pollution, such as those along freight corridors.



Stubborn barriers remain, including connecting distributed electricity and biogas projects, which have slowed previous efforts to reduce emissions of SLCPs and capture a wide array of benefits. These barriers are not insurmountable, and now is the time to solve them. State agencies, utilities, and other stakeholders need to work immediately to identify and resolve remaining obstacles to connecting distributed electricity with the grid and injecting renewable natural gas into the pipeline. Supporting the use of the cleanest

technologies with funding and strategies that maximize air quality, climate, and water quality benefits can accelerate their introduction. Building market certainty and value for the energy, soil amendment, and other products that come from compost or anaerobic digestion facilities will help to secure financing to accelerate and scale project development.

Building on California Leadership

This Proposed Strategy builds on California's ongoing leadership to address climate change and improve air quality. It has been developed with input from State and local agencies, academic experts, a working group of agricultural experts and farmers convened by the California Department of Food and Agriculture (CDFA), businesses, and other interested stakeholders in an open and public process. ARB and State agencies collaborated to identify reduction measures for specific sectors, including the dairy, wastewater, and waste sectors. In addition, ARB collaborated with the local air districts to identify SLCP emission reduction measures that could be implemented

through district action. Throughout this process, ARB has sought advice from academic, industry, and environmental justice representatives. Additionally, ARB staff is working closely with manufacturers to determine the feasibility and cost of replacement products for high-GWP refrigerants, and with the dairy industry and academics to evaluate options and costs for reducing emissions of methane at dairies.

While reducing GHG emissions is a key objective for the State, California remains committed to further reducing emissions of criteria (smog-forming) pollutants and toxic air pollutants, as well. Many of the concepts described in this Proposed Strategy have already been discussed in the context of the California Sustainable Freight Action Plan, 2016 Mobile Source Strategy and other efforts related to developing State Implementation Plans for air quality, and plans for bioenergy, waste management, water management, healthy soils, and sustainable management of the state's natural resources. The SLCP Strategy, along with those other planning efforts, will inform and be integrated into the upcoming 2030 Target Scoping Plan Update, which will incorporate input from a wide range of stakeholders to develop an integrated plan for reducing emissions of GHGs, criteria pollutants, and toxic air pollutants through 2030. The process for updating the Scoping Plan began in fall 2015 and is scheduled for completion by 2017.

State agencies and the air districts are committed to continuing to work together to ensure that the concepts outlined in this Proposed Strategy are implemented in a coordinated and synergistic way. The sections below describe goals, regulations, incentives, and other efforts that would:

- Encourage national and international deployment of California's well-established and proven measures to reduce black carbon emissions;
- Further reduce black carbon emissions from off-road and non-mobile sources, including forests;
- Cut in half methane emissions from dairy operations and effectively eliminate disposal of organics in landfills;
- Create and expand industries to capture value from organic waste resources in California;
- Significantly reduce fugitive methane emissions from oil and gas systems and other sources; and
- Accelerate the transition to low-GWP refrigerants and more energy efficient refrigeration systems.

ARB staff will receive and consider comments on this Proposed Strategy and prepare a final Strategy to present to the Board for consideration in fall 2016.

Achieving Significant Emission Reductions

Based on stakeholder feedback on the Concept Paper released in May 2015 and the subsequent Draft Strategy, ARB is proposing planning targets to reduce emissions of methane and HFCs by 40 percent below current (2013) levels by 2030, and

anthropogenic (non-forest) black carbon emissions by 50 percent below current levels by 2030. Meeting these targets will help to achieve the Governor’s goal to cut all GHG emissions in California by 40 percent below 1990 levels by 2030 and help meet federal air quality standards for 2031 and beyond.

The proposed targets are summarized in Table 1. The goals and proposed measures included in this Proposed Strategy will reduce SLCP emissions to levels in line with these targets. Due to the urgency of the issue, and recognizing the climate potency of SLCPs in the near-term, we use 20-year global warming potential values (GWPs) in this report to quantify emissions of SLCPs.

Table 1: California SLCP Emissions and Proposed Target Emission Levels (MMTCO2e)*

| Pollutant | 2013 | 2030 BAU** | 2030 Proposed Strategy |
|---------------------------|------|------------|------------------------|
| Black carbon (non-forest) | 38 | 26 | 19 |
| Methane | 118 | 117 | 71 |
| Hydrofluorocarbons (HFCs) | 40 | 65 | 24 |

*Using 20-year GWPs from the 4th Assessment report of the IPCC for methane and HFCs, and 5th Assessment report for black carbon (the first report to define a GWP for black carbon)

**Business As Usual (BAU) forecasted inventory includes reductions from implementation of current regulations

Black Carbon

Black carbon is not one of the climate pollutants originally included in international climate frameworks, and it is not included in California’s AB 32 inventory. However, recent studies have shown that black carbon plays a far greater role in global warming than previously believed. California has made tremendous progress in reducing black carbon emissions as part of its efforts to reduce carcinogenic diesel particulate matter emissions and improve air quality. California has already cut anthropogenic black carbon emissions by over 90 percent since the 1960s, and existing measures are projected to cut mobile source emissions by 75 percent and total anthropogenic emissions by nearly 60 percent between 2000 and 2020. Putting measures in place to achieve similar levels of reductions worldwide is the quickest way to reduce the impacts of climate change, and would save millions of lives per year.



These reductions have come from strong efforts to reduce on-road vehicle emissions, especially diesel particulate matter. Car and truck engines used to be the largest sources of black carbon emissions in California, but the State's existing air quality

policies will virtually eliminate black carbon emissions from on-road diesel engines within 10 years. These policies are based on existing technologies, which could be deployed throughout the U.S. and the world.

With the large reduction in emissions of black carbon from vehicles, other sources of black carbon emissions will become more significant contributors to the State's black carbon inventory over time. In particular, without additional actions, off-road mobile, fuel combustion in the industrial and power sectors, and woodstoves and fireplaces will account for more than three-quarters of anthropogenic black carbon emissions in California in 2030. However, black carbon emissions from these sources have declined significantly as well, by almost 30 percent since 2000. Continued progress on these sectors—transitioning to cleaner and more efficient uses of energy, reducing emissions



from woodstoves and fireplaces, taking steps to meet federal health-based air quality standards by 2031, and developing and implementing a sustainable freight system—will continue to reduce black carbon emissions and should allow us to meet the targets established in this Proposed Strategy.

The State's 2016 Mobile Source Strategy, 2030 Target Scoping Plan Update, and Sustainable Freight Action Plan, a multi-agency effort to deploy a sustainable and efficient system for goods movement, will build on these measures to reduce black carbon. Additionally, ARB will work with local air districts to further reduce particulate matter and black carbon emissions from woodstoves and fireplaces. Governor Brown's 2016-17 proposed budget includes \$40 million to reduce black carbon from woodsmoke.

The largest source of black carbon emissions in California is, by far, wildfire. An average wildfire season contributes two-thirds of current black carbon emissions in California. As climate change accelerates, our drought-ravaged forests will only become more vulnerable to wildfire and disease. Indeed, many of California's forests are already in a perilous condition and require accelerated management and investment to protect them. Several Federal, State, and local agencies are currently coordinating on forest planning, pursuant to Governor Brown's Proclamation of a State of Emergency on Tree Mortality and through other forums.

This Proposed Strategy focuses on actions to reduce wildfire risk and black carbon emissions by increasing the rate of fuel reduction to improve forest health, aligning financial incentives with beneficial uses of woody waste, supporting management efforts and market development through research, and integrating state planning efforts. The State's Forest Carbon Plan and the 2030 Target Scoping Plan Update will identify additional goals and measures to improve forest health. Goals and actions identified in the 2030 Target Scoping Plan Update and Forest Carbon Plan will include those related to forest carbon storage, which is beyond the scope of this Proposed Strategy. State agencies are coordinating to ensure that the goals and recommendations in each of

these plans complement one another. Any proposed targets or actions will be considered through those public planning processes.

Methane

Methane is responsible for about 20 percent of current net climate forcing globally. In California, about half of methane emissions come from organic waste streams that can be put to valuable use as sources of renewable energy or fuel and soil amendments. The other half mostly comes from enteric fermentation (burps) from dairy cows and livestock and fugitive emissions (leaks) from oil production, processing, and storage, gas pipeline system, or industrial operations. California can cut methane emissions by 40 percent below current levels in 2030 by capturing or altogether avoiding methane from manure at dairies, meeting national industry targets for reducing methane emissions from enteric fermentation, effectively eliminating disposal of organics in landfills, and reducing fugitive methane emissions by 40-45 percent from all sources.

Strong market support and broad collaboration among State agencies, industry, and other stakeholders will be necessary to reduce landfill and manure methane emissions by putting organic waste streams to beneficial use. The State will support early action to build infrastructure capacity and reduce emissions through existing incentives and accelerated efforts to overcome barriers and foster markets. Government agencies and stakeholders will work to foster market conditions to support private sector investment in expanded or new infrastructure, including building markets for compost and soil amendments, overcoming barriers to pipeline injection of biomethane, and identifying optimal financing mechanisms and levels to reach the goals in this Proposed Strategy.

Ultimately, a combination of incentives, State and private sector investment, and regulations will be necessary to capture the value in organic waste streams and ensure lasting emission reductions. For dairies, California will aim to reduce methane emissions from dairy manure management by at least 20 percent in 2020, 50 percent in 2025, and 75 percent in 2030. The State will encourage and support near-term actions by dairies to reduce emissions through financial incentives, collaboration to overcome barriers, and other market support, before subsequent regulations take hold. Following ARB approval of the final SLCP strategy, and in coordination with CDFA and local air quality and water quality agencies, ARB will initiate a rulemaking process to reduce manure methane emissions from the dairy industry in-line with the objectives in this Proposed Strategy. The regulatory process will include consideration of available financial incentives, market support, and the potential for emissions leakage in identifying appropriate timelines and requirements for the industry.

The rulemaking will also include requirements for mandatory reporting and recordkeeping of parameters affecting GHG emissions at California dairy farms. Reported information will be used to refine inventory quantification, evaluate policy effectiveness, and aid in future policy planning and regulatory development. ARB will work with other State agencies and industry groups to improve outreach on new

reporting requirements, as well as merge and streamline reporting activities with current forms and requirements to avoid duplicative reporting wherever feasible.



For landfills, ARB will work with CalRecycle to develop a regulation by 2018 to effectively eliminate organic disposal in landfills by 2025. To support this, CalRecycle will build on its partnerships with local governments, industry, nonprofits, local air districts and water boards to support regional planning efforts and identify ways to safely and effectively develop necessary organics recycling capacity. CalRecycle will also explore new ways to foster food waste prevention and food rescue, to help meet a goal of 10 percent food rescue by 2020, and 20 percent by 2025. Recovering and utilizing food that would otherwise be landfilled can help to reduce methane emissions and increase access to healthy foods for millions of Californians who suffer from food insecurity. Additionally, ARB and CalRecycle will work with the State and regional Water Boards to assess the feasibility and benefits of actions to require capturing and effectively utilizing methane generated from wastewater treatment, and opportunities for co-digestion of food waste at existing or new anaerobic digesters at wastewater treatment plants.

This Proposed Strategy also establishes a goal of reducing fugitive methane emissions from oil and gas by 40 percent below current levels in 2025 and 45 percent in 2030, and from all other sources by 40 percent in 2030. This aligns with the Obama Administration goal of reducing methane emissions from oil and gas operations by 40–45 percent below 2012 levels by 2025.



California has a comprehensive and stringent emerging framework to reduce methane emissions from oil and gas systems. ARB is developing a regulation to reduce fugitive methane emissions from the oil and gas production, processing and storage sector, which will be among the most stringent such regulations in the country. Additionally, pursuant to Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014), the California Public Utilities Commission has launched a rulemaking to minimize methane leaks from natural gas transmission and distribution pipelines. Increases in energy efficiency and renewable energy, as well as more dense development patterns, will reduce oil and gas demand and fugitive emissions. ARB and the California Energy Commission (CEC) have also conducted several research projects to improve methane emission monitoring and accounting, as well as identify emission “hotspots,” which are responsible for large fractions of total fugitive emissions. These efforts will continue, and are critical to accelerating leak detection and fugitive methane emission reductions from all sectors, not just oil and gas. Ultimately, to

eliminate fugitive methane emissions, the State needs to transition away from its use of oil and natural gas.

HFCs

Fluorinated gases, and in particular HFCs, are the fastest-growing source of GHG emissions in California and globally. More than three-quarters of HFC emissions in California come from the use of refrigerants in the commercial, industrial, residential, and transportation sectors. In many cases, alternatives with much lower GWPs are already available and the United States Environmental Protection Agency (U.S. EPA) is beginning to impose bans on the use of F-gases with the highest GWPs in certain applications and sectors. Additionally, there is strong international momentum and interest to phase down the use of HFCs under the Montreal Protocol, as has already been done for other F-gases. The annual Meeting of Parties in November 2015 resulted in a decision to continue working on an HFC phasedown schedule in 2016. In the absence of a sufficiently rigorous international agreement by the end of 2016, ARB will evaluate the feasibility of a phasedown for California that aligns with similar efforts and stringency levels in Australia, Canada, Europe, and Japan.

California can complement these national and potential international actions by taking additional steps to reduce HFC emissions at low cost. Early action, ahead of some of



the phase down schedules being proposed internationally, can avoid locking-in the use of high-GWP refrigerants in new or retrofitted systems in the coming years. Without early action to reduce unnecessary emissions now and into the future, the State would need to take additional—likely more costly—steps to meet its 2030 climate targets. An important step would be developing an incentive program to encourage the use of low-

GWP refrigerants, which could lead to very low cost emission reductions and could be implemented while further regulations are considered or developed. The Governor's proposed 2016-2017 budget includes \$20 million for incentives to reduce HFC emissions from refrigerants. Also, as effective alternatives become available, ARB will consider developing bans on the use of high-GWP refrigerants in sectors and applications not covered by U.S. EPA regulations.

This Proposed Strategy identifies measures that can reduce HFC emissions by 40 percent in California by 2030 and potentially capture additional, available reductions in HFC emissions now, and into the future. Many of these measures could have associated energy efficiency benefits, as well.

A summary of all proposed SLCP emission reduction measures and estimated reductions is presented in Table 2.

Table 2: Summary of Proposed New SLCP Measures and Estimated Emission Reductions (MMTCO₂e)*

| Measure Name | 2030 Annual Emission Reductions | 2030 Annual Emissions |
|--------------|---------------------------------|-----------------------|
|--------------|---------------------------------|-----------------------|

BLACK CARBON (NON-FOREST)

| | | |
|---|---|-----------|
| 2030 BAU** | | 26 |
| Residential Fireplace and Woodstove Conversion | 3 | |
| California Sustainable Freight Action Plan State Implementation Plans Clean Energy Goals*** | 4 | |
| 2030 BAU with new measures | | 19 |

METHANE

| | | |
|---|----|------------|
| 2030 BAU** | | 117 |
| Dairy Manure | 21 | |
| Dairy and Livestock Enteric Fermentation | 5 | |
| Landfill | 5 | |
| Wastewater, industrial and Other Miscellaneous Sources | 7 | |
| Oil and Gas Sector | 8 | |
| 2030 BAU with new measures | | 71 |

HYDROFLUOROCARBONS

| | | |
|--|----|-----------|
| 2030 BAU** | | 65 |
| Financial Incentive for Low-GWP Refrigeration Early Adoption | 2 | |
| HFC Supply Phasedown | 19 | |
| Sales ban of very-high GWP refrigerants | 5 | |
| Prohibition on new equipment with high-GWP Refrigerants | 15 | |
| 2030 BAU with new measures | | 24 |

*Using 20-year GWPs from the 4th Assessment report of the IPCC for methane and HFCs, and 5th Assessment report for black carbon (the first report to define a GWP for black carbon)

**Business As Usual (BAU) forecasted inventory includes reductions from implementation of current regulations

***Future emission reduction measures that will be developed to help the State meet its air quality and climate change goals are also expected to help the State meet the black carbon target by 2030. However, an estimate of emission reductions is not currently available, but will be developed as part of these planning efforts.

Cost-Effective Measures with Significant Health Benefits

Significantly reducing SLCP emissions in line with the targets presented in this Proposed Strategy will continue California's long and successful legacy of implementing innovative and effective environmental and health policies while fostering the growth of a vibrant and sustainable economy. The proposed actions can contribute to health, environmental, and economic benefits that will positively impact Californian businesses and individuals. Many of these benefits will be concentrated in disadvantaged communities or other parts of the State most in need of economic development opportunities, including the San Joaquin Valley, rural areas where wood smoke is a primary health concern, and communities along freight corridors.

Collectively, implementing these measures would bring thousands of jobs from several billion dollars of investment in clean technologies and strategies that would lead to significant reductions in SLCP emissions. Potential revenues and efficiency savings could also be significant – and potentially outweigh the costs of some measures. In particular, for projects that utilize organic waste to create transportation fuel, the value of LCFS credits and RIN credits from the federal Renewable Fuel Standard can make these projects profitable. However, there remain significant institutional, market, and technical uncertainties that must be addressed, and continued incentives and State support can help to demonstrate and scale these strategies. In other cases, there may be net costs, but associated SLCP emission reductions may come at relatively low cost or provide other environmental and health benefits. For example, strategies at dairies that may not include energy production and associated revenues can still reduce emissions at low cost, and may deliver other environmental benefits, as well. And the collection of HFC measures identified in this Proposed Strategy could reduce GHG emissions by 260 MMTCO₂e cumulatively through 2030 (20-year GWP) at a very low cost per tonne.

Achieving the targets identified in this Proposed Strategy would help reduce ambient levels of ozone and particulate matter, and the cardiovascular and respiratory health effects associated with air pollution. These and other health benefits can be maximized as part of an integrated approach to ensure that strategies used to reduce SLCP emissions also help to improve air quality and water quality on a regional basis. Many of these benefits would accrue in disadvantaged communities, which are often located near sources of SLCP emissions.

The proposed actions are supported through an integrated set of air quality and climate policies in the State, including the Low Carbon Fuel Standard, Bioenergy Feed-In-Tariff, utility investments to defray the costs of connecting renewable natural gas supplies to the pipeline, and direct investments from State funds. Together, and with additional targeted State support, we can meet the goals identified in this Proposed Strategy and capture additional economic, environmental and health benefits.

Putting the Strategy into Action

All regulatory measures developed pursuant to the SLCP Reduction Strategy would undergo a complete, public rulemaking process including workshops, and economic and environmental evaluations. While this Proposed Strategy is intended to be comprehensive, it is not exhaustive. We will continue to pursue new cost-effective programs and measures as technology and research on SLCP emission sources and potential mitigation measures advances.

Effectively implementing this Proposed Strategy will require working with local, regional, federal and international partners, and strategically investing time and money to overcome market barriers that hinder progress. The extent to which we do so will drive results, which can include a wide range of significant economic and environmental benefits for California broadly, and many of the State's most disadvantaged communities, specifically.

Finally, the State will only realize the full benefits of strong action to reduce SLCP and CO₂ emissions if others take committed action, as well. Strong, near-term action to cut emissions of SLCPs, in conjunction with immediate and continuous reductions in emissions of CO₂, is the only way to stabilize global warming below 2°C. Accordingly, California has signed a number of agreements to work together with other countries, including China and Mexico, to support actions to fight climate change and cut air pollution. Additionally, California is bringing together subnational jurisdictions under the Subnational Global Climate Leadership Memorandum of Understanding (the "Under 2 MOU"), which commits signatories to take steps to reduce SLCP and CO₂ emissions and meet the goal of keeping global average warming below the 2°C threshold by reducing their GHG emissions to under 2 metric tons per capita, or 80–95 percent below 1990 levels, by 2050. To date, a total of 127 jurisdictions have signed or endorsed the Under 2 MOU, collectively representing more than 729 million people and \$20.4 trillion in GDP, equivalent to more than a quarter of the global economy. If the signatories represented a single country, it would be the second largest economy in the world behind only the United States. As it implements the actions identified in this Proposed Strategy and other related climate change planning efforts, California will continue to share its successes and approach with others, to expand action to address climate change and deliver local and global benefits for the State.

I. Introduction: Showing the Way to 2°C

California must achieve deep reductions in short-lived climate pollutant (SLCP) emissions by 2030 to help avoid the worst impacts of climate change and meet air quality goals. Additionally, intensified, global action to reduce these emissions is the only practical way to immediately slow global warming and is necessary to keep warming below 2°C through at least 2050, which is a critical threshold to manage the damaging effects of climate change. A broad scientific consensus has emerged, based on extensive research, that a 2°C (3.6°F) increase in global average temperature above pre-industrial levels poses severe risks to natural systems and human health and well-being. This is an increase of only 1.1°C (2.0°F) above the present level. Even a slight increase in global warming would lead to significant sea level rise, and the overall impact from climate change would be substantially greater if global warming exceeds 2°C. Strong, near-term action to cut emissions of SLCPs, in conjunction with immediate and continuous reductions in emissions of carbon dioxide (CO₂), is the only way to stabilize global warming below 2°C.

In December 2015, at the 21st Conference of Parties (COP21), 25,000 delegates from 196 countries gathered recognizing that “climate change represents an urgent and potentially irreversible threat to human societies and the planet and thus requires the widest possible cooperation by all countries, and their participation in an effective and appropriate international response, with a view to accelerating the reduction of global greenhouse gas emissions.” An agreement was reached to substantially reduce GHG emissions with the aim of limiting a global temperature increase to below 2°C, mobilize investments to support low-carbon development, and create a pathway for long-term de-carbonization. Additionally, the agreement aims to strengthen the ability to deal with the impacts of climate change.

Short-lived climate pollutants, including methane (CH₄), black carbon (soot), and fluorinated gases (F-gases, including hydrofluorocarbons, or HFCs), are among the most harmful to both human health and global climate. They are powerful climate forcers that remain in the atmosphere for a much shorter period of time than longer-lived climate pollutants, including CO₂, which is the primary driver of climate change. Their relative climate forcing, when measured in terms of how they heat the atmosphere, can be tens, hundreds, or even thousands of times greater than that of CO₂. Short-lived climate pollutants contribute about 40 percent to current anthropogenic global radiative forcing, which is the primary forcing agent for observed climate change.^{1,2,3,4,5}

¹ Calculation based on [IPCC AR5 WGI Chapter 8. https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf](https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf)

² Ramanathan V, Xu Y. The Copenhagen Accord for limiting global warming: criteria, constraints, and available avenues. *Proceedings of the National Academy of Sciences of the United States of America*. 2010;107 (18):8055–8062. [\[PMC free article\]](#)

³ IGSD (2013) *Primer on Short-Lived Climate Pollutants*, Institute for Governance and Sustainable Development, February 2013. <http://igsd.org/documents/PrimeronShort-LivedClimatePollutantsFeb192013.pdf>

California has taken significant steps to reduce SLCP emissions, especially black carbon from transportation, methane from oil and gas operations and landfill emissions, and HFC emissions from refrigerants, insulating foams, and aerosol propellants. Still, more can and must be done to reduce emissions from these and other sources in the State, including methane from waste management and dairies, black carbon from off-road and non-mobile sources, and HFC emissions from refrigeration and air conditioning systems.

The State is committed to further reducing SLCP emissions. SLCP emission reductions are important, first of all, to continuing and maintaining the GHG emission reductions called for by AB 32, and to ensuring emissions meet the statewide GHG emission limit it established. The Proposed Strategy is identified in the First Update to the Climate Change Scoping Plan as one of the recommended actions to achieve additional GHG emission reductions. Growing SLCP emissions (such as from fluorinated gases) threaten to erode the State's progress towards this limit; in other sectors (such as from oil and gas and agriculture) continued emissions will put increased pressure on the remainder of ARB's regulatory structure to maintain overall emissions below the GHG limit and to continue reductions. Conversely, addressing SLCP emissions will help to ensure that the AB 32 limit is maintained, and will fulfill AB 32's mandate to continue to seek the maximum technologically feasible and cost-effective reductions of GHG emissions. Reducing these powerful climate-forcers early also produces a compound-interest effect through which the effectiveness of future reductions are magnified: those future reductions start from a baseline substantially lower than where they would have started in the absence of aggressive early reduction efforts.

The Legislature directly recognized the critical role that SLCPs must play in the State's climate efforts with the passage of Senate Bill 605 (Lara, Chapter 523, Statutes of 2014), which requires the Air Resources Board (ARB or Board) to develop a strategy by the end of 2015 to reduce SLCP emissions. In his 2015 Inaugural Address, Governor Brown reinforced this commitment and called on California to show the world the path to limiting global warming below 2°C through 2050, while highlighting the role that action to cut SLCPs must play in this effort. In April 2015, the Governor set a target for reducing overall GHG emissions to 40 percent below 1990 levels by 2030, which the actions identified in this report will support.

⁴ Akbar, Sameer; Ebinger, Jane; Kleiman, Gary; Oguah, Samuel. 2013. *Integration of short-lived climate pollutants in World Bank activities: a report prepared at the request of the G8*. Washington DC ; World Bank. <http://documents.worldbank.org/curated/en/2013/06/18119798/integration-short-lived-climate-pollutants-world-bank-activities-report-prepared-request-g8>
web.stanford.edu/group/efmh/jacobson/Articles/VIII/BCCLimRespJGR0710.pdf

⁵ Molina M, Zaelke D, Sarma KM, Andersen SO, Ramanathan V, Kaniaru D. Reducing abrupt climate change risk using the Montreal Protocol and other regulatory actions to complement cuts in CO₂ emissions. *Proceedings of the National Academy of Sciences of the United States of America*. 2009;106(49):20616-20621. doi:10.1073/pnas.0902568106.
<http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2791591/>

Significant reductions in SLCP emissions can be achieved globally using cost-effective technologies and strategies, some of which have already been demonstrated effectively in California. Over the past several decades, the State's efforts in controlling these harmful emissions have prevented thousands of premature deaths in California, saved the State many tens of billions of dollars in energy and health costs, and have occurred alongside strong economic growth throughout our diverse economy. Applying California's experiences to reduce SLCP emissions globally would help prevent millions of premature deaths each year; boost agricultural productivity; limit disruption of historic rainfall patterns; slow the melting of glaciers, snowpack, and sea ice; reduce sea level rise; and provide trillions of dollars in economic benefits each year.

A. Significant Benefits from Accelerated Action to Cut SLCP Emissions

While reducing CO₂ emissions limits climate change over the long term, reducing emissions of SLCPs will effectively slow the rate of climate change in the near-term. Therefore, the best path forward is to emphasize parallel strategies for reducing SLCP and CO₂ emissions.^{6,7} Studies indicate that available technologies, if universally adopted, can effectively reduce global methane emissions an estimated 40 percent and black carbon an estimated 80 percent below 1990 levels by 2030.⁸ Additionally, a new proposed global phase down of HFCs under the Montreal Protocol (if adopted) and other efforts could cut the expected production of HFCs by up to 70 percent by 2030, and up to 85 percent by 2035.^{9,10}

Achieving this scale of global reductions would deliver significant climate benefits. It would cut the expected rate of global warming in half by 2050, slowing global temperature rise by about 0.6°C,^{11,12} which would reduce the risk of dangerous climate

⁶ Shoemaker, J K; Schrag, D P; Molina, M J; Ramanathan, V (2013) What Role for Short-Lived Climate Pollutants in Mitigation Policy? *Science* 342 (6164) 1323-1324

⁷ Rogelj, J, Schaeffer M, Meinshausen M, Shindell D, Hare W, Klimont Z, Velders G, Amann M, Schellnhuber HJ. 2014. Disentangling the effects of CO₂ and short-lived climate forcer mitigation. *Proceedings of the National Academy of Sciences (PNAS)*.

<http://www.pnas.org/cgi/doi/10.1073/pnas.1415631111>

⁸ UNEP (2014) Time to Act (To Reduce Short-Lived Climate Pollutants), The Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, United Nations Environment Programme, Second Edition, May. <http://www.unep.org/ccac/Publications/Publications/TimeToAct/tabid/133392/Default.aspx>

⁹ Velders et al (2009) The Large Contribution of Projected HFC Emissions to Future Climate Forcing, *Proceedings of the National Academies* 106 (27), 10949-10954.

www.pnas.org/cgi/doi/10.1073/pnas.0902817106

¹⁰ Velders et al (2014) "Growth of climate change commitments from HFC banks and emissions", G. J. M. Velders, S. Solomon, and J. S. Daniel. *Atmospheric Chemistry and Physics*, 14, 4563–4572, 2014. doi:10.5194/acp-14-4563-2014. www.atmos-chem-phys.net/14/4563/2014/.

¹¹ Ramanathan V, Xu Y. The Copenhagen Accord for limiting global warming: criteria, constraints, and available avenues. *Proceedings of the National Academy of Sciences of the United States of America*. 2010;107 (18):8055–8062. [\[PMC free article\]](#)

¹² UNEP (2014) Time to Act (To Reduce Short-Lived Climate Pollutants), The Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, United Nations Environment Programme, Second Edition, May. <http://www.unep.org/ccac/Publications/Publications/TimeToAct/tabid/133392/Default.aspx>

feedbacks such as accelerated Arctic melting and sea level rise.¹³ It would also increase the probability of staying below the 2°C threshold to more than 90 percent through 2050.^{14,15}

The benefits could be even greater in the Arctic, which is especially vulnerable to black carbon emissions and is warming twice as fast as the rest of the world.¹⁶ Slowing climate change impacts in the Arctic could be critically important for stabilizing climate change and its impacts, as the Arctic is an important driver of sea level rise and weather patterns throughout the Northern Hemisphere.^{17,18} Reducing emissions of SLCPs can slow down the rate of sea level rise by 24–50 percent this century, if efforts to reduce emissions begin now. Mitigating emissions of both CO₂ and SLCPs can reduce the projected sea level rise rate by 50–67 percent by 2100.¹⁹

Deploying existing, cost-effective technologies to reduce SLCP emissions can also cut global emissions of fine particulate matter (PM_{2.5}) by an estimated 50 percent, oxides of nitrogen (NO_x) emissions by 35 percent, and carbon monoxide (CO) emissions by 60 percent.²⁰ If these measures were fully in place by 2030, an estimated 3.5 million premature deaths and 53 million metric tons of crop losses could be avoided globally, each year. The economic value of these climate, crop, and health benefits is estimated to be about \$5.9 trillion annually.²¹ Most of these benefits would accrue in the developing world and places where disproportionate climate impacts are already being felt.

Many of the benefits of cutting SLCP emissions in California will accrue in the most disadvantaged parts of the State, where pollution levels and their health impacts are

¹³ UNEP and WMO (2011) Integrated Assessment of Black Carbon and Tropospheric Ozone, United Nations Environment Programme and World Meteorological Association.

http://www.unep.org/dewa/Portals/67/pdf/BlackCarbon_report.pdf

¹⁴ Ramanathan, V. and Yangyang Xu (2010) The Copenhagen Accord for Limiting Global Warming: Criteria, Constraints, and Available Avenues, *Proceedings of the National Academies of Sciences* **107** (18), pp.8055-8062. <http://www.pnas.org/content/107/18/8055>

¹⁵ Xu, Y., D. Zaelke, G. J. M. Velders, and V. Ramanathan (2013), [The role of HFCs in mitigating 21st century climate change](https://doi.org/10.1021/climate1869), *Atmos. Chem. Phys.*, **13**(12), 6083–6089

¹⁶ Quinn et al (2008) Short-lived pollutants in the Arctic: Their impact and possible mitigation strategies, *Atmospheric Chemistry and Physics* **8**, 1723-1735. <http://www.atmos-chem-phys.net/8/1723/2008/acp-8-1723-2008.html>

¹⁷ Francis, J. A. and S. J. Vavrus. 2012. Evidence linking Arctic amplification to extreme weather in mid-latitudes. *Geophysical Research Letters* **39**.

¹⁸ Screen, J. A. and I. Simmonds. 2013. Exploring links between Arctic amplification and mid-latitude weather. *Geophysical Research Letters* **40**(5):959-964.

¹⁹ Hu, A., Y. Xu, C. Tebaldi, W. M. Washington, and V. Ramanathan (2013), [Mitigation of short-lived climate pollutants slows sea-level rise](https://doi.org/10.1038/nclimate1869) *Nature Climate Change* **3**(5), 1–5, doi:10.1038/nclimate1869

²⁰ UNEP and WMO (2011) Integrated Assessment of Black Carbon and Tropospheric Ozone, United Nations Environment Programme and World Meteorological Association.

http://www.unep.org/dewa/Portals/67/pdf/BlackCarbon_report.pdf

²¹ Shindell et al. (2012) Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security, *Science* **335**, 183 (2012). <http://www.sciencemag.org/content/335/6065/183>

often highest, and where further economic development may be most needed. For example:

- Further cutting black carbon emissions from the transportation sector and building a sustainable freight system would have health and economic benefits for communities in the East Bay, Southern California, and the Inland Empire along freight corridors and near ports and railyards where diesel particulate matter concentrations are highest.
- Investments to cut methane and black carbon emissions as part of an integrated strategy to reduce emissions from agriculture and waste can provide important benefits for the Central Valley and other agricultural communities. They can help build an increasingly resilient and competitive agricultural sector by supporting jobs and economic growth, healthy soils, and improved air quality, water quality, and public health in those communities.
- Improving management and health of forests and rural landscapes to sustainably sequester carbon and mitigate black carbon emissions from wildfires can help bring investment, economic, and climate resiliency benefits throughout the Sierra, the North Coast, and other rural parts of California.
- Switching to low-GWP refrigerants can also improve the energy efficiency of refrigeration and air conditioning equipment, which can help to cut electricity bills throughout the State.

B. Building on California's Air Quality and Climate Leadership

California's ongoing efforts to improve air quality and address climate change have already led to important reductions in SLCP emissions, and they provide a strong foundation to support further efforts to reduce emissions of these dangerous pollutants.

- *Black carbon:* California has cut anthropogenic sources of black carbon emissions by more than 90 percent since the 1960s. From 2000 to 2020, California will have cut black carbon from mobile sources by 75 percent. These efforts prevent an estimated 5,000 premature deaths in the State each year, and deliver important climate benefits. If the world replicated this success, it would slow global warming by an estimated 15 percent,²² essentially offsetting one to two decades' worth of CO₂ emissions.²³
- *Methane:* California has the nation's strongest standards for limiting methane emissions from landfills, has offset protocols under our Cap-and-Trade program to encourage the reduction of methane emissions, and has rules under development and being implemented to create a comprehensive approach to limit methane leaks from the oil and gas production, processing, and storage

²² Ramanathan et al (2013) Black Carbon and the Regional Climate of California, Report to the California Air Resources Board, Contract 08-323, April 15. http://www.arb.ca.gov/research/single-project.php?row_id=64841

²³ Wallack, J. and Veerabhadran Ramanathan (2009) The Other Climate Changers: Why Black Carbon and Ozone Also Matter, *Foreign Affairs*, September/October 2009, pp. 105-113. <https://www.foreignaffairs.com/articles/2009-09-01/other-climate-changers>

sector, and the natural gas pipeline system. These efforts are serving to keep methane emissions fairly steady in the State.

- *HFCs*: The State has regulations in place to reduce emissions from refrigerants, motor vehicle air-conditioning, and consumer products that together will cut emissions of HFCs by 25 percent below otherwise projected levels in 2020.

Still, more remains to be done. California is home to some of the highest levels of air pollution in the country, and although the State has substantially reduced particulate matter and black carbon emissions from on-road transportation, vehicles still pollute the air in our communities and harm the lungs of some of our most vulnerable populations. Global methane emissions are responsible for about 20 percent of current global warming,²⁴ and its emissions continue to increase. F-gases, specifically HFCs, are the fastest growing source of GHG emissions in California and globally.

C. Purpose of SLCP Reduction Strategy

The State is committed to further reducing SLCP emissions. The 2014 Update to the Climate Change Scoping Plan (2014 Scoping Plan Update) identified SLCPs as an important aspect of a comprehensive approach to addressing climate change. Senate Bill 605 (Lara, Chapter 523, Statutes of 2014) requires ARB to develop a plan to reduce emissions of SLCPs. Additionally, Governor Brown has identified reductions of SLCP emissions as one of “five pillars” to meet an overarching goal to reduce California’s GHG emissions by 40 percent below 1990 levels by 2030. Senate Bill 605 (Lara, Chapter 523, Statutes of 2014), requires ARB to develop a comprehensive strategy to reduce emissions of SLCPs in the State, and in developing the strategy to:

- Complete an inventory of sources and emissions of SLCPs in the State based on available data;
- Identify research needs to address any data gaps;
- Identify existing and potential new control measures to reduce emissions;
- Prioritize the development of new measures for SLCPs that offer co-benefits by improving water quality or reducing other air pollutants that impact community health and benefit disadvantaged communities, as identified pursuant to California Health and Safety Code Section 39711;
- Coordinate with other State agencies and air districts to develop and implement measures identified as part of the comprehensive strategy;
- Consult with experts in academia, industry, and the community on SLCPs. The topics shall include, but not be limited to, all of the following:
 - Assessment of the current status of controls that directly or indirectly reduce emissions of SLCPs in the State.
 - Identification of opportunities and challenges for controlling emissions.
 - Recommendations to further reduce emissions; and
- Hold at least one public workshop during the development of the strategy.

²⁴ Kirschke, S. *et al.* (2013) Three decades of global methane sources and sinks. *Nature Geosci.* **6**, 813–823. http://www.nature.com/ngeo/journal/v6/n10/full/ngeo1955.html?WT.ec_id=NGEO-201310

ARB developed this proposed SLCP Reduction Strategy report (Proposed Strategy) pursuant to SB 605, in coordination with other State agencies and local air quality management and air pollution control districts. The Proposed Strategy has been developed with input from interested stakeholders in an open and public process and describes a proposed strategy for California to reduce emissions of SLCPs through 2030. It describes ongoing and potential new measures to reduce SLCP emissions from all major sources in the State, and describes current and future research needs for improving the SLCP emission inventory and better understanding potential mitigation measures. California's SLCP emission inventory²⁵ and current and future research needs are included in Appendix A, and research efforts to evaluate potential mitigation measures for each SLCP is included in Appendix B. Measures included in the final SLCP Reduction Strategy would be developed under future public regulatory processes with the appropriate public process, economic analyses, environmental analyses, and consideration of environmental justice.

D. Achieving Science-Based Targets

This Proposed Strategy is designed to meet planning targets of reducing methane and HFC emissions by 40 percent below current (2013) levels by 2030, and black carbon emissions by 50 percent below current levels by 2030. The targets are translated into millions of metric tonnes of CO₂-equivalent (MMTCo₂e) in Table 3. These proposed targets are in-line with science-based assessments of reductions needed globally to limit warming below 2°C through at least 2050, as well as efforts needed in California to reduce overall GHG emissions by 40 percent below 1990 levels by 2030.

Table 3: California SLCP Emissions and Proposed Target Emission Levels (MMTCo₂e)*

| Pollutant | Inventory 2013 | Forecast** 2030 | Targets 2030 |
|--------------------|----------------|-----------------|--------------|
| Black Carbon*** | 38 | 26 | 19 |
| Methane | 118 | 117 | 71 |
| Hydrofluorocarbons | 40 | 65 | 24 |

*Using 20-year Global Warming Potentials and AR4 except Black Carbon, which uses AR5 (the first report to define a GWP for black carbon)

**Includes reductions from implementation of current regulations

***All non-forest sources

These targets are not binding, but provide important indices against which to measure the State's progress to reduce SLCP emissions. California efforts to reduce SLCP emissions, consistent with these targets, are important to further the purposes of AB 32, whose requirements charge ARB with reaching and maintaining the statewide GHG limit, as well as taking steps to continue reductions. Several Executive Orders (EO), including Governor Brown's EO B-30-15, further charge ARB with continuing and

²⁵ Inventory methodology and detailed inventory tables available at: <http://www.arb.ca.gov/cc/inventory/slcp/slcp.htm>

maintaining emission reductions. The measures identified in this Proposed Strategy and their expected emission reductions will feed into the update to the Climate Change Scoping Plan that is currently being developed pursuant to EO B-30-15. The 2030 Target Scoping Plan Update will establish a broad framework for meeting all of California's climate-related targets and will include an evaluation of all proposed GHG reducing activities, for both short-lived and longer-lived pollutants.

Throughout this Proposed Strategy, there is an emphasis on early actions, often supported by public investments and strong policy incentives. This approach is intended to achieve earlier reductions (in the 2020 timeframe), bring projects online quickly, and help scale sector-wide solutions while potential regulatory or other measures to reduce SLCP emissions are developed. By supporting early action through investments and commitments to overcome barriers, we can maximize benefits throughout California, while minimizing the impact of future regulations on businesses in these sectors.

Together with California's previous efforts to successfully reduce black carbon and other SLCP emissions, implementing the measures identified in this Proposed Strategy to meet these targets would put California on the path to meet the Governor's 2030 climate goals, while delivering significant agricultural, air quality, economic, health, water, and other climate co-benefits.

E. Coordinating Research Efforts Related to SLCPs

Many California State agencies sponsor climate-related research. State-sponsored climate research, including research related to SLCPs, has been guided by the needs identified in state laws, Executive Orders, and other policy documents, as well as the best and latest science.

Since 2008, the Climate Action Team Research Working Group (CATRWG) has provided a forum for State agencies to discuss and coordinate their proposed research activities. The CATRWG also facilitates coordination with external groups including academia, federal agencies, the international community, and private entities. Integration and coordination with non-state sponsored research programs is important to leverage State resources and to provide coherent and practical research results for California.



To support these efforts, the CATRWG has created a catalog of relevant research projects supported by the State since the early 2000s.²⁶ The catalog keeps State agencies and interested stakeholders informed about the range of activities and the status of individual projects. The catalog includes a number of projects related to the impacts of SLCPs on regional climate in California, research underway to enhance SLCP inventories, and evaluations of SLCP mitigation strategies.

In 2015, the CATRWG released a Climate Change Research Plan for California.²⁷ The Plan synthesizes the knowledge gaps, and presents research priorities for the next three to five years for policy-relevant, California-specific research. It includes research needs related to the mitigation of SLCPs and specific needs to improve SLCP inventories. The Plan outlines these research needs in order to inform the State's ongoing activities without duplicating federal research activities. This is an unprecedented effort resulting in the first comprehensive climate change research plan developed by any state. The CATRWG will update the Plan every other year, with major revisions every four years. Research related to SLCPs will continue to be a priority in these updates.

Future State-sponsored research will be guided by recommendations in the CATRWG Research Plan, as well as other documents such as the SLCP Reduction Strategy. State agencies will continue to leverage funding and avoid duplication of effort through coordination in CATRWG meetings. State agencies that sponsor research will also continue their individual efforts to align future research needs with input from stakeholders, academic experts and other public and private research entities.

F. Process for Developing the SLCP Reduction Strategy

This Proposed Strategy was developed with input from State and local agencies, academic experts, a working group of agricultural experts and farmers convened by CDFA, and other interested stakeholders in an open and public process. ARB and State agencies collaborated to identify reduction measures for specific sectors, including the dairy, wastewater, and waste sectors. In addition, ARB collaborated with the local air districts to identify SLCP emission reduction measures that could be implemented through district action. The Proposed Strategy will be further refined based on stakeholder input.

In May 2015, ARB released for public review, a Concept Paper to initiate discussion on the



²⁶ California's State-sponsored Research Catalog: <http://cal-adapt.org/research/>

²⁷ Climate Change Research Plan for California (2015) http://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf

development of this Proposed Strategy.²⁸ The paper described initial ideas to be explored as the Strategy was developed, and sought to elicit new ideas and refinement of current measures to reduce emissions of SLCPs throughout the State. The Concept Paper was presented at a public meeting later in May, to solicit public input. After consideration of comments received, staff developed a Draft SLCP Reduction Strategy,²⁹ which was released for public comment on September 30, 2015. Comments received on the Draft Strategy are posted at:

<http://www.arb.ca.gov/lispub/comm2/bccommlog.php?listname=slcpdraftstrategy-ws>

ARB held workshops in October 2015 to solicit comments on the Draft Strategy, including comments related to the development of a California Environmental Quality Act (CEQA) document. After consideration of public comments received, ARB developed this Proposed Strategy and an accompanying draft Environmental Analysis (Appendix C). Additional workshops will be held to solicit comments on this Proposed Strategy, before it is presented to the Board in May 2016. Staff will present the final proposed SLCP Reduction Strategy, the final EA, and written responses to comments received on the EA to the Board for consideration at a public hearing in fall 2016.

²⁸ http://www.arb.ca.gov/cc/shortlived/concept_paper.pdf

²⁹ <http://www.arb.ca.gov/cc/shortlived/2015draft.pdf>

II. California's Approach to Reducing SLCP Emissions

The 2014 Scoping Plan Update described California's approach to climate change as one reliant on science and foundational research. The Update focused on: preserving natural resources that provide for our economy and define our lifestyle in California, fostering resilient economic growth throughout the State, improving public health, and supporting economic, social and environmental justice. The State's commitment to addressing climate change and public health is born of necessity, but provides tremendous opportunity to build competitiveness and resilience into our communities, resources, and economy. We understand that steps we take to reduce emissions and strengthen our State against the impacts of climate change provide economic opportunities today, and untether our future potential from limits imposed by resource constraints and pollution.

This approach continues to guide us as we focus on reducing emissions of SLCPs to meet science-based targets in this Proposed Strategy. Additionally, California's approach to reducing SLCP emissions is framed by the principles described below.

A. Prioritize Actions with Diverse Benefits

The direct benefits of cutting SLCP emissions will be immediately tangible, and can be substantial. As part of an integrated strategy to not only reduce emissions of SLCPs, but also to develop renewable sources of energy and strengthen the competitiveness and resiliency of our agricultural, waste, and other sectors, they can deliver even greater benefits, including:

- Reduced asthma risk, hospitalization, premature death, and associated medical costs from air pollution, especially in disadvantaged communities;
- Reduced global and localized climate change impacts, including sea level rise and disrupted precipitation patterns, and associated costs;
- Reduced crop losses from air pollution;
- Healthier forests, wildlife habitats, and watersheds;
- Healthy soils that are more sustainable and resilient to climate change, sequester GHGs, require less synthetic amendments, and improve water retention;
- The creation of a new industry, mostly in rural parts of the State and the Central Valley, around utilizing organic waste streams to generate renewable energy, fuels, and compost—bringing billions in investment; and
- Stronger agricultural and freight sectors that are well positioned to continue competing globally and growing as a source of jobs and economic development in California.

Clearly, there are a number of drivers and benefits to reducing SLCP emissions that extend beyond mitigating the impacts of climate change. The measures identified in this Proposed Strategy are intended to provide a wide array of climate, health, and economic benefits throughout the State. As they are further developed and implemented, a key focus will be to provide and maximize multiple benefits.

B. Put Organic Waste to Beneficial Use

California's organic waste streams are responsible for half of the State's methane emissions and represent a valuable energy and soil-enhancing resource. Effectively implementing the measures described in this Proposed Strategy will not only reduce methane emissions but provide many other benefits as well, including cutting emissions of CO₂ and boosting economic growth in agricultural and rural communities.

Building infrastructure to better manage organic waste streams could lead to billions of dollars of investment and thousands of jobs in the State.^{30,31} This infrastructure could provide valuable new sources of renewable electricity or biogas, clean transportation fuels, compost other beneficial soil amendments, and other products. Adopting state policies to promote biogas from organic waste would provide a strong durable market signal to industry, agencies, and investors. In addition, this biogas can help the State meet its 33 percent renewable mandate for hydrogen transportation fuel. The State's new 50 percent renewable portfolio standard may drive renewable hydrogen production even higher. Collectively, products from organic waste streams in California, and potential environmental credits from them, could represent a market worth billions of dollars in California.

Utilizing clean technologies to put organic waste streams to a beneficial use can also serve to improve regional air and water quality and support economic growth in



agricultural and other communities throughout the State. For example, most dairies in California currently store manure in uncovered lagoons and use lagoon water to fertilize on-site forage crops. This approach to managing manure has helped to improve the efficiency of dairy farms and milk production over the years. However, these lagoons also create one of the largest sources of methane emissions in the

State, and—when combined with imprecise or improper land application of nutrients, water, and salts via flood irrigation of lagoon effluent—can create adverse groundwater

³⁰ Kaffka et al (2011) Economic, Social, and Environmental Effects of Current and Near-term Biomass Use in California, California Biomass Collaborative, University of California, Davis.

<http://biomass.ucdavis.edu/publications/>

³¹ Due to its large dairy industry, California likely represents more than its share of the estimated 11,000 potential new biogas systems that could be built in the U.S. and the associated \$33 billion in capital deployment, 275,000 short-term construction jobs, and 18,000 permanent jobs.

USDA, USEPA, USDOE (2014) Biogas Opportunities Roadmap: Voluntary Actions to Reduce Methane Emissions and Increase Energy Independence.

http://www.usda.gov/oce/reports/energy/Biogas_Opportunities_Roadmap_8-1-14.pdf

and nutrient management issues on farms. Alternatively, manure can be managed in a way to reduce or avoid methane emissions and open up opportunities for improving farm nutrient management activities.

In order to capture the entire potential value from California's waste resources, significant amounts of infrastructure remain to be built and markets must be fully enabled. Barriers remain to achieving these wide-ranging economic and environmental benefits, and must be addressed.

C. Identify Practical Solutions to Overcome Barriers

Maximizing the diverse benefits of putting organic waste streams to beneficial uses will require overcoming barriers that have hindered such efforts in the past. Barriers affect many parts of the supply and marketing chain, including feedstock, technology, market/economics, permitting, technical feasibility, infrastructure, logistics, and user behavior.

For example, inexpensive and abundant landfill capacity may make diverting organic material relatively costly in some cases. Developing projects to generate renewable energy and soil amendments from this waste stream will require additional investments in clean technology and management practices, aligning economic incentives that currently favor landfilling with the State's objectives to put organic resources to better use, and streamlining various governmental and utility permitting processes.

Technology or market barriers also remain in some sectors. Interconnecting distributed sources of renewable energy onto the electricity grid, or biogas into pipelines, remains an unnecessarily long and costly process in many cases. Utilizing biogas in a conventional combustion engine to create electricity can exacerbate air quality problems in many parts of the State, including the Central Valley and Southern California. Clean engine and fuel options, or low-GWP refrigerants, are not available for all applications. Markets for compost and soil amendments need to be built out and strengthened, which would provide an important value stream for financing anaerobic digestion and compost facilities. Additional support and time may be needed to strengthen existing and emerging markets for renewable natural gas and fuels, soil amendments, and their associated environmental attributes.

But these barriers are not insurmountable. As California develops a SLCP Strategy to reduce SLCP emissions and plans to meet its climate and air quality goals for 2030, now is the time to solve them. This Proposed Strategy identifies strategies and funding mechanisms to encourage the use of the cleanest technologies to advance the State's air quality, water quality, climate change, and other environmental objectives. Solutions that address several environmental concerns—air quality, climate, and water quality—and can be easily financed, are clear winners.

Several existing programs already provide incentives to convert waste streams to various forms of energy, which can be leveraged along with new efforts to increase the

share of renewable biogas used in California buildings, industry, and transportation. For example, the Low Carbon Fuel Standard (LCFS) and federal Renewable Fuel Standard provide strong economic incentives to utilize organic waste resources for production of transportation fuels. At current LCFS and RIN credit prices, anaerobic digestion projects that generate transportation fuels at dairies, wastewater treatment plants, or elsewhere can be profitable (see Chapter VIII). In order to enable this market, however, barriers to pipeline injection of biogas, among others, must be addressed. The CPUC has authorized an incentive program, capped at \$40 million, to offset half of renewable natural gas interconnection costs, up to \$1.5 million per project. State agencies are already collaborating to overcome barriers to pipeline injection of biogas, pursuant to the Governor's call to make heating fuels cleaner,³² and they will redouble their efforts. This includes monitoring market progress pursuant to Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) and considering appropriate adjustments, as needed. Also, supplemental policy options to accelerate biogas projects and access to the pipeline will be considered, including steps that utilities can take, options to accommodate varying heat rates of pipeline gas in certain instances, and potential new policies like a feed-in-tariff for renewable natural gas.

Building market certainty and value for compost and other soil amendment products will also help to secure financing for projects to use organic waste and cut emissions of SLCPs. Soil amendments from organic waste streams in California represent a potential \$200-400 million market in California, exceeding the likely value of energy products from the resource.³³ Efforts to increase composting and anaerobic digestion—



and capture the diverse benefits from doing so—can be supported by efforts to promote and account for the benefits of using compost, manure, and other soil amendments that come from these processes. ARB is coordinating with CDFA and other agencies working on the Healthy Soils Initiative to identify additional research needs to inform the science and accounting methods necessary to quantify the benefits of using compost and other soil amendments and address any potential problems such as buildup of salts or heavy metals in soil. Collaboration among state agencies, water districts, and local governments will help quantify the benefits of using compost for urban storm water management, soil remediation, water conservation, and other beneficial uses.

³² <https://www.gov.ca.gov/news.php?id=18828>

³³ Informa Economics (2013) National Market Value of Anaerobic Digester Products, Prepared for the Innovation Center for U.S. Dairy, February.

D. Invest in SLCP Emission Reductions and Communities

Achieving significant reductions in SLCPs will require substantial investments to provide incentives and direct funding for priority sectors, sources, and technologies. Public investments should be smart and strategic, to leverage private investment and accelerate market transitions to cleaner technologies that foster significant system-wide solutions to cut emissions of SLCPs, maximize resource recovery from organic waste streams, and provide economic and health benefits in agricultural, disadvantaged, and rural parts of the State. Examples may include targeted support to reduce emissions of SLCPs and CO₂ through integrated strategies at dairies and in organic waste management; throughout the freight system; in commercial refrigeration applications; and from the management of woody waste materials in the urban, agricultural and forestry sectors.

Many of the sources and sectors responsible for SLCP emissions are concentrated in communities with high levels of pollution or unemployment, which could especially benefit from targeted investments to improve public health and boost economic growth. These include SLCP emissions from sources of organic waste and dairies in the Central Valley; ports and freight corridors in the East Bay, Los Angeles area and Inland Empire; and oil production, landfills and other sources of SLCP emissions throughout the State. Many communities in these areas, along with forested and rural communities in the northern part of the State and the Sierra, have some of the worst pollution burdens in the State, and high rates of poverty and unemployment. They are also where many billions of dollars in public and private investment will accrue in the coming years to reduce SLCP and CO₂ emissions and strengthen our agricultural sector, build sustainable freight systems, and grow healthy forests.

Initial estimates regarding State support for infrastructure to meet the goals identified in this Proposed Strategy is similar for both the waste sector and dairy sector. CalRecycle and CDFA both estimate that direct investments or incentives on the order of \$100 million per year for five years could significantly scale project development to cut SLCP emissions associated with dairy manure and waste management. There could also be some opportunity to optimize investments and co-locate infrastructure or utilize existing infrastructure, including excess digestion capacity that exists at many wastewater treatment plants, which could potentially reduce the level of incentive funding needed to reach the targets outlined in this Proposed Strategy. Additional research and working group efforts will focus on opportunities to optimize infrastructure rollout and maximize benefit from any State investment.

The State will need to continue coordinating and utilizing funding sources, such as the Greenhouse Gas Reduction Fund (Cap-and-Trade auction proceeds),³⁴ the Alternative and Renewable Fuel and Vehicle Technology Program (AB 118), Electric Program Investment Charge (EPIC) Program, Carl Moyer program, Air Quality Improvement

³⁴ AB 1532 (Pérez, Chapter 807), SB 535 (De León, Chapter 830), and SB 1018 (Senate Budget Committee, Chapter 39) established the GHG Reduction Fund to receive Cap-and-Trade auction proceeds.

Program, and Proposition 39 to expand clean energy investments in California and further reduce emissions of SLCPs and other GHGs. Additionally, programs including the Bioenergy Feed-In Tariff, created by Senate Bill 1122 (Rubio, Chapter 612, Statutes of 2012), Low Carbon Fuel Standard, Cap-and-Trade, Self-Generation Incentive Program, Federal Renewable Fuel Standard, utility incentives pursuant to Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012), and others provide important market signals and potential revenue streams to support projects to reduce SLCP emissions. These programs are described in more detail in Chapter VII.

Potential new funding mechanisms and incentive structures must also be considered. These could include adjusting the waste disposal tipping fee structure to account for the full cost of managing organic materials and landfills, state procurement contracts for renewable natural gas and other fuels in buildings or vehicles as well as for compost and mulch products in landscaping and erosion control, or labeling programs to recognize leading companies in the market place, including those producing milk with low levels of dairy methane emissions or freight haulers using clean technologies.

E. Advance the Science of SLCP Sources and Emissions

Data related to SLCPs and their sources is often less available or of lower quality than it is for CO₂. One reason is that energy-related emissions of CO₂ are often easier to quantify than emissions of other GHGs, which may form through complex biological or other processes where existing reporting guidelines and procedures may not apply. There has also been less of a focus on collecting additional data that could help to quantify GHG emissions from some non-CO₂ sources.



This Proposed Strategy, including Appendices A and B, describes several coordinated research efforts under way and potential new ones. To provide a better understanding of methane emissions from the natural gas system and natural gas and oil supplied to California, dairy operations, landfills, as well as various sources of HFCs and black carbon emissions, others not identified here also may be considered in the future.

For example, methane emissions are emitted from a wide range of biological processes and fugitive and area sources that make estimating emissions difficult. California's methane emission estimates are derived from a variety of surveys, government data sources, growth assumptions and modeling methodologies. ARB staff is continuously assessing ways to improve the methane inventory by incorporating the latest scientific understanding of methane sources, through coordinated research with other agencies, and by using the best available activity data. Additional research and improved data sources will be needed to continue to refine the methane inventory and provide California-specific activity data.

While improving data access and quality is not a prerequisite for many actions to reduce emissions of SLCPs, it is nonetheless important for informing ongoing efforts to reduce SLCP emissions and meet broader climate targets. Improved data and reliable GHG measurements from landfills, dairies, and other more difficult-to-measure sources would also be necessary before these sources could be potentially included in California's Cap-and-Trade Program. State agencies will continue to monitor technology development and support continued research to improve the accuracy and reliability of emissions accounting from these sources.

F. Need for Focused SLCP Programs

This Proposed Strategy outlines specific emission reduction measures that could reduce California's emissions of SLCPs. This reliance on direct regulations, in concert with the existing greenhouse gas Cap-and-Trade Program, is consistent with California's approach on addressing climate change. California has already adopted several direct measures that ensure GHG emission reductions are achieved in specific sectors, including for SLCPs (for example, the Refrigerant Management Program that regulates F-gas emissions). These types of requirements motivate focused change—such as increased deployment of renewable energy (Renewable Portfolio Standard) or transformation of transportation fuels (Low Carbon Fuel Standard)—which may be more readily realized through direct measures than sole reliance on the Cap-and-Trade Program.

The Cap-and-Trade Program covers combustion and process operations. These emissions can be measured according to the accuracy requirements of the Mandatory Greenhouse Gas Emissions Reporting Regulation, which includes accurate quantification methodologies that allow for consistent carbon costs,³⁵ and the sources align with those covered by federal reporting programs.³⁶ In contrast, most fugitive emissions³⁷ (a category into which SLCP emissions generally fall) do not meet these criteria.³⁸ They are frequently difficult to measure, measurements have high

³⁵ *California Air Resources Board (2011) California's Cap-and-Trade Program Final Statement of Reasons*, Response to Comment E-31, at pg. 425. available at <http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>.

³⁶ *Id.*, Response to Comment E-69, at pg. 448. available at <http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>.

³⁷ Fugitives from certain oil and gas sources are an exception because, unlike other fugitive emissions, they are possible to quantify with rigor.

³⁸ ARB's responses to comments in the 2011 Final Statement of Reasons for the Regulation and Western Climate Initiative design documentation provide detailed rationale for the treatment of fugitive emissions in specific sectors. For example, the quantification methods that are often used to quantify fugitive emissions, including calibrated bagging, high volume sampling, and a default emissions factor, only provide a snapshot of emissions rather than actual measurements of emissions from the source. See also Western Climate Initiative, Inc. (2010) WCI Comments on the Proposed Mandatory Reporting of GHG Emissions from Proposed Reporting for Oil and Gas Operations (Subpart W), at pg. 44. available at http://www.westernclimateinitiative.org/document-archives/func-download/258/chk,ab6041717dc1be9cd3430f4f7585cb8e/no_html,1/.

uncertainties,³⁹ measurement methods are often difficult and less precise,⁴⁰ and carbon costs are hard to assign with the same reliability as for combustion sources of CO₂.⁴¹ Because of these difficulties, and the importance of seeking SLCP-specific emission reductions, which the Cap-and-Trade Program is not designed to produce, this Proposed Strategy does not recommend expanding Cap-and-Trade Program coverage.⁴² Instead, the Proposed Strategy focuses on specific measures for SLCP-emitting sectors, consistent with the approach ARB adopted while developing the AB 32 Scoping Plan and Cap-and-Trade Program.

ARB notes that stakeholders have expressed divergent views on this basic approach as it relates to animal agriculture. On one hand, the Animal Legal Defense Fund has petitioned ARB to include emissions from that sector in the Cap-and-Trade Program. On the other hand, representatives of many environmental justice and environmental groups have argued that direct, sector-specific measures are preferable, as have representatives of the dairy industry. This Proposed Strategy focuses on direct measures, consistent with the necessity of reducing SLCP emissions from the dairy sector specifically, and in-line with the design principles that underlie the State's climate strategy and the Cap-and-Trade Regulation.⁴³

³⁹ Western Climate Initiative, Inc. (2010) WCI Comments on the Proposed Mandatory Reporting of GHG Emissions from Proposed Reporting for Oil and Gas Operations (Subpart W) at pg. 39. available at http://www.westernclimateinitiative.org/document-archives/func-download/258/chk.ab6041717dc1be9cd3430f4f7585cb8e/no_html,1/.

⁴⁰ California Air Resources Board (2011) California's Cap-and-Trade Program Final Statement of Reasons, Response to Comment E-69, pg. 430 and 448. available at <http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>.

⁴¹ *Id.*, Response to Comment E-31, at pg. 425. available at <http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>.

⁴² ARB considered this option in detail, however. Further discussion is available in the California Environmental Quality Act (CEQA) appendix to this Proposed Strategy (Appendix C).

⁴³ The Livestock Project Compliance Offset Protocol is one such more focused measure now in operation. It contrasts with the wholesale coverage of the sector by the Cap-and-Trade Program that some stakeholders suggest. This protocol, focused on encouraging sector-specific reductions, would not operate if facilities in the sector had compliance obligations in the Program. The protocol balances the need for clear quantification methodologies and regulatory program requirements and ensures any credited voluntary GHG emission reductions meet the AB 32 criteria. The quantification methods included in this protocol use conservative factors to ensure that only real emission reductions are eligible for issuance of compliance offset credit.

III. Latest Understanding of Science on SLCPs

Climate change is already beginning to transform life on Earth. Around the globe, seasons are shifting, temperatures are climbing and sea levels are rising. Continued emissions of GHGs will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of GHG emissions.

There is growing recognition within the scientific and policy communities that efforts to address climate change should focus not only on reducing CO₂ emissions, but also on reducing emissions of SLCPs. While reducing CO₂ emissions will limit total warming over the long-term, reducing emissions of SLCPs will effectively slow the near-term rate



of climate change. Therefore, the best path forward is to emphasize a coordinated strategy for simultaneous emission reductions for both SLCPs and CO₂,^{44,45} which is needed to keep average warming below 2°C this century.

Short-lived climate pollutants have atmospheric lifetimes on the order of a few days to a few decades, and their relative climate forcing impacts, when measured in terms of how they heat the atmosphere, can

be tens, hundreds, or even thousands of times greater than that of CO₂. Short-lived climate pollutants contribute about 40 percent to the current anthropogenic global radiative forcing, which is the primary forcing agent for observed climate change.

^{46,47,48,49,50}

⁴⁴ Shoemaker, J K; Schrag, D P; Molina, M J; Ramanathan, V (2013) What Role for Short-Lived Climate Pollutants in Mitigation Policy? *Science* 342 (6164) 1323-1324

⁴⁵ Rogelj, J, Schaeffer M, Meinshausen M, Shindell D, Hare W, Klimont Z, Velders G, Amann M, Schellnhuber HJ. 2014. Disentangling the effects of CO₂ and short-lived climate forcer mitigation. *Proceedings of the National Academy of Sciences (PNAS)*.

<http://www.pnas.org/cgi/doi/10.1073/pnas.1415631111>

⁴⁶ Calculation based on [IPCC AR5 WGI Chapter 8](https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf). https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

⁴⁷ Molina M, Zaelke D, Sarma KM, Andersen SO, Ramanathan V, Kaniaru D. (2009) Reducing abrupt climate change risk using the Montreal Protocol and other regulatory actions to complement cuts in CO₂ emissions. *Proceedings of the National Academy of Sciences of the United States of America*. 2009;106(49):20616-20621. doi:10.1073/pnas.0902568106.

<http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2791591/>

⁴⁸ Ramanathan V, Xu Y. (2010) The Copenhagen Accord for limiting global warming: criteria, constraints, and available avenues. *Proceedings of the National Academy of Sciences of the United States of America*. 2010;107 (18):8055–8062. [\[PMC free article\]](#)

⁴⁹ IGSD (2013) Primer on Short-Lived Climate Pollutants, Institute for Governance and Sustainable Development, February 2013.

<http://igsd.org/documents/PrimeronShort-LivedClimatePollutantsFeb192013.pdf>.

⁵⁰ Akbar, Sameer; Ebinger, Jane; Kleiman, Gary; Oguah, Samuel. (2013) *Integration of short-lived climate*

Co-Benefits of Reducing SLCPs

In addition to limiting climate change impacts already underway, SLCP emission reductions would reduce local air pollution and produce other co-benefits. The benefits could be even greater in the Arctic, which is especially vulnerable to black carbon emissions and is warming twice as fast as the rest of the world.⁵¹ This would be critically important for stabilizing climate change and its impacts, as the Arctic is an important driver of sea level rise and weather patterns throughout the Northern Hemisphere. Climate change in the Arctic potentially impacts drought in California and extreme snow and cold in the upper Midwest and New England, although such links have not been definitively proven.^{52,53} Accelerated warming in the Arctic could also lead to irreversible climate “tipping points,” such as the release of vast quantities of CO₂ and methane from melting permafrost.⁵⁴

In California, State and international action to reduce emissions of SLCPs can improve air quality and reduce related health risks. Other benefits to California include reducing damage to forests and crops, reducing background ozone and particulate levels to help meet federal air quality standards, and reducing disruption of historic rainfall patterns. California is working with a set of national and subnational partners throughout the world to fight air pollution and climate change, which will help deliver these benefits to our State while providing significant benefits where emission reductions occur.

Climate Impact

Global mean sea level will continue to rise during the twenty-first century, and the rate of sea level rise will exceed that observed during 1971 to 2010 due to increased ocean warming and increased loss of mass from glaciers and ice sheets.⁵⁵ A recent study raises the possibility of a more rapid rate of sea level rise in this century than forecast

pollutants in World Bank activities: a report prepared at the request of the G8. Washington DC; World Bank. http://www-wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/2013/08/19/000333037_20130819113818/Rendered/PDF/804810WP0G80Re00Box0379805B00OU090.pdf

⁵¹ Quinn et al (2008) Short-lived pollutants in the Arctic: Their impact and possible mitigation strategies, *Atmospheric Chemistry and Physics* **8**, 1723-1735. <http://www.atmos-chem-phys.net/8/1723/2008/acp-8-1723-2008.html>

⁵² Francis, J. A. and S. J. Vavrus. 2012. Evidence linking Arctic amplification to extreme weather in mid-latitudes. *Geophysical Research Letters* 39.

⁵³ Screen, J. A. and I. Simmonds (2013) Exploring links between Arctic amplification and mid-latitude weather. *Geophysical Research Letters* 40(5):959-964.

⁵⁴ Ramanathan V, Xu Y. The Copenhagen Accord for limiting global warming: criteria, constraints, and available avenues. *Proceedings of the National Academy of Sciences of the United States of America*. 2010;107 (18):8055–8062. [[PMC free article](#)].

⁵⁵ IPCC, 2013: Summary for Policymakers. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf.

by the U.N.'s Intergovernmental Panel on Climate Change (IPCC).⁵⁶ The authors conclude that 2° C global warming above the preindustrial level would spur ice shelf melt sufficient to cause a sea level rise of several meters. Sea level rise is an important impact of climate change on California due to the long coastline and large population that lives near coastal waters. Mitigating SLCP emissions can have significant benefits for slowing sea level rise, reducing the rate by 24-50 percent by 2100, if it begins now. Mitigating emissions of both CO₂ and SLCPs can reduce the projected rate of sea level rise by 50–67 percent by 2100.⁵⁷



Climate warming has intensified the recent drought in the southwestern U.S. as part of a trend toward enhanced drought that is projected to intensify through this century.⁵⁸ California droughts may be increasingly intensified due to declining availability of groundwater reserves. In the Central Valley, the current drought has cost California agriculture about \$2.7 billion and more than 20,000 jobs in 2015, and agriculture is expected to face more frequent drought.⁵⁹ The current California drought highlights the critical need for developing drought resilience, even if wet conditions mitigate the current drought.^{60,61}

Achieving Climate Stabilization

Scientific research indicates that an increase in the global average temperature of 2°C (3.6°F) above pre-industrial levels, which is only 1.1°C (2.0°F) above present levels, poses severe risks to natural systems and human health and well-being. Increased climate extremes, already apparent at present day climate warming (~0.9°C), will be

⁵⁶ Hansen, J., Sato, M., Hearty, P., Ruedy, R., Kelley, M., Masson-Delmotte, V., Russell, G., Tselioudis, G., Cao, J., Rignot, E., Velicogna, I., Kandiano, E., von Schuckmann, K., Kharecha, P., Legrande, A. N., Bauer, M., and Lo, K.-W. (2015) Ice melt, sea level rise and superstorms: evidence from paleoclimate data, climate modeling, and modern observations that 2 °C global warming is highly dangerous, *Atmos. Chem. Phys. Discuss.*, 15, 20059-20179, doi:10.5194/acpd-15-20059-2015, 2015. <http://www.atmos-chem-phys-discuss.net/15/20059/2015/acpd-15-20059-2015.html>

⁵⁷ Hu, A., Y. Xu, C. Tebaldi, W. M. Washington, and V. Ramanathan (2013), [Mitigation of short-lived climate pollutants slows sea-level rise *Nature Climate Change* 3\(5\), 1–5, doi:10.1038/nclimate1869](#)

⁵⁸ Cook, B. I., T. R. Ault, and J. E. Smerdon (2015), Unprecedented 21st century drought risk in the American Southwest and Central Plains, *Science Advances*, 1(1), e1400082, doi:10.1126/sciadv.1400082.

⁵⁹ Economic Analysis of the 2015 Drought for California Agriculture. <https://watershed.ucdavis.edu/droughtimpacts>

⁶⁰ Noah S. Diffenbaugh, N.S., D.L. Swain, and D. Touma (2015) Anthropogenic warming has increased drought risk in California *PNAS* 2015 112 (13) 3931-3936; published ahead of print March 2, 2015, doi:10.1073/pnas.1422385112. <http://www.pnas.org/content/112/13/3931.abstract>

⁶¹ A.P. Williams et al. (2015) Contribution of anthropogenic warming to California drought during 2012–2014. *Geophysical Research Letters*, 2015 DOI: [10.1002/2015GL064924](https://doi.org/10.1002/2015GL064924)

more severe. Studies indicate that available technologies, if universally adopted, can effectively reduce global methane emissions an estimated 40 percent and black carbon an estimated 80 percent below 1990 levels by 2030.⁶² Additionally, a new proposed global phase down of HFCs under the Montreal Protocol (if adopted) and other efforts could cut the expected production of HFCs by up to 70 percent by 2030, and up to 85 percent by 2035.^{63,64} Achieving this scale of global reductions would deliver significant climate benefits. It would cut the expected rate of global warming in half by 2050, slowing global temperature rise by about 0.6°C,^{65,66} which would reduce the risk of dangerous climate feedbacks such as accelerated Arctic melting and sea level rise.⁶⁷ It would also increase the probability of staying below the 2°C threshold to more than 90 percent through 2050.^{68,69}

Global Warming Potential

The IPCC developed the concept of global warming potential (GWP) as an index to evaluate the climate impacts of different GHGs, including SLCPs. This metric provides a comparison of the ability of each GHG to trap heat in the atmosphere relative to CO₂ over a specified time horizon. Global warming potentials account for the lifetime of different GHGs in the atmosphere, and the amount of energy they absorb on a per-kilogram basis, relative to CO₂, to represent the relative climate forcing of a kilogram of emissions when averaged over a time period of interest (for example, 20 years or 10 years). Current practice in most of the world for developing GHG emission inventories, including California's inventory, is to use GWP values from the 4th Assessment Report of the IPCC (AR4), which was released in 2007. For the first time, GWP estimates for black carbon are reported in the 5th Assessment Report of the IPCC (AR5), which includes the independent scientific assessment of black carbon

⁶² UNEP (2014) Time to Act (To Reduce Short-Lived Climate Pollutants), The Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, United Nations Environment Programme, Second Edition, May. <http://www.unep.org/ccac/Publications/Publications/TimeToAct/tabid/133392/Default.aspx>

⁶³ Velders et al (2009) The Large Contribution of Projected HFC Emissions to Future Climate Forcing, *Proceedings of the National Academies* 106 (27), 10949-10954. www.pnas.org/cgi/doi/10.1073/pnas.0902817106

⁶⁴ Velders et al (2014) "Growth of climate change commitments from HFC banks and emissions", G. J. M. Velders, S. Solomon, and J. S. Daniel. *Atmospheric Chemistry and Physics*, 14, 4563–4572, 2014. doi:10.5194/acp-14-4563-2014. www.atmos-chem-phys.net/14/4563/2014/.

⁶⁵ Ramanathan V, Xu Y. The Copenhagen Accord for limiting global warming: criteria, constraints, and available avenues. *Proceedings of the National Academy of Sciences of the United States of America*. 2010;107 (18):8055–8062. [\[PMC free article\]](#)

⁶⁶ UNEP (2014) Time to Act (To Reduce Short-Lived Climate Pollutants), The Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, United Nations Environment Programme, Second Edition, May. <http://www.unep.org/ccac/Publications/Publications/TimeToAct/tabid/133392/Default.aspx>

⁶⁷ UNEP and WMO (2011) Integrated Assessment of Black Carbon and Tropospheric Ozone, United Nations Environment Programme and World Meteorological Association. http://www.unep.org/dewa/Portals/67/pdf/BlackCarbon_report.pdf

⁶⁸ Ramanathan, V. and Yangyang Xu (2010) The Copenhagen Accord for Limiting Global Warming: Criteria, Constraints, and Available Avenues, *Proceedings of the National Academies of Sciences* 107 (18), pp.8055-8062. <http://www.pnas.org/content/107/18/8055>

⁶⁹ Xu, Y., D. Zaelke, G. J. M. Velders, and V. Ramanathan (2013), [The role of HFCs in mitigating 21st century climate change](#), *Atmos. Chem. Phys.*, 13(12), 6083–6089

radiative forcing published by Bond et al.⁷⁰ This Proposed Strategy uses AR4 values for methane and HFCs, but AR5 for black carbon.

Considering ways of comparing the contributions of different climate pollutants to climate change has been raised in the IPCC AR5. The report focuses the discussion on the more well-known GWP and Global Temperature change Potential (GTP), though other concepts are also briefly discussed. The GTP is defined as the change in global mean surface temperature at a chosen point in time in response to an emission pulse, relative to that of CO₂. The Norwegian Environment Agency has recently performed an integrated assessment of climate, health and environmental effects of Norwegian emissions of SLCPs, and proposed measures for reducing such effects by 2030.⁷¹ Specifically, they used the “GTP10, Norway”, a global temperature change potential calculated ten years after the emission occurred in Norway, which they identify as the most practically appropriate metric for analyzing measures for Norwegian emissions of SLCPs in the short term. Overall, there is not one, single metric that describes the comparative climate effects of various short-lived and long-lived climate pollutants perfectly. The use of GWPs with a time horizon of 20 years better captures the importance of the SLCPs and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO₂ emission controls. Thus, the emission estimates presented later in this report are calculated using 20-year GWP. Table 4 illustrates the lifetime and 20-year GWP for each SLCP.

Table 4: Global Warming Potential for SLCPs¹

| Pollutant | Lifetime (years) | 20-year GWP |
|---------------------------------|-------------------|-------------|
| Carbon dioxide | ~100 ² | 1 |
| Methane | 12 | 72 |
| F-Gases (Hydrofluorocarbons) | 1.4 – 52 | 437 – 6350 |
| Black carbon | Days to weeks | 3,200 |

¹All AR4 except black carbon which uses AR5 (the first report to define a GWP for black carbon)

²CO₂ has a variable atmospheric lifetime and cannot be readily approximated as a single number

The following sections describe the major SLCPs. An inventory of sources and emissions, and a discussion of current and proposed new control measures are included in other portions of this report.

⁷⁰ Bond, T. C., S. J. Doherty, D. W. Fahey, et al. (2013) “Bounding the role of black carbon in the climate system: A scientific assessment.” *Journal of Geophysical Research: Atmospheres* doi:10.1002/jgrd.50171. <http://onlinelibrary.wiley.com/doi/10.1002/jgrd.50171/pdf>

⁷¹ Norwegian Environment Agency, *Summary of proposed action plan for Norwegian emissions of short lived climate forcers*, report M135/2014; <http://www.miljodirektoratet.no/Documents/publikasjoner/M135/M135.pdf>

A. Black Carbon

Airborne particulate matter (PM) varies in its composition and plays a significant role in human health and the climate system. Particulate matter is emitted from a variety of natural processes and human activities, and tends to remain in the air for only a few days to about a week, resulting in extreme spatial and temporal variability. Among different types of particles, carbonaceous particles (those that contain organic and black carbon) are particularly important because of their abundance in the atmosphere. With respect to climate impact, black carbon is the principal absorber of visible solar radiation in the atmosphere while organic carbon is often described as a light-reflecting compound.

Black carbon is emitted from burning fuels such as coal, diesel, and biomass. Black carbon contributes to climate change both directly by absorbing sunlight and indirectly by depositing on snow and by interacting with clouds and affecting cloud formation. In addition to its climate and health impacts, black carbon disrupts cloud formation, precipitation patterns, water storage in snowpack and glaciers, and agricultural productivity.

Scientists have known for some time that sources that emit black carbon also emit other short-lived particles that may either cool or warm the atmosphere. Lighter colored particles, for example, tend to reflect rather than absorb solar radiation and so have a cooling rather than warming impact. Until recently, it had been thought that the impact of lighter colored and reflecting organic carbon from combustion sources largely offset the warming impact of black carbon from this source. However, new studies have suggested that certain fractions of organic carbon known as “brown carbon” could be a stronger absorber of solar radiation than previously understood.^{72,73} The warming effect of brown carbon may offset the cooling impact of other organic carbon particles; hence, quantification of that absorption is necessary so that climate models can evaluate the net climate effect of organic carbon.

To help characterize and differentiate sources of brown carbon from black carbon and understand their climate impact in California, a current ARB-funded research project is applying advanced measurement methodology along with regional and global climate modeling simulations to characterize the extent to which brown carbon contributes to climate forcing in California. This project will improve our understanding of the fundamental processes that dominate brown carbon formation, and help to determine the potential climate benefit of mitigating sources of brown carbon emissions in California.

⁷² Jacobson, M. Z. (2014), Effects of biomass burning on climate, accounting for heat and moisture fluxes, black and brown carbon, and cloud absorption effects, *J. Geophys. Res. Atmos.*, 119, 8980–9002, doi:10.1002/2014JD021861 <http://onlinelibrary.wiley.com/doi/10.1002/2014JD021861/pdf>

⁷³ Kodros, J. K., Scott, C. E., Farina, S. C., Lee, Y. H., L'Orange, C., Volckens, J., and Pierce, J. R.: Uncertainties in global aerosols and climate effects due to biofuel emissions, *Atmos. Chem. Phys.*, 15, 8577-8596, doi:10.5194/acp-15-8577-2015, 2015. <http://www.atmos-chem-phys.net/15/8577/2015/acp-15-8577-2015.pdf>

B. Methane

Methane is the principal component of natural gas and is also produced biologically under anaerobic conditions in ruminants (animals with a four-part stomach, including cattle and sheep), landfills, and waste handling. Atmospheric methane concentrations have been increasing as a result of human activities related to agriculture, fossil fuel extraction and distribution, and waste generation and processing. The atmospheric lifetime of methane is about 12 years. It is well-mixed within the atmosphere, and like other GHGs, warms the atmosphere by blocking infrared radiation (heat) that is re-emitted from the earth's surface from reaching space. Almost all of methane's impact occurs within the first two decades after it is emitted.

Methane is responsible for about 20 percent of current global warming,⁷⁴ and methane emissions continue to increase globally. There is particular concern among scientists that continued climate warming may cause massive releases of methane from thawing arctic permafrost, and dissolve frozen methane clathrate deposits trapped within shallow ocean sea floors.

A recent study, which examines the interaction of methane with other atmospheric gases, indicates methane emissions may have even greater climate change impacts than previously understood.⁷⁵ In the AR5 report, when all the feedbacks are included, the GWP for methane was increased, from 25 to 28 over a 100-year timespan and from 72 to 84 over a 20-year timespan. However, for consistency with reporting requirements under the United Nations Framework Convention on Climate Change, ARB is using GWP values from the AR4.

Methane also contributes to global background levels of ozone in the lower atmosphere (troposphere). Photo-oxidation of both methane and carbon monoxide lead to net production of global background levels of ozone. Ozone itself is a powerful SLCP as well as a regional ground level air pollutant. Tropospheric ozone is not emitted directly into the atmosphere, but rather formed by photochemical reactions. Its average atmospheric lifetime of a few weeks produces a global distribution highly variable by season, altitude, and location. The radiative forcing of tropospheric ozone is primarily attributed to emissions of methane, but also to carbon monoxide, volatile organics, and nitrogen oxides that eventually form ozone.

Ozone negatively impacts human health, and can lead to asthma attacks, hospitalizations, and even premature death. It impairs the ability of plants to absorb CO₂, thereby suppressing crop yields and harming ecosystems. Ozone also affects evaporation rates, cloud formation, and precipitation levels. In addition to the direct climate benefits of cutting methane emissions, it can also reduce global background

⁷⁴ Kirschke, S. *et al.* (2013) Three decades of global methane sources and sinks. *Nature Geosci.* **6**, 813–823. http://www.nature.com/ngeo/journal/v6/n10/full/ngeo1955.html?WT.ec_id=NGEO-201310

⁷⁵ Holmes, C. D., M. J. Prather, O. A. Sovde, and G. Myhre. 2013. "Future methane, hydroxyl, and their uncertainties: Key climate and emission parameters for future predictions." *Atmospheric Chemistry and Physics* **13**: 285–302. <http://www.atmos-chem-phys.net/13/285/2013/acp-13-285-2013.pdf>

levels of ozone pollution and provide additional climate, health, and other benefits.^{76,77,78}

Regional ozone concentrations reflect contributions from both ozone formed from criteria pollutant emissions (NO_x and volatile organic compounds [VOCs]) on a regional scale, and ozone transported on hemispheric scales (global background levels of ozone). Due to its low reactivity, methane emissions do not affect regional scale ozone production that occurs over hours to days. However, regional methane emissions which are fairly well-mixed in the atmosphere contribute to the global abundance of methane, which in turn contributes to global background levels of ozone. About two-thirds of the rise in global levels of tropospheric background ozone can be attributed to methane emissions. Studies have also shown that the global background ozone concentrations can approach 40 parts per billion and have been increasing in recent years. Increases in background ozone make it harder to attain the health-based ambient air quality standards set by U.S. EPA and California.

C. Fluorinated Gases (Hydrofluorocarbons)

Hydrofluorocarbons (HFCs) are synthetic gases used in refrigeration, air conditioning, insulating foams, solvents, aerosol products, and fire protection. They are primarily produced for use as substitutes for ozone-depleting substances, including chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), which are being phased out under the Montreal Protocol. Currently, HFCs are a small fraction of the total climate forcing, but they are the fastest growing source of GHG emissions in California and globally, primarily driven by the increased demand for refrigeration and air conditioning.

HFCs vary significantly in their ability to influence climate. Their differing ability is mostly due to differences in their atmospheric lifetimes, which determine how much they accumulate in the atmosphere. The mix of HFCs in current use, weighted by usage (tonnage), has an average atmospheric lifetime of 15 years. HFCs are also potent GHGs, with a warming effect hundreds to thousands of times more powerful than CO₂. The average 100-year GWP of the current mix of HFCs being used is about 1600, and the average 20-year GWP is about 3500. The major concern with respect to HFCs is that their contribution to climate forcing is expected to increase rapidly in the future as

⁷⁶ Fiore, A. M., J. J. West, L. W. Horowitz, V. Naik, and M. D. Schwarzkopf (2008) Characterizing the tropospheric ozone response to methane emission controls and the benefits to climate and air quality, *J. Geophys. Res.*, 113, D08307, doi:10.1029/2007JD009162.

⁷⁷ West, J. J., A. M. Fiore, L. W. Horowitz, and D. L. Mauzerall (2006), Global health benefits of mitigating ozone pollution with methane emission controls, *Proc. Natl. Acad. Sci. U.S.A.*, 103, 3988–3993.

⁷⁸ Fiore, A. M., F. J. Dentener, O. Wild, C. Cuvelier, M. G. Schultz, P. Hess, C. Textor, M. Schulz, R. M. Doherty, L. W. Horowitz, I. A. MacKenzie, M. G. Sanderson, D. Shindell, D. S. Stevenson, S. Szopa, R. Van Dingenen, G. Zeng, C. Atherton, D. J. Bergmann, I. Bey, G. Carmichael, W. J. Collins, B. Duncan, G. Faluvegi, G. Folberth, M. Gauss, S. Gong, D. Hauglustaine, T. Holloway, I. S. A. Isaksen, D. Jacob, J. E. Jonson, J. W. Kaminski, T. J. Keating, A. Lupu, E. Marmer, V. Montanaro, R. J. Park, G. Pitari, K. J. Pringle, J. A. Pyle, S. Schroeder, M. G. Vivanco, P. Wind, G. Wojcik, S. Wu, and A. Zuber (2009), Multimodel estimates of intercontinental source-receptor relationships for ozone pollution, *J. Geophys. Res.*, 114, D04301, doi:10.1029/2008JD010816.

they continue to replace ozone depleting substances (ODS), such that they will become very significant contributors. Studies indicate that a lack of action to prevent the growth of HFCs would greatly undermine efforts to address climate change. A recent study concluded that replacing high-GWP HFCs with low-GWP alternatives could avoid 0.1°C of warming by 2050 and warming of up to 0.5°C by 2100,⁷⁹ offering one of the most cost-effective climate mitigation strategies available.

The successful phase-out of CFCs and the ongoing phase-out of HCFCs have made the Montreal Protocol an effective climate treaty.^{80,81} Between 1990 and 2010 the Montreal Protocol reduced CO₂e emissions nearly twenty times more than the initial commitment period of the Kyoto Protocol.⁸² Although HFCs have contributed a miniscule amount of historical climate forcing, they are projected to increase significantly in the absence of control policies. Hence, a global phase down of HFCs is necessary to slow their effect on climate change. International, national, and state efforts to reduce emissions of HFCs are discussed in more detail in Chapter VI.

⁷⁹ Xu Y., Zaelke D., Velders G. J. M., & Ramanathan V. (2013) The role of HFCs in mitigating 21st century climate change, *ATMOS. CHEM. PHYS.* 13:6083-608.

⁸⁰ Velders G. J. M. *et al.* (2007) *The importance of the Montreal Protocol in protecting climate*, *Proc. Nat'l. Acad. Sci. USA* 104:4814.

⁸¹ Wu, Y., L.M. Polvani and R. Seager, (2013): The Importance of the Montreal Protocol in Protecting the Earth's Hydroclimate. *J. Climate*, 26, DOI: 10.1175/JCLI-D-12-00675.1, http://www.ideo.columbia.edu/res/div/ocp/glodech/PDFS/Wu_etal_O3_2013.pdf

⁸² UNEP (2012) *The Montreal Protocol and the Green Economy: Assessing the contributions and co-benefits of a Multilateral Environmental Agreement*.

IV. Reducing Black Carbon Emissions

Black carbon is the light-absorbing component of fine particulate matter (PM) produced during incomplete combustion of fuels. Black carbon does not account for the warming effects of brown carbon. The lifetime of black carbon is very short, from days to weeks, compared to other SLCPs, which may remain in the atmosphere for a few decades.

California has done more than any other jurisdiction in the world to reduce PM and black carbon emissions. As a result, ambient levels of black carbon in California are now 90 percent lower than in the early 1960s, despite the use of diesel fuel more than tripling over the same time period.⁸³ If the rest of the world achieved similar reductions, it could substantially improve health and slow global warming. California's actions can serve as a blue print for other jurisdictions to reduce SLCP emissions and improve public health. California is continuing to explore additional ways to reduce black carbon emissions. Complying with federal air quality standards and reducing localized risk will require substantial reductions in smog-forming and PM emissions from mobile sources and other source categories.

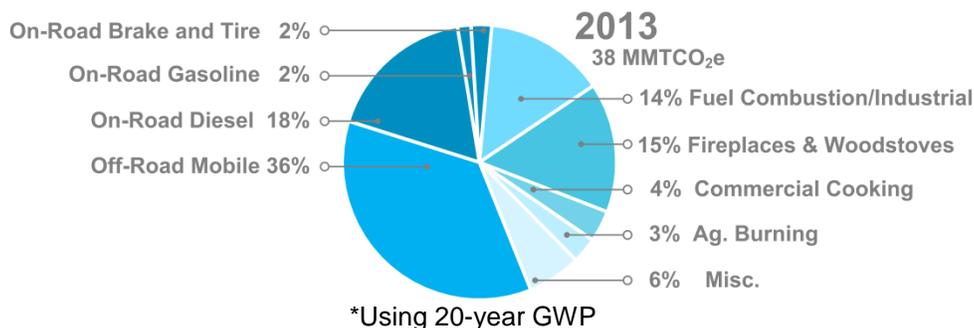
For purposes of this report, black carbon emissions are discussed in two categories, anthropogenic (non-forest) sources and forest-related sources. Anthropogenic sources include on- and off-road transportation, residential wood burning, fuel combustion, and industrial processes. Forest-related sources include prescribed fire and wildfire and are separated to account for the unique challenges associated with inventorying and mitigating these sources. In a typical year, wildfires account for approximately two-thirds of California's black carbon emissions, but this varies from year to year. Prescribed fires also emit black carbon, but are an important tool for forest managers to help restore and maintain forest health, which in turn can reduce wildfire severity and the associated black carbon emissions from catastrophic wildfires.

A. Anthropogenic (Non-Forest) Sources of Black Carbon Emissions

California's major anthropogenic sources of black carbon include off-road transportation, on-road transportation, residential wood burning, fuel combustion, and industrial processes (Figure 1). The fuel combustion and industrial source categories include a variety of stationary and portable equipment such as boilers, turbines, and steam generators, as well as process emissions from industrial operations, such as cement and asphalt production and pulp and paper mills. Sources in the miscellaneous category include dust, waste disposal, unplanned structure and car fires, residential natural gas combustion, and non-agricultural open burning (mostly residential green waste burning).

⁸³ V. Ramanathan et al. 2013. Black Carbon and the Regional Climate of California. Report to the California Air Resources Board No. 08-323. <http://www.arb.ca.gov/research/apr/past/08-323.pdf>

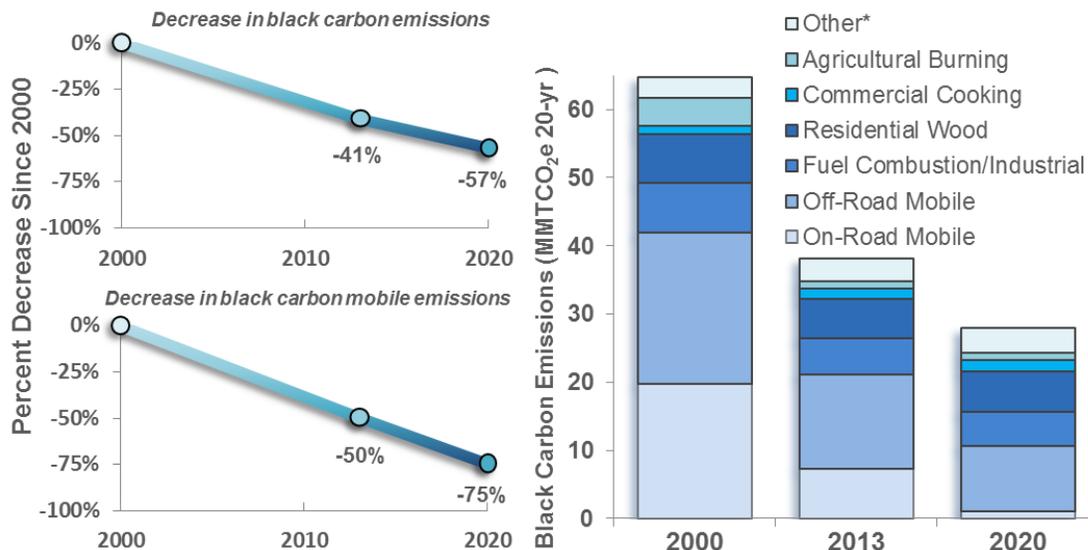
Figure 1: California 2013 Anthropogenic (non-forest) Black Carbon Emission Sources*



1. Progress to Date

California’s program to reduce emissions from transportation sources of black carbon can serve as a blueprint for other jurisdictions seeking to address both the climate change and public health impacts of mobile sources, particularly diesel engines. Over the last few decades, ARB has employed a variety of strategies that has drastically reduced black carbon emissions from mobile sources, including lower emission standards, clean fuel requirements, in-use rules, incentives, and investments in research and new technology. Diesel particulate filters have been instrumental in reducing black carbon in on-road and major portions of the off-road sector. Today’s diesel particulate filter-equipped trucks are more than 99 percent cleaner than those manufactured in 1990. Measures have also been implemented on the State and local level to reduce PM, and thus black carbon, emissions from non-mobile sources, including residential burning, commercial cooking, and agricultural burning. Existing measures are projected to cut mobile source emissions by 75 percent and total anthropogenic (non-forest) emissions by nearly 60 percent between 2000 and 2020 (Figure 2).

Figure 2: California's Black Carbon Emissions between 2000 and 2020 with Existing Measures



California has highlighted our accomplishments in discussions with other jurisdictions, including a SLCP-focused side event, jointly hosted with Mexico, at the Conference of Parties in Lima in 2014 and at international climate conferences in 2015. We will continue to work closely with our partners in other states, in the federal government, and internationally to highlight the successful actions California has taken, and will continue to take, to reduce black carbon from mobile sources.

Mobile Sources

In 2000, ARB approved a Diesel Risk Reduction Plan, calling for an 85 percent reduction in diesel PM emissions by 2020.⁸⁴ Diesel engines often operate for decades after they are purchased, so while lower emission standards provide major emission



reductions, those reductions can take time to materialize as older engines are replaced with new ones meeting the standard. To reduce risk and speed emission reductions, ARB implemented in-use rules for on-road and off-road fleets to meet performance standards through the use of alternative fuels, after-treatment retrofits, or replacement of older vehicles with newer vehicles manufactured to current emission standards. In-use on-road rules are expected to reduce black carbon emissions from on-road sources by 80 percent between 2000 and 2020. ARB's off-road rules

⁸⁴ Final Diesel Risk Reduction Plan available at: <http://www.arb.ca.gov/diesel/documents/rrpapp.htm>

apply to approximately 150,000 off-road vehicles and are expected to reduce diesel PM emissions by 20 percent between 2009 and 2023.

These regulations provide significant reduction in diesel PM exposure in communities located near California's major ports and intermodal railyards and contribute to a larger coordinated effort to reduce black carbon and PM emissions from all sources at ports and railyards.⁸⁵ Overall, since 2005, California has reduced diesel particulate emissions, along with the associated health risks, by 70 percent at the largest ports and 50–70 percent at the highest-risk railyards.

Incentive programs, including the Carl Moyer Memorial Program, AB 923, AB 118 Air Quality Improvement Program (AQIP), Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), and Proposition 1B, have provided the means to transform California's mobile fleet into one of the cleanest in the world. These programs have provided more than \$1.6 billion over the past 15 years to clean up diesel engines and simultaneously reduce black carbon.

Cleaner fuels have been a cornerstone of ARB efforts to reduce mobile emissions, enabling cleaner vehicle technologies that have reduced smog-forming emissions by 15 percent and reduced cancer risks from vehicle pollution by 40 percent. The Low Carbon Fuel Standard provides a strong financial incentive to develop clean fuel alternatives, which may also reduce black carbon. For example, renewable diesel and biodiesel may reduce both PM and black carbon emissions compared to conventional diesel, especially in engines where diesel particulate filter technology is not available.

California has also paved the way for increased penetration of zero-emission vehicles (ZEV) through incentive programs and investment in new technology. The ZEV regulation was first adopted in 1990, as part of the Low Emission Vehicle Program. Today California is the world's single largest market for light-duty passenger ZEVs, accounting for 20 percent of all ZEVs on the road.⁸⁶ ARB will continue to lead in this area with the Governor's ZEV action plans to accelerate use of ZEVs and deploy 1.5 million passenger ZEVs in California by 2025. Providing financial and technological pathways to accelerating growth in ZEVs and other advanced engine technologies within California will push market development for clean and zero-emission vehicles throughout the world, providing additional black carbon emission reductions outside of California.

ARB is developing an integrated mobile source strategy to meet California's air quality and climate mandates, reduce petroleum use, and reduce near source risk. Accomplishing this will require a transformation to near-zero and zero emission technologies, cleaner renewable fuels, greater system and operational efficiencies, and

⁸⁵ Dallmann et al. 2011. Effects of Diesel Particle Filter Retrofits and Accelerated Fleet Turnover on Drayage Truck Emissions at the Port of Oakland, *Environmental Science & Technology*, 45, 10773-10779.

⁸⁶ Draft 2015 ZEV Action Plan available at:
http://gov.ca.gov/docs/DRAFT_2015_ZEV_Action_Plan_042415.pdf

new approaches to passenger and freight mobility. These coordinated efforts will provide California a clear path forward to reduce the State's impacts on climate change including reductions in black carbon emissions.

In April 2015, ARB released the *Sustainable Freight Pathways to Zero and Near-Zero Discussion Document* that outlines initial steps ARB is taking to accelerate progress toward zero and near-zero emission freight vehicle and equipment technology in California.⁸⁷ In July 2015, the Governor signed Executive Order B-32-15, that directs the Secretaries of Transportation, Environmental Protection, and Natural Resources to lead staff from the California Department of Transportation (Caltrans), ARB, the California Energy Commission (Energy Commission), and the Governor's Office of Business and Economic Development (GO-Biz), in the development of an integrated action plan, the California Sustainable Freight Action Plan (Action Plan). The agencies must develop the Action Plan by July 2016 that establishes targets, identifies actions to achieve the targets, and initiates work on pilot projects.

In September 2015, ARB staff released the *Mobile Source Strategy Discussion Draft*, which introduced a comprehensive plan to control emissions from mobile sources in order to meet critical air quality and climate goals over the next fifteen years.⁸⁸ Since October, developments in planning efforts have continued to shape staff's mobile source approach. The Mobile Source Strategy will be released in April 2016, reflecting these developments.

Specifically for criteria pollutants, the ARB staff developed the State SIP Strategy that will propose measures to meet federal air quality standards for ozone and fine particulate matter (PM2.5). SIPs are due to U.S. EPA in 2016. Building on measures first introduced in the *Mobile Source Strategy Discussion Draft*, the State SIP Strategy will be also released in April 2016.

As emissions from mobile sources decrease, non-mobile sources will become an increasingly important fraction of the black carbon inventory. The main non-mobile emission sources include residential wood combustion, fuel combustion from stationary and small portable equipment, and industrial sources. Commercial cooking and agricultural burning make up a smaller portion of emissions.

Residential Wood Combustion

A number of local air districts have residential wood combustion rules, and are working to make further progress in this category to meet air quality standards and protect public health.⁸⁹ Strategies in place to reduce emissions from residential wood combustion

⁸⁷ <http://www.arb.ca.gov/gmp/stti/sustainable-freight-pathways-to-zero-and-near-zero-emissions-discussion-document.pdf>

⁸⁸ http://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc_dd.pdf

⁸⁹ Yap and Garcia 2015. Effectiveness of residential wood-burning regulation on decreasing particulate matter levels and hospitalizations in the San Joaquin Valley Air Basin, *Am J Public Health*, 105(4), 772-778.

include winter burning curtailment, opacity emission limits, incentives to replace old wood burning devices with more efficient models, and banning or limiting wood burning devices in new and existing housing. Additionally the U.S. EPA has recently introduced a new source performance standard requiring manufacturers of residential wood stoves, pellet stoves, forced air furnaces, and hydronic heaters to meet national emission standards. Statewide black carbon emissions from residential wood combustion have declined by nearly 20 percent between 2000 and 2013 in response to existing district rules.

Stationary Fuel Combustion and Industrial Sources

Emissions from stationary fuel combustion will be addressed by a number of State and federal planning efforts, including the SIP, Cap-and-Trade Program, increased building energy efficiency and renewable energy goals, and the federal Clean Power Plan (promulgated under Clean Air Act Section 111(d)). California's Cap-and-Trade regulation and the LCFS create market signals to incentivize efficiency improvements as well as the use of biomass-derived liquid fuels that would emit lower levels of PM and black carbon than traditional fossil fuels. The federal Clean Power Plan, which accelerates the transition from coal towards lower carbon-intensive fuels for electricity production, will reduce black carbon emissions, and emissions of other GHGs, across the nation. Further emission reduction opportunities from stationary fuel combustion and industrial processes may also be identified as part of the SIP process.

Commercial Cooking

Commercial cooking emissions are primarily from charbroiling. The two types of charbroilers include chain-driven, where food moves mechanically through a semi-enclosed broiler, and under-fired, where food is cooked on a grill similar to a home barbeque. A number of local air districts require air pollution control technologies for chain-driven broilers, reducing particulate emissions from these charbroilers by over 80 percent. Under-fired charbroilers are a larger source of PM, but no cost-effective air pollution control technology has been identified to date. Air districts are working to develop air pollution control devices for under-fired charbroilers. Demonstration projects for emerging control technologies are in progress and it is anticipated that large districts will develop rules for these emissions going forward.



Agriculture

Agricultural burning was historically used as a cost-effective way to remove agricultural residue left behind on fields, help control weeds and pests, and prevent the spread of plant disease, but emissions impacted local air quality and prompted concern for public health. Various programs are currently administered by the local air districts in

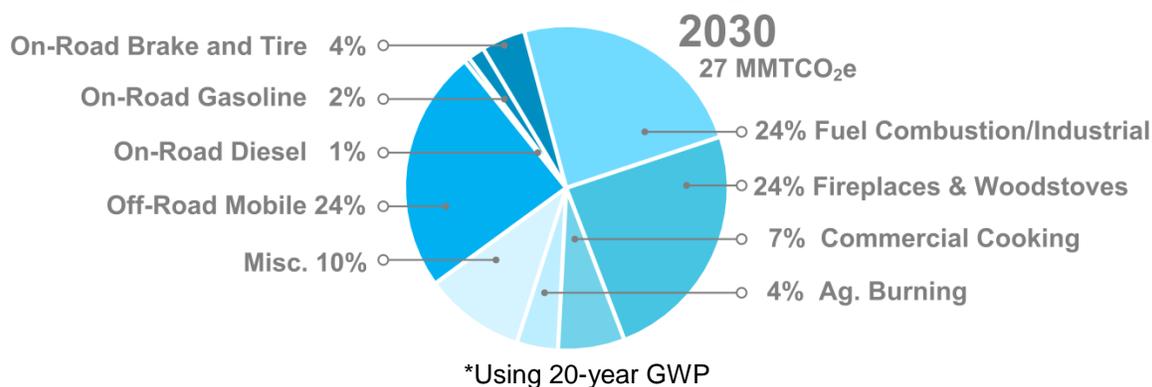
coordination with ARB to reasonably regulate agricultural burning as required by state law. The Sacramento Valley Rice Straw Burning Phasedown Program, local district Smoke Management Programs, and San Joaquin Valley agricultural burning phase down efforts have resulted in an approximately 70 percent reduction in black carbon emissions from agricultural burning between 2000 and 2013. Some agricultural waste that was previously burned went to bioenergy facilities; however, many of these facilities have shut down over the last few years due to their inability to procure long-term power purchase contracts. If this trend continues, the diminishing agricultural waste utilization options could result in the potential for increased agricultural burning. The San Joaquin Valley Air Pollution Control District is considering the need to allow increased agriculture burning of certain crops due to the lack of feasible alternatives to removing this waste in the fields. Programs to support clean energy and fuel production and markets for wood products, similar to the recommendations later in this section for forest woody biomass, would provide opportunities for alternative beneficial uses for this waste material.

Agriculture irrigation pumps are a small source of black carbon on a statewide level, but may be an important local source. Multiple federal, state, and local governments have provided incentives to convert agricultural diesel irrigation engines to either newer cleaner diesel engines or to electric motors. This has led to black carbon emissions from irrigation pumps declining by half between 2000 and 2013, with additional reductions expected going forward in response to existing measures.

California has achieved tremendous reductions in black carbon emissions, especially in the mobile sector, and even more reductions are expected as current measures are fully implemented. In 2000, on-road mobile sources contributed a third of anthropogenic black carbon emissions, but are projected to account for only a small fraction of total emissions by 2030. Off-road mobile emissions, including aircraft, watercraft, trains, small equipment, forklifts and farm equipment, have declined by over a third since 2000, and are projected to decrease by another half by 2030.

However, meeting the 2030 black carbon emission target identified in this Proposed Strategy (for non-forest only) requires additional emission reductions across multiple sectors. Off-road mobile sources, along with stationary fuel combustion and residential wood burning, will make up the majority of emissions by 2030 (Figure 3). Additional 2030 reductions will be realized through implementation of measures identified in plans currently being developed, including the California Sustainable Freight Action Plan and the State Implementation Plans (SIPs). Additional reductions are also expected through a district-lead commercial cooking regulation, but the magnitude of emission reductions is currently unknown.

Figure 3: California’s 2030 Anthropogenic (non-forest) Black Carbon Emission Sources with Existing Measures*



2. Recommended Actions to Further Reduce Non-Forest Black Carbon Emissions

This section describes proposed new measures (summarized in Table 5 below) to assist the State in meeting the proposed 2030 black carbon emission target.

Table 5: Proposed New Black Carbon Emission Reduction Measures and Estimated Emission Reductions (MMTCO₂e)¹

| Measure Name | 2030 Annual Emission Reductions | 2030 Annual Emissions |
|---|---------------------------------|-----------------------|
| 2030 BAU ² | | 26 |
| Residential Fireplace and Woodstove Conversion | 3 | |
| California Sustainable Freight Action Plan State Implementation Plans Clean Energy Goals ³ | 4 | |
| 2030 BAU with new measures | | 19 |

¹Using 20-year GWPs from the 5th Assessment report of the IPCC

²Business As Usual (BAU) forecasted inventory includes reductions from implementation of current regulations

³Additional black carbon reductions will be realized from planned measures and are expected to help the State meet the black carbon target. However, an estimate of emission reductions is not currently available, but will be developed as part of these planning efforts.

Residential Fireplace and Woodstove Conversion Measure

Residential wood combustion is forecast to be the largest individual anthropogenic source of black carbon in 2030 if no new programs are implemented, accounting for a quarter of anthropogenic black carbon emissions. Reducing 2030 residential wood

combustion black carbon emissions by half (3 MMTCO₂e) would set California on a path toward meeting the 2030 target in this Proposed Strategy.

Removal of old fireplaces and woodstoves and replacement with EPA-Certified wood-burning devices, electric heaters, or gas fireplaces can provide long lasting reductions in emissions of black carbon, criterial pollutants, and air toxics in residential neighborhoods. Removed wood burning devices should be destroyed or recycled to ensure permanent emission reductions.

Monetary incentives to stimulate removal of old wood burning devices are popular and can achieve significant emission reductions. Multiple air districts have invested in incentive programs, but additional funding is necessary to continue to realize emission reductions in this category. In addition, programs should be expanded to include all regions of California. Incentive funding to support further district efforts could come from a variety of national, State, and local resources. The Governor's 2016-2017 proposed budget includes \$40 million of Cap-and-Trade expenditure for a residential woodstove replacement incentive program, but this potential incentive program will not be developed and implemented until the Legislature appropriates funds for this Program.



In addition, ARB is proposing to work with the air districts to determine the most effective approach to avoid new residential wood combustion emissions in California. This could include encouraging the installation of non-wood burning centralized heating in new construction. In areas where central heat is cost-prohibitive, the cleanest available burning technology could be required.

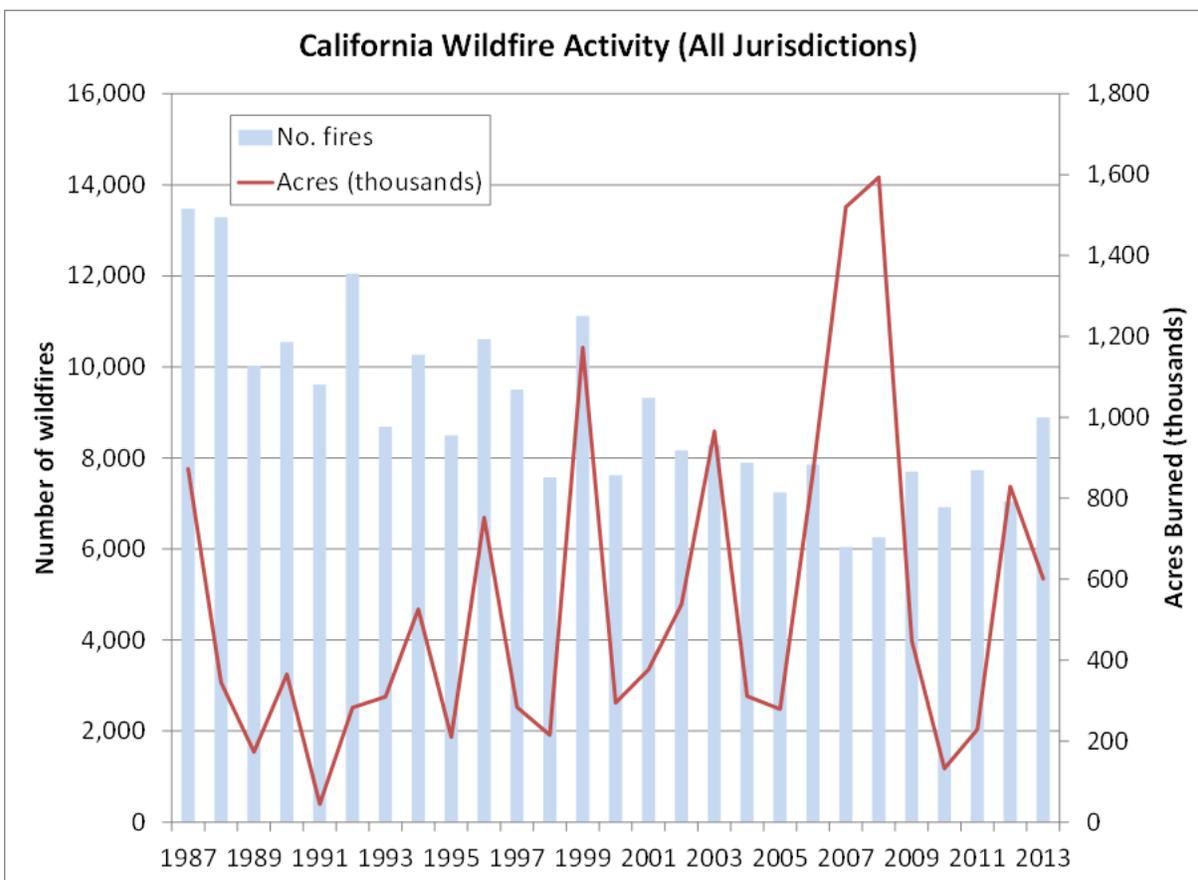
Education and outreach are important tools to reduce emissions from residential wood combustion. A broader public understanding of the health and environmental impacts of wood smoke may cause voluntary changes in behavior to use other heating sources and may cause individuals to avoid unnecessary burning both indoors and outdoors. Education on proper burn practices may reduce emissions when wood is used, and is essential to achieve full emission reductions from EPA-Certified wood burning devices. Some districts have already implemented education programs, which should be expanded to all parts of the State as part of this measure.

B. Forest-Related Sources of Black Carbon Emissions

Wildfires account for the majority of black carbon emissions during a typical year in California. On average, an area the size of Las Vegas burns each year. The extent and severity of wildfire varies significantly from one year to the next and is impacted by forest conditions that are influenced by historic management, drought, and climate change (see Figure 4).

While we must act to reduce wildfire risk in the State, we will never be able to fully control wildfire and associated black carbon emissions to meet specific targets in any given year. Consequently, forest-related emissions are not included in the anthropogenic black carbon emission reduction target identified in this Proposed Strategy. Still, efforts to reduce black carbon from wildfires are critical to California's efforts to cut SLCP emissions. As part of an integrated and long-term effort to sustainably manage forests, California can reduce the risk of catastrophic wildfire and forest-related black carbon emissions in California over time.

Figure 4: Wildfire Activity in California.⁹⁰

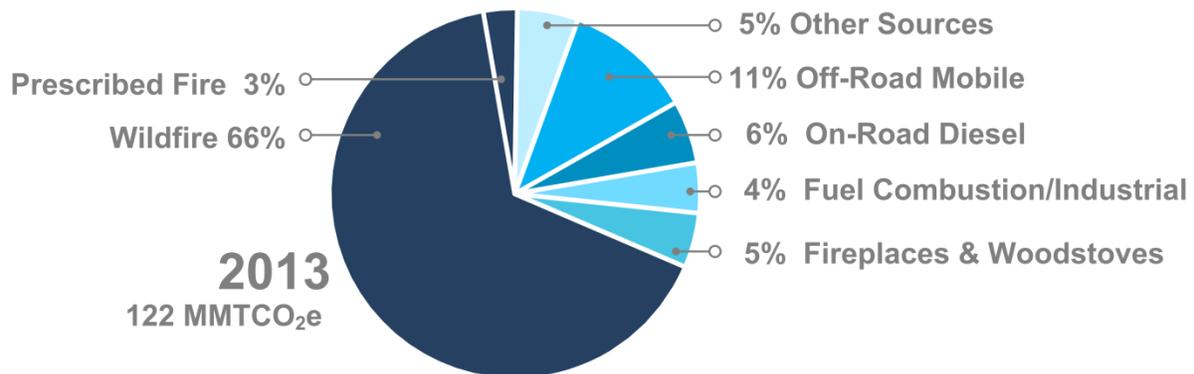


California's black carbon inventory uses the 10-year average from 2001-2011 of PM2.5 emissions from wildfire to represent average conditions and avoid large year-to-year variations in the inventory. Based on these methods, a typical recent wildfire year would account for two-thirds of the State's black carbon emissions in 2013 (Figure 5). The frequency of large fire events and the associated emissions will likely increase in the future, due to climate change, heavy fuel loading, historic fire suppression practices, and development in forested areas.^{91,92}

⁹⁰ http://calfire.ca.gov/communications/downloads/fact_sheets/AllAgenciesAcres&Fires.pdf

⁹¹ Westerling et al. 2006. Warming and earlier spring increase western US forest wildfire activity. Science, 313(5789), 940-943.

Figure 5: California 2013 Black Carbon Emissions (including 10-year average emissions from forest-related sources)*



*Using 20-year GWP. "Prescribed Fire" does not include agriculture.

California's forests consist of a range of ecosystems, managed under various regulatory structures by different landowners. This patchwork of regulation and ownership, as well as physical accessibility, affects forest conditions and management practices. Private forests and areas designated as timberlands tend to be less susceptible to wildfire, as they are managed to minimize fuel loads and protect commercial assets. The value of timber harvest can help offset forest management costs, but may not be optimal from an ecological standpoint. More than 35 percent of California's forests are privately-owned, 60 percent of which is managed as timberlands. Federal agencies manage well over half of the nearly 33 million acres of forestland in California. Federal lands are managed for multiple objectives, including timber harvest, but also with ecological restoration as a focal point. Continued coordination with private and federal land owners is necessary to ensure that improved management practices, resulting in overall black carbon and GHG benefits, reach throughout California's forest lands.

1. Progress to Date

After a century of fire suppression, chronic underfunding for forest management at the State and Federal level, and exacerbating impacts of climate change, bark beetle infestations and drought, California's forests are highly vulnerable and potentially a source of increasing black carbon emissions. The current rate of fuel reduction activity is insufficient to improve forest health, avoid catastrophic wildfire, produce resilient forests, and reduce black carbon emissions. For example, the U.S. Forest Service estimates that less than 20 percent of the Forest Service lands in need of fuels reduction treatment have been treated.⁹³ Once treated, these forest stands must be retreated every 15-30 years to be properly maintained. California is accelerating its efforts to improve forest health and reduce wildfire risk, but doing so requires

⁹² Hurteau et al. 2014. Projected effects of climate and development on California wildfire emissions through 2100. *Environmental Science & Technology*, 48(4), 2298-2304.

⁹³ North, M., Collins, B.M., and Scott Stephens (2012) Using Fire to Increase the Scale, Benefits, and Future Maintenance of Fuels Treatments, *Journal of Forestry* 110(7):392-401.

comprehensive planning and strategic investment and will take time before there is a steady trend toward declining wildfire and associated black carbon emissions.

In response to the current epidemic of tree mortality, Governor Brown issued a Proclamation of a State of Emergency on Tree Mortality (Proclamation) in October 2015.⁹⁴ It requires State agencies to identify high hazard zones for wildfire and falling trees and prioritize tree removal in those areas. Among several actions to reduce wildfire risk and support forest management operations, the Proclamation calls for expanding the practice of prescribed burns, extending operation of existing biomass power plants that receive feedstock from high hazard zones, and facilitating power contracts for new facilities. To help implement the Proclamation, the Governor launched the State Tree Mortality Task Force in November 2015. The group includes State, Federal, and local government agencies, as well as key stakeholders, and will also monitor tree removal efforts and forest health and resilience.

This Proposed Strategy is one in a series of planning efforts underway that collectively contribute towards an integrated forest management and climate strategy for the State. Here, the focus is on actions to help reduce wildfire risk and black carbon emissions. The State's Forest Carbon Plan will identify climate-related targets for the natural and working lands sector, including forests, for incorporation into the 2030 Target Scoping Plan Update that will build on these recommendations. Goals and actions identified in the 2030 Target Scoping Plan Update and Forest Carbon Plan will include those related to forest carbon storage, which is beyond the scope of this Proposed Strategy. State agencies are coordinating to ensure that the goals and recommendations in each of these plans complement one another. And any proposed targets or actions will be considered through those public planning processes.

Reducing wildfire risk requires active management to reduce fuel availability and returning forests to more resilient states that can withstand fire. This starts with thinning overstocked forests, removing dead and dying trees, and altering stand characteristics to allow mature, larger trees to proliferate and thrive. Forests may be thinned manually, mechanically, or through the use of prescribed fire. These activities also reduce competition from understory vegetation and remove "ladder fuels" that allow ground fires to propagate into the forest canopy and quickly spread.

Prescribed fire can be a useful management tool, particularly in areas that are not suitable for other fuel reduction treatments. While prescribed fire emits black carbon, it can reduce the risk of crown fires, which are a driver for large, catastrophic wildfires.^{95,96} Unlike wildfire, prescribed fire can be timed with favorable atmospheric conditions and managed to minimize air quality impacts. ARB and the local air districts have smoke

⁹⁴ http://gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf

⁹⁵ Schweizer and Cisernos 2014. Wildland fire management and air quality in the southern Sierra Nevada: Using the Lion Fire as a case study with a multi-year perspective on PM_{2.5} impacts and fire policy. *Journal of Environmental Management* 144, 265-278.

⁹⁶ Cisneros et al. 2014. Spatial and seasonal patterns of particulate matter less than 2.5 microns in the Sierra Nevada Mountains, California. *Atmospheric Pollution Research* 5, 581-590.

management programs in place to manage the timing and location of prescribed burns to protect public health.

Mechanical or manual thinning produces a large amount of woody biomass. While much of this is not marketable as commercial timber, it represents a potentially valuable resource that can support new industries in rural parts of the State and elsewhere. Currently, however, more than half of it is likely left in the forest, where it is often simply piled up and burned. This produces uncontrolled black carbon emissions and wastes a resource that could preferably be used to produce renewable electricity or low-carbon fuels, create wood products or landscaping materials, or potentially as a soil amendment in the form of biochar. These uses can help to reduce forest-related black carbon emissions, while creating jobs and fostering rural economic development. In addition, enabling markets that would capture value from this resource would help foster broader investment in active forest management practices that are needed to improve forest health and reduce wildfire risk on a lasting basis.

Utilizing more of this resource in a beneficial way to avoid open pile burning requires additional infrastructure to generate clean energy, fuels, or other products in areas near the resource base. Current capacity, mostly in the form of electricity production, is aging and insufficient for the existing resource, much less increased volumes that could come from increased forest management activities. Additionally, many of these facilities face expiring power contracts and are shutting down or in danger of doing so. In the near term, a priority is to keep existing facilities operating that receive woody biomass from high hazard areas, as called for in the Governor's Proclamation.

A longer-term, sustainable biomass management strategy requires increasing the capacity and diversity of uses and prioritizing community-scaled facilities near the forest. The most value from woody biomass may come from converting the feedstock into liquid or gaseous transportation fuels, which is supported by the State's Low Carbon Fuel Standard (LCFS). Additionally, the State's bioenergy feed-in tariff (Senate Bill 1122, Rubio, Statutes of 2012) requires the State's large investor-owned utilities to procure 50 MW of electricity from new, small scale bioenergy facilities using byproducts of sustainable forest management. Finally, part of the funding from the State's Electric Program Investment Charge (EPIC) is dedicated to research and development, deployment, and market facilitation for biomass-fueled facilities.

California, in partnership with Tuolumne County and the U.S. Department of Agriculture Forest Service (USFS), was awarded a \$70 million grant as part of the National Disaster Resilience Competition to develop and implement such an integrated community-scale strategy.⁹⁷ The proposed \$117 million project would create a replicable model for community and watershed resilience that could facilitate transitions to sustainable forest economies in rural parts of California. It includes three pillars related to recovery from the catastrophic Rim Fire in 2013:

⁹⁷ <http://www.hcd.ca.gov/nationaldisaster/ndrc-application.html>

- Forest and Watershed Health: Thinning, biomass removal, restoration, and reforestation activities in the Rim Fire burn area.
- Integrated Biomass and Wood Products Campus: The campus hosts facilities that will provide clean power, cooling and heating, and wood products to utilize biomass material and serve communities near the impacted disaster area.
- Community Resilience Centers: These facilities will provide services during an emergency and also provide year-round services, including education and job training to support forest and watershed work and the biomass facility.

As recent years of historic drought and wildfire have made abundantly clear, California needs to adjust historic forest management practices to reduce wildfire risk in the face of a changing climate. The State is responding quickly and effectively, but more needs to be done to build resiliency into our forests.

2. Recommended Actions to Reduce Wildfire Risk and Black Carbon Emissions

Reducing black carbon emissions from forests requires reducing wildfire risk by actively managing forests to reduce the threats posed by historic fire suppression activities and the increasing effects of drought and climate change. The U.S. Forest Service, which owns and manages approximately 20 million acres in California, has established a restoration goal of 500,000 acres/year in the State, including fuels reduction. Reaching that goal would require an additional \$300 million per year to more than double the current pace of restoration, but could potentially save \$800 million per year in fire suppression costs.⁹⁸ A matching goal for the State and private landowners to treat 500,000 acres per year of non-federal forestlands could require annual investment on the order of \$500 million to \$1 billion⁹⁹

There is a clear need to identify sustainable funding streams to support this level of treatment. Increased State and Federal funding is needed, as well as private sector investment. Enabling markets for the beneficial use of woody biomass can help to support and maximize these investments. For example, coupled with the Low Carbon Fuel Standard, additional steps to help to facilitate affordable and reliable supplies of sustainably harvested woody biomass could help spur a biofuels industry in rural parts of the State that could foster significant private sector investment in forest management activities.

The recommendations below will help reduce wildfire risk by improving forest management, putting woody waste resources to beneficial use to create value from forest management activities, and supporting these efforts with research and ongoing coordination. These actions will help increase public and private investment to unlock a broad array of economic and environmental benefits in rural communities and Statewide.

⁹⁸ <http://www.fs.usda.gov/detail/r5/landmanagement/?cid=stelprdb5412095>

⁹⁹ Assuming average treatment costs of \$1,000-2,000/acre. Actual treatment costs will vary across the landscape.

Increase Rate of Fuel Reduction to Reduce Wildfire Risk

The State is committed to increasing active management of its forests to reduce fuel loadings, wildfire risk, and black carbon emissions. Wherever possible, material should be thinned and put to beneficial use, which in turn, can help to finance fuel reduction activities. Prescribed fire has an important role to play, and should be utilized in manners protective of public health and as part of a scaled effort to improve forest and ecosystem health. Throughout, activities to reduce wildfire risk should be coordinated to support various State priorities, including enhancing forest health, protecting air quality, addressing climate change, and supporting watersheds, biodiversity and other ecosystem services. The State will work in these regards, and with federal and private land owners, to accelerate activities to reduce wildfire risk and associated black carbon emissions:

- **Increase investment in forest health programs.** Governor Brown's Cap-and-Trade Expenditure Plan in his proposed budget for fiscal years 2016-17 includes \$140 million for CAL FIRE to support forest health and resiliency programs that reduce GHG emissions. While additional public and private investment is needed on an ongoing basis, this represents an appropriate and significant increase beyond the \$24 million that these efforts received in the 2014-15 budget year.
- **Foster private sector investment.** The State will continue to support programs such as the Low Carbon Fuel Standard and Bioenergy Feed-In Tariff that support private sector investment to support sustainable forest management and utilization of woody biomass. Additionally, in developing the Scoping Plan and Forest Carbon Plan, State agencies will consider opportunities to support thinning, collecting, and transporting woody biomass to facilities that can beneficially use it. This may come in the form of direct investment, coordination to streamline facility development, or other activities as described below. These efforts will help to scale private sector investment in forest management and clean energy efforts, and reduce black carbon emissions from pile burning and wildfire.
- **Implement Governor Brown's Proclamation.** Among other activities, the Proclamation calls for ARB and CAL FIRE to work with federal agencies and land managers to "expand the practice of prescribed burns, which reduce fire risk and avoid significant pollution from major wildfires, and increase the number of allowable days on a temporary basis to burn tree waste that has been removed in high hazard areas." The agencies will implement this Proclamation to reduce the wildfire risk posed by dead and dying trees, through the public process of the Tree Mortality Task Force.
- **Collaborate with federal and private landowners.** The State is targeting investments to achieve net GHG emission benefits in areas that have high rates of carbon stock and face heightened wildfire risk from overstocked forests and dead or dying trees. Coordinating with public and private land owners in shared watersheds or firesheds is important to maximize the positive impacts of these treatments beyond the immediately treated area. Additionally, CAL FIRE will

continue working with Federal agencies, local jurisdictions and private land owners through existing agreements and mechanisms to support forest management operations.

Align Financial Incentives with Beneficial Use of Woody Waste

Current volumes of woody waste from forests and other sources, let alone increased volumes that will come from improved forest management practices, far exceed the markets and available uses for this material. By helping to develop markets for industries that can utilize this material, the State can help unlock the value intrinsic in California's woody biomass waste streams and capture additional economic and environmental benefits associated with forest management. This will help improve the economics associated with transporting residues from the forest, providing alternatives to pile burning and reducing black carbon emissions associated with forest management. It will also help to scale investment to help sustain forest management operations at necessary levels. Accordingly, the State will take additional steps to support beneficial uses of woody waste:

- **Demonstrate and prioritize integrated, community-based models.** Projects like the one awarded to California as part of the National Disaster Resilience Competition offer a wide array of benefits, including community-scale benefits much broader than those just associated with forest health. This project can serve as a model for rural communities near forested lands to support ecological restoration and hazardous fuels reduction, while supporting economic growth and diversification and community wildfire protection. The State will work with its partners to secure financing and develop this project, with a key focus on replicability and scalability.
- **Support clean energy and fuel production.** As described above, California has several programs in place to support clean energy and fuel production from sustainably harvested forest waste and other organic resources. Some of these programs, such as the bioenergy feed-in tariff, LCFS, and Cap-and-Trade, are relatively new programs and could support more clean projects moving forward. The State will encourage policies, strategies and investments, from both private and public funds, to further support clean energy and fuel production from forest biomass. One potential source of public funding is the \$140 million for healthy forests in the Governor's 2016-17 budget proposal, which includes support for biomass electricity generation projects. Governor Brown's Proclamation directs the CEC to prioritize EPIC grant funding for woody biomass-to-energy technology development and deployment. CEC is now accelerating the schedule for more than \$15 million in EPIC research funding to support woody biomass to energy projects. The State is also evaluating a variety of potential policies that could reduce the cost to collect and transport woody biomass to energy and fuel production facilities, modernize existing biomass facilities, build new community-scale facilities that use the best available emission control technologies, and develop and transfer new technologies to market. To the extent possible,

policies will support technologies and strategies that minimize criteria and air toxic pollutants.

- **Foster markets for sustainably harvested wood products.** A diversified industry infrastructure is necessary to allow different species and sizes of woody biomass to be effectively utilized. Wood products industries are an important element of this infrastructure. They can also be an important part of integrated, community-based models that the State will continue to prioritize. In addition to scaling these models, and pursuant to Governor Brown's Proclamation, State agencies will work to expand and diversify markets for sustainably harvested wood products.

Support Management Efforts and Market Development through Research

Additional research will help support the actions identified above to further target forest management activities to reduce black carbon emissions, accelerate market development for beneficial use of woody biomass, and to maximize the economic and environmental benefits provided by California's forests. Several benefits associated with forest management practices are not well-understood or valued in current markets or policy programs. For example, current research suggests biochar could contribute to significant carbon storage globally, but the benefits of large-scale projects have not been demonstrated or quantified, and several research gaps remain. Healthy, resilient forests provide water supply and quality benefits to major metropolitan areas and agricultural landowners but management is not supported through user fees.¹⁰⁰ Quantifying and verifying these benefits could allow them to be captured in State policies or commercial transactions, supporting private investment in healthy forest management.

- **Improve understanding of the feedstock.** Pursuant to the Emergency Proclamation on Tree Mortality, CAL FIRE and CEC will work with land managers to estimate biomass feedstock availability, storage locations, and volumes that may be available for use as bioenergy feedstock at existing and new facilities. These data will be used to develop medium- and long-range plans to diversify biomass markets, expand existing ones, and for the identification and distribution of incentives.
- **Identify a broad scope of benefits and options to value them.** Resilient forests and healthy watersheds provide valuable goods and services, including but not limited to secure water supply and water quality, wildlife habitat, clean air, carbon storage and reduced forest GHG emissions, timber resources and local economic development opportunities. Investing in forest health has a large multiplier impact, however several of these goods and services are difficult to quantify and even those that can be quantified are often not accounted for when evaluating economic benefits. State agencies will support research and demonstration projects to improve accounting of potential benefits associated with healthy forest management, and will consider incorporating the range of

¹⁰⁰ R Bales, M Conklin et al. (2015) Sierra Nevada Adaptation Management Project, Appendix E: Water Team Final Report.

benefits into programs and cost/benefit calculations where they can be appropriately quantified. If they can be reliably quantified and valued, these benefits may provide a revenue source to support forest management.

Integrate State Planning Efforts and Goals

The actions identified in this Proposed Strategy, and those already underway pursuant to Governor Brown's Proclamation on Tree Mortality, represent immediate steps that the State can take to reduce wildfire risk and black carbon emissions. Additional planning efforts underway will flesh out a broader vision and set of activities to improve forest health and enhance carbon storage over time. Throughout these and other efforts, State agencies will coordinate efforts to align priorities and actions. They will also increase information sharing associated with research, monitoring, and the state of forest management practices.

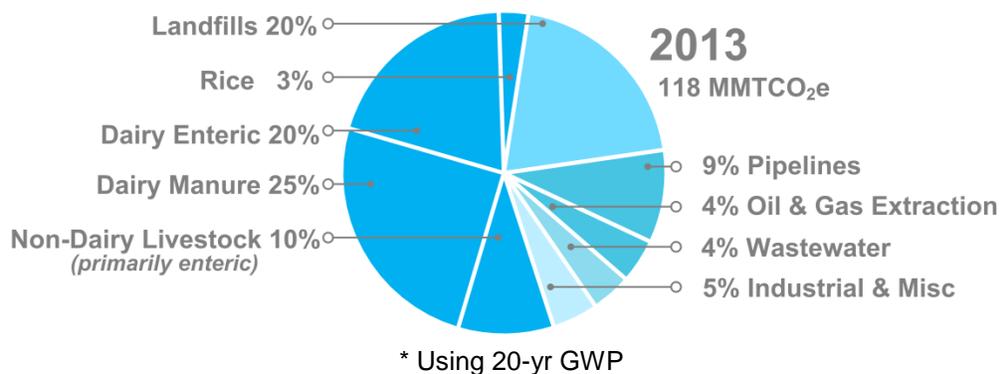
- **Identify targets for forest and climate planning in 2030 Target Scoping Plan Update.** The 2030 Target Scoping Plan Update will include specific climate-related planning targets for natural and working lands, including forests, and an accounting and monitoring framework for monitoring progress toward meeting the targets. Agencies will work together to develop methods for monitoring the black carbon and GHG emission reductions and carbon sequestration associated with these targets, and will report on progress in regular updates to the Scoping Plan.
- **Develop Forest Carbon Plan to outline implementation activities to meet 2030 Target Scoping Plan Update and other targets.** The Forest Climate Action Team (F-CAT) will complete a Forest Carbon Plan, which will cover a broad range of management and conservation priorities for California's forests and implementation mechanisms and strategies for achieving them, including the targets and recommendations included in this Proposed Strategy and the 2030 Target Scoping Plan Update. This coordinated planning process will provide for an ongoing and collaborative forum guiding sustainable forest management activities in California moving forward.

V. Reducing Methane Emissions

Methane is emitted from a wide range of fugitive sources and biological processes, and is the second largest source of GHG emissions globally. Methane emissions are growing globally as a result of human activities related to agriculture, waste handling and treatment, and oil and gas production. Agriculture represents the largest methane source in California, accounting for nearly 60 percent of methane emissions (Figure 6). Landfills are the next largest source of methane, accounting for a fifth of statewide methane emissions. Pipeline leaks, oil and gas extraction, wastewater, and other industrial and miscellaneous sources make up the remainder of emissions. As California continues to rely on natural gas for a large fraction of its energy supply, it is critical to increase supplies of renewable natural gas and minimize fugitive emissions of methane from natural gas infrastructure.

In California, where natural gas may increasingly fuel trucks and heavy-duty vehicles, we must ensure that the use of natural gas provides a climate benefit compared to the diesel fuel it displaces. As we increase the number of facilities producing and using renewable supplies of natural gas, hydrogen, or other fuels in a cleaner energy economy, we must also take steps to minimize potential methane leaks from those facilities. ARB and other agencies are funding research to identify high-methane “hot spot” emitters in the oil and natural gas sector and other sectors throughout California.

Figure 6: California 2013 Methane Emission Sources*



California can cut methane emissions by 40 percent below current levels in 2030 by avoiding or capturing methane from manure at large dairies, meeting industry targets for reducing methane emissions from enteric fermentation, effectively eliminating disposal of organics in landfills, and reducing fugitive methane emissions by 40-45 percent from all sources.

A. Progress to Date

The State has taken important steps to reduce methane emissions from all its major sources, but more needs to be done to control methane emissions, especially from organic waste streams going to landfills and at dairies. In addition to reducing methane

emissions from these sources, capturing methane can provide fuel for power plants, buildings, vehicles and industrial operations to displace fossil-based natural gas use.

Technologies to recover methane are already widely available and used in key sectors. For example, some methane emissions from landfills, wastewater treatment facilities or from manure at dairies are already captured and used as a renewable source of natural gas to fuel vehicles or generate electricity. Some organic materials, such as food waste and yard trimmings, are being redirected from landfill disposal to anaerobic digestion and composting facilities to produce renewable energy, fuel and soil amendments.



Steps are also being taken to reduce natural gas leaks from oil and gas wells, pipelines, valves, and pumps to improve safety, avoid energy losses, and reduce methane emissions associated with natural gas use.

In addition to ongoing efforts and practices to reduce and use captured methane for beneficial purposes, several recent legislative and regulatory actions will further support the reduction or capture of methane within these sectors. These actions prioritize diverting organic

material from landfills and include incentivizing the use of biogas for transportation fuel, pipeline injection, or electricity generation.

- California has established clear goals to reduce waste disposal, and divert organic material from landfills for beneficial purposes. AB 341 (Chesbro, Chapter 476, Statutes of 2011) established a State target to reduce the amount of solid waste sent to landfills by 75 percent by 2020, through recycling, composting, and source reduction practices. The 2014 Scoping Plan Update calls for eliminating the disposal of organic materials at landfills, which would potentially eliminate future methane emissions from landfills.
- The Legislature recently took steps to further increase the diversion of organic materials from landfills. AB 1826 (Chesbro, Chapter 727, Statutes of 2014) requires businesses generating specified amounts of organic wastes to begin arranging for the recycling and diversion of those wastes from landfill disposal beginning in 2016. CalRecycle will provide an annual public update on the disposal, diversion, and recycling of organics, beginning in 2016, pursuant to this mandate. AB 1594 (Williams, Chapter 719, Statutes of 2014) re-classifies the use of green waste for landfill “alternative daily cover” as disposal, beginning in 2020. AB 876 (McCarty, Chapter 593, Statutes of 2015) requires local governments, beginning August 2017, to assess the amount of organic waste that will be generated in a region during a 15-year period and identify locations

for new or expanded organic waste recycling facilities capable of handling this material.

- Methane emissions from landfills are controlled under ARB's Landfill Methane Control Measure, which was approved in 2009. The regulation requires owners and operators of certain previously uncontrolled municipal solid waste landfills to install gas collection and control systems, and requires existing and newly installed gas and control systems to operate in an optimal manner. The regulation allows local air districts to voluntarily enter into agreements with ARB to implement and enforce the regulation and to assess fees to cover costs. .
- Senate Bill 1122 (Rubio, Chapter 612, Statutes 2012), directed the California Public Utility Commission (CPUC) to require the State's investor owned utilities to develop and offer 10 to 20 year market-price contracts to procure an additional 250 megawatts of cumulative electricity generation from biogas facilities that commence operating on or after June of 2013. Eligible projects and sources include biogas-generated electricity from wastewater treatment, municipal organic waste, food processing, dairy manure and agricultural organic material, and sustainable forest materials.
- The Low Carbon Fuel Standard (LCFS) requires transportation fuel providers to procure clean fuels to reduce the carbon intensity of California's fuel mix. In doing so, it provides a market signal to incentivize developing clean fuel options, including capturing or avoiding methane emissions and using associated renewable natural gas as a transportation fuel. Some LCFS pathways related to renewable natural gas have the lowest carbon intensities of pathways to date. Specifically, the production of biomethane from high solids anaerobic digestion of organic (food and green) wastes has a carbon intensity of -15 gCO₂/MJ, and a recently approved pathway for biogas from a dairy digester project has a carbon intensity of -276 gCO₂/MJ. If LCFS credit prices are \$100/MT, as they have been recently, the value of LCFS credits from these pathways is about \$1.50 per diesel-gallon equivalent and \$5.00 per diesel gallon equivalent, respectively (or about \$11/MMBtu and \$36/MMBtu of natural gas, respectively). Transportation fuel derived from biogas may also qualify for Renewable Identification Number (RIN) credits as part of the U.S. EPA Renewable Fuel Standard 2, which could add additional value to these types of projects.
- Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) directed the CPUC to adopt natural gas constituent standards (in consultation with ARB and the Office of Environmental Health and Hazard Assessment). The legislation is also designed to streamline and standardize customer pipeline access rules, and encourage the development of statewide policies and programs to promote all sources of biomethane production and distribution. It also directs the CEC to identify constraints to the use and interconnection of biomethane and offer solutions in its Integrated Energy Policy Report. The CPUC has adopted natural gas constituent standards and created a program to offset a portion of gas

producers' costs of connecting to utility pipelines by providing up to \$1.5 million per biomethane project, up to a cap of \$40 million total.

- Pursuant to Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013), the CEC has released a report identifying strategies for maximizing the benefits obtained from natural gas as an energy source.¹⁰¹ The report examines strategies and recommendations regarding natural gas, including low emission resources such as biogas and biomethane; the use of natural gas as a transportation fuel; centralized and distributed electricity generation; cooking, cooling, and space heating; engine and appliance applications; its role in the development of zero net energy buildings; and GHG emissions associated with the natural gas system. The report also examines infrastructure and storage needs and pipeline and system reliability concerns.
- ARB's Cap-and-Trade Program will reduce demand of fossil fuels and provide incentives to accelerate efficiency and clean energy. Compliance Offset Protocols under the Cap-and-Trade Program provide methods to quantify, report, and credit GHG emission reductions from sectors not covered by the Cap-and-Trade Program. The Offset Protocols include a livestock protocol, rice cultivation protocol, and mine methane capture protocol.¹⁰² The livestock protocol credits operators who voluntarily install manure biogas capture and destruction technologies. The rice protocol allows compliance offset credits to be issued for emission reductions achieved by switching to rice cultivation practices that reduce methane emissions. The mine methane capture protocol incentivizes capturing methane that would otherwise be vented into the atmosphere from active and abandoned mines.

A broad array of these and other state programs reducing dependence on fossil fuels are also already working to reduce methane emissions, especially from the oil and gas sector. Ultimately, fugitive methane emissions in the oil and gas sector are a function of our demand for these products. As state policies continue pushing our evolution away from conventional oil and natural gas, they will also help to reduce emissions of methane from the production and distribution of fossil fuels. In particular, efforts to improve efficiency or electrify appliances, buildings, and vehicles will not only reduce energy use and CO₂ emissions, but also serve to reduce or avoid fugitive methane

¹⁰¹ *AB 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source*, California Energy Commission, September 2015.

<https://efiling.energy.ca.gov/Lists/DocketLog.aspx?doctetnumber=15-IEPR-04>

¹⁰² As is discussed in more length in the CEQA document accompanying this document, the livestock offset protocol would likely cease accepting new projects for offset credits after the effective date of substantive regulations controlling agricultural methane from dairies; however, existing projects could continue generating credits throughout their crediting periods. ARB expects this continued funding stream, along with increased focus on regulatory and incentive measures in this area, to mean many projects now receiving offsets to continue functioning at the end of the crediting period; this, along with new regulations, will produce significant net reductions in methane even if some offset projects cease to function. This transition from offset protocols towards regulations has long been ARB policy.

emissions from the production, and potentially transmission and distribution, of oil and natural gas.

The State has strong targets to reduce the use of natural gas and petroleum by 2030, and several studies show that California must virtually eliminate the use of all fossil fuels to meet its 2050 climate targets. Notably, Governor Brown has called for reducing on-road petroleum use by up to 50 percent by 2030, and Senate Bill 350 (De León, Chapter 547, Statutes of 2015) requires the State to procure 50 percent of its electricity from renewable resources by 2030 and double the rate of natural gas and electricity efficiency savings. ARB's draft 2016 Mobile Source Strategy describes actions to achieve the State's air quality and climate targets from the transportation sector, and cut petroleum use by 50 percent by 2030. The State's Low Carbon Fuel Standard is sending a clear signal to the market that is leading to investment and use of a broad spectrum of cleaner transportation fuels in California including electricity, biogas, as well as biodiesel and renewable diesel, all of which are displacing petroleum. Further, the State's Cap-and-Trade program encourages efficiency and use of non-fossil energy sources across all sectors of the economy, and various programs provide billions of dollars in incentives to support energy efficiency throughout the State.

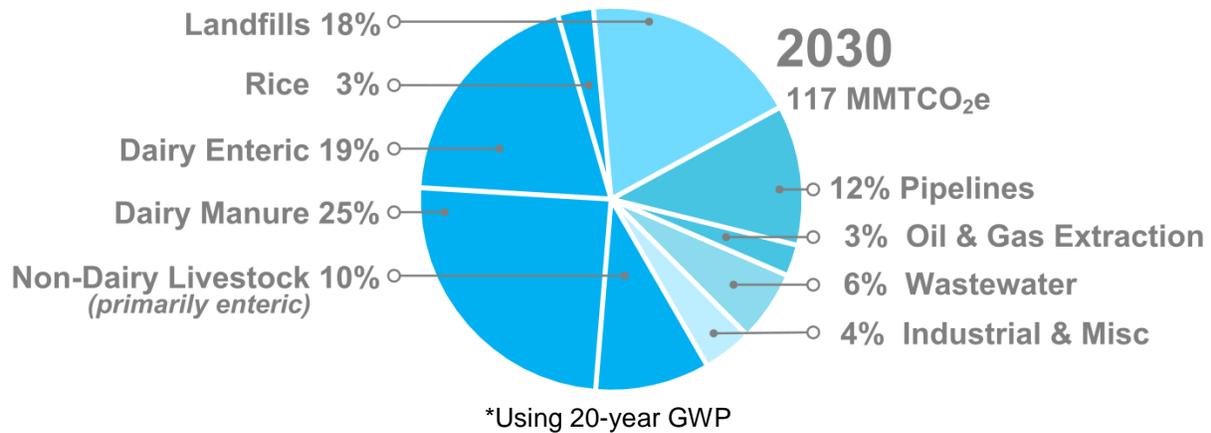
Effectively implementing these actions and programs will significantly cut demand for fossil fuels and associated CO₂ emissions on trajectories we need, while further reducing methane emissions from oil and gas systems. As State agencies implement and refine these programs and plans, they will seek opportunities to better align them with these objectives. Additionally, State agencies will support research to inform appropriate approaches to continue its transition away from fossil fuels.

Further, several efforts are underway at the CEC and ARB to improve emissions monitoring to help identify sources of fugitive methane emissions and reduce them. For example, the CEC provided research funding for operation of a mobile leak detection platform. In 2016, ARB will release a Request for Proposal (RFP) to collect emissions data from oil production wastewater ponds. Results from this contract are expected in 2018, and if they indicate that these ponds are significant sources of methane, ARB may initiate a regulatory process to reduce those methane emissions. Additionally, ARB and NASA's Jet Propulsion Laboratory are collaborating to identify large "hot spot" methane sources through a systematic survey of high methane emitters throughout California. This project will use aerial and ground measurement to survey oil and gas fields and infrastructures, dairies, feedlots, digesters, landfills, rice fields, and wastewater treatment facilities to provide a greater understanding of methane sources. Finally, ARB is actively participating in the Megacities Carbon Project being conducted in the South Coast Air Basin, which is developing and testing methods for monitoring various GHG emissions to link monitored concentrations to emission activity. These efforts will help identify significant fugitive methane sources in California and improve leak detection.

Collectively, these measures will help to keep methane emissions in California fairly steady through 2030. However, the science-based pathway to limiting global warming

below 2°C—including meeting the Governor’s goal to reduce GHG emissions by 40 percent below 1990 levels by 2030—requires further reducing methane emissions in California. Significant opportunity remains to further reduce methane emissions from the major sources in the State (Figure 7). Doing so will require overcoming various economic and institutional barriers, but will provide a wide range of economic and environmental benefits throughout the State, especially where they are most needed.

Figure 7: California’s 2030 Methane Emission Sources with Existing Measures*



B. Recommended Actions to Further Reduce Methane Emissions

California can reduce methane emissions by 40 percent below current levels through a collaborative and mixed approach that combines incentives, public and private investment and partnerships, systematic planning, and regulatory efforts. California’s strategy to reduce methane emissions reflects and supports the variety of approaches and options available to achieve the goal in the most efficient, cost-effective, and environmentally-sensitive manner. This Proposed Strategy promotes and encourages opportunities for industry innovation, the efficient use of existing infrastructure and facilities, and supports the development of integrated systems across various sectors to handle, process, and reuse waste materials and captured methane. For example, significant anaerobic digestion and composting infrastructure capacity needs to be established, and appropriate market opportunities developed for compost and captured methane, before the State can fully use existing organic waste streams for beneficial purposes. State agencies will work with industry and other stakeholders to support and accelerate new project development and activities to maximize methane emission reduction at existing facilities. The State will also work with communities and regional stakeholders to plan and develop integrated infrastructure systems and markets to reduce wastes and associated emissions in the most environmentally-sensitive manner. By investing early and committing to the immediate resolution of issues that hinder progress, California can make significant progress in the near-term, and capture associated benefits.

There are a host of activities underway at the State and Federal level, and by gas utilities, to reduce methane emissions from the natural gas system. In particular,

regulations are being developed to reduce fugitive methane emissions from the oil and gas production, processing and storage sector, and from the natural gas transmission and distribution system. By effectively implementing these policies, and supporting them with continued and improved emissions monitoring, California can match the goals of the Obama Administration to reduce methane emissions from the oil and gas sector by 40-45 percent by 2025. The State will aim to extend successful approaches to reduce emissions from the oil and gas sector to other sectors, and overall, to reduce fugitive methane emissions from all sources by similar levels by 2030.

Table 6, below, describes emission reductions by sector to reduce methane emissions by 40 percent below current levels by 2030. The expected emission reductions for each sector are: 75 percent reduction of dairy manure methane from 2013 levels by 2030; 25 percent reduction of enteric fermentation methane by 2030; 90 percent diversion of organic waste by 2025; 40 percent reduction of wastewater and other industrial sources methane by 2030; and 45 percent reduction of oil and gas methane by 2030.

Table 6: Proposed New Methane Emission Reduction Measures and Estimated Emission Reductions (MMTCO₂e)¹

| Measure Name | 2030 Annual Emission Reductions | 2030 Annual Emissions |
|--|---------------------------------|-----------------------|
| 2030 BAU ² | | 117 |
| Dairy Manure | 21 | |
| Dairy and Livestock Enteric Fermentation | 5 | |
| Landfill | 5 | |
| Wastewater, industrial and Other Miscellaneous Sources | 7 | |
| Oil and Gas Sector | 8 | |
| 2030 BAU with new measures | | 71 |

¹ Using 20-year GWPs from the 4th Assessment report of the IPCC

² "Business As Usual" (BAU) forecasted inventory includes reductions from implementation of current regulations

1. Dairy Manure

California's dairy and livestock industries account for roughly half of the State's total methane emissions and about five percent of the State's overall GHG emissions. About half of the emissions from the State's 5.5 million total beef and dairy cows come from enteric fermentation (mostly belching), and the other half from manure management practices, primarily lagoon storage of flushed manure from milking cows.

California has the most dairy cows in the country and the highest aggregated dairy methane emissions. The State also has higher per-milking cow methane emissions than most of the rest of the United States, due to the widespread use of flush water lagoon systems for collecting and storing manure. Milk production feed efficiency at California dairies, however, is among the best in the world; California dairy cows produce low enteric fermentation emissions per gallon of milk. So if dairy farms in California were to manage manure in a way to further reduce methane emissions, a gallon of California milk might be the least GHG intensive in the world.



Dairy methane emissions may be significantly reduced by switching from flush water lagoon systems without methane capture to solid-scrape (i.e. slurry) or dry manure management practices. Anaerobic digesters can also be installed to capture and utilize manure methane, and can be used with flush water lagoon systems, dry, or solid-scrape manure collection practices. The use of manure systems such as vacuum or scrape also allows for easier transport and storage of manure off-site or to centralized digester systems, which can improve economies of scale, biogas production efficiencies, and nutrient management on the dairy. Dairy manure can also be mixed with other organic materials diverted from landfills or at wastewater treatment plants to improve digester performance and economics, with centralized digesters playing a key role in helping California meet its organic diversion and bioenergy goals.

Dairies with flush water lagoon systems typically flood irrigate dairy feed crops, such as corn silage and alfalfa, to dilute and disperse nutrients from manure in the lagoon. This practice can lead to soil and groundwater contamination despite being subject to regulation by regional water quality control boards, including the Dairy General Order in the Central Valley. Solid-scrape manure management may lead to air quality challenges, however, which need to be fully considered. Ultimately, the optimal mix of technologies and manure management practices to reduce methane emissions, protect air and water quality, and support dairy economics will depend on dairy-specific factors and vary across the State.

In some instances, pasture-based dairy management may be an option, as well, but there are tradeoffs that limit its applicability. In a pasture system, manure is left in the field and decomposes aerobically (versus anaerobically in a lagoon), which avoids methane emissions. Many organic milk producers rely on pasture systems for much of their operations, and it is a fairly common practice in other states and at smaller dairies in coastal and northern parts of California. However, for larger dairies and those in the Central Valley, pasture would require using significantly more irrigated land and may also pose feed production issues and animal welfare concerns due to heat exposure. Pasture dairy operations may still face potential nutrient management and groundwater

issues, and still must maintain some capacity to store liquid coming from milking parlor operations (chilling milk, cleaning facilities, etc.) for the required 100 year stormwater retention. Milk production and feed efficiencies are lower in pasture-based systems, requiring more cows and higher enteric fermentation emissions per unit of milk, and pasture-based systems limit the ability to manage manure as a valuable organic waste resource. Pasture-based systems are a viable option that is appropriate in some cases, but likely challenging to implement at many existing, larger dairies in the Central Valley.

Captured biogas from dairy manure can be used to power farm trucks and equipment, injected into natural gas pipelines, used as a transportation fuel, or used to generate on-site renewable electricity and heat. However, tapping into this resource in California has been complicated in the past due to air quality constraints, especially in the Central Valley and Southern California. Utilizing newer and clean technologies can help to overcome air quality permitting issues that have previously hindered project development. In particular, technologies or strategies that reduce or eliminate criteria pollutant and toxic emissions should be encouraged in both incentive and regulatory programs, particularly in areas with severe or extreme air pollution. For example, using ARB-certified distributed generation technologies, such as microturbines or fuel cells, can significantly cut NO_x emissions compared to internal combustion engines. Injecting biogas into the natural gas pipeline can avoid most new combustion or associated emissions altogether. As part of an integrated strategy that includes replacing diesel trucks and equipment with certified ultra-low NO_x vehicles or equipment, fueling vehicles with dairy-derived biogas could help to reduce criteria pollution in impacted air basins.

California will aim to reduce methane emissions from dairy manure management by at least 20 percent in 2020, 50 percent in 2025, and 75 percent in 2030. If dairy cow populations don't grow in California, in line with current forecasts, these reductions would reduce overall methane emissions from the dairy industry by more than 40 percent in 2030. Through this Proposed Strategy and related efforts, we can quickly and effectively reduce methane emissions from the State's largest source, while creating economic value in farming communities. While barriers remain to building out necessary infrastructure in the State, if the market were fully enabled, anaerobic digestion at California dairies could lead to billions of dollars of investment and thousands of new jobs, concentrated in the Central Valley (see Chapter VIII). Working together, State agencies, dairy farmers, and other stakeholders can achieve this level of reduction through a combination of financial incentives, infrastructure deployment, market development and regulatory actions.

These targets can be achieved by capturing or avoiding methane currently emitted from lagoons or other anaerobically stored manure at a relatively small fraction of the State's dairies. For example, dairy manure emissions can be reduced by 75 percent by capturing or avoiding the methane generated by about 60 percent of the State's milking cows (1.05 million) on about 30-35 percent of the State's dairies (about 500 dairies).¹⁰³

¹⁰³ California has over 1,400 dairies, with approximately 1,000 having more than 500 milking cows which might be suitable for methane capture or abatement (refer to Chapter VIII for a discussion on potential manure methane mitigation options and cost estimates).

The 2020 and 2025 targets could be met by capturing or avoiding methane generated by about 15 percent and 40 percent of the State's milking cows, respectively.

Depending on the strategies pursued to reduce emissions, individual dairies may be able to reduce emissions profitably, and the industry as a whole may be able to meet these targets at little or no net cost (see Chapter VIII). However, revenues in some cases are highly dependent on uncertain environmental credit and energy markets, as well as the ability to interconnect to natural gas pipeline systems, where economic and institutional barriers remain. If regulations impose costs on the industry that cannot be recouped, a result could be emissions leakage, if some dairies relocate outside of California or herd sizes grow elsewhere. This could include places where milk production efficiencies are lower and associated enteric fermentation emissions are higher and could increase mobile source emissions from heavy duty vehicles associated with transport of dairy products to established processing facilities and distribution centers.

Accordingly, the State will encourage and support near-term actions by dairies to reduce emissions through market support and financial incentives. At the same time, ARB will initiate a rulemaking process to develop regulations for dairy manure management in California. This coordinated approach will aim to develop a competitive, low-carbon dairy industry in California and avoid emissions leakage. Specifically, California will take the following steps to significantly cut methane emissions from manure management at dairies:

Accelerate Project Development and Emission Reductions at Dairies

The State will support the industry to accelerate project development and help the industry reduce emissions before regulatory requirements take effect. In particular, the State will work to support improved manure management practices through financial incentives, collaboration to overcome barriers, and other market support.

Continued State funding or incentives should support initial infrastructure investments to convert dairies away from flushwater management systems and support market opportunities for the use of captured or produced biomethane. CDFA estimates that at least \$100 million will be needed for each of the next five years to support the development of necessary manure management infrastructure in the form of grants, loans, or other incentive payments. The economic analysis in



Chapter VIII suggests that this level of funding could significantly accelerate project development by reducing capital costs and economic risks. Different types of funding mechanisms and level of support may be appropriate for different types of projects.

ARB and CDFA staff will establish a working group with other relevant agencies and stakeholders to focus specifically on solutions to barriers to dairy manure projects. The group will aim to ensure and accelerate market and institutional progress. It may cover several topics, including: project finance, permit coordination, CEQA, feed-in tariffs, simplified interconnection procedures and contracts, credits under the LCFS, increasing the market value of manure products, and uniform biogas pipeline standards. This group will be coordinated with similar working group efforts related to anaerobic digestion, composting, energy, healthy soils, and water. Additionally, State agencies will coordinate activities with federal agencies, including the U.S. Department of Agriculture and U.S. Department of Energy, to align common efforts and attract federal investment to California. Further, ARB will work with State and Regional water quality agencies to ensure opportunities for conservation and water quality efforts are developed jointly and with the air districts to ensure opportunities for air quality efforts are developed jointly.

In many cases, converting to scrape systems or installing anaerobic digesters at dairies may not yet be cost-effective, if the only marketable product is energy. However, if compost or other soil amendment products and environmental credits can be monetized from these projects, as well, they may offer attractive rates of return for farmers and investors.¹⁰⁴ Markets for these other products need further support, however, before they can offer reliable returns to help finance projects. CalRecycle, CDFA, and other agencies are working together to support healthy soils through composting and building markets for soil amendment products in the State. Enabling pipeline injection of biomethane and minimizing associated costs will help get dairy biogas into the transportation sector and allow for the generation of LCFS and RIN credits, which could provide an especially valuable revenue stream.¹⁰⁵ The State will continue to support these efforts.

Develop Regulations to Ensure Emission Reductions

While the State will encourage early emission reduction actions by dairies through market support and financial incentives, regulations will be necessary to ensure manure management practices lead to lasting emission reductions. In 2017, and in coordination with CDFA and local air quality and water quality agencies, ARB will initiate a rulemaking process to reduce manure methane emissions from the dairy industry in-line with the objectives in this Proposed Strategy. The regulatory process will include

¹⁰⁴ For example, one report estimates that the average internal rate of return for dairy digester projects in the U.S. that only capture value from energy production would be about 8 percent in a mid-valuation scenario, but would increase to 38 percent if value can be captured from soil amendments and markets for environmental credits.

Informa Economics (2013) National Market Value of Anaerobic Digester Products, Prepared for the Innovation Center for U.S. Dairy, February.

¹⁰⁵ Under the LCFS, ARB recently approved a dairy digester fuel pathway with a carbon intensity of -276 gCO₂e/MJ. <http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/calbio-sum-122115.pdf>
At credit prices of \$100/MT, these credits could be worth about \$5 per diesel gallon equivalent.

consideration of available financial incentives, market support, and the potential for emissions leakage in identifying appropriate timelines and requirements for the industry.

The rulemaking will also include requirements for mandatory reporting and recordkeeping of parameters affecting GHG emissions at California dairy farms. Reported information will be used to refine inventory quantification, evaluate policy effectiveness, and aid in future policy planning and regulatory development. ARB will work with other State agencies and industry groups to improve outreach on new reporting requirements, as well as merge and streamline reporting activities with current forms and requirements to avoid duplicative reporting wherever feasible.

Regulatory requirements to achieve large emission reductions from the industry will affect incentives for dairy methane reduction projects, such as the availability and amount of credits under the Cap-and-Trade program and LCFS. Once a regulation is in place, credits for avoided methane emissions under the LCFS or the Cap-and-Trade Programs would not be available for new projects as the reductions would not be additional to regulation or business-as-usual. However, projects in place before the regulation takes effect would still be able to generate credits for avoided methane emissions for their current crediting period, which is ten years of operation. For new projects after a regulation takes effect, credits under the LCFS would still be available, but would only consider the displacement of petroleum fuel. ARB will clarify the impact of potential regulations on LCFS credits before finalizing a regulation, and will make appropriate adjustments to the Cap-and-Trade Program to ensure only reductions that meet the AB32 offset criteria are credited. Sufficient lead time will be provided before regulatory requirements take effect to allow the market to react.

Research the Reduction Potential of Manure Management Practices

While the need and potential to reduce methane emissions from dairy manure is clear, some potentially effective strategies are still in the development stage. In particular, the use of solid separators and converting flush systems to dry manure management systems could be potentially low cost methods to reduce methane emissions. However, little data exists to quantify costs and benefits associated with these practices. Additionally, some uncertainty remains regarding cross-media impacts and accounting of various dairy manure management practices. ARB and CDFA will continue to support research to eliminate information gaps and improve understanding of potential manure management practices and their associated methane reduction benefits, as well as potential air quality or water quality impacts.

2. Dairy and Livestock Enteric Fermentation

Methane is also produced by the microorganisms involved in the digestive processes in the stomachs of dairy cows and other ruminants, such as sheep, goats, buffalo and cattle. This process is referred to as enteric fermentation. These emissions account for 29 percent of California's methane inventory, making it essential to develop strategies to reduce emissions from these sources to meet State GHG emission reduction targets.

Strategies that have been investigated to reduce enteric fermentation include increasing production efficiencies to reduce the amount of methane produced for a given amount of product, breeding animals for lower methane production, gut microbial interventions, and changes to nutrition and animal management. Further research is needed to fully evaluate the viability of these strategies to California; and to assess their associated costs and co-benefits, potential impacts on animal productivity, on animal and human health, other environmental impacts, and GHG and air toxic emissions associated with feed lifecycles. Strategies to produce more easily digestible feed that lowers enteric fermentation might increase emissions associated with GHG-intensive feed production and transport. Therefore, regionally-specific lifecycle emission assessments of enteric fermentation emission reduction strategies would need to be used to account for any unintended emission increases in other sectors.



The dairy industry in California and the U.S. has been working to increase efficiencies associated with their operations and product. A broad coalition of the national dairy industry set GHG sustainability targets for 2020. The targets include reducing the GHG intensity of fluid milk by 25 percent,¹⁰⁶ and enteric fermentation emissions by 25 percent.¹⁰⁷ If a 25 percent reduction in enteric fermentation emissions from California's dairy cows were achieved by 2030, it would reduce the State's methane emissions by 5 MMTCO₂e (based on a 20-year GWP).

This Proposed Strategy sets those levels as a goal for reducing methane emissions from enteric fermentation in California. Combined with the goals for manure management, this would bring emissions for the dairy industry down by 40 percent below current levels in 2030. By continuing historic annual improvements in milk production efficiency and progressing toward their established voluntary targets, the industry may meet this goal independently. Additionally, various studies are pointing to new feed supplements that have the potential to reduce enteric fermentation emissions 20-30 percent without affecting milk production.^{108,109}

¹⁰⁶ <http://www.usda.gov/wps/portal/usda/usdamediafb?contentid=2013/04/0076.xml&printable=true&contentidonly=true>

¹⁰⁷ Innovation Center for U.S. Dairy (2008) U.S. Dairy Sustainability Initiative: A Roadmap to Reduce Greenhouse Gas Emissions and Increase Business Value, December. <http://www.usdairy.com/~media/usd/public/roadmapreduceghgemissions.pdf.pdf>

¹⁰⁸ Hristov et al (2015) An inhibitor persistently decreased enteric methane emission from dairy cows with no negative effect on milk production, *Proceedings of the National Academy of Sciences*, 112(34):10663-10668. www.pnas.org/cgi/doi/10.1073/pnas.1515515112

¹⁰⁹ Moate et al (2014) Grape marc reduces methane emissions when fed to dairy cows, *Journal of Dairy Science*, 97(8):5073-5087. <http://dx.doi.org/10.3168/jds.2013-7588>

Research Mitigation Strategies for Enteric Fermentation

Federal and State agencies, industry, and academia will support research through available funding mechanisms (e.g. ARB's annual research program, Greenhouse Gas Reduction Fund), and continue to monitor progress to develop strategies that can help to reduce enteric fermentation emissions from dairy cows and livestock in the California context. Once mitigation strategies have been successfully evaluated, long-term emission reduction potential and goals can be established on a broader scale. As ARB develops an emission reduction regulation for manure management, staff will continue to evaluate the latest science of enteric fermentation and identify the best approach to addressing these emissions.

3. Landfills

Landfilling organic materials leads to the anaerobic breakdown of these materials into methane, which can work its way out of the landfill as a fugitive emission. Organic waste constitutes more than 40 percent of California's waste stream, and as with dairy manure, a holistic approach is needed to effectively divert and manage it. This means not only keeping organics out of landfills, either through source reduction or diversion, but also improving the infrastructure for diverting and/or recycling organics, including minimizing and salvaging edible food wastes, composting, anaerobic digestion and other novel processes for energy recovery. In particular, California must have enough in-state composting and in-vessel digestion or other organics processing and recycling capacity to maximize the benefits from this waste stream and effectively minimize the spreading of unprocessed organic waste on open lands, which can have adverse environmental impacts. It also means having markets for this material that are robust and resilient whether as food recovery or waste avoidance, compost, soil amendments, mulch for erosion control, transportation fuels, energy, or other uses. The State can accelerate progress by providing more consistent financial and institutional support for these efforts, and taking steps to align tipping fees and financial incentives in the sector with its organics diversion goals.

Diverting organic wastes can provide a variety of environmental and economic benefits. Food rescue or recovery is the practice of utilizing edible foods that would otherwise go to waste from restaurants, grocery stores, dining facilities and produce markets and distributing it to local food programs. Food recovered from farms, which would otherwise be plowed under, is typically gathered by volunteers. The main benefit of food rescue programs is that they provide healthy foods to those in need, but they also reduce organic waste disposal. Food wastes that may not be easily utilized for human consumption may alternatively be used as animal feed. Composting returns nutrients to the soil, builds soil organic matter, improves water holding capacity, increases carbon sequestration in the landscape, and avoids the use of fossil fuel-intense inorganic fertilizers. Anaerobic digestion can support the State's efforts to obtain at least 50 percent of its electricity from renewable resources, aid in reducing the carbon intensity of transportation fuels, and displace fossil natural gas consumption. As described in Chapter II, eliminating the disposal of organics in landfills as part of a broad

effort to put California's organic waste streams to beneficial use can generate thousands of jobs and provide billions of dollars in value, much of it concentrated in the Central Valley and other rural areas.

Eliminating the disposal of organics in landfills would align California with a growing range of efforts to do so in other states and countries. In California, San Francisco and Alameda County require that food waste be separated and kept out of the landfill, and both Los Angeles and San Francisco, along with other cities, have plans in place to become zero-waste.

The State has already established its intent to phase out the disposal of organics from landfills. Existing law sets a goal of diverting 75 percent of solid waste from landfills by 2020 and provides other measures and requirements to support diverting organics from landfills. California will build on that intent and progress, with market and institutional support, and divert 90 percent of organics from landfills by 2025, effectively eliminating the disposal of organics in landfills.¹¹⁰ Due to the multi-year timeframe required to breakdown landfilled organic material, emission reductions from organics diversion accumulate over time. These actions would reduce landfill emissions by 5 MMTCO_{2e} in 2030,¹¹¹ increasing to 21 MMTCO_{2e} by 2050 (using a 20-year GWP).

Still, waste-in-place will continue to emit methane for decades to come. California has a Landfill Regulation in place that requires owners and operators of certain uncontrolled municipal solid waste landfills to install gas collection and control systems. This effort has improved management of landfills in California and reduced methane emissions. There may be additional opportunities to employ best practices and further reduce methane emissions from landfills over time.

However, quantifying emissions from landfills is difficult, due to their area-wide nature and several landfill-specific factors (size, age, materials deposited, local atmospheric conditions, soils, landfill cover, and gas collection system). In the GHG inventory, and its climate programs, ARB assumes a methane capture efficiency of 75 percent at landfills. This conforms with common practice nationally. In its Landfill Regulation, ARB estimated that the landfill regulation may increase the collection efficiency at regulated landfills to 80-85 percent.

Estimates of methane collection efficiency at landfills, both with and without gas collection systems, vary widely. In the U.S. EPA landfill database, the weighted

¹¹⁰ Specifics of this measure will be developed during the regulatory process. For the sake of calculating emission reductions in this plan, it is estimated that 75 percent of organics will be diverted from landfills by 2020 and 90 percent will be diverted by 2025 (this would amount to an 80 percent reduction below current levels).

¹¹¹ Methane emission reductions from landfills (Table 6) are calculated assuming regulated landfills achieve methane capture efficiencies of 80 percent by 2030 and 85 percent by 2050, and that the State effectively eliminates organic disposal at landfills by 2025 by meeting the organics diversion targets identified in this Proposed Strategy.

average of collection efficiencies at California landfills is 78 percent.¹¹² However, this data is self-reported and the emission estimation method does not incorporate emission changes due to California's regulation. Additionally, various studies suggest that California's methane inventory is underestimating methane emissions in the State. The source(s) of potential incremental methane emissions has not been identified. Continuing evaluation of major sources of methane in the State is necessary, and this includes landfill emissions.

The State will support research to improve understanding of emissions from landfills and engage stakeholders in potential opportunities to further control them. Once more is understood about emissions from California's diverse set of landfills, ARB may update the assumptions regarding collection efficiency used in its inventory and various programs and consider whether additional actions, including a "phase 2" of the landfill regulation, would deliver further cost-effective GHG emission reductions.

Uncertainty around landfill emissions does not suggest that the existing Landfill Regulation is not reducing emissions or that steps to divert organics from landfills should be delayed. To the contrary, what is certain is that best management practices at landfills reduce methane emissions, diverting organics from landfills can provide a wide range of economic and environmental benefits in California, and that doing so is the only reliable way to avoid methane emissions from landfills on a lasting basis.

The State will take the following actions to reduce methane emissions from landfills in California:

Require Organics Diversion from Landfills

ARB, in conjunction with CalRecycle, will develop a regulation by 2018 to effectively eliminate the disposal of organics in landfills by 2025. Under this proposed regulation, the agencies will explore and prioritize opportunities to recover organic materials through local food waste prevention and rescue programs, which could account for 10 percent food waste reduction by 2020 and 20 percent reduction by 2025 in California. Food waste prevention includes activities such as education regarding food preparation and storage, refining food purchasing practices, and software that can help inform food ordering and menu selections. Rescue includes local organizations such as homeless shelters, food banks and community kitchens that provide food for people in need. Material that cannot be effectively recovered would be diverted to organics recycling facilities to make useful products,



¹¹² The average collection efficiency at California landfills in 2013, according to EPA's database is 76 percent. When weighted by methane generation, the average is 78 percent. <http://www3.epa.gov/airtoxics/landfill/landflpg.html>

including compost, fuel or energy. These facilities may be developed at existing landfills, other waste management sites, or at new stand-alone sites. Organic wastes could also be diverted to regional wastewater treatment plants or dairies for co-digestion with wastewater sludge, biosolids, or manure. Local governments must play an important role in diverting organics both as land use and permitting authorities for recycling facilities and as partners in implementing diversion requirements. The State will work with its local partners to develop helpful tools such as programmatic EIRs or guidance documents. Community engagement in the planning and environmental review processes is critical, both for understanding and mitigating potential negative health and environmental impacts and for understanding the positive economic and health and environmental benefits afforded by such projects.

Align Financial Incentives with Organics Diversion

Eliminating organics disposal in landfill will require additional infrastructure capacity to process and reuse diverted organic waste from landfills—through composting (including chipping and grinding), anaerobic digestion, or other methods. Continued, increased State funding is critical to building this necessary infrastructure. An increase in California's Integrated Waste Management Fee is also needed to support the establishment of food rescue programs, discourage the landfilling of organic waste and other recyclables, and provide funding to support organics recycling infrastructure. CalRecycle estimates that State support of at least \$100 million per year for five years, in the form of grants, loans, or incentive payments, will be needed to leverage private sector financing and local rate structure changes to support the development of necessary organic infrastructure and help to foster markets.

Collaborate to Overcome Barriers

State agencies will collaborate to resolve existing constraints in the permitting process and provide clear standards and compliance pathways for all public health and environmental goals. The beneficial use of methane produced at organic waste processing facilities faces many of the same obstacles described for dairy manure or wastewater treatment, and a common workshop or work group effort to address barriers to beneficial use of organic waste streams may be useful. Also, appropriate standards should be developed to guide the direct application of organic materials on land and ensure this activity does not pose a threat to human or environmental health.

Foster Recovery Programs and Markets

CalRecycle will work collaboratively with other agencies and departments to help establish food rescue programs and to identify, develop, and expand markets for the use of compost, mulch, and renewable fuels and energy. CalRecycle and CDFA will continue their efforts to incentivize the use of compost on agricultural lands in support of the Healthy Soils Initiative, including developing best management practices for agricultural use. They will also work with the State Water Resources Control Board to evaluate potential mechanisms to account for the use of compost and its impacts on

nitrogen budgets in the Irrigated Lands Program. CalRecycle will continue to work towards strengthening State procurement requirements relative to compost and mulch. Finally, building on the existing use of mulch and compost as a water conservation practice that is essential for climate adaptation with respect to drought, State agencies will support research to quantify water conservation and other potential benefits and consider developing mechanisms to account for and value them.

Improve Understanding of Landfill Emissions

ARB and CalRecycle will support research to improve understanding of emissions from California landfills and identify opportunities to further reduce emissions from existing waste-in-place. ARB will consider the latest science and whether adjustments to emissions accounting in the inventory or other programs is warranted. Based on this information, ARB, in collaboration with CalRecycle, may consider additional actions to further reduce and capture methane emissions from landfills in the future.

4. Wastewater Treatment and other Miscellaneous Sources

Wastewater treatment, industrial operations, rice cultivation, septic tanks, and other sources of methane account for about nine percent of the State's methane inventory.



Wastewater treatment plants provide a promising complementary opportunity to help divert a portion of organic wastes from landfills and create useful byproducts such as electricity, biofuels and soil amendments.

Wastewater treatment plants are designed to remove contaminants from wastewater, primarily from household sewage, but with infrastructure improvements could increase acceptance of food waste and fats, oils, and grease (FOG) for co-digestion. Anaerobic digestion is a typical part of the wastewater treatment process employed at most of the larger plants, with many plants capturing the methane they currently generate for on-site heating or electricity needs.

Many of these plants may have spare capacity, and can potentially take in additional sources of organic waste for anaerobic digestion. Existing or new digesters at these facilities can be designed to co-digest materials such as food waste and FOG from residential, commercial, or industrial facilities. Many of the largest plants are ideally located close to population centers and could potentially obtain and process significant amounts of food and other suitable waste streams within the region. The State proposes to take the following actions to evaluate this opportunity.

Develop Regional Opportunities to Co-Digest Waste

ARB will work with CalRecycle, the State Water Resources Control Board, Regional Water Quality Control Boards, and others to determine opportunities to support the co-digestion of food-related waste streams at existing and new digester facilities, including wastewater treatment plants.

Align Financial Incentives with Methane Capture and Reuse at Wastewater Treatment Facilities

A program that relies on financial incentives and/or regulatory actions could be implemented to ensure that new and existing wastewater treatment plants in California fully implement methane capture systems (ideally to produce on-site renewable electricity, transportation fuel, or pipeline biogas), and maximize digestion of regional organic materials. The potential actions would need to be tailored to each wastewater treatment plant based on size or capacity, and other factors such as potential for co-digestion expansion, proximity of organic waste streams, and regional air quality standards and rules. The Water Boards could develop permit terms and other regulatory tools to support the program while achieving water supply, water quality, and related co-benefits.

Collaborate to Overcome Barriers

Many wastewater treatment plants are permitted to burn digester biogas through flaring and are classified as industrial facilities. Capturing the biogas to produce electricity, such as through a combined heat and power (CHP) system may result in re-classifying the facility's purpose as "electricity generation" and subject the plant to more onerous emission compliance and abatement equipment rules. In addition, the beneficial use of methane generated at wastewater treatment facilities faces many of the same hurdles faced by dairy digesters and organic waste composting facilities. Support for technologies and strategies to capture biogas to generate electricity, supplement natural gas pipeline fuel, or for use as a transportation fuel, is needed to overcome some of these barriers and may open up more valuable fuel and credit markets. ARB will work with other relevant State and local agencies to identify and remove financial and regulatory barriers that hinder the productive use of waste streams processed at wastewater treatment plants.

5. Oil and Gas

California has a large oil and gas industry with more than 50,000 oil and 1,500 gas wells, including off-shore platforms. The majority of the oil wells are located in Southern California with most of the gas fields located in Northern California. An extensive network of oil and gas pipelines within the State transport California's crude oil from import terminals and on- and off-shore oil fields to refineries, and distributes finished fuels to more than 70 product terminals throughout the State.

California also has about 215,000 miles of natural gas transmission and distribution pipelines; 22 compressor stations; and 25,000 metering and regulating stations (M&R) stations. Natural gas is currently California's largest source of fuel for electricity generation, and supplies most of the energy used for industrial operations. Natural gas is also a primary source of energy used for residential and commercial space heating and cooking, and represents the primary source of GHG emissions from the residential and commercial sectors.

Much of the equipment in the oil and gas industry has been regulated for decades by the local air districts. The districts have rules and regulations to limit VOC and NO_x emissions because they are precursors of ground-level ozone. Many of the VOC controls also reduce methane as a co-benefit. In 2015, U.S. EPA proposed additional federal measures that could address methane primarily at new oil and natural gas sources, with coverage at some existing sources. Additional actions to reduce methane from the oil and gas sector should also reduce VOC and toxic air contaminant emissions, although those co-benefits have not yet been estimated.

California has an emerging, comprehensive framework in place to reduce methane emissions from oil and gas infrastructure. Effectively implementing this framework can reduce methane emissions from oil and gas systems by 40-45 percent in 2025, matching federal commitments.¹¹³ Additional opportunities may emerge to further reduce emissions from infrastructure and will be considered when they do. But further reducing methane emissions from the oil and gas sector will ultimately require reducing in-state demand. A rapid decline for demand for oil and natural gas is also necessary to meet the State's 2030 and 2050 climate targets, more broadly.

About 90 percent of California's natural gas comes from out of State, and ultimately, action by other jurisdictions is needed to minimize leaks associated with our natural gas use. The Obama administration has taken steps to address oil and gas sector methane emissions, especially at the point of production, but more may need to be done to reduce emissions from pipelines and other equipment out-of-state. There may be steps that California agencies or utilities can take to ensure that infrastructure supplying gas to the state has minimal leakage, and to ensure that natural gas is providing environmental benefits compared to use of other fossil fuels in the State.

The State's framework on oil and gas methane emissions includes the following elements:

Adopt and Implement a Greenhouse Gas Emission Standards For Crude Oil and Natural Gas Facilities Regulation

ARB is currently working with local air districts and other stakeholders to develop a regulation for Board consideration by mid-2016. The proposed regulation, still being developed, will likely require:

¹¹³ For the purposes of calculating emission reductions in 2030, Table 6 assumes a 45 percent reduction below current levels by 2030.

- Vapor collection on uncontrolled oil and water separators and storage tanks with emissions above a set methane standard;
- Vapor collection on all uncontrolled well stimulation circulation tanks;
- Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors, currently not covered by local air district rules, as well as from soil at underground natural gas storage well sites;
- Vapor collection of large reciprocating compressors' vent gas, or require repair of the compressor when it is leaking above a set emission flow rate;
- Vapor collection of centrifugal compressor vent gas, or replacement of higher emitting "wet seals" with lower emitting "dry seals";
- "No bleed" pneumatic devices and pumps; and
- More frequent methane monitoring at underground natural gas storage facilities.

This regulation would uniformly expand some local regulations to all air districts and include additional infrastructure components (such as valves, flanges, and seals) that are not currently covered by local district programs. ARB staff is investigating ways to ensure that any combustion-based controls will not interfere with efforts to achieve and maintain compliance with ambient air quality standards in cases where methane and VOC emissions cannot be sent into existing sales lines, fuel lines, or reinjection wells, and are instead captured by installing new vapor collection on existing storage tanks, with the collected vapors being sent to a low-NOx incinerator that will replace an existing flare.

Improve Monitoring and Standards to Detect and Minimize Emissions

ARB and DOGGR are working together to ensure that both above and below ground monitoring of storage facilities is improved. As mentioned above, ARB is considering improved above-ground methane monitoring of underground storage facilities in its upcoming Oil and Gas Production, Processing, and Storage Regulation. In January 2016, DOGGR released notice of an emergency regulatory action to implement protective standards specifically designed to ensure that operators of underground gas storage facilities are properly minimizing risks and taking all appropriate steps to prevent uncontrolled releases, blowouts, and other infrastructure-related accidents. The emergency regulations will ensure that operators of existing underground gas storage facilities monitor for and report leaks to DOGGR, function test all safety valve systems, perform inspections of wellheads and surrounding area and equipment, develop risk management plans that require verification of mechanical integrity and corrosion assessment and monitoring, and provide DOGGR with complete project data and risk assessment results. Immediate implementation of these standards will ensure that underground gas storage facilities are properly operated, minimizing the potential that an incident such as the gas leak at the Aliso Canyon Natural Gas Storage Facility does

not recur.¹¹⁴ ARB and DOGGR will coordinate on the monitoring provisions to ensure consistency and comprehensiveness while limiting duplication.

Additionally, Assembly Bill 1496 (Thurmond, Statutes of 2015, Chapter 604) requires ARB, in consultation with scientific experts and other state, local, and federal agencies, to undertake monitoring and measurements of high-emission methane “hot spots” and conduct lifecycle GHG emission analysis for natural gas produced in and imported into California. Pursuant to this bill, ARB will continue its efforts related to hot spots monitoring and lifecycle greenhouse gas accounting for fuels, and will host a scientific workshop to collect the best available knowledge on these topics. ARB will update relevant policies and programs to incorporate any new information gathered as a result of these efforts.

Effectively Implement SB 1371 to Reduce Emissions from Pipelines

Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014) directs the CPUC, in consultation with ARB, to adopt rules and procedures to minimize natural gas leaks from CPUC-regulated intrastate transmission and distribution gas pipelines and facilities. Among other requirements, SB 1371 directs the CPUC to adopt rules and procedures that provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components. In January 2015, the CPUC launched a rulemaking proceeding (R.15-01-008) to carry out the intent of SB 1371. Under this proceeding, CPUC published a report that identifies new gas leak detection technologies that can be used to optimize methane reductions from transmission, distribution and storage processes. CPUC also required utility companies and gas suppliers to report natural gas emission data and best leak management practices by May 15, 2015. In June 2015, CPUC conducted a prehearing conference to discuss the draft scoping memo of relevant topics to be deliberated during the 24-month timeframe of the proceeding.

ARB continues to actively participate in the proceeding and will lead efforts to analyze collected utility emission data, develop quantification protocols, and identify potential mitigation strategies. In particular, ARB will focus on the emission reduction potential of the proceeding in keeping with the objectives of AB 32 as they pertain to:

- Comparing the data collected under SB 1371 with the Mandatory Reporting Regulation;

¹¹⁴ Preliminary estimates suggest the incident resulted in about 8 MMTCO₂e (AR5 20-year GWP) of methane emissions, an approximately 20 percent increase in statewide methane emissions for the duration of the leak (October 23, 2015–February 17, 2016). Governor Brown’s January 2016 Aliso Canyon Proclamation directs the ARB to develop a mitigation plan for the leaked methane emissions by March 31, 2016. It can be accessed at: http://www.arb.ca.gov/research/aliso_canyon/arb_aliso_canyon_methane_leak_climate_impacts_mitigation_program.pdf

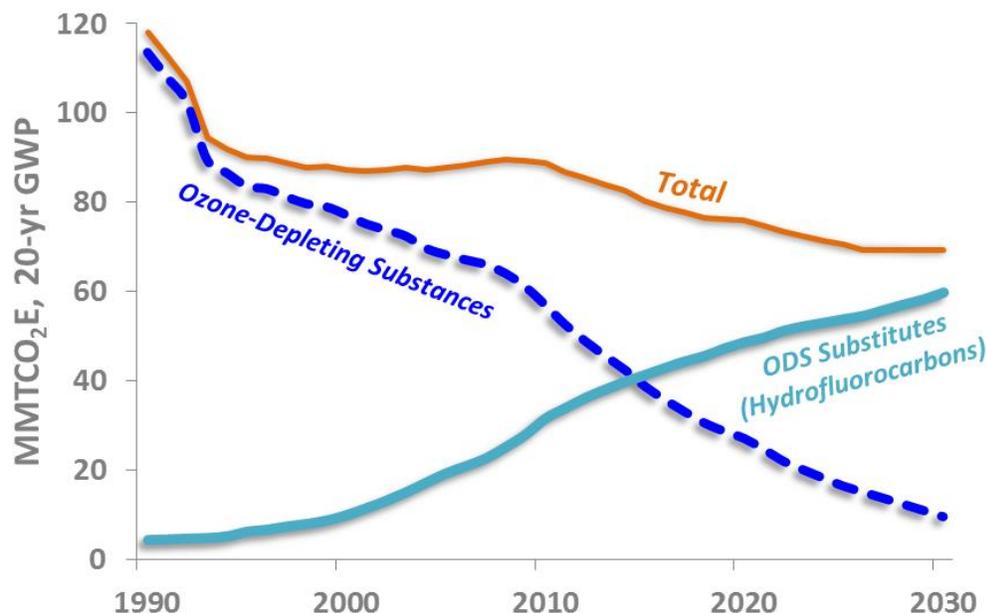
- Analyzing emission data to determine potential mitigation strategies. For example, the proceeding may require the replacement of older pipelines or pipelines constructed of a certain material;
- Identifying any remaining data gaps;
- Establishing procedures for the development and use of metrics to quantify emissions; and
- Reviewing and evaluating the effectiveness of existing practices for the operation, maintenance, repair, and replacement of natural gas pipeline facilities to determine the potential to reduce methane leaks and where alternative practices may be required.

The final decision on potential rules and procedures by the CPUC, including ratemaking and financial incentives to minimize gas leaks, is anticipated in the Fall of 2017. Upon evaluation of the industry's compliance with the decision, ARB will determine whether additional regulatory actions or incentives are required to further reduce methane emissions from this source.

VI. Reducing HFC Emissions

Hydrofluorocarbons (HFCs) are the fastest-growing source of GHG emissions both globally and in California. HFCs are fluorinated gases (F-gases), which also include the ozone-depleting substances (ODS) that are being phased out under the Montreal Protocol. HFCs currently comprise four percent of all GHG emissions in California, although annual HFC emissions are expected to increase 60 percent under business-as-usual by 2030 as HFCs continue to replace ODS (Figure 8).

Figure 8: Emission Trends of ODS and ODS substitutes (hydrofluorocarbons) – (as ODS are phased out, HFCs increase)

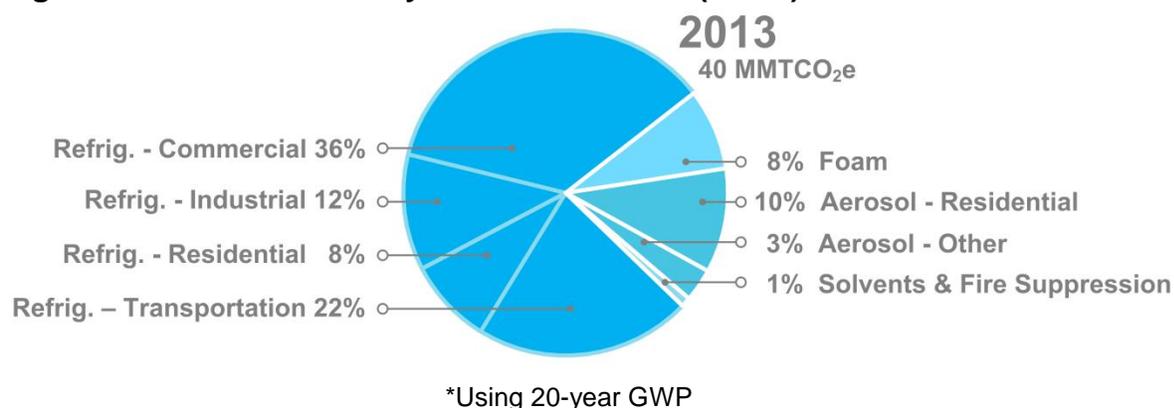


The majority of HFC emissions come from fugitive emissions of refrigerants used in refrigeration and air-conditioning (AC) systems. The largest uses of HFCs are in commercial and industrial refrigeration and air-conditioning, which comprise 48 percent of HFC emissions. More than half of refrigeration and air-conditioning equipment currently uses HCFC-22, a high-GWP ODS which is scheduled for a complete phase-out of new production and import in the U.S. by 2020. The HCFC-22 refrigerant is being replaced with HFCs that have higher GWPs, thus increasing the GHG impact of refrigerants. We expect that in anticipation of the HCFC-22 phase-out by 2020, most owners of equipment using HCFC-22 will either replace the equipment by 2020, or at a minimum replace the HCFC-22 refrigerant in the same equipment (retrofit) with a high-GWP HFC refrigerant. A window of opportunity exists in the next five years to accelerate the transition of refrigeration and air-conditioning equipment to lower-GWP refrigerants, before another generation of equipment is locked into using higher-GWP refrigerants over their average lifetimes of 15 to 20 years.

HFC emissions from transportation are largely from mobile vehicle air-conditioning (MVAC), and as California and the U.S. EPA implement the MVAC credits programs

under their light-duty vehicle GHG emission standards, and the MVAC leakage standards under their heavy-duty vehicle GHG emission standards, the share of HFC emissions from the transportation sector will decline. Aerosol propellants (industrial, consumer, and medical dose inhalers) comprise 13 percent of HFC emissions, and insulating foam expansion agents contribute another eight percent of HFC emissions. Solvents and fire suppressant emissions contribute one percent of all HFC emissions. Figure 9 shows the emissions sectors that contribute to California's overall HFC emissions. (ODS emissions are not shown because they are being completely phased out under the Montreal Protocol and are not included in the AB 32 GHG emission reduction targets.)

Figure 9: California 2013 Hydrofluorocarbons (HFCs) Emission Sources*



This Draft Proposal identifies measures that can reduce HFC emissions by 40 percent in California by 2030. They represent a reasonable path forward for California, but the State's approach on HFCs could be affected by a potential international agreement that may be reached in 2016 to phase down the use of HFCs globally.

A. Progress to Date

California is among the world's leaders in reducing HFCs and other F-gas emissions. Measures adopted under AB 32 have reduced emissions from a variety of sources. The State's Cap-and-Trade offset protocol for ozone depleting substances incentivizes the capture and destruction of ODS refrigerants and foam expansion agents. The biggest reductions of high-GWP F-gases are coming from ARB's Refrigerant Management Program, which requires facilities with refrigeration systems to inspect and repair leaks, maintain service records, and in some cases, report refrigerant use. The Refrigerant Management Program has helped change industry practices to become more proactive in preventing refrigerant leaks, which has helped businesses save money by avoiding system repairs and downtime as well as the cost of replacement refrigerant. Other measures already in place include low-GWP requirements for consumer product aerosol propellants and a self-sealing valve requirement for small cans of automotive refrigerants purchased by "do-it-yourself" mechanics.

California's efforts to reduce emissions of F-gases are part of a broader set of national and international commitments. World leaders have agreed to work together and

through the Montreal Protocol to phase down the production of HFCs. The U.S. EPA



can impose federal bans on F-gases under the Significant New Alternatives Policy (SNAP) Program. In July 2015, the U.S. EPA adopted future bans on specific HFCs with very high GWPs used in new commercial refrigeration systems, the manufacture of polyurethane foam, and new light-duty motor vehicle air-conditioning systems.¹¹⁵ In many cases, these national bans copied programs that were first demonstrated in California.

The U.S. national bans are expected to decrease HFC emissions in California by ten percent annually below business as usual by 2025. The European Union (EU) has adopted the world's leading F-gas regulation that will phase down the production and import of HFCs by almost 80 percent from 2014 levels by 2030.^{116,117}

Additionally, in response to President Obama's Climate Action Plan, in September 2014, and again in October 2015, the White House announced private sector commitments and executive actions to reduce emissions of hydrofluorocarbons (HFCs).^{118,119} U.S. industry is leading the way by investing billions of dollars to develop and deploy the next generation of HFC alternatives that are safer for the environment. These investments span the entire HFC supply chain— from where the chemicals are produced, to where they are used in manufacturing, to where consumers see them in stores.

Further private sector commitments were made in February 2016, when both the Air Conditioning Heating & Refrigeration Institute (AHRI) and the Association of Home Appliance Manufacturers (AHAM) made voluntary commitments to phase down the use of high-GWP HFCs in new equipment.^{120,121}

¹¹⁵ Protection of Stratospheric Ozone: Change of Listing Status for Certain Substitutes Under the Significant New Alternatives Policy Program; Final Rule. Federal Register. Volume 80, Number 138, Monday, July 20, 2015. Part II. Environmental Protection Agency. 40 CFR Part 82. <http://www.epa.gov/ozone/snap/regulations.html>

¹¹⁶ Velders et al (2014) "Growth of climate change commitments from HFC banks and emissions", G. J. M. Velders, S. Solomon, and J. S. Daniel. *Atmospheric Chemistry and Physics*, 14, 4563–4572, 2014. doi:10.5194/acp-14-4563-2014. www.atmos-chem-phys.net/14/4563/2014/.

¹¹⁷ EC (2014) European Commission (EC), April 16, 2006 "Regulation (EU) No 517/2014 of the European Parliament and of the Council on fluorinated greenhouse gases and repealing Regulation (EC) No 842/2006". http://ec.europa.eu/clima/policies/f-gas/legislation/documentation_en.htm

¹¹⁸ Fact Sheet: Obama Administration Partners with Private Sector on New Commitments to Slash Emissions of Potent Greenhouse Gases and Catalyze Global HFC Phase Down. September 16, 2014: <http://www.igsd.org/documents/20140916HFCFactSheet.pdf>

¹¹⁹ Fact Sheet: Obama Administration and Private-Sector Leaders Announce Ambitious Commitments and Robust Progress to Address Potent Greenhouse Gases. October 15, 2015. <https://www.whitehouse.gov/the-press-office/2015/10/15/fact-sheet-obama-administration-and-private-sector-leaders-announce>.

¹²⁰ AHRI and Natural Resources Defense Council (NRDC) February 1, 2016 petition to U.S. EPA Significant New Alternatives Policy (SNAP) Program to remove high-GWP HFCs from the list of

In March 2016, the U.S. EPA proposed additional bans on high-GWP HFCs in new retail food refrigeration, cold storage, chillers used for air-conditioning, and household refrigerator-freezers.¹²² The proposal had not been adopted as of April 2016.

Substantial progress has also been made to safely use natural refrigerants (such as CO₂, ammonia (NH₃), and hydrocarbons (HCs), with GWPs at or near zero) all over the world, especially in Europe and Asia. The refrigeration and air-conditioning industry is looking closely at which applications suit which natural refrigerants. Reports summarizing the progress made in North America show nearly 300,000 pieces of light commercial equipment using CO₂ or hydrocarbons, more than 250 stores using CO₂ systems, and over 250 “next-generation” small-charge ammonia systems in industrial installations. Large companies investing in natural refrigerants include end users, and a wide range of equipment manufacturers.

In addition to the natural refrigerants, a new generation of fluorinated refrigerants known as hydrofluoro-olefins (HFOs) have been developed that are non-ODS and have GWP values less than five. HFOs can be used in pure form for some cooling applications, such as motor vehicle AC, and are also used in blends with HFCs for other cooling applications, such as commercial and industrial refrigeration. Initial results indicate that the newest generation of fluorinated refrigerants perform as well as the high-GWP HFCs they replace.

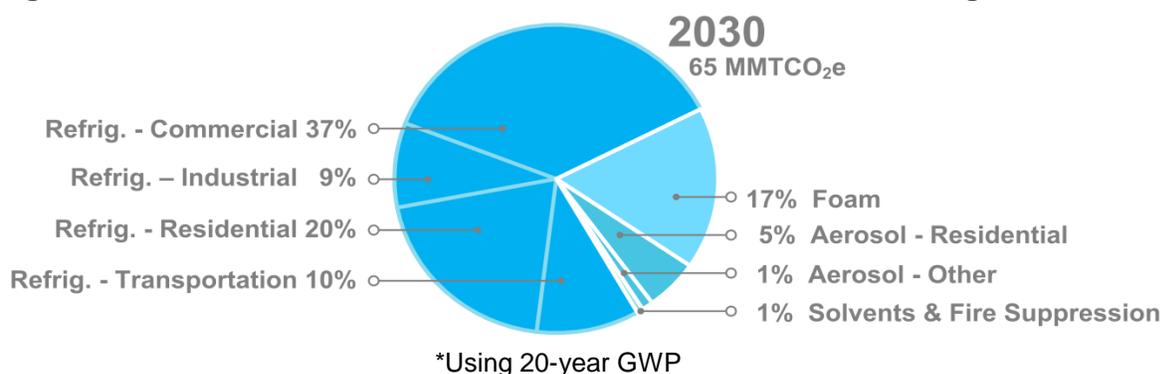
These State and national efforts will lead to significant reductions in HFC emissions in California through 2030, compared to where they would be otherwise. Still, HFC emissions in California are expected to grow by more than 60 percent without additional action (Figure 10).

acceptable substitutes in new air-cooled and water-cooled chillers using centrifugal, screw, scroll, and all other compressor types.

¹²¹ “Home Appliance Industry Sets Goal to Eliminate Use of HFC Refrigerants”, Press Release February 9, 2016 from Association of Home Appliance Manufacturers (AHAM). <http://www.prnewswire.com/news-releases/home-appliance-industry-sets-goal-to-eliminate-use-of-hfc-refrigerants-300217501.html>.

¹²² Fact Sheet. Proposed Rule - Protection of Stratospheric Ozone: New Listings of Substitutes; Changes of Listing Status; Reinterpretation of Unacceptability for Closed Cell Foam Products under the Significant New Alternatives Policy Program; and Revision of Clean Air Act Section 608’s Venting Prohibition for Propane. U.S. EPA, March 29, 2016. <https://www.epa.gov/snap/snap-regulations>

Figure 10: California's 2030 HFC Emission Sources with Existing Measures*



B. Recommended Actions to Further Reduce HFC Emissions

The State supports strong, national, and international actions to reduce HFC emissions. The U.S. EPA has already taken a number of steps to prohibit the use of new high-GWP HFCs in consumer product aerosol propellants, polyurethane insulating foam, and light-duty mobile vehicle air-conditioning. An international agreement could be reached in 2016 to phase down the production and use of HFCs under the Montreal Protocol. The proposed Montreal Protocol HFC phase down amendments, if adopted, will reduce HFC emissions significantly by 2050.

However, if additional measures can be applied in California to achieve further GHG emission reductions in the near-term and at low cost, California will consider them to support the State's 2020 and 2030 GHG targets. Specifically, as effective alternatives become available, ARB will consider developing bans on the use of high-GWP refrigerants in sectors and applications where lower-GWP alternates are feasible and readily available. All refrigerants and substitutes to high-GWP F-gases must first be approved by the U.S. EPA's SNAP Program to ensure the alternatives meet health and safety criteria. The approval process is designed to minimize the risk of using newer alternatives to F-gases by identifying substitutes that offer lower overall risks to human health and the environment.

Also, in the absence of a sufficiently rigorous international agreement by the end of 2016, ARB will evaluate the feasibility of a phasedown for California that aligns with similar efforts and stringency levels in Australia, Canada, the EU, and Japan.

Even with a strong international agreement to phase down the use of HFCs, additional opportunities remain to reduce their emissions in California in the near-term and through 2030 at low cost. Early action, ahead of some of the phase down schedules being proposed internationally, can avoid locking-in the use of high-GWP refrigerants in new or retrofitted systems in the coming years

For example, the State should consider developing an incentive program to encourage the use of low-GWP refrigerants, which could lead to very low-cost emission reductions and could be implemented while further regulations are considered or developed. This

would provide long-term avoided emissions by countering the current trend of replacing HCFC-22, the most common refrigerant for both refrigeration and air-conditioning, with higher-GWP HFCs. This trend is accelerating in the U.S. in response to the 2020 phase-out of HCFC-22 under the Montreal Protocol.

In light of ongoing international discussions, this Draft Proposal describes a set of potential measures that can reduce HFC emissions by 40 percent in California by 2030 (see Table 7). This set of measures has been designed to minimize regulatory requirements and achieve fast and assured emission reductions.

Table 7: Proposed New HFC Emission Reduction Measures and Estimated Emission Reductions (MMTCO₂e)¹

| Measure Name | 2030 Annual Emission Reductions | 2030 Annual Emissions |
|--|---------------------------------|-----------------------|
| 2030 BAU ² | | 65 |
| Financial Incentive for Low-GWP Refrigeration Early Adoption | 2 | |
| HFC Supply Phasedown | 19 | |
| Sales ban of very-high GWP refrigerants | 5 | |
| Prohibition on new equipment with high-GWP Refrigerants | 15 | |
| 2030 BAU with new measures | | 24 |

¹Using 20-year GWPs from the 4th Assessment report of the IPCC

²"Business as Usual" (BAU) forecasted inventory includes reductions from implementation of current ARB and U.S. EPA regulations

Incentive Programs

In his 2016-2017 Proposed Budget, Governor Brown includes \$20 million for a financial incentive program to defray the potential added cost of installing new low-GWP refrigeration equipment or converting existing high-GWP systems to lower-GWP options. This program could provide immediate and ongoing emission reductions. A loan or grant program would support qualifying facilities that take action to reduce emissions prior to any national or state requirements to do so.

Data reported under the existing Refrigerant Management Program indicates that more than 2,400 facilities with large commercial refrigeration systems in California currently use HCFC-22 refrigerant. This refrigerant has not been allowed in new equipment since January 2010, and all new production and import will cease by January 1, 2020. Therefore, these facilities must either buy increasingly scarce recycled HCFC-22 to maintain their systems, or replace or retrofit their existing systems with another refrigerant within five years.

Although lower-GWP options are currently available and can be cost effective, in most cases with improved energy efficiency, there are two main barriers to more widespread adoption of low-GWP commercial refrigeration: 1) potentially higher up-front costs, and 2) lack of familiarity with low-GWP refrigeration. The incentive program could remove the added initial cost barrier and build familiarity with low-GWP refrigeration systems to help them scale throughout the sector.

One of the advantages of an incentive program is that it could fund early adoption of low-GWP technologies, with substantial long-term effects on avoided emissions. The incentive program would “lock in” early and permanent GHG reductions prior to any mandatory measures.

Phasedown in Supply of HFCs

An HFC phasedown allows industry the flexibility to make market-based decisions on when and where to continue using high-GWP HFCs before transitioning to lower-GWP options. The EU has recently adopted a supply phasedown, at the top level of supply for both production and import (first arrival of virgin refrigerant). The EU model identified the existing market based on past production and import and aims to reduce it 79 percent by 2030. Broad-based national or international agreements are the most effective phasedown approaches, minimizing the possibility of simply displacing emissions to other locations.

In the international arena, countries met in Dubai in November 2015 to discuss an HFC phasedown amendment to the Montreal Protocol. The meeting did not result in a specific phase-down agreement, but the outcome was viewed as positive by most participants, with countries agreeing to a series of meetings in 2016 designed to reach an international phase-down. If a national or international HFC phasedown agreement cannot be reached in 2016, ARB may pursue a California HFC phasedown schedule that will help meet the State GHG emission reduction goals. California would seek a partnership with the EU, Canada, Japan, and Australia, all of which are currently pursuing their own separate HFC phasedown programs.

Phasedown programs offer several advantages over other regulatory approaches, such as fees or fixed limits on the maximum GWP of HFCs allowed. A broad-based phasedown program significantly reduces the number of regulated entities compared to downstream regulation, causes minimum disruption to industry, and guarantees emission reductions. Industry stakeholders generally favor a phasedown approach as a technically feasible, fair, and cost-effective means of reducing HFC emissions, while allowing them flexibility in transitioning to low-GWP alternates.

Prohibition on the Sale of New Refrigerant with Very-High GWPs

This measure would prohibit the sale or distribution of refrigerants with 100-year GWP values of 2500 or greater, beginning January 1, 2020. Refrigerants that are certified reclaimed or recycled would be exempt from the sales ban.

In July 2015, the U.S. EPA adopted a ban on using refrigerants with a very-high 100-year GWP of 2500 or greater in new and retrofitted refrigeration systems at retail food facilities beginning in the second half of 2016. Several refrigerants are currently available with a 100-year GWP of less than 1500 that can be used in existing equipment designed for higher-GWP refrigerants.

A sales ban on very high-GWP refrigerants is enforceable and provides immediate reductions. Such a ban facilitates a much faster transition from very high-GWP refrigerants to lower-GWP alternatives in existing equipment (thus avoiding the ongoing high-GWP emissions from equipment that typically lasts for 15 years or longer).

High-GWP Refrigerant Prohibitions in New Stationary Systems

This measure would prohibit the use of high-GWP refrigerants in new commercial, industrial, and residential stationary refrigeration and air-conditioning equipment, as follows:

| Stationary Refrigeration or Stationary Air-Conditioning Sector | Refrigerants Prohibited in New Equipment with a 100-year GWP Value: | Proposed Start Date |
|---|--|----------------------------|
| Non-residential refrigeration | 150 or greater | January 1, 2020 |
| Air-conditioning (non-residential and residential) | 750 or greater | January 1, 2021 |
| Residential refrigerator-freezers | 150 or greater | January 1, 2021 |

Certain exceptions could be made to any maximum GWP limit if a low-GWP refrigerant is not technically feasible in a specific application. GWP limits may be subject to change as additional low-GWP refrigerants become available. For example, low and medium-pressure chillers used for air-conditioning may be able to use refrigerants with a GWP less than 150.

Low-GWP commercial refrigeration using ammonia is already extensively used in food processing and cold storage. Additionally, more than 250 retail food stores in the U.S. have begun using CO₂ as the primary or secondary refrigerant. In Europe, CO₂ refrigeration is used in more than 5,200 retail food stores, and generally is cost neutral compared to HFC refrigeration systems. In the hotter climate zones of California, using 100 percent CO₂ refrigeration may not be as energy-efficient as HFC refrigerants, although newly demonstrated adiabatic cooling technology has promise to neutralize energy efficiency concerns. Alternatively, manufacturers are currently developing blends of HFC refrigerants combined with a new class of very-low GWP synthetic refrigerants known as hydrofluoro-olefins (HFOs). The HFO-HFC blends have 100-year GWPs between 88 and 1400, and their use would reduce GHGs in these systems by

more than 75 percent compared to business as usual.¹²³ Hybrid refrigeration such as secondary loop and cascade systems, using a small HFC central charge and a larger CO₂ charge, experience no energy penalty, even in hotter climates.

With respect to air-conditioning, in September 2014, the Air-Conditioning Heating & Refrigeration Institute (AHRI), an industry association representing 90 percent of U.S. air-conditioning manufacturing and 70 percent of the global industry, made a commitment through the White

House Council on Environmental Quality to spend \$5 billion over the next ten years to develop low-GWP options for refrigeration and air-conditioning. Many commercially available lower-GWP air-conditioning options are expected by 2020. In order to comply with the EU F-gas regulation that went into effect January 1, 2015, manufacturers



are already developing air-conditioning systems that use refrigerants with a 100-year GWP of less than 750. Large chillers used primarily for office building air-conditioning are already commercially available that use an HFO refrigerant with a GWP of one.

Current fire and appliance codes do not allow the use of hydrocarbon refrigerants, which are flammable, unless the system is below a small charge size threshold of 150 grams for commercial refrigerators, and 57 grams for household refrigerators. Experience in Europe and other jurisdictions demonstrates that these codes can be designed to allow for the use of these refrigerants while ensuring safety, where current limits are 150 grams for household refrigerators and up to 1.5 kg for commercial uses. More work is required to update the safety codes in the U.S. before slightly flammable refrigerants can be used in more applications while maintaining safety.

A prohibition, or ban on the use of high-GWP HFCs in new equipment would result in certainty of reductions in applications where alternatives are readily available. By requiring equipment manufacturers to sell only ARB-compliant equipment in California, the enforcement focus is on the manufacturers and is not placed on the end-user.

Additional measures that may be more effectively addressed at the Federal level include prohibitions on high-GWP HFCs in the following sectors: consumer product aerosol propellants, insulation spray foam, heavy-duty motor vehicle air-conditioning, transport refrigeration units (TRUs), and refrigerated shipping containers. ARB will continue to work with the U.S. EPA on reducing HFC emissions from these sectors, and may pursue state-level measures if progress is not made on the Federal level.

¹²³ HFOs are hydrofluoro-olefins, an emerging class of F-gas with very low GWPs of 1-5, but which are classified as slightly flammable (A2L). By blending HFOs with HFCs, refrigerant blends which are non-flammable have been created and U.S. EPA SNAP-approved for certain applications.

C. Sulfuryl Fluoride

Sulfuryl fluoride (SO_2F_2) is a pesticide fumigant and one of the most common replacements for methyl bromide, an ozone-depleting substance whose use is being phased out. Sulfuryl fluoride is regulated by the California Department of Pesticide Regulation (DPR), and was listed as a toxic air contaminant (TAC) in 2006. As a pesticide and TAC, sulfuryl fluoride's use is strictly controlled. In December 2015, DPR submitted a report to the Legislature, which provided an update on adopted control measures for sulfuryl fluoride,¹²⁴ as required by AB 304 (Williams, Chapter 584, Statutes of 2013). DPR plans to develop additional mitigation measures by September 2016, to address unacceptable exposures of sulfuryl fluoride to bystanders and residents. Sulfuryl fluoride is not registered for use as a field soil fumigant and is not used on agricultural fields.

Until 2009, sulfuryl fluoride was believed to have a negligible GWP. Further research concluded that SO_2F_2 has a 20-year GWP of 6840, with a lifetime of several decades. According to the DPR, 3 million pounds of sulfuryl fluoride were used in California in 2013 (most recent data available).¹²⁵ Its main use is as a structural pest control fumigant to kill drywood termites in homes and buildings, accounting for 82 percent of all usage in 2013. Sulfuryl fluoride is also a common fumigant for dried fruits, nuts, and other agricultural commodities that must be kept pest-free during storage prior to shipping (15 percent of all usage in 2013). The remaining three percent of sulfuryl fluoride application was for other fumigation uses. A complete listing of sulfuryl fluoride usage in California by commodity is listed in Appendix A.

Because sulfuryl fluoride was not identified as a high-GWP gas by the time AB 32 was enacted, it was not initially included as a part of ARB's statewide GHG inventory. However, the annual usage of sulfuryl fluoride is inventoried by DPR as a highly-regulated pesticide and ARB uses this data to track emissions. In 2013, the 3 million pounds of SO_2F_2 usage was equivalent to 9.4 MMT CO_2E emissions (using 20-year GWP values), or approximately 20 percent of all F-gas emissions.

Identifying less toxic or lower-GWP alternatives to sulfuryl fluoride remains problematic. Methyl bromide (CH_3Br), with a 20-year GWP of 17, was the pesticide fumigant of choice for many applications until its use was almost completely phased-out by the Montreal Protocol because of its ozone-depleting potential. Currently, sulfuryl fluoride is the only fumigant registered for treating structural pests in California. Termites or other wood-destroying pests are detected in over 250,000 California homes each year, with the cost of control and repair of damage from dry-wood termites in California exceeding \$300 million annually (with 80 percent of fumigations occurring in Southern California).

¹²⁴ Report to the Legislature Required by AB 3014 (2013) Food & Agricultural Code Section 140124(c)(2)(A): Update on the Adoption of Control Measures for the Toxic Air Contaminant Sulfuryl Fluoride. Report submitted by the California Department of Pesticide Regulation to the California Legislature, December 22, 2015.

¹²⁵ Summary of Pesticide Use Report Data 2013 - Indexed by Commodity, California. California Department of Pesticide Regulation, May 2015. Available at: http://www.cdpr.ca.gov/docs/pur/pur13rep/13_pur.htm.

For agricultural commodity fumigation storage (primarily dried fruits and nuts), methyl bromide is still used on a limited basis through special use exemptions, although its use is decreasing annually. An alternative fumigant, phosphine (PH₃), with a GWP of 0, is also used as an alternative to methyl bromide and sulfuryl fluoride. However, reported insect tolerance to phosphine has limited its widespread usage.¹²⁶ Non-chemical commodity treatment has been studied since 1995, including irradiation, and controlling the atmosphere to “suffocate” insects in either low-oxygen or high carbon dioxide environments.¹²⁷ Chemical treatment remains dominant due to cost and feasibility issues of non-chemical alternatives.

The effectiveness of less toxic (and lower-GWP) alternatives to sulfuryl fluoride in structural fumigation for drywood termites is the subject of much research, opinion, and disagreement. Structural fumigation generally includes tenting the entire structure and treating it to kill termites, or more rarely, wood-boring beetles and other pests living in the structure. While many termite control companies only use sulfuryl fluoride, many others have begun using alternative termite control methods, including orange oil, structure heating or extreme cooling, microwaves, and electricity. Additional research is required before sulfuryl fluoride mitigation measures can be proposed. ARB will continue working with the DPR to assess mitigation measures to sulfuryl fluoride emissions. Additional discussion on potential research of sulfuryl fluoride mitigation is included in Appendix B.

¹²⁶ Phosphine Fumigation of Stored Agricultural Commodity - Programmatic Environmental Assessment. November 2013. United States Agency for International Development (USAID), prepared under USAID's Global Environmental Management Support (GEMS) project. Available at: http://www.usaidgems.org/documents/fumigationpea/fumigationpeafeb24_2014.pdf.

¹²⁷ Alternatives to Methyl Bromide: Research Needs for California - Report of the Methyl Bromide Research Task Force To The Department of Pesticide Regulation and The California Department of Food and Agriculture. September, 1995. Available at: <http://www.cdpr.ca.gov/docs/emon/methbrom/mb4chg.htm>.

VII. Achieving Success

Successfully implementing a strategy to reduce SLCP emissions will require integrated planning to achieve multiple objectives, coordination and collaboration among agencies at all levels of government, and focused investments and market support.

A. Integrate and Coordinate Planning

The SLCP Reduction Strategy fits within a wide range of ongoing planning efforts throughout the State to advance economic and environmental priorities. Integrated planning to achieve multiple objectives requires coordination among planning agencies and across sectors, systems, and government jurisdictions. Development of a strategy to reduce emissions of SLCPs is being closely coordinated with other relevant planning efforts. For example, this Proposed Strategy acknowledges that further reductions in black carbon from California's freight system will be realized through strategies identified in the California Sustainable Freight Action Plan. That plan is currently being developed by ARB and other state agencies, and will accelerate emission reductions and implementation of zero and near-zero technology in California's freight transport system. Also, ARB staff and local air districts will develop additional strategies through the upcoming SIPs process, which is expected to reduce black carbon emissions from both mobile and non-mobile sources.

The 2014 Scoping Plan Update identified the important role of SLCPs to reduce climate change impacts and provided suggested recommended actions for further emission reductions. Those recommendations were evaluated and expanded upon in this Proposed Strategy.

The ARB is embarking on the next update to the Scoping Plan to describe how the State can meet the Governor's goal of reducing total GHG emissions by 40 percent by 2030. This SLCP strategy is a forerunner to the Scoping Plan, providing justification for accelerated action on SLCP. The next Scoping

State Plans that will Assist the State in Meeting SLCP Emission Reduction Goals

CalRecycle AB 341 Report to the Legislature

California Sustainable Freight Action Plan

Additional Scoping Plan Updates

2016 California State Implementation Plan

Auction Proceeds Investment Plan

Caltrans Strategic Management Plan for 2015-2020

Funding Plan for Low Carbon Transportation Investments and the Air Quality Improvement Program

Mobile Source Strategy

ARB Annual Research Plan

Climate Change Research Plan for California

California Water Action Plan

CEC Electric Program Investment Charge Program

Annual Investment Plan for Alternative and Renewable Fuels and Vehicle Technology Program

DWR Climate Action Plan

Bioenergy Action Plan

Forest Carbon Plan

Healthy Soils Initiative

Plan will augment the strategies presented in this document with measures focused on CO₂, providing a balanced portfolio of near-term and long-term measures.

Other concurrent planning efforts in the State could also identify additional activities that may serve to reduce SLCP emissions. For example, CEC's Integrated Energy Policy Report, the Healthy Soils Initiative, and the Forest Carbon Plan are all ongoing efforts that intersect with many of the concepts described in this Draft Report. ARB will collaborate with other agencies developing those plans to identify and prioritize activities to reduce SLCP emissions that would also support other State priorities and integrated planning efforts. Climate action planning efforts by city, county, and other local government entities will also play a key role in reducing SLCP emissions, especially if these action plans begin to incorporate SLCP emission inventories and mitigation actions.

B. Enable Local and Regional Leadership

State policy is most effective with the support, engagement, and complementary actions of regional and local efforts. As the State shifts its climate-protection focus to the long-term and increases its efforts to reduce SLCP emissions, regional and local governments and agencies will play an increasingly important role in achieving California's GHG goals. The efforts of regional agencies, such as air districts, water districts, and municipal solid waste authorities, to incorporate GHG emission reduction strategies into their respective jurisdictions increases the State's leverage to further reduce SLCP emissions from various sources.

Local air districts have a key role to play in reducing regional and local sources of SLCP emissions, because air pollution reduction strategies employed by air districts often also reduce GHG emissions. City and county governments also play a pivotal role in reducing emissions of SLCPs. Many GHG emission reduction strategies identified by cities and counties in their local Sustainability or Climate Action Plans directly correlate to strategies necessary for SLCP emission reductions, such as improved waste management (increased recycling and composting), use of alternative and renewable fuels, and simply reducing vehicle miles traveled. These local government Climate Action Plans encourage, and sometimes mandate at the local level, actions taken by households and businesses within a community. Often times, these actions involve behavior change by individuals, which leads to increased conservation and sustainability, ultimately driving both community-scale GHG and SLCP emission reductions.

Below are examples of local and regional government efforts that are helping the State reduce SLCP emissions.

Methane

In California, agriculture and landfills are the primary sources of methane emissions. Aside from air district rules to reduce methane emissions at landfills, upstream efforts by

cities, counties, and regional agencies to both reduce and divert food waste and other organic materials from the waste stream have the potential to greatly reduce landfill-related methane emissions. Additionally, local municipalities and solid waste agencies are working collaboratively with air districts to foster renewable fuel opportunities, such as waste-to-energy and waste-to-fuel projects. For example, through its leadership role with Clean Cities, the Sacramento Metropolitan Air Quality Management District is working closely with numerous partners to build awareness and increase separation and diversion of organic waste to a local anaerobic digester.

Local agencies also play a role in utilizing methane beneficially at wastewater treatment plants. Many local agencies own and operate wastewater treatment facilities and are implementing strategies for on-site energy production. Local strategies to improve management and utilization of organic waste throughout the State may also have the ability to help reduce methane emissions throughout the agricultural sectors. Wastewater treatment plants offer a tremendous opportunity to divert organics from landfills and utilize them for producing energy, transportation fuel, and soil amendments. Many treatment plants are located near population centers and could potentially utilize significant amounts of food and other organic waste streams that come from cities and towns. Collaboration amongst local and regional agencies, such as solid waste management and wastewater agencies, is the key to success.

Black Carbon

Local air districts have worked with ARB to develop programs to comply with federal air quality standards for PM (that will also reduce black carbon), such as mandatory and voluntary rules to restrict residential wood-burning in fireplaces and wood stoves, along with incentive programs to switch to cleaner burning devices. In fact, in October 2015, the Bay Area Air Quality Management District adopted a new rule banning all wood burning devices in new construction. Districts have also enacted rules regulating commercial cooking and smoke management programs addressing agricultural, forest and rangeland burning operations, which have reduced black carbon and PM emissions.



In addition to air district efforts, metropolitan planning organizations, in coordination with city and county governments, can be credited with efforts to reduce vehicle emissions, and ultimately on-road related emissions, particularly through their Sustainable Community Strategy planning and implementation efforts. Local governments have stepped up by beginning with their own fleets. For example, in Sonoma County, the Board directed County staff to reduce emissions from the County's on-road fleet by 20 percent by 2010.

Local efforts to reduce diesel particulate matter, such as farm and construction equipment rules and incentive programs by air districts, play a significant role in the reduction of black carbon emissions such as the San Joaquin Valley Air Pollution Control District's program to replace diesel agricultural irrigation pump engines with electric motors. In addition, efforts by local port authorities, such as the San Pedro Bay Standards, have resulted in the establishment of more aggressive targets to reduce black carbon emissions, health risks, and further improve air quality, particularly for those in nearby disadvantaged communities.

HFCs and other F-gases

Local air districts can play an instrumental role in aiding the reduction of HFC emissions, including developing regulations to require low-GWP replacements. For example, the South Coast Air Quality Management District has three regulations to reduce refrigerant emissions from stationary air conditioning and refrigeration systems and motor vehicle servicing, as well as restrictions on CFCs and halons from sterilization, fumigation, and fire extinguishing equipment. In addition, many local governments are also tracking emissions of refrigerants, and some have adopted policies to reduce refrigerant emissions from city-owned air conditioning units, vehicles, and refrigerators.

C. Investments

Investments in financial incentives and direct funding are critical components for successful implementation of SLCP emission reduction strategies. Many existing State funding programs work in tandem to reduce emissions from GHGs (including SLCPs), criteria pollutants, and toxic air contaminants, and are helping foster the transition to a clean energy economy. In particular, State law (Senate Bill 535, De León, Chapter 830, Statutes of 2012) requires focused investment in communities disproportionately impacted by pollution. Many of these communities, especially in the Central Valley, along freight corridors, and in rural parts of the State, stand to benefit from dedicated action and investment to reduce emissions of SLCPs.



Although California has a number of existing incentive programs, the pool of funds is limited and it is critical to target public investments in ways that encourage system-wide solutions to produce deep and lasting public benefits. Significant investments of private capital, supported by targeted, priority investments of public funding, are necessary to scale deployment and to maximize benefits. Public investments can help incentivize

early action to accelerate market transition to cleaner technologies, which can then be supported by regulatory measures. The State must coordinate funding sources such as the California Climate Investments, supported by the Greenhouse Gas Reduction Fund (GGRF), Alternative and Renewable Fuel and Vehicle Technology Program (AB 118), Electric Program Investment Charge (EPIC) Program, Carl Moyer Program, Air Quality Improvement Program, and Proposition 39 to expand investments in California's clean economy and further reductions in SLCPs and other GHG emissions. Current activities and funding allocations for a few of these programs are described herein.

The GGRF is an important part of California's overall climate investment efforts to advance the goals of AB 32 (Nunez, Chapter 488, Statutes of 2006) and target investment in disadvantaged communities. To guide the investment of Cap-and-Trade auction proceeds, the Department of Finance, in consultation with the Air Resources Board and other State agencies, is required to submit a triennial Investment Plan to the Legislature. The Investment Plan identifies priority investments that will help California achieve its GHG emission reduction goals while realizing additional health, economic, and environmental benefits. The Investment Plan is required to identify near-term and long-term greenhouse gas emission reduction goals and targets, analyze gaps in current State funding for meeting these goals, and identify priority investments that facilitate GHG emission reduction. The second Investment Plan for Fiscal Years 2016-17 through 2018-19 was submitted to the Legislature in January 2016. The Second Investment Plan identifies potential State investment priorities to help achieve GHG emission reduction goals, benefit disadvantaged communities, and yield valuable co-benefits within the Transportation & Sustainable Communities, Clean Energy & Energy Efficiency, and the Natural Resources and Waste Diversion categories. The priorities identified in the Second Investment Plan would reduce a range of GHGs, including short-lived climate pollutant emissions. The Second Investment Plan informed Governor Brown's 2016-2017 Proposed Budget, which includes \$215 million of Cap-and-Trade expenditures specifically targeting SLCP emission reductions. These include \$40 million for black carbon residential woodsmoke reductions, \$20 million for HFC reductions from refrigerants, \$100 million for waste diversion, \$20 million for Healthy Soils, and \$35 million for dairy digester development.

A critical piece of the State's investment strategy, which is overseen by ARB and focused on clean transportation incentives, is the Low Carbon Transportation Investments and the Air Quality Improvement Program (AQIP). Consistent with the First Investment Plan, these programs have identified zero-emission passenger transportation and low-carbon freight transport as investment priorities, which reduce criteria pollutant and toxic emissions with concurrent reductions in GHG emissions, including black carbon. ARB has focused AQIP investments on technology advancing projects that support long-term air quality and climate change goals in addition to providing immediate emission benefits. In recent years, funding has included rebates for zero and near-zero emission passenger vehicles through the Clean Vehicle Rebate Project (CVRP), vouchers for hybrid and zero-emission trucks and buses through the Hybrid and Zero-Emission truck and Bus Voucher Incentive Program (HVIP), and the

Truck Loan Assistance Program for small business truck owners in need of truck replacements or retrofits.

The CEC administers an additional key GHG reduction investment program for the transportation sector – the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). Funds that are collected from vehicle and vessel registration fees, vehicle identification plates, and vehicle smog fees provide up to \$100 million per year for projects that will transform California’s fuel and vehicles to help attain the State’s climate change policies. Investments in alternative fuel production and infrastructure, and vehicle projects can contribute to SLCP emission reductions through reduced diesel consumption, capture and use of biogas from waste management activities as a transportation fuel, demonstration and early commercialization of advanced technology trucks that utilize biogas, and avoided fugitive methane emissions from fossil fuel production and distribution operations.

Another CEC-administered program, the Electric Program Investment Charge (EPIC) Program, supports investments in clean technologies and strategies to improve the State’s electricity systems. The program provides opportunities to support SLCP emission reductions from reduced or avoided fugitive methane emissions stemming from fossil fuel production and distribution via investments such as improved energy efficiency technologies in building, industrial, agricultural and water sectors; demand response; distributed renewable generation; electric vehicle infrastructure; demonstration of biomass-to-energy conversion systems; advanced energy storage interconnection systems; and vehicle-to-grid power transfer for electric vehicles.

CDFA administers the Dairy Digester Research and Development Program. This incentive-based program supports digester development in California and can provide grants for research and demonstration projects that improve scientific and technical understanding of technologies and practices that reduce methane and other greenhouse gases emissions on dairies. CalRecycle administers greenhouse gas reduction grant and loan programs that include incentives for infrastructure supporting organics diversion.

These programs represent just a portion of opportunities that exist at the federal, State, and local levels to incentivize SLCP and GHG emission reductions. The availability of dedicated and long-lasting funding sources is critical to help meet AB 32 objectives and help provide certainty and additional partnership opportunities at the national, State, regional, and local levels for further investing in projects that have the potential to reduce emissions of SLCPs.

D. Coordinate with Subnational, Federal, and International Partners

California is working with a set of national and subnational partners throughout the world to fight air pollution and climate change. This includes signatories to the Under 2 MOU, as well as others in Mexico, China, India, the U.S., Canada, and elsewhere.

Many of the efforts underway through these collaborations will help reduce emissions of black carbon from the transportation sector and emissions of other SLCPs.

At the 2014 United Nations (UN) Climate Summit, ARB became the first state-level entity to sign onto action statements of the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants. At the 2014 UN Conference of Parties in Lima, California co-sponsored an event with Mexico on SLCPs and their role in an international framework to contribute to national commitments to reduce emissions. At UN climate meetings in New York and Paris in 2015, Governor Brown presented the targets described in this Proposed Strategy, and suggested that action on SLCPs may be the most important and most immediate need to address climate change. The State continues to be committed to acting both bilaterally and multilaterally to cooperate with other jurisdictions to cut SLCP emissions, and will explore additional opportunities to further reduce air pollution, greenhouse gas, and SLCP emissions through partnerships.

Building on leadership around SLCPs can provide an important example for action in other countries and jurisdictions, and is one of the most significant opportunities to accelerate international progress to fight climate change. California is in a unique position to serve as a model for action for other countries and jurisdictions to accelerate their progress to reduce emissions of both SLCPs and CO₂, based on the State's demonstrated leadership on air quality and climate change, commitments to set stringent, science-based targets to reduce emissions of both CO₂ and SLCPs, and integrated planning efforts, like this one, to develop a comprehensive policy framework to achieve those goals.

As we have done for decades already, California's actions on SLCPs can demonstrate win-win opportunities for both the most developed countries, where reducing SLCP emissions is an important element of broad efforts to cut GHG emissions, as well as for the least developed countries, where SLCP emission reductions have tremendous benefits for air quality and human health.

Ultimately, each state, region, or country has its own mix of SLCP sources, needs, and opportunities to reduce emissions. Coordinated planning to meet scientific-based emission targets, like this Proposed Strategy does, is important to successfully reducing emissions and maximizing local and global benefits.

California will share this planning effort with others, and encourage them to adopt specific SLCP emission reduction targets and plans to achieve them. A few already have; President Obama has set specific targets to cut methane emissions from the oil and gas sector, Mexico has included targets to cut black carbon emissions in its Intended Nationally Determined Contribution to the United Nations Framework Convention on Climate Change, Europe and other countries have taken steps to phase down the use of HFCs, Australia and Brazil are working to reduce methane from agriculture, and Norway has developed an SLCP action plan of its own.¹²⁸ These types

¹²⁸ NEA (2014) Summary of Proposed Action Plan for Norwegian Emissions of Short lived Climate Forcers, Norwegian Environment Agency, March.

of commitments and planning efforts need to be adopted more broadly. By developing a comprehensive plan to achieve necessary SLCP emission reductions in an effective and beneficial way, California can foster broader action beyond its borders and demonstrate effective processes and strategies to address climate change.

VIII. Evaluations

This chapter discusses the economic, public health, and environmental justice evaluations of the proposed new measures in this Proposed Strategy. It also discusses the environmental analysis that was prepared for the Proposed Strategy. It should be noted that to the extent that any of the proposals in the Proposed Strategy result in regulatory action, each proposed regulation will be subject to its own public process with workshops, opportunities for stakeholder discussion, consideration of environmental justice, and legally required analyses of the economic and environmental impacts.

A. Economic Assessment of Measures in the Proposed Strategy

This section presents the economic analyses for the new measures identified in this Proposed Strategy. Supporting documentation for this analysis is presented in Appendix D. Activities already underway separately—including development of the California State Implementation Plan to meet federal health-based air quality standards, the California Sustainable Freight Action Plan, the 2030 Target Scoping Plan, and implementation of Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014)—will have important impacts on SLCP emissions in California, but are not evaluated here. Also, economic impacts associated with improved forest management to reduce black carbon emissions from wildfires and address additional State goals for forest management are not considered here, as many of those goals and potential actions to are currently under development through separate planning processes. As described in Chapter IV, improving forest management in California requires a significant financial commitment, on the order of \$500 million to \$1 billion annually, which can complement efforts to put organic waste resources to beneficial use in California, as described in this section for the dairy and waste sectors.

The analyses presented here consider direct economic costs associated with new technologies and management strategies that can help to reduce SLCP emissions. They also consider direct economic benefits in the form of savings as a result of efficiency improvements, or revenue from marketable products. This analysis does not include a macroeconomic analysis at the statewide level, nor does it include a monetary accounting of societal benefits, such as the value of reducing exposure to fine particulate pollution or reducing the impacts of climate change.

While there are potentially significant market opportunities associated with some of the proposed measures, including putting organics to beneficial use, there are also substantial costs and funding needs. These include costs to increase market penetration of existing technologies and research and development of innovative advanced technology. Initial analyses and various literature sources suggest that SLCP emissions from several sources, including those identified in this Proposed Strategy, can be reduced at low, and sometimes negative, lifetime costs.

Long-term regulatory signals can play a vital role in facilitating low cost SLCP emission reductions. The Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuel

Standard (RFS) incentivize the use of renewable natural gas as a transportation fuel, creating large revenue potential within the dairy manure and organic diversion measures. These programs in particular can help support cost-effective projects to reduce methane from the dairy and waste sectors. Without the LCFS and RFS programs, additional sources for financial incentives and funding may be needed.

The measures laid out in this Proposed Strategy are transformative, leading to uncertainty in the potential costs and revenue of proposed measures as well as the ultimate pathway to compliance. There is a wide range of potential costs and savings, uncertainty in how the strategies will be met, and uncertainty in some cases for how costs in literature translate in the California context. In conjunction with State agencies, ARB will continue to work closely with stakeholders and manufacturers to evaluate the feasibility and costs of existing and developing technologies to determine the best approaches to meeting the targets in the Proposed Strategy.

The measures included in the Proposed Strategy will also strengthen California's environment and the economy by developing infrastructure, generating cost savings, and creating jobs. Measures that reduce methane emissions through waste digestion will have a large impact on the California economy, including disadvantaged communities.

The dairy manure measure has the potential to create jobs in California's Central Valley. These jobs include construction jobs to build digesters and farm and waste management jobs to operate and maintain the facilities. In this analysis, it is assumed that the construction of an anaerobic digester for a 2,000 head dairy farm can result in 25 to 60 construction jobs and 2 to 5 full-time farm jobs.¹²⁹ As the dairy manure measure is estimated to impact 1.05 million dairy cows, many in the San Joaquin Valley, the measure could result in over 30,000 construction jobs and 2,500 permanent jobs potentially providing employment opportunities in disadvantaged communities.

Diverting organic waste can also result in increased employment, providing an estimated 2 jobs per 1,000 tons of diverted organic material.¹³⁰ In 2030, this could result in 32,000 jobs in waste management and garbage collecting, food recovery and distribution. As demonstrated in the CalRecycle funded Food to Share project, food waste prevention programs not only produce emission reductions, but employment and nutritious meals to California's most vulnerable populations.¹³¹

The proposed measures will also build on and support existing California efforts related to climate change and air quality. Measures will support infrastructure, research, development, and deployment of advanced technologies that will help achieve

¹²⁹ Sample of industry information relied upon for the estimate: <http://www.gundersenenvision.org/renewable-energy/turning-cow-waste-into-energy-middleton> and http://www.usda.gov/oce/reports/energy/Biogas_Opportunities_Roadmap_8-1-14.pdf.

¹³⁰ <http://www.calrecycle.ca.gov/publications/Documents/1463%5C20131463.pdf>

¹³¹ More information available at: <http://greenlining.org/wp-content/uploads/2015/10/CAClimateInvestmentsCaseStudies.pdf>.

California's near- and long-term climate and air quality goals. Encouraging the collection of methane gas from waste streams, for example, can provide renewable fuel to reduce the carbon footprint of the transportation sector. Plans that stand to benefit from proposed SLCP measures include the 2030 Target Scoping Plan Update, the California State Implementation Plan, and California's Sustainable Freight Action Plan.

The 2030 Target Scoping Plan, expected to be finalized in 2016, will include a detailed macroeconomic assessment of ARB's complete climate change strategy, including those contained in the final SLCP Strategy. While this Proposed Strategy begins to explore the costs and benefits of proposed measures, detailed economic analyses will allow for a comprehensive assessment of the impact of California's climate strategy on Californians, businesses, and the California economy.

All proposed regulatory SLCP strategies will also be subject to the economic requirements of the Administrative Procedures Act (APA) as part of the public regulatory process. Prior to finalization, regulatory measures will be analyzed in a public process including an Economic Impact Statement, Economic Impact Assessment, and a Standardized Regulatory Impact Assessment for major regulations. Therefore, there will be many opportunities to assess the economic impact of measures in the Proposed Strategy.

The costs, savings, and potential revenue streams of the five measures are assessed in the following sections, 1 through 5. Collectively, implementing these measures would require several billion dollars of investment in clean technologies and strategies that would lead to significant reductions in SLCP emissions. Potential revenues and efficiency gains could also be significant - potentially outweighing the costs of some measures. In other cases, there may be net costs, but associated SLCP emission reductions may come at relatively low cost or provide other environmental and health benefits. While uncertainties remain – especially for costs and revenues associated with some strategies that utilize either emerging technologies or those that haven't been widely deployed already in California – these measures can help to significantly cut SLCP emissions in California at reasonable cost. With ongoing, targeted financial and market support, coordinated with regulatory development and other economic and environmental priorities where appropriate, California can meet the targets identified in the Proposed Strategy plan while delivering a broad range of benefits.

1. Residential Wood Combustion Black Carbon Emission Reductions

Residential wood combustion (RWC) constitutes 15 percent of California's non-forestry black carbon (BC) emissions, and is projected to be the largest individual source of BC by 2030. This Strategy recommends a 3.0 MMTCO₂e (20-yr GWP) reduction in RWC BC emissions by 2030 to meet the SLCP BC emission reduction target.

There are a variety of ways to reduce RWC emissions, and multiple air districts have already put measures in place. Past incentive programs to replace old polluting wood-burning devices with the cleanest EPA-certified devices have been popular and

effective. However, rural districts that rely most heavily on RWC for their primary source of heat are largely located outside of regions that provide incentives. Additionally, past incentive programs have not acquired sufficient funding to achieve the substantial emission reductions proposed in this strategy.

The cost share of this strategy between homeowners and governmental incentives primarily depends on the incentive amount provided per device, and total costs depend on the emission reduction achieved per device. Both of these factors will vary by region and by household, thus incentives funding and homeowners share of costs are calculated as a range. The cost to replace a device can range between \$3,000 and \$5,000.¹³² Purchase and installation of woodstoves was assumed to cost \$4,000 while gas devices were assumed to cost \$4,500. Incentives typically cover a portion of the cost, from \$1,000¹³³ up to the full installation price.¹³⁴ In many rural areas that rely heavily on wood combustion as a source of heat will require nearly full coverage of the installation price to spur voluntary participation; therefore, the incentive range was assumed to be \$1,000 to \$4,500.

The BC emission reduction per household depends on how much wood is burnt per year, the density and moisture content of the wood, the old device type, and the new device type. Emissions were calculated for two replacement cases. The “wood to wood” case assumes conversion of non-certified woodstove to EPA certified wood stove.¹³⁵ The “wood to gas” case assumes conversion of non-certified woodstove to gas device. An incentives program may contain a mixture of different replacement types and these two cases are used to bound potential reductions and costs. Other parameters used in emission reduction calculations were provided by the US EPA residential wood combustion replacement calculator, which includes California-specific data when available (Table 8).¹³⁶ The calculator was updated to account for replacement with cleaner EPA certified wood burning devices that will be required by 2020.

¹³² USEPA (2014). How to Implement a Wood-Burning Appliance Change out Program. Available at: <http://www.epa.gov/sites/production/files/201508/documents/howtoimplementawoodstovechangeout.pdf>

¹³³ SJVAPCD (2016). Burn Cleaner Program. <http://valleyair.org/grants/burncleaner.htm>

¹³⁴ <http://www.epa.gov/sites/production/files/201508/documents/howtoimplementawoodstovechangeout.pdf>

¹³⁵ Specifically, a woodstove that meets the U.S. EPA 2020 new source performance standard (2.0 grams particulate matter per hour) USEPA (2015). Fact Sheet: Summary of Requirements for Woodstoves and Pellet Stoves. Available at: <http://www.epa.gov/residential-wood-heaters/fact-sheet-summary-requirements-woodstoves-and-pellet-stoves>

¹³⁶ USEPA (2009). Burn Wise Additional Resources - Emission Calculator. <http://www.epa.gov/burnwise/burn-wise-additional-resources>.

Table 8: Emission Summary

| Parameter | Wood to Wood | Wood to Gas |
|---|--------------|-------------|
| Cords wood burnt per year ¹³⁷ | 1.5 | 1.5 |
| Wood Density (tons/cord) ¹³⁸ | 1.04 | 1.04 |
| PM _{2.5} Emissions Reduction per device (tons/yr) ¹³⁹ | 0.0218 | 0.0245 |
| BC Speciation (fraction of PM _{2.5}) ¹⁴⁰ | 0.125 | 0.125 |
| BC Reduction per device per year (MTCO _{2e} , 20-yr GWP) | 7.9 | 8.9 |
| BC Emissions Target 2030 (MTCO _{2e} , 20-yr GWP) | 3,000,000 | 3,000,000 |
| Number of average replacements needed to meet target | 379,000 | 337,000 |

The cost of incentives was calculated by multiplying the number of replacements needed to meet the target (Table 8) by the range of incentives that could be provided, from \$1,000 to the full cost of replacement.¹⁴¹ The cost to homeowners was calculated as the total replacement cost, minus the portion covered by incentives. The “low incentives” case in Table 9 is a scenario where only \$1,000 in incentives is paid, and homeowners pay a portion of the replacement. In the “high incentives” case, incentives cover 100 percent of replacement costs and homeowners pay no money out of pocket. Costs to oversee and administer the incentives program were assumed to be similar in either case, because a similar number of devices are replaced (Table 8), and were calculated as 10 percent of the lower incentive value.¹⁴² Educational and outreach costs were estimated at 1 percent of the lower incentives value. Education and outreach includes education about the health effects of wood smoke and educating residents about proper use of their new devices to minimize emissions and maximize the lifetime of the equipment. Studies indicate that education and outreach are vital components of RWC replacement programs.¹⁴³ A summary of costs can be found in Table 9. The results in Table 9 show that the total costs for either a low incentives or high incentives case would be the same, but the distribution of costs between incentives and homeowner responsibility is different. These scenarios represent extremes use to bound the range of possible costs; actual program implementation may lie between the low and high incentives cases presented in Table 9.

¹³⁷ Based on average California Climate, from USEPA Emission Calculator.

¹³⁸ Average California wood density, from USEPA Emission Calculator.

¹³⁹ Results are from USEPA Emission Calculator for wood to gas conversion. This result assumes approximately 100% reduction in PM.

¹⁴⁰ ARB (2015). 2015 Edition Black Carbon Technical Support Document. Available at: <http://www.arb.ca.gov/cc/inventory/slcp/slcp.htm>

¹⁴¹ \$4,000 for woodstove installation and \$4,500 for gas devices.

¹⁴² <http://www.epa.gov/sites/production/files/201508/documents/howtoimplementawoodstovechangeout.pdf>

¹⁴³ <http://www.epa.gov/sites/production/files/201508/documents/howtoimplementawoodstovechangeout.pdf>

Table 9: Range of Costs (Million Dollars)¹⁴⁴

| Cost | Low Incentives | High Incentives |
|------------------------------|-----------------------|------------------------|
| Incentives | \$340 | \$1,500 |
| Oversight and Administration | \$34 | \$34 |
| Cost to Homeowners | \$1,180 | \$0 |
| Education and Outreach | \$3.4 | \$3.4 |
| Total Cost | \$1,557 | \$1,537 |

Savings associated with this plan include reduced wood use in more efficient devices or any savings (or cost) to convert from wood fuel to natural gas. US EPA estimates that EPA-certified devices burn a third less wood for the same heat output.¹⁴⁵ Table 10 summarizes the range of potential savings depending on the conversion scenario.

Wood to wood total savings were calculated using the average annual amount of wood burnt (Table 8), the fraction of residents who pay for wood,¹⁴⁶ the cost of a cord of wood, and the assumption that a third less wood is used by the replaced devices. This analysis assumes 20 percent of wood is gathered for free, and would not provide a savings to the resident. The cost of a cord of wood will vary from approximately \$100 to \$480 depending on location and type of wood¹⁴⁷. This analysis uses the midpoint value of \$290 per cord. Reducing annual wood consumption from 1.5 to 1 cord per year would save the average resident \$145 per year. Approximately 379,000 wood to wood conversions (Table 9) would result in savings of approximately 44 million dollars per year to consumers receiving incentives to replace their inefficient wood stove.

Wood to gas savings can be calculated assuming 1.5 cords of wood are not purchased (Table 8), the cost of wood is \$290 a cord, and that the heat-equivalent amount of natural gas must be purchased, and assuming 337,000 devices are replaced (Table 9). The price of natural gas was assumed to be \$11.51 per thousand standard cubic feet.¹⁴⁸ The savings from not purchasing wood is nearly in balance with the additional cost of purchasing natural gas using these assumptions (Table 10).

¹⁴⁴ Low incentives are \$1,000 and high incentives cover 100 percent of device purchase and installation costs (\$4,000-\$4,500 depending on the device). Under the high incentive there is no out of pocket expense to homeowners.

¹⁴⁵ <http://www.epa.gov/sites/production/files/201508/documents/howtoimplementawoodstovechangeout.pdf>

¹⁴⁶ A portion of residents who rely on residential wood combustion for heat gather wood from local lands at no cost.

¹⁴⁷ CDFA (2010). California Department of Food and Agriculture News Release. Available at https://www.cdfa.ca.gov/egov/Press_Releases/Press_Release.asp?PRnum=10-074

¹⁴⁸ EIA (2015). California 2014 price of natural gas delivered to residential customers. Available at https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SCA_a.htm.

Table 10: Savings Associated with Residential Wood Stove Conversion (Million Dollars)

| Conversion Scenario | Savings on Purchase of Wood | Increased Cost for Natural Gas | Net Fuel Savings |
|---------------------|-----------------------------|--------------------------------|------------------|
| 100 % Wood to Wood | \$44 | \$0 | \$44 |
| 100 % Wood to Gas | \$117 | \$109 | \$8 |

2. Methane Emission Reductions from Dairy Manure

As noted in Chapter V, emissions from dairy manure can be reduced by 75 percent by capturing or avoiding methane produced by about 1.05 million of the State’s 1.4 million milking cows whose manure is managed anaerobically. Achieving these targets for the industry could lead to significant GHG emission reductions – 22 MMTCO₂e annually by 2030, and 168 MMTCO₂e cumulatively through 2030 (8 MMTCO₂e and 58 MMTCO₂, respectively, using a 100-year GWP).

Several options exist to reduce methane emissions from manure management in California. Five strategies were considered in this analysis, which are described in further detail in Appendix D:

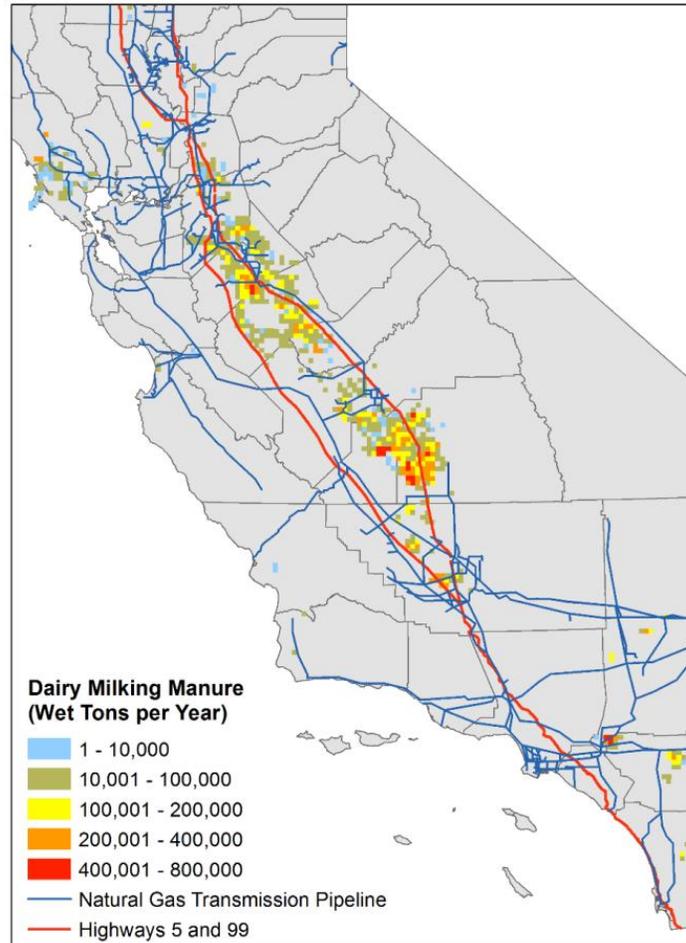
1. Scrape conversion and onsite manure digestion producing pipeline-injected renewable natural gas vehicle fuel
2. Scrape conversion and transport of manure offsite for centralized digestion producing pipeline injected renewable natural gas as a vehicle fuel
3. Scrape conversion, collection and open solar drying of manure onsite
4. Scrape conversion and onsite manure digestion for onsite production of renewable electricity
5. Conversion of dairy operations to pasture-based management

These represent example pathways that could be important to a sector-wide approach to reduce emissions, but they are not meant to rule out other solutions. The cost and efficacy of some options, such as solids separation, are not yet known with certainty and could not be included in this analysis. Solids separation and other potential mitigation methods deserve additional study of both emission reduction potential and economic feasibility.

The strategies considered here aim to balance cost and feasibility, while prioritizing economic and environmental benefits. Specifically, they aim to address water quality issues on dairies by including conversion to scrape systems, maximize renewable natural gas production by utilizing above ground tank/plug flow digesters, and avoid increases in criteria pollutant emissions (most notably oxides of nitrogen, or NO_x) and maximize potential revenues by prioritizing pipeline injection of renewable natural gas. Prioritizing these goals adds costs compared to a pathway that focuses on methane mitigation only, but deliver important environmental, health and potential economic benefits.

ARB conducted a Geographic Information System (GIS) analysis of dairies throughout the State to inform the scenario development. GIS informed estimates related to the number of dairies that could feasibly inject renewable natural gas into the pipeline, associated costs, availability and costs associated with “clustering” dairies to centralize digestion and pipeline injection, and opportunities for converting to pasture-based operations. Figure 11 provides a spatial analysis of manure from milking cows in California.

Figure 11: Location of Manure from Milking Cows in California



The analysis was informed by direct consultation with CDFA, academic researchers at UC Davis and elsewhere, project developers, and stakeholders. In particular, as part of developing this Proposed Strategy, ARB supported research at UC Davis to inform cost and performance estimates for dry scrape conversions, anaerobic digesters, and other

pathways.¹⁴⁹ Additional research was also used to inform the cost and performance parameters assumed for this analysis, which are detailed in Appendix D.¹⁵⁰

Potential revenues from energy or electricity sales and environmental credits were included. For the value of energy and credits, the current or estimated average value through 2030 was used. No revenue was included for soil amendment products that could be potentially generated from these pathways, and provide value,¹⁵¹ because their market potential remains uncertain at this time. The LCFS, Cap-and-Trade, and federal Renewable Fuel Standard program are all assumed to be in place through at least 2030. Cap-and-trade offsets are not available for projects built after a regulation takes effect, assumed here to be in 2025, and the carbon intensity for LCFS accounting is assumed to increase for new projects from -276 gCO₂e/MJ to +13 gCO₂e/MJ at that point, as well.

The first two strategies produce biomethane that is injected into the pipeline and used as transportation fuel. They receive revenue for energy sales at the price of wholesale natural gas (\$3.46/Mscf), as well as LCFS credits (\$100/MT) and cellulosic RIN credits (\$1.85/RIN)¹⁵² from the federal Renewable Fuel Standard program. In the first strategy, digesters are developed onsite at each dairy, while the second captures economies of scale by utilizing centralized digesters, biogas upgrading, and pipeline injection points for “clustered” dairies. The third pathway mitigates manure methane emissions by converting from flush management to scrape systems, but is assumed to generate no revenue. This represents a low cost option, but low value, as well. In the fourth strategy, manure is digested onsite to produce electricity using microturbines (to limit NO_x emissions). This pathway receives revenue from electricity sales (\$0.126/kWh) and Cap-and-Trade offsets (\$13/MTCO₂e). Finally, in the fifth strategy, dairies convert to pasture-based operations. No revenue is assumed from this pathway.

Costs and revenues for these strategies, normalized to a dairy with 2,000 milking cows, are summarized in Table 11. The table includes the net present value for each over a 10-year time horizon, assuming a 10 year loan on capital at 7 percent interest, and a 5 percent discount rate.

¹⁴⁹ Kaffka, S. et al (2016) Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California, Final Technical Report to the State of California Air Resources Board, February.

¹⁵⁰ In particular: Sustainable Conservation (2015) Combating Climate Change: Dairies Key in Reducing Methane, July: <http://www.suscon.org/blog/2015/07/combating-climate-change-dairies-key-in-reducing-methane/>.

¹⁵¹ Soil amendment products from dairy digesters could provide greater potential revenues than energy sales from the digesters, potentially as much as \$300 per cow per year in California. Informa Economics (2013) National Market Value of Anaerobic Digester Products, Prepared for Innovation Center for U.S. Dairy, February.

¹⁵² The assumed cellulosic RIN credit value of \$1.85 includes a D5 RIN (\$0.85), cellulosic waiver credit (\$0.90) and value from the Blenders Tax Credit (\$0.10 per D5 RIN).

Table 11: Economic Analysis for Projects at a Representative Dairy with 2,000 Milking cows Over 10-year Accounting Period¹⁵³

| | Strategy | | | | |
|--|--|---|----------------------------|---|-----------------------------------|
| | 1 Onsite Digestion to Fuel | 2 Central Digestion to Fuel | 3 Scrape Only | 4 Onsite Digestion to Electricity | 5 Convert to Pasture |
| Capital (million dollars) | \$5.4 | \$3.3 | \$1.6 | \$5.8 | \$5.0 |
| O&M (million dollars) | \$3.5 | \$2.4 | \$0.4 | \$3.5 | \$2.8 |
| Revenue (million dollars) | \$11.3 | \$11.3 | -- | \$3.6 | -- |
| NPV (million dollars) | \$2.5 | \$5.5 | -\$2.1 | -\$5.7 | -\$7.8 |
| \$/MT CO₂e (20-yr GWP) | -\$5.8 | -\$13.0 | \$4.9 | \$13.5 | \$18.2 |
| \$/MT CO₂e (100-yr GWP) | -\$16.6 | -\$37.6 | \$14.2 | \$38.8 | \$52.5 |
| Breakeven Upfront Grant (million dollars) | -- | -- | \$1.9 | \$5.3 | \$7.1 |

Based on the assumptions used here, projects that generate transportation fuel and can capture LCFS credits can generate a positive return (strategies 1 and 2). These pathways may also contribute to regional air quality benefits, as part of an integrated approach to utilize renewable fuel in low-NOx engines. But revenue for these strategies, and the resulting project economics (as measured by net present value), are highly dependent on the value of LCFS and RIN credits. As shown in Table 12, the net present value can fluctuate by several million dollars, depending on the value of these revenue streams. Without these programs, these projects would have net present values similar to strategies 4 and 5.

Table 12: Net Present Value for Strategies Producing Transportation Fuel, as a Function of LCFS and RIN Credit Prices (Million Dollars)

| | | Strategy 1: Onsite Digestion to Vehicle Fuel | | | | | Strategy 2: Centralized Digestion to Vehicle Fuel | | | | |
|--|---------------|---|-------------|--------------|--------------|--------------|--|-------------|--------------|--------------|--------------|
| | | LCFS Credit Price | | | | | LCFS Credit Price | | | | |
| | | \$0 | \$50 | \$100 | \$150 | \$200 | \$0 | \$50 | \$100 | \$150 | \$200 |
| Cellulosic RIN Credit Price | \$0.00 | -\$8.2 | -\$5.0 | -\$1.7 | \$1.6 | \$4.8 | -\$5.1 | -\$1.9 | \$1.4 | \$4.7 | \$7.9 |
| | \$0.50 | -\$7.1 | -\$3.8 | -\$0.6 | \$2.7 | \$6.0 | -\$4.0 | -\$0.7 | \$2.5 | \$5.8 | \$9.0 |
| | \$1.00 | -\$6.0 | -\$2.7 | \$0.5 | \$3.8 | \$7.1 | -\$2.9 | \$0.4 | \$3.6 | \$6.9 | \$10.2 |
| | \$1.85 | -\$4.1 | -\$0.8 | \$2.5 | \$5.7 | \$9.0 | -\$1.0 | \$2.3 | \$5.5 | \$8.8 | \$12.1 |
| | \$2.50 | -\$2.6 | \$0.6 | \$3.9 | \$7.2 | \$10.4 | \$0.5 | \$3.7 | \$7.0 | \$10.3 | \$13.5 |
| | \$3.00 | -\$1.5 | \$1.8 | \$5.0 | \$8.3 | \$11.6 | \$1.6 | \$4.9 | \$8.1 | \$11.4 | \$14.6 |
| | \$3.50 | -\$0.4 | \$2.9 | \$6.1 | \$9.4 | \$12.7 | \$2.7 | \$6.0 | \$9.2 | \$12.5 | \$15.8 |
| | \$4.00 | \$0.7 | \$4.0 | \$7.3 | \$10.5 | \$13.8 | \$3.8 | \$7.1 | \$10.4 | \$13.6 | \$16.9 |

¹⁵³Summation may not be exact due to rounding. Capital costs amortized over 10 years with 7% interest. Discount rate is 5%. Costs normalized to representative 2,000 cow dairy.

Other types of dairy projects may not generate positive returns without additional support and/or other potential revenue streams, such as for soil amendments. The third strategy requires the lowest capital outlay among strategies considered in this analysis, but it is not assumed to generate any revenue, leading to a net present value loss of about \$2.1 million over 10 years. Still, this pathway represents fairly low cost emission reductions (\$4.9/MT using a 20-year GWP) and could break even with an upfront grant, or its equivalent, of about \$1.9 million.

The fourth strategy provides revenue streams that are more stable than for the transportation fuel pathways in strategies 1 and 2, but they are also significantly lower, and the project economics are less favorable. The net present value of this project over ten years is -\$5.7 million, and an upfront grant of \$5.3 million would be needed to break even. Note, however, that if electricity generated from biogas is used to charge electric vehicles, biogas used to generate electricity can be credited with cellulosic RIN credits, which could add another valuable revenue stream. In this case, RIN credits would more than double revenue and add more than \$4 million in net present value over 10 years. That type of project, based on the assumptions here, would still represent a net loss of \$1.6 million over ten years, but it could break even with an upfront grant of \$1.5 million. Costs of emission reductions over 10 years would fall to \$4/MTCO_{2e} using a 20-year GWP (\$11/MTCO_{2e} using a 100-year GWP).

Converting to pasture-based systems is assumed to have relatively high costs and no revenue, leading to a pathway with a net present value of -\$7.8 million over 10 years. Three-quarters of the estimated capital cost and over 90 percent of the estimated operating costs come from irrigation, so if dairies were to convert to pasture in areas where less irrigation may be needed (perhaps in northern parts of the State), they might be able to significantly cut costs associated with reducing methane from their operations. In general, little information is available on the economics associated with converting to pasture, and additional research and potential demonstration projects could help to evaluate the viability of this strategy to reduce dairy methane emissions in California.

Costs and Revenues for Sector-Wide Scenarios to Meet Proposed Targets

These individual pathways were combined into three industry-wide scenarios (Table 13) for reducing methane emissions from manure management at California dairies by 20 percent in 2020, 50 percent in 2025 and 75 percent by 2030:

- Scenario A: All strategy 3 (scrape to manure collection and drying)
- Scenario B: Mixed approach (including all five strategies)
- Scenario C: All strategy 2 (centralized digestion and pipeline injection)

**Table 13: Mix of Strategies in Scenarios:
Number of Milking cows Covered by Projects in 2030**

| Strategy | A | B | C |
|---|------------------|------------------|------------------|
| (1) Scrape conversion and onsite manure digestion producing pipeline-injected renewable natural gas vehicle fuel | | 350,000 | |
| (2) Scrape conversion transport of manure offsite for centralized digestion producing pipeline injected renewable natural gas as a vehicle fuel | | 300,000 | 1,050,000 |
| (3) Scrape conversion, collection and open solar drying of manure onsite | 1,050,000 | 200,000 | |
| (4) Scrape conversion and onsite manure digestion for onsite production of renewable electricity | | 150,000 | |
| (5) Conversion of dairy operations to pasture-based management | | 50,000 | |
| Total | 1,050,000 | 1,050,000 | 1,050,000 |

Results for the scenarios are summarized in Table 14. Scenario A represents a low cost, zero revenue case where a sufficient number of dairies transition to scrape operations to reduce methane emissions from manure management by 75 percent by 2030. This could have potential benefits, as described in Chapter V, for nutrient management and water quality on the farm. There could also be potential revenue (along with added costs) if manure were composted and sold, which is not considered here. The sector-wide, net present value through 2030 for this scenario is -\$636 million, which represents emission reductions of about \$4/MTCO_{2e} using a 20-year GWP (\$11/MTCO_{2e} using 100-year GWP).

Table 14: Economic Analysis for Sector-Wide Scenarios Through 2030 (Million Dollars)¹⁵⁴

| | Scenario | | |
|---|-----------------|----------|----------|
| | A | B | C |
| Capital | \$493 | \$1,235 | \$995 |
| O&M | \$142 | \$837 | \$788 |
| Revenue | \$0 | \$2,157 | \$3,237 |
| Net Present Value \$100 LCFS Credit \$1.85 RIN Credit | -\$636 | \$84 | \$1,454 |
| \$/MT CO₂e (20-yr GWP) | \$3.8 | -\$0.5 | -\$8.7 |
| \$/MT CO₂e (100-yr GWP) | \$10.9 | -\$1.5 | -\$24.9 |
| Net Present Value \$40 LCFS Credit \$1.00 RIN Credit | -\$636 | -\$926 | -\$176 |

Scenario B includes a mix of all five strategies. Collectively, with LCFS credits assumed to be valued at \$100/MT and RINs at \$1.85, this scenario meets the targets in this Proposed Strategy with a positive net present value of \$84 million through 2030. If the portion of milking cows in this scenario utilizing Strategy 4 were to use generated electricity for transportation fuel to capture RIN credits, it would increase revenues and net present value by about \$200 million. Again, revenues are highly dependent on LCFS and RIN credit values. If LCFS credits were \$40/MT and RINs were \$1.00, the net present value of this scenario would fall by about \$1 billion, to -\$926 million (and -\$823 million if the electricity is used as transportation fuel).

The value of LCFS and RIN credits is even more noticeable in Scenario C, where all emission reductions are achieved through centralized digestion that generates renewable natural gas for transportation fuel and LCFS credits. If instead of the assumptions used here, LCFS and RIN credits were valued at \$40/MT and \$1.00, respectively, the net present value would fall by \$1.6 billion, and the scenario would have a net loss of \$176 million through 2030.

Altogether, this analysis suggests that the dairy industry in California can significantly cut methane emissions and deliver low-cost GHG reductions. There are important uncertainties associated with project costs and potential revenues, however, which may limit project development without targeted support. And the State may wish to support

¹⁵⁴ Summation may not be exact due to rounding. Capital costs amortized over 10 years with 7% interest. Discount rate is 5%. In Scenarios B and C, beginning in 2025, regulation eliminates availability of C&T offsets for new electricity generating projects (Strategy 4) and for those that have been operating for 10 years. For projects producing transportation fuel (Strategy 1 and 2), beginning in 2025, the carbon intensity for LCFS credits for new projects and those that have been operating for 10 years increases from -276 to 13 gCO₂e/MJ. The impact of regulation on existing projects under the LCFS has not been determined, and this simply an assumption used for the sake of this analysis.

some higher cost strategies, including conversions to scrape or pasture-based systems, for other environmental reasons.

A mix of grants, especially for projects with lower revenues, and other mechanisms for pathways with higher revenues may be appropriate. This funding could come from federal sources, California's Greenhouse Gas Reduction Fund (GGRF), utility programs, the programs included in this analysis, or other sources. Limited federal grant funding is currently available, and more should be pursued. In his proposed 2016-17 Budget,¹⁵⁵ Governor Brown has proposed committing \$55 million in GGRF funding for climate smart agriculture, including dairy digesters and healthy soils. And under a rulemaking by the CPUC pursuant to Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012), California's natural gas utilities will offset half of renewable natural gas interconnection costs, up to \$1.5 million per project and \$40 million Statewide.

These programs provide a strong starting point for supporting the industry in reducing methane emissions and achieving the targets and benefits identified here. They should be built upon and bolstered. A financial working group may be helpful in recommending ways to leverage private sector investment and significantly scale efforts to rapidly cut methane emissions in California. Through careful investments and structured market-based incentives, project development may be accelerated to achieve emission reductions more quickly than the targets identified in this Proposed Strategy, and ahead of potential regulation of the industry.

3. Methane Emission Reductions from Diversion of Landfill Organic Waste

As noted in Chapter V, diverting organic materials from landfills can reduce landfill emissions by 5 MMTCO₂e in 2030, increasing to 21 MMTCO₂e by 2050 (using a 20-year GWP). Achieving these methane reduction targets requires optimized use and disposal of methane generating organic materials. To that end, the Proposed Strategy recommends reducing organics deposited to landfills by 90 percent by 2025, consistent with AB341. This ambitious target requires putting organic materials to the highest feasible use and developing infrastructure and markets to optimize the economic and environmental value of California's waste streams across sources.

When considering waste diversion options it is essential to balance environmental and economic benefits with any potential impacts on criteria pollutant emissions and ecosystem and human health, especially in disadvantaged communities. Avoiding organic waste generation entirely is the best option to reduce emissions, protect health, and minimize costs. However, once generated, there are many options for creating environmental and economic benefit through the appropriate utilization organic waste. Organics can be diverted to waste facilities with existing excess capacity, including composting facilities, stand-alone anaerobic digesters (AD), and wastewater treatment anaerobic digesters. New facilities can be also built in optimized locations.

¹⁵⁵ <http://www.ebudget.ca.gov/2016-17/BudgetSummary/BSS/BSS.html>

In this analysis three scenarios were considered that can achieve the organic diversion target outlined in the Proposed Strategy. The three scenarios are based on projected waste data and potential diversion outlined in Appendix D. The only difference between the scenarios is the waste utilization of grass and leaves. The three scenarios evaluate the costs and revenues for utilizing food waste and grass and leaves in three pathways:

1. New anaerobic digestion facilities
2. Existing excess capacity at wastewater treatment anaerobic digestion facilities
3. New compost facilities

The actual future utilization of food waste and grass and leaves will most likely be some mix of these options. Since it is not possible to predict the exact mix of utilization pathways, these three scenarios were developed to bound potential costs and revenues. The scenarios considered here aim to balance cost and feasibility, while prioritizing economic and environmental benefits. To this end, the analysis focuses on the capture and pipeline injection of renewable natural gas from diverted organic waste. Using renewable natural gas as a transportation fuel can result in significant potential revenue streams and reduce criteria pollutant emissions from the transportation sector. Prioritizing the use of biomethane as a transportation fuel may increase costs relative to scenarios that focus solely on methane mitigation. However, important environmental, health, and economic benefits may be realized by prioritizing pipeline injection of renewable natural gas.

Within scenario 1, food waste and a portion of grasses and leaves are handled through new centralized AD facilities and the resulting methane is pipeline injected. New AD facilities are assumed to accept 100,000 tons per year of organic waste. The costs of scenario 1 include facility construction and permitting, operating and maintenance (O&M), waste and digestate processing and transportation, and the costs associated with pipeline injection of renewable natural gas. These include pipeline, interconnection, and biogas upgrading costs. Potential revenue streams include tipping fees, the sale of biogas, LCFS credits, and RIN credits, as outlined in Appendix D.

Scenario 2 assumes that food waste is diverted to wastewater treatment facilities with existing excess capacity. The analysis assumes that, with modification, existing wastewater treatment facilities can accept 50,000 tons of organic material per year on average by 2030, with some facilities accepting more or less depending on size. Costs for this scenario include upgrading and permitting costs that may be required for facilities to accept food waste, waste and biosolid processing and transportation, O&M, as well as the costs associated with pipeline injection of renewable natural gas. Potential revenue streams include tipping fees, sale of biogas, LCFS credits, and RINs.

Scenario 3 assumes that all food waste and grasses and leaves are composted at new facilities with a throughput of 100,000 tons per year. Costs within the scenario include facility construction, O&M, and transportation of organic materials to the compost facility. The only revenue stream included in scenario 3 is the tipping fee, though additional revenue streams could result from the sale of compost.

A principal difference in outcomes from these three scenarios is the number of new facilities needed to achieve the organic diversion targets. Table 15 shows the number of new compost or AD facilities needed for each scenario.¹⁵⁶

Table 15: Estimated Number of New Facilities

| Scenario | Estimated Number of New Compost Facilities to Achieve Target | | | Estimated Number of New AD Facilities to Achieve Target | | |
|------------------|--|------|------|---|------|------|
| | 2020 | 2025 | 2030 | 2020 | 2025 | 2030 |
| 1. New AD | 43 | 52 | 54 | 40 | 56 | 58 |
| 2. Existing WWTP | 50 | 62 | 65 | - | - | - |
| 3. Compost Only | 76 | 97 | 102 | - | - | - |

There is uncertainty regarding the costs, savings, and potential revenue streams associated with organic waste diversion. Social welfare impacts, including those related to health, noise, odor, ecosystem benefit, and water impacts, are not included in this analysis but require additional consideration and analysis prior to the implantation of any organic diversion measure. Additional uncertainty related to existing infrastructure and technology development may also create economic impacts not analyzed in this analysis, which relies on available data from California agencies, academic researchers, and industry to estimate the direct economic impact, including costs, fuel and energy savings, and potential revenue streams, of achieving the organic waste diversion target in the Proposed Strategy.

Net present value calculations were used to estimate the potential profitability of the three scenarios. By calculating the present value of future cost and organic diversion over a 10-year financing period, the net present value calculation provides insight into the feasibility of projects at the facility level, including the need for upfront grants and incentives as well as the significant opportunities and uncertainty surrounding revenue streams based on existing regulations.

Costs and revenues for the three scenarios are summarized in Table 16. The table includes the net present value for each scenario over a 10-year financing period

¹⁵⁶ This analysis assumes existing wastewater treatment facilities can handle 50,000 wet tons of food waste per year, while new AD facilities and compost facilities have a throughput of 100,000 wet tons per year. Additional information regarding the projected organic waste streams by waste, the assumptions surrounding required facilities, and the handling of residuals are presented in Appendix D.

Table 16: Cumulative Estimated Costs and Revenues by Scenario Over 10-Year Accounting Period (Million Dollars)

| Scenario 1: New AD | Component | Capital Cost | O&M | Revenue |
|----------------------------------|------------------|---------------------|----------------|----------------|
| New AD | 54 Facilities | \$1,200 | \$2,100 | \$5,800 |
| New Compost | 58 Facilities | \$600 | \$650 | \$1,200 |
| Total | | \$1,800 | \$2,750 | \$7,000 |
| 10-Year Net Present Value | | \$2,500 | | |
| Scenario 2: WWTP | Component | Capital Cost | O&M | Revenue |
| New Compost | 65 Facilities | \$720 | \$790 | \$1,500 |
| Existing Wastewater Treatment | 118 Facilities | \$1,300 | \$3,700 | \$5,100 |
| Total | | \$2,020 | \$4,490 | \$6,600 |
| 10-Year Net Present Value | | \$162 | | |
| Scenario 3: Compost | Component | Capital Cost | O&M | Revenue |
| New Compost | 102 Facilities | \$1,000 | \$1,100 | \$2,100 |
| Total | | \$1,000 | \$1,100 | \$2,100 |
| 10-Year Net Present Value | | -\$43 | | |

Table 16 suggests that under Scenario 1 and Scenario 2, organic waste diversion can generate a positive return. These scenarios may also contribute to regional air quality benefits, through reduced transportation emissions. However, revenue for these strategies, and the resulting net present value, is highly dependent on the value of LCFS and RIN credits. As shown in Table 17, for representative wastewater treatment and new AD facilities, the net present value of diverting organic materials – at the facility level – is negative without revenue from LCFS credits and RINs.

Table 17: Net Present Value of Representative Wastewater Treatment and New AD Facility under Varying LCFS Credit Prices and RIN Credit Prices (Million Dollars)

| | | Wastewater Treatment Facility | | | | | New AD Facility | | | | |
|------------------------------|--------|-------------------------------|---------|--------|--------|--------|--------------------------|---------|---------|---------|---------|
| | | <u>LCFS credit price</u> | | | | | <u>LCFS credit price</u> | | | | |
| | | \$0 | \$50 | \$100 | \$150 | \$200 | \$0 | \$50 | \$100 | \$150 | \$200 |
| Cellulosic RIN credit prices | \$0.00 | -\$17.0 | -\$12.1 | -\$7.2 | -\$2.2 | \$2.7 | -\$34.4 | -\$18.9 | -\$3.4 | \$11.9 | \$27.3 |
| | \$0.50 | -\$8.1 | -\$3.1 | \$1.8 | \$6.7 | \$11.7 | -\$14.4 | \$0.9 | \$16.4 | \$31.8 | \$47.3 |
| | \$1.00 | \$0.9 | \$5.8 | \$10.8 | \$15.7 | \$20.7 | \$5.4 | \$20.9 | \$36.3 | \$51.8 | \$67.2 |
| | \$1.85 | \$16.3 | \$21.2 | \$26.1 | \$31.1 | \$30.0 | \$39.3 | \$54.8 | \$70.2 | \$85.6 | \$101.1 |
| | \$2.50 | \$27.9 | \$32.9 | \$37.8 | \$42.8 | \$47.8 | \$65.2 | \$80.7 | \$96.1 | \$116.7 | \$133.9 |
| | \$3.00 | \$36.9 | \$41.9 | \$46.9 | \$51.8 | \$56.8 | \$85.2 | \$100.6 | \$116.0 | \$131.5 | \$146.9 |
| | \$3.50 | \$46.0 | \$50.9 | \$55.9 | \$60.8 | \$65.8 | \$105.1 | \$120.5 | \$136.0 | \$151.4 | \$166.9 |
| | \$4.00 | \$55.0 | \$59.9 | \$64.9 | \$69.9 | \$74.8 | \$125.0 | \$140.5 | \$155.9 | \$171.4 | \$186.8 |

State resources could be deployed to supplement financing of biomethane projects through mechanisms such as upfront grants, loan assistance programs, and tax incentives. For example, the illustrative wastewater treatment facility in Table 17 would break even over a 10-year financing period with an upfront grant of \$16 million. Looking at LCFS credits and RINs in isolation, without revenue from LCFS credits, this illustrative wastewater treatment facility would break even with a RIN price of \$1 over the 10-year financing period. In the absence of revenue from RINs, the facility would breakeven at an LCFS credit price of \$173. The US EPA’s Renewable Fuel Standard (under which RINs are generated and sold) and California’s LCFS program can offset large upfront capital costs that otherwise may prevent project development.

In the absence of revenue from the sale of LCFS credits, a RIN price of \$0.87 is required for a representative new AD facility to breakeven over a 10-year financing period. In the absence of RIN credit revenue, an LCFS credit price of \$112 is required for that same facility to breakeven over a 10-year financing period. Without revenue from RINs or LCFS credits, an upfront grant of \$32 million would be required in order for the illustrative new AD facility to breakeven over a 10-year financing period.

Altogether, this analysis suggests that the diversion of organic waste can result in environmental and economic value to California. There are important uncertainties associated with facility costs and potential revenues, however, which may limit project development without additional support. In the absence of revenue from LCFS credits and RINs, significant financial support, may be required to achieve the target identified in this Proposed Strategy and deliver other environmental benefits. Through careful research, investments, and structured market-based incentives, the State can work with industry to significantly and permanently reduce methane emissions and divert organic waste.

4. Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Regulation

The Proposed Strategy has a four-pronged approach to methane reductions in the oil and gas sector including regulation of production, processing, and storage facilities and implementation of SB 1371. The process to adopt rules and procedures to minimize natural gas leaks from natural gas pipelines under SB 1371 is just beginning and an analysis of the costs and potential benefits of SB 1371 will be conducted as measures are implemented.

ARB is developing a regulation to address methane from oil and gas production, processing, and storage facilities for Board consideration in 2016. The regulation is anticipated to deliver environmental benefits that include an estimated reduction in GHG emissions through 2030 of about 13.8 MMTCO₂e from oil and gas related emissions in California. In addition, the measure is expected to save about 650 million standard cubic foot (scf) per year of industrial natural gas through reductions of leaks and through vapor recovery systems, the monetized value of which is approximately \$2.7 million per year.¹⁵⁷

While air districts are currently combatting volatile organic compounds (VOC) leaks locally, these rules vary by district and are not addressing any methane only leaks. This measure is designed to expand upon existing local rules, promote statewide uniformity, minimize the administrative burden on local air districts, harmonize state requirements with current and near-future local and federal requirements, and achieve further methane reductions to achieve the goal outlined in this strategy of reducing fugitive methane emissions from all sources in the oil and natural gas sector by 45% by 2030.

The Oil and Gas measure proposes eight main control provisions that are designed to achieve emission reductions in crude oil and natural gas operations. These provisions build upon and in some ways increase existing local air district requirements to monitor, replace, and expand current capital at crude oil and natural gas facilities.

The cost of this measure includes capital costs to: Install Vapor Recovery Units for tanks, well stimulations tanks, and centrifugal compressors; replace rod packing on reciprocating compressors; and change pneumatic devices. In addition, a leak detection and repair program (LDAR) as well as emissions reduction and leak monitoring plans will have ongoing costs in each year beginning in 2018. The amortized¹⁵⁸ capital cost plus the ongoing costs yield an overall cost of the measure of just over \$190 million through 2030. These costs are offset by natural gas collection from the reduction in leaks and vapor recovery; these savings amount to savings of almost \$33 million through 2030 and persisting thereafter. The costs, cost-savings, and emission reductions are outlined in Table 18 by each provision.

¹⁵⁷ <http://www.energy.ca.gov/2014publications/CEC-200-2014-001/CEC-200-2014-001-SF.pdf>. Using a value of \$4.10 per Mscf, which is the value of the natural gas prices are based upon wholesale prices that are forecasted by the California Energy Commission using their NAMGas general equilibrium model.

¹⁵⁸ Using a 5% discount rate.

Table 18: Costs and Emissions for Oil and Gas Measure

| Segment of Regulation | Total Reductions to 2030 (MTCO₂e) | Annual Cost | Annual Savings | Total Cost to 2030 | Total Savings to 2030 |
|----------------------------------|---|---------------------|-----------------------|---------------------------|------------------------------|
| VRU for Tanks | 6,456,000 | \$4,674,000 | \$653,000 | \$56,088,000 | \$7,836,000 |
| Reciprocating Compressors | 804,000 | \$203,000 | \$230,000 | \$2,436,000 | \$2,760,000 |
| LDAR | 2,640,000 | \$8,902,000 | \$756,000 | \$115,726,000 | \$9,450,000 |
| Pneumatic Devices | 3,828,000 | \$1,153,000 | \$1,043,000 | \$13,836,000 | \$12,516,000 |
| Well Stimulations | 60,000 | \$186,000 | \$17,000 | \$2,232,000 | \$204,000 |
| Centrifugal Compressors | 36,000 | \$4,000 | \$12,000 | \$48,000 | \$144,000 |
| Monitoring Plan | TBD | TBD | TBD | TBD | TBD |
| Total | 13,824,000 | \$15,122,000 | \$2,711,000 | \$190,366,000 | \$32,910,000 |

5. Hydrofluorocarbon (HFC) Emission Reductions

Hydrofluorocarbons (HFCs) are used primarily as refrigerant substitutes to ozone-depleting refrigerants, and although not ozone-depleting, HFCs have high-global warming potentials (GWP) between 500 and 12,000 (20-year GWP values). HFCs currently account for 4 percent of California’s GHG emissions, but are expected to double in emissions in the next few decades without additional reduction actions. Four HFC measures are proposed in this strategy to reduce cumulative HFC emissions by 260 MMTCO₂E (20-year GWP) by 2030 to meet the SLCP emission reduction target.

The proposed reduction measures include the following:

- Financial incentive program to install new low-GWP refrigeration and air-conditioning (AC) equipment
- Sales ban on refrigerants with very-high GWPs
- Phasedown in the supply of high-GWP HFCs

- Prohibitions on high-GWP refrigerants in new stationary refrigeration and AC equipment

The cost of strategies to reduce HFCs is highly dependent upon assumptions of the added initial cost of low-GWP equipment, which is estimated to be approximately 10 percent higher than baseline high-GWP equipment, as detailed in Appendix D. The additional initial cost ranges from \$500,000 for a large cold storage facility, and \$200,000 for a supermarket; to \$400 for a residential AC system, and \$140 for a residential refrigerator-freezer. In many cases, the added initial cost is offset or reversed through energy savings of low-GWP refrigeration and AC. Additionally, low-GWP refrigerants such as carbon dioxide refrigerant, ammonia, and hydrocarbons are less expensive than HFCs. The main barrier to adoption of low-GWP refrigeration equipment is the added initial cost. For low-GWP AC, the barriers include added initial cost and current building codes that do not allow very slightly flammable low-GWP refrigerants.

Measure costs were derived using the incremental per-unit equipment cost over the number of new units replacing retiring units each year. The total cost savings result from less energy use and less expensive refrigerant over the lifetime of the equipment. The cumulative costs and savings are outlined in Table 19.

The cost and savings from HFC reduction measures were estimated separately for each measure and then summed together to show total estimated cost and total estimated savings from all measures. This approach was used to avoid double-counting emission reductions, cost, and savings from measures that overlap significantly. For example, businesses installing low-GWP refrigeration because of the early adoption incentive program would not be subject to required prohibitions of high-GWP refrigerant in new equipment, and would not be affected by an HFC phasedown. An HFC phasedown could incentivize new equipment to use low-GWP refrigeration and AC, and a prohibition on high-GWP refrigeration and AC would largely overlap with HFC phasedown requirements. Detailed cost and savings for each individual measure are presented in Appendix D.

Table 19: HFC Measure Costs and Savings Through 2030 (Million Dollars)

| | Total Cost | Total Savings | Net Cost | Emission Reductions (MMTCO₂e) |
|-------------------------------|-------------------|----------------------|-----------------|---|
| HFC Reduction Measures | \$5,060 | (\$4,850) | \$210 | 260 |

GHG reductions from direct refrigerant emissions are estimated by modeling equipment sectors using a constant refrigerant charge size and annual leak rate, with the only variable that of the refrigerant's GWP. The reduction per unit per year is the difference between the emissions of the high-GWP equipment and the emissions expected from the new, low-GWP equipment. Indirect GHG emissions from less energy usage were also estimated using the default carbon intensity of California's

electricity from the Cap and Trade Program. Note that the indirect emission reductions account for less than 4 percent of GHG reductions from refrigeration and AC (the carbon intensity of electricity generation used to power cooling equipment is overwhelmed by the very-high GWPs of HFC refrigerants).

B. Public Health Assessment

Short-lived climate pollutants are not only powerful climate forcers but are also harmful air pollutants with many direct and indirect impacts on health. The focused efforts identified in this Proposed Strategy will not only help to limit the impacts of climate change that are already underway, but also reduce local air pollution and produce other co-benefits. The World Health Organization (WHO) describes the direct and indirect impacts of SLCP emissions, on a global level, as follows:¹⁵⁹

Since SLCPs contribute to ambient levels of ozone and PM2.5, SLCP [sic] emissions are directly associated with cardiovascular and respiratory diseases, including heart disease, pulmonary disease, respiratory infections and lung cancer. SLCP emissions thus contribute significantly to the more than 7 million premature deaths annually linked to air pollution.

Indirectly, the SLCPs ozone and black carbon reduce plant photosynthesis and growth, thus decreasing agricultural yields, which in turn threatens food security. They also affect weather patterns and the melting of snow and ice, which may harm and endanger health through extreme weather events such as floods.

Furthermore, in its report on *Reducing global health risks through mitigation of short-lived climate pollutants*,¹⁶⁰ the WHO notes that certain efforts to cut emissions of SLCPs may provide other types of health benefits not associated with air pollution. These include improved diets or more opportunities for safe active travel and physical activity. As described in this Proposed Strategy, some strategies to cut emissions of SLCPs in California could have important benefits for water quality, and potentially for water supply in the State, as well.

The measures and goals identified in this Proposed Strategy could deliver many of these types of benefits in California, which might accrue especially in disadvantaged communities (see Section C). As they are further developed and implemented, it will be important to consider a broad array of potential impacts and benefits to ensure that prioritized strategies to cut SLCP emissions also maximize other health benefits. For example, as part of an integrated strategy that includes use of ultra-low-NOx vehicles

¹⁵⁹ World Health Organization, "Reducing global health risks through mitigation of short-lived climate pollutants," accessed April 1, 2016. http://www.who.int/phe/health_topics/outdoorair/climate-reducing-health-risks-faq/en/

¹⁶⁰ WHO (2015) Reducing global health risks through mitigation of short-lived climate pollutants, Summary report for policymakers, World Health Organization, October. <http://www.who.int/phe/publications/climate-reducing-health-risks/en/>

and renewable natural gas in the transportation sector, converting manure management operations to scrape systems and injecting renewable natural gas into the pipeline can help to improve air quality and water quality near dairies and elsewhere in California. A discussion of the health impacts associated with the measures in this Proposed Strategy is provided below. A more detailed public health impacts analysis will be developed as part of any potential subsequent regulatory process.

Black carbon is a component of fine particulate matter (PM_{2.5}). A large number of studies, particularly epidemiological (population-based) studies, have linked exposure to PM_{2.5} to a number of adverse health effects, including premature death, hospital admissions for the worsening of chronic cardiovascular and lung diseases, and emergency room visits for asthma.^{161,162,163} Diesel particulate matter is a subset of PM_{2.5}, and consists of black carbon particle cores that are coated with a variety of other chemical substances, including over 40 carcinogenic organic compounds, nitrates, sulfates, and heavy metals. To date, no studies have directly investigated potential health effects of black carbon. However, since black carbon particulate matter is a subset of PM_{2.5}, which has been clearly shown to be related to adverse health effects, the scientific community has concluded that diesel and black carbon particulate matter likely have similar adverse effects as PM_{2.5}. As part of its periodic reviews of the national ambient air quality standards, the U.S. EPA draws conclusions as to the strength of the relationship between exposure to air pollution and broad categories of adverse health effects. In its most recent integrated science assessment for the PM standards, it concluded that PM_{2.5} plays a “causal” role in premature death and cardiovascular effects, and a “likely causal” role in respiratory effects.¹⁶⁴

As a result of State and local efforts over the past decades to improve air quality, California has significantly cut particulate matter emissions from anthropogenic sources, especially from diesel engines. The result is that black carbon emissions are about 90 percent lower than they were in the 1960s and approximately 5,000 premature deaths are avoided in the State each year. Current NO_x and PM emission standards for on-road and off-road diesel engines that phase in between 2012 and 2020 will lead to significant additional reductions in primary PM_{2.5} emissions from

¹⁶¹ Krewski D., Jerrett M., Burnett R.T., Ma R., Hughes E., Shi Y., Turner M.C., Pope C.A. III, Thurston G., Calle E.E., Thun M.J.. 2009. Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality. HEI Research Report 140. Health Effects Institute, Boston, MA. <http://www.healtheffects.org/Pubs/RR140-Krewski.pdf>

¹⁶² Bell M.L., Ebisu K., Peng R.D., Walker J., Samet J.M., Zeger S.L., Dominici F. 2008. Seasonal and regional short-term effects of fine particles on hospital admissions in 202 U.S. counties, 1999–2005. *Am J Epidemiol* 168:1301–1310.

¹⁶³ Ito, K., G. D. Thurston and R. A. Silverman. 2007. Characterization of PM_{2.5}, gaseous pollutants, and meteorological interactions in the context of time - series health effects models. *J Expo Sci Environ Epidemiol*. Vol. 17 Suppl 2: S45 - 60.

¹⁶⁴ U.S. EPA. 2009. Integrated Science Assessment for PM. U.S. Environmental Protection Agency, Washington, DC Publication EPA/600/R-08/139F. http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_2007_isa.html

diesel equipment.¹⁶⁵ (NO_x emissions are also projected to decrease, which could reduce ozone and secondary PM.) As a result, the health-related impacts associated with diesel PM_{2.5} are expected to continue to decrease through 2030.

Residential wood burning (fireplaces and woodstoves) is another important source of black carbon emissions and local air pollution, and its share of the State's black carbon inventory is increasing, as emissions from diesel engines fall. Fireplaces and woodstoves produce PM_{2.5}, carbon monoxide, volatile organic compounds, and hazardous air pollutants. In ARB's black carbon inventory, emissions from these sources are assumed to increase between 2013 and 2030, due to increased residential construction. Actions outlined in this Proposed Strategy, such as restricting residential wood-burning fireplaces and promoting the conversion to cleaner wood-burning stoves, can help reduce these emissions and health-related impacts, which especially impact rural areas.

Methane contributes to global background levels of ozone in the lower atmosphere (troposphere). Global background ozone (tropospheric ozone) concentrations have roughly doubled since preindustrial times, and are projected to continue to increase. Ozone itself is a powerful SLCP as well as a regional ground level air pollutant. Ozone exposure has been linked to increases in emergency room visits for worsening of asthma, hospitalizations due to respiratory disease, and premature death. Additionally, ozone suppresses crop yields; harms ecosystems; and affects evaporation, cloud formation, and precipitation.¹⁶⁶ Thus, reducing methane emissions as part of a broader effort to address climate change can complement local and regional efforts to reduce ground-level ozone.

Strategies to reduce methane emissions from dairy manure management can deliver important health benefits, especially if developed as part of a systematic approach to addressing air quality and water quality. For example, converting operations to pasture-based systems would likely reduce concentrations of and exposure to potentially harmful constituents, such as hydrogen sulfide, ammonia, and particulate matter. One study suggests that ammonia emissions could be 30 percent lower for pasture-based than for confinement systems.¹⁶⁷ It could also improve nutrient management on farms, helping to reduce soil and groundwater contamination. This strategy could be an important element of a sector-wide approach to reducing dairy methane emissions, but may have limited applicability. ARB estimates that about 25

¹⁶⁵ Primary particles are directly released into the atmosphere by combustion processes (such as soot or black carbon and a large variety of organic carbons). "Secondary" particles also form in the atmosphere from other gaseous pollutants, particularly sulfur dioxide, nitrogen oxides (NO_x), ammonia, and volatile organic compounds (VOCs). The transportation sector is an important source of secondary particulate matter such as ammonium nitrate, especially in the winter.

¹⁶⁶ UNEP and WMO (2011) Integrated Assessment of Black Carbon and Tropospheric Ozone, United Nations Environment Programme and World Meteorological Association. http://www.unep.org/dewa/Portals/67/pdf/BlackCarbon_report.pdf.

¹⁶⁷ Perry, A. (2011) Putting dairy cows out to pasture: An environmental plus, USDA-ARS Agricultural Research Magazine, May-June. <http://www.ars.usda.gov/is/AR/2011/may11/cows0511.htm>

dairies in the State could convert to pasture-based operations without reducing herd size or procuring new land.

Other strategies could also deliver environmental and health benefits. Converting dairies from flushwater manure management systems to dry manure management systems would also improve nutrient management, thereby helping to improve groundwater quality. It is possible that farms may choose some management strategies which could increase or decrease emissions of pollutants of concern. If emissions increase, measures should be implemented to mitigate the impacts as part of the permitting process.

Strategies that capture or produce methane and utilize it for production of renewable energy and fuels could lead to additional sources of combustion, but as part of a regional approach to utilize low-NO_x vehicles and renewable fuels, can displace diesel combustion and help to improve air quality. If electricity is generated onsite using dairy derived biogas, using microturbines or fuel cells can minimize new emissions of NO_x and PM, minimizing potential local health impacts. To the extent that renewable natural gas is produced and injected into the natural gas pipeline network, or used in low-NO_x engines to displace diesel combustion, air quality impacts can be avoided. Prioritizing pipeline injection and onsite usage in low-NO_x vehicles, in addition to a coordinated effort to increase use of low-NO_x vehicles with renewable fuels in areas surrounding dairies and elsewhere can reduce air pollution regionally and statewide. These emission reductions translate directly into health benefits, especially in disadvantaged communities near dairies and along transportation corridors, and in areas of non-attainment for ambient air quality standards.

Diverting organics from landfills to compost facilities and anaerobic digestion facilities, along with implementing food rescue and recovery programs, will significantly reduce the need for further landfill development in California, and may help reduce the lifespan of existing landfills, many of which are located in or near environmental justice communities. Phasing out the landfilling of organic materials will also help reduce future levels of fugitive methane emissions from landfills during their operational and post-closure stages. The number and frequency of heavy vehicle or truck trips to existing landfills, through neighboring communities, could potentially be reduced as organic materials are directed to anaerobic digestion facilities and regional compost facilities. To the extent that truck trips are reduced to and from landfills, they could increase in areas where facilities handling diverted organic waste are located. The net effect on overall truck trips in the State and associated emissions is uncertain, and could potentially increase as a result of changes in organic waste management, depending on how strategies are implemented. Many of the same issues associated landfilling organic waste—potential criteria pollutant emissions, water quality impacts, and odors—could be issues at anaerobic digestion or compost facilities. In many cases, these can be effectively limited with available technologies and management strategies, including limiting trucking emissions by utilizing zero emission vehicles or renewable natural gas in low-NO_x engines associated with these operations.

Food rescue and recovery could deliver additional potential health benefits by utilizing useable food to relieve food insecurity and provide better access to healthy foods. Increasing edible food recovery—especially from large-scale food producers, processors, and users—and safely redirecting food to those in need could increase access to healthy fruits and vegetables and benefit millions of Californians who suffer from food insecurity.

Reducing leaks from the oil and gas sector will also reduce VOC emissions, which contributes to ground level ozone formation and related health impacts. For example, ARB's oil and gas regulation is expected to reduce VOC emissions and toxic air contaminants that are emitted from uncontrolled oil and water storage tanks and released from well stimulation recirculation tanks. The estimated reduction in VOCs from this measure is approximately 3,000 tons per year, or about 8 tons per day, statewide.

The measures identified in this Proposed Strategy for HFCs are unlikely to have noticeable health impacts. HFCs have negligible impacts on smog formation and are exempt from U.S. EPA's definition of volatile organic compounds. At higher concentrations that could result from an accidental release in occupational settings, they might be toxic, and emissions of vapors containing HFCs in the workplace environment should be prevented. But at ambient concentrations, HFCs pose no significant health risk, and efforts described in this Proposed Strategy to phase down their use are not expected to deliver noticeable health benefits. Some potential replacements for HFCs could result in emissions of VOCs and particulate matter, but they would be negligible.

C. Environmental Justice and Disadvantaged Communities

The State of California defines environmental justice in statute as, "the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations and policies." (Government Code Section 65040.12). ARB is committed to continuing to strengthen its outreach efforts to ensure that all California communities have the opportunity to participate in its public processes and benefit from the State's climate-related programs, policies, and regulations.

ARB endeavors to integrate environmental justice into all of its programs, policies, and regulations and is taking additional steps to strengthen its work with the environmental justice community. Specifically, every major program, policy, plan or strategy, and rulemaking explicitly discusses environmental justice and promotes the fair treatment of people from all races, cultures, geographic areas, and income levels—especially in disadvantaged communities. As part of the development and implementation of the AB 32 Scoping Plan, ARB convened an Environmental Justice Advisory Committee (EJAC). ARB has briefed the EJAC on this Proposed Strategy development multiple times, and at its April 2016 meeting, the EJAC discussed and made recommendations on this Proposed Strategy. ARB also works extensively with local air districts and

stakeholders during the development and implementation of its programs to respond to concerns about environmental justice.

The EJAC developed the following recommendations for inclusion in this Proposed Strategy:

- (1) Create a declining methane target specific to dairies that would lead to a 40% reduction mandate for dairies by 2030.
- (2) The dairy emission target should include all methane emissions from dairies, not just from manure handling.
- (3) The Proposed Strategy should explicitly say no disposal of food waste to landfills or incinerators.
- (4) Explore synergies with methane reductions from dairies and the management of organic waste, such as wood waste.
- (5) Include Concentrated Animal Feeding Operations (CAFO) in the methane emission reduction goal.
- (6) Mitigate all additional ancillary emissions generated through achieving the methane emission reduction goal.

This Proposed Strategy includes a measure that would create a regulatory program to achieve a 75 percent reduction in methane emissions from dairy manure management by 2030. It also includes a commitment to work to further examine enteric emissions and reduction opportunities. The GHG inventory includes methane emissions associated with CAFO facilities, which are primarily from enteric fermentation and manure management. The organic diversion measure identified in this Proposed Strategy will virtually eliminate organics from landfills, including food waste.

ARB staff has been working with staff from other state agencies to develop an holistic and synergistic approach to reducing methane emissions, and will continue to work with them to implement these measures. ARB staff will continue to consult with environmental justice communities as we implement the measures to ensure minimum impact and maximum benefit to environmental justice communities. Furthermore, the EJAC recommendations will be taken into consideration as specific actions and policies discussed in this Proposed Strategy are developed into regulatory measures.

The California Environmental Protection Agency and pursuant to Senate Bill 535 (De León, Chapter 830, Statutes of 2012), has identified the communities in California that are most disproportionately burdened by pollution for the purposes of expenditure of California Climate Change Investment Funds. Of the 12 indicators of pollution included in its methodology, three are directly related to SLCP emissions (fine particle emissions, diesel particulate emissions, and solid waste sites and facilities), and at least six others (mostly related to water quality and air quality) are at least related to sources of SLCP emissions.

The distribution of these communities aligns with locations of SLCP emission sources, including sources of organic waste streams and dairies in the Central Valley; ports and

freight corridors in the East Bay, Los Angeles area and Inland Empire; and oil production, landfills and other sources of SLCP emissions throughout the State. Many communities in these areas have some of the worst pollution burdens in the State and high rates of poverty and unemployment. Forested and rural communities in the northern part of the State and the Sierra also are stricken with high rates of poverty and unemployment. They are also where many billions of dollars in public and private investment will accrue in the coming years to reduce SLCP and CO₂ emissions and strengthen our agricultural sector, build sustainable freight systems, and grow healthy forests. To the extent new facilities are built to manage organic waste streams in the State, care must be taken to locate, design, and operate them in a manner that protects local air quality.

The integrated strategy to reduce SLCP emissions from agriculture and waste, developed in this Proposed Strategy, can be part of an integrated strategy to improve air and water quality in agriculture regions, such as in the Central Valley. Additionally, the Healthy Soils Initiative will improve California's agriculture economy and support further economic development in these communities. California's commitment to improve the health and management of forests will boost California's forest economy and limit black carbon emissions and many other air pollutants from wildfires.

The measures identified in this Proposed Strategy will be further developed in a formal public process that specifically considers environmental justice concerns. Opportunities for public participation will be provided during the development of each measure, and regulatory language will be made available in easily understood and useful formats, such as program-specific webpages and slide presentations.

D. Environmental Analysis

ARB, as the lead agency for the Proposed Strategy, prepared a Draft Environmental Analysis (EA) in accordance with the requirements of the California Environmental Quality Act (CEQA) and ARB's regulatory program certified by the Secretary of Natural Resources (California Code of Regulation, title 17, sections 60006-60008; California Code of Regulation, title 14, section 15251, subdivision (d)). The resource areas from the CEQA Guidelines Environmental Checklist were used as a framework for a programmatic environmental analysis of the reasonably foreseeable compliance responses resulting from implementation of the proposed measures discussed in the Proposed Strategy. The Draft EA provides an analysis of both the beneficial and adverse impacts and feasible mitigation measures for the reasonably foreseeable compliance responses associated with the proposed measures under each of 17 environmental resource areas. Collectively, the Draft EA concluded implementation of these actions could result in the following short-term and long-term beneficial and adverse impacts : beneficial long-term impacts in reduced greenhouse gas emissions; less than significant impacts to air quality, biological resources, energy demand, geology and soils, greenhouse gases (short-term), hazards and hazardous materials, hydrology and water quality, resources related to land use planning, mineral resources, noise, population and housing, public services, and recreational services; and

potentially significant and unavoidable adverse impacts to aesthetics, agriculture and forest resources, air quality, biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, resources related to land use planning, noise, transportation/traffic, and utilities and service systems. The potentially significant and unavoidable adverse impacts are primarily related to short-term construction-related activities, which explains why some resource areas are identified above as having both less-than-significant impacts and potentially significant impacts. Please refer to the Draft EA in Appendix C for further details.

ARB will prepare written responses to all comments received on the Draft EA, which will be presented to the Board for consideration along with the Final EA.

IX. Next Steps

This Proposed Strategy and an accompanying draft Environmental Analysis (EA), was released for public comment. Staff will provide an update to the Board on the Proposed Strategy in May 2016. In fall 2016, staff will present the final proposed SLCP Reduction Strategy, the final EA, and written responses to comments received on the EA to the Board for consideration.

To the extent that the proposals in the SLCP Reduction Strategy result in regulatory action, each proposed regulation will be subject to its own public process with workshops, opportunities for stakeholder discussion, consideration of environmental justice, and legally required analyses of the economic and environmental impacts.

While this Proposed Strategy is intended to be comprehensive, it is not exhaustive. We will continue to pursue new cost-effective programs and measures as technology and research on SLCP emission sources and potential mitigation measures advances. Effectively implementing this Proposed Strategy will require working with local, regional, federal and international partners, and diligently investing time and money to overcome market barriers that hinder progress. The extent to which we do so will drive results, which can include a wide range of significant economic and environmental benefits for California broadly, and many of the State's most disadvantaged communities, specifically.

Appendix B: Economic Analysis

ECONOMIC ANALYSIS

A. Summary of Proposed Costs and Impacts

The proposed Regulation for the Reduction of Greenhouse Gas Emission Standards from Crude Oil and Natural Gas Facilities (proposed regulation) is intended to reduce GHG emissions from oil and gas production, processing, storage and transmission compressor stations. The economic impacts of the proposed regulation are discussed in this section, and include impacts and benefits to businesses, individuals, and government agencies. This section also includes a discussion of the estimated cost of the proposed regulation and an analysis of alternatives.

The proposed regulation increases costs on the complying industries, which are primarily involved with oil and gas extraction, and natural gas storage and transmission. These industries, referred to as primary industries, pay for control equipment and services from secondary industries but may also achieve operational cost savings through recovery of natural gas captured by the proposed control strategies. ARB estimates the proposed regulation will cost about \$23 million dollars per year, or about \$14 million per year without the Monitoring Plan, and is expected to reduce GHG emissions by about 1.5 Million MT CO₂e per year on a 20 year horizon. However, considering the size and diversity of the California economy, the economic impacts of the proposed regulation on the California economy are negligible, including the impact on growth of employment, investment, personal income, and production.

B. Major Regulations

For a major regulation proposed on or after January 1, 2014, a Standardized Regulatory Impact Assessment (SRIA) is required. A major regulation is one “that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars (\$50,000,000), as estimated by the agency.” (Govt. Code Section 11342.548) Further, the Health and Safety Code Section 57005(b) defines a “major regulation” as any regulation that will have an economic impact on the state’s business enterprises in an amount exceeding ten million dollars (\$10,000,000), as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a) of Section 11346.3 of the Govt. Code.

When amortized, the proposed regulation will cost \$23 million per year; however, the largest expenditures will be in 2018 when most of the capital equipment is expected to be purchased. This upfront cost is estimated to be over \$40 million in direct costs in 2018, resulting in an overall economic impact of over \$50 million. Due to the estimated economic impact of compliance exceeding \$50 million in a 12 month period during 2018, the proposed

regulation was determined to be a major regulation and required a SRIA. A SRIA was submitted to the Department of Finance (DOF) in April 2015. On May 28, 2015, ARB received a letter from the DOF acknowledging the status of a major regulation, and commenting on the information presented in the SRIA. These comments are addressed at the end of this Appendix.

Since the submittal of the SRIA, the proposed regulation has undergone several changes. In addition to changes in the standards, there have been changes to the methodology of estimating the cost and emissions for provisions of the proposed regulation due to the availability of updated data and feedback from industry representatives and other stakeholders. Although these changes have been made after the submittal of the SRIA, staff believes the conclusions of the SRIA continue to be accurate, since the overall annual cost, emissions, reductions, and impacted industries are similar.

In addition to changes made to the standards of the proposed regulation, ARB is now using the 20 year AR4 value (72) of GWP for methane instead of the 100 year AR4 value (25) to determine the reductions in CO₂e. The use of GWPs with a time horizon of 20 years better captures the importance of the short lived climate pollutant (SLCP) and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO₂ emission controls. Also, the value assigned to natural gas saved changed from \$4.10 per mscf to \$3.44 per mscf. This value was changed to reflect the most recently available data and is the average wholesale price that is specific to California over the last 12 months of available data, from November 2014 to October 2015 (EIA, 2016). Also, the compliance dates for the regulation have changed from starting January 1, 2017, to starting January 1, 2018.

In addition to the changes discussed above, some of the methodologies of estimating the potential costs and emissions have changed. This is due to the availability of better data, stakeholder comments, as well as the continued development of the proposed regulation. These changes are described in detail below. All SRIA emissions use a GWP of 25, and all current emissions use a GWP of 72 in the descriptions.

1. Changes from SRIA by Category

a) Reciprocating Compressors

In the SRIA version of the proposed regulation, all reciprocating compressors would need to replace a rod packing after three years of use. In the current version of the proposed regulation, compressors at production facilities are no longer subject to a rod packing leak standard, but instead are required to meet an LDAR standard. Many of the compressors at production facilities are smaller, may be portable, and handle a different composition of gas than compressors

at processing, storage or transmission facilities. Also, most of the available data concerning leak rates and rod packing cost and performance are from larger compressors that are typically not found at production facilities. The provision to exclude production type compressors eliminated over 600 of almost 1000 compressors from this segment, for determining cost and emissions. In addition, industry provided data on the leak rate by compressor for a large subset of the remaining compressors. This new data was used in place of the emission factors previously used. With the reduction in number of compressors, the change from a time based standard to a performance based standard, and using measurement data instead of emission factors, the estimated reduction of emissions has changed from 143,000 MT CO₂e to about 68,000 MT CO₂e. Based on the decrease of compressors potentially impacted by the standard for rod packing leaks, the estimated cost of compliance has decreased from about \$600,000 per year to about \$260,000 per year.

b) Centrifugal Compressors

In the SRIA version of the proposed regulation, twenty five centrifugal compressors with wet seals were anticipated to need a vapor recovery system or to be converted to a dry seal. In an effort to verify this data from ARB's 2009 Oil and Gas Industry Survey (ARB, 2013), staff contacted the facilities that would be impacted by this provision in the proposed regulation. All centrifugal compressors, except for one, were reported with wet seals in error, are no longer in use, have been replaced with a compressor with a dry seal, or now have a vapor recovery system installed to control emissions. In addition, measurement data taken directly from this single compressor was used in place of the emission factors used to generate the emissions and reductions for the SRIA. Due to the updated number of impacted units, the emissions dropped from about 20,000 MT CO₂e to about 3,700 MT CO₂e and the reduction estimates dropped from about 11,000 MT CO₂e to about 3,500 MT CO₂e. The associated cost of compliance decreased from about \$375,000 per year to about \$6,000 per year.

a) Leak Detection and Repair (LDAR)

In the SRIA version of the proposed regulation, the emissions did not include a small percentage of super emitter components, which are responsible for the majority of emissions. In addition, the LDAR program was changed from an annual inspection to a quarterly inspection requirement. These changes were made to address stakeholder comments, and ensure emissions were determined with the best available data. The estimated emissions reduction has

changed from about 1,200 MT CO₂e to about 590,000 MT CO₂e, and the estimated cost has changed from about \$2 million per year to about \$10 million per year.

b) Pneumatic Devices

At the time of the SRIA, all continuous bleed pneumatic devices were required to change to a low bleed pneumatic device. Based on stakeholder feedback, this has been changed to require a no bleed pneumatic device in the current proposed regulation to maximize emission reductions with no increased cost. Also, after a review of the data, the count of continuous bleed devices was overestimated by about 170. The anticipated emissions reduction from this segment have changed from about 124,000 MT CO₂e to about 320,000 MT CO₂e, and the estimated cost has changed from about \$1.3 million per year to about \$1.2 million per year.

c) Tank and Separator Systems

The provisions for tank and separator systems have changed from requiring a vapor recovery system for all uncontrolled systems, to require vapor recovery and comply with a NO_x emission standard, but only for uncontrolled systems that are anticipated to have over 10 MT per year of CH₄ emissions. Due to this change, the estimated number of systems impacted changed from over 600 to about 300. It is now assumed that a low NO_x incinerator will be used to comply with the NO_x emission standard in place of a flare. The emissions are now calculated with the throughput to the separators instead of reported emissions from the 2009 Survey. The estimated emissions reductions have changed from about 252,000 MT CO₂e to about 540,000 MT CO₂e. The estimated cost has changed from about \$16 million per year to about \$4.7 million per year.

d) Well Stimulations

The current proposal uses emission factors from WSPA (WSPA, 2015) to estimate emissions from well stimulations. These emission factors became available after the submittal of the SRIA when the best available data projected much greater emissions. The estimated emissions reduction from this segment of the proposed regulation has changed from about 24,400 MT CO₂e to about 5,000 MT CO₂e. The estimated cost has changed from about \$200,000 per year to about \$460,000 per year due better cost data becoming available and inclusion of additional compliance equipment in the current Proposed Regulation.

e) Liquids Unloading

The requirement for controls for liquids unloading were removed for the proposed regulation, and replaced with a reporting requirement. The estimated reductions of about 350 MT CO₂e have been eliminated, and the expected cost of \$450,000 per year has been replaced with a cost of about \$6,000 for recordkeeping, reporting and other administrative tasks.

f) Monitoring Plan

The proposed regulation now includes a requirement for operators of natural gas underground storage facilities to follow a Monitoring Plan, which includes daily monitoring of natural gas storage wells, and continuous ambient air monitoring. This was not included in the SRIA version of the proposed regulation. The cost for the Monitoring Plan is estimated to be about \$8.7 million per year.

C. Summary and Interpretation of the Results of the Economic Impact Assessment

The proposed regulation encourages the use of more efficient and potentially cost-saving technology to ensure maximum production of natural gas. Much of the capital equipment purchased, such as vapor recovery for tanks, have lifetimes that far exceed the pay-off period. Though at some point the primary industries no longer are making payments for the capital required for compliance, they continue to enjoy the natural gas savings that are provided by that capital. Therefore the primary industries, oil and gas extraction and natural gas distribution, are required to make minor changes to their production facilities, these modifications include increases in efficiency. Secondary industries face increased product demand, resulting in increased output and employment in those industries.

The proposed regulation was analyzed using generally high estimates and GHG emission reduction estimates, thus the analysis may serve as an upper bound of anticipated impacts. To the extent there are greater cost savings due to increased product capture, the economic impacts of the proposed regulation would be less negative in all years, and likely show a benefit to the economy. This result would persist in later years and the primary industries, having made a large initial investment in the capital necessary to prevent substantive leaks, would continue to see savings long after the payments for the capital are finished.

The proposed regulation is unlikely to significantly impact California's economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from Business as Usual (BAU).

D. Benefits

The proposed regulation is anticipated to deliver environmental benefits that include an estimated annual reduction in GHG emissions, beginning in 2018, of about 1.5 million MT CO₂e per year from oil and gas related operations in California. In addition, the proposed regulation is expected to save primary industries about 800 million standard cubic foot (scf) per year of industrial natural gas through reductions of leaks and vapor recovery systems¹. This will result in a savings of about \$3 million per year, assuming the value of this gas is \$3.44 per Mscf. The cost per ton of the proposed regulation is estimated to be approximately \$15 per MT CO₂e reduced. These estimates use the 20-year GWP for methane (i.e., 72) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4).

Reducing SLCPs, such as methane, can produce near term results that deliver immediate and tangible climate, air quality, economic, and health benefits while longer-term changes are being implemented.

The proposed regulation is expected to provide co-benefits of reductions in emissions of VOCs and toxic air contaminants that are emitted from uncontrolled oil and water storage tanks and released from well stimulation circulation tanks. The estimated reduction in VOCs is approximately 3,630 tons per year, or about 10 tons per day statewide. There was the potential for NO_x increases for vapor recovery units if the facility used a flare. Since ARB is requiring a NO_x standard in these cases, the tank measure provides a benefit of 1.6 tonnes per year but there are NO_x impacts from LDAR, leading to an overall impact that is neutral for the state as a whole. Table B-1 summarizes reductions of all pollutants, and detailed calculations are in Appendix D.

¹ This assumes gas is 94.9% CH₄.

Table B-1. Summary of Non-GHG Pollutant Reductions

| Category | Total Hydrocarbons | VOCs | Benzene | Toluene | Ethyl-Benzene | Xylenes | NOx |
|--|--------------------|--------------|-----------|-----------|---------------|-----------|--------------------|
| Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard ¹ | 10,458 | 1,362 | 23 | 11 | 1.7 | 8.5 | 1.6 |
| Control of vapors from uncontrolled well stimulation circulation tanks | 96 | 12 | 0.2 | 0.1 | <0.1 | <0.1 | <0.1 |
| Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules | 9,698 | 1,264 | 22 | 10 | 1.5 | 7.9 | (1.6) ² |
| Inspection and repair requirements for reciprocating natural gas compressors | 1,318 | 172 | 3.0 | 1.4 | 0.21 | 1.1 | NA |
| Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting "wet seals" with lower emitting "dry seals" | 68 | 9 | 0.2 | <0.1 | <0.1 | <0.1 | NA |
| Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances | 6,199 | 808 | 14 | 6.5 | 1.0 | 5.0 | NA |
| TOTAL (benefits from proposed regulation) | 27,837 | 3,627 | 62 | 29 | 4.6 | 23 | (<0.1) |
| ¹ All estimated emission reductions from this category are occurring in the San Joaquin Valley Air Basin. ² ARB estimates that increased LDAR will result in increased NOx from vehicle emissions by 1.6 tons/year. | | | | | | | |

1. Benefits to Individuals

The proposed regulation will not directly affect individual consumers; however, as a result of the anticipated decrease in methane emissions, VOCs, and other toxic air contaminants, the proposed regulation will provide health and climate benefits.

Like emissions of other GHGs, emissions of methane due to human activities (anthropogenic emissions) have increased markedly since pre-industrial times. Of the GHGs emitted as a result of human activities, methane is the second most important GHG after carbon dioxide (CO₂), accounting for 14 percent of global GHG emissions in 2005. Though methane is emitted into the atmosphere in smaller quantities than CO₂, its global warming potential (i.e., the ability of the gas to trap heat in the atmosphere) is 72 times that of CO₂, resulting in methane's stronger influence on warming during its atmospheric life time.²

Emissions reductions of GHGs, VOCs and other pollutants have been correlated with a reduction in the risk of premature deaths, hospital visits, and a variety of other health impacts, especially in sensitive receptors including children, elderly, and people with chronic heart or lung disease. Methane is a contributor to ground level ozone, and cutting methane emissions reduces smog, which is associated with higher rates of asthma attacks. Ozone affects respiratory health, crop productivity, and ecosystems, and recent studies have shown substantial evidence that ozone influences premature mortality.³⁴

2. Benefits to California Businesses

The proposed regulation requires the oil and gas industry to purchase, retrofit, and service capital equipment. The requirements of the regulation would increase the demand for these services and increase business opportunities for secondary industries both within and outside of California. Additionally, the proposed regulation is designed to reduce industrial natural gas leakage, which will result in cost savings for the regulated parties. For example, many of the proposed control strategies are designed such that natural gas can be recovered and either used on site as energy or captured for sale. These savings are estimated to be about \$3 million per year. While the primary industries are not small businesses, some of the secondary industries contain small businesses. If these businesses were able to meet

2 GMI. 2016. About Methane. <https://www.globalmethane.org/about/methane.aspx>

3 Whitehouse. 2016. Climate Action Plan Strategy to Reduce Methane Emissions.

https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

4 West, Jason J., Arlene M. Fiore, Larry W. Horowitz, and Denise L. Mauzerall. 2016. Ozone Air Quality Management by Reducing Methane Emissions: Global Health Benefits (HTAP, 2016).

http://www.htap.org/meetings/2006/2006_01/posters/West_methane.pdf

the increased demand and provide the capital equipment and services to the primary industries for compliance, small businesses would see increased demand, output and, likely, employment.

ARB estimates that more than \$25 million each year will be spent on control equipment and inspection services. This includes over \$10 million to comply with the LDAR provisions in the proposed regulation, and over \$8 million to comply with the Monitoring Plan. Companies involved in LDAR inspections may see an increase in business or expansion. In areas of the state that previously did not have an inspection program, there will be new demand for a previously unneeded service, which may result in new businesses being created.

In areas without existing VOC based regulations for LDAR or higher pressure natural gas systems, LDAR is likely to be more cost effective. In addition, we believe that with the advent of newer technologies, the efficiency of LDAR inspections will improve.

While direct costs to the primary industries exceed \$40 million in the first year of implementation, these industries achieve savings of about \$3 million annually from leakage prevention strategies within the proposed regulation. Secondary industries also achieve benefits, as demand for their equipment, services, or other products such as natural gas increases yielding positive economic benefits.

3. Costs per Ton

Table B-2. Summary of Cost, Emissions, and Cost per Ton

| Provision | Annual Cost | Annual Savings | Reductions (MT CO2e) | Cost per Ton (\$ / MT CO2e reduced) | Cost per Ton with Savings (\$ / MT CO2e reduced) |
|---------------------------|---------------------|--------------------|----------------------|-------------------------------------|--|
| VRU for Tanks | \$4,700,000 | \$500,000 | 540,000 | \$ 9.00 | \$ 8.00 |
| Reciprocating Compressors | \$260,000 | \$180,000 | 68,000 | \$ 4.00 | \$ 1.00 |
| LDAR | \$10,000,000 | \$1,500,000 | 590,000 | \$ 17.00 | \$ 14.00 |
| Pneumatic Devices | \$1,200,000 | \$840,000 | 319,000 | \$ 4.00 | \$ 1.00 |
| Well Stimulations | \$460,000 | \$0 | 5,000 | \$ 91.00 | \$ 91.00 |
| Centrifugal Compressors | \$6,000 | \$9,000 | 3,500 | \$ 2.00 | \$ (1.00) |
| Monitoring Plan | \$8,700,000 | \$0 | 0 | - | - |
| Total | \$25,400,000 | \$3,000,000 | 1,500,000 | \$17.00 | \$15.00 |

All Figures are in 2015 dollars

E. Direct Costs

1. Direct Costs on Individuals

For 2017, the baseline projected outputs for oil and gas extraction and natural gas distribution industries are approximately \$25 billion and \$19 billion respectively. The ratio of compliance cost to total output is less than 0.5 percent for both industries, making pass-through of costs unnoticeable. However, to the extent that any potential costs are passed on to individual consumers, minor increases in the price of natural gas and electricity may occur.

2. Direct Costs on Typical Businesses

Any business involved with crude oil or natural gas extraction, natural gas storage, crude oil processing excluding refineries, natural gas processing (including gas plants), crude oil tank farms (excluding tank farms at refineries), or transmission of natural gas will potentially be impacted by the proposed regulation. In February 2009, ARB conducted an Oil and Gas Industry Survey for crude oil and natural gas production, processing, and storage facilities in California (ARB, 2013). The survey was completed by 325 companies representing over 1,600 facilities and approximately 97 percent of the 2007 crude oil and natural gas production in California. Out of these companies, 272 companies that responded to the survey are expected to be impacted by the provisions in our proposed regulation.

ARB estimates the direct cost to industry for the proposed regulation to be approximately \$25.4 million per year. This includes the amortized cost of capital equipment, and annual costs for labor, maintenance, reporting and recordkeeping. ARB generally used high estimates throughout for estimating emissions, costs, and reductions. The average impact each of the 272 businesses is expected to be about \$100,000 per year. The typical businesses are not small because the primary industries are ineligible to be classified as small under government code.⁵ Therefore, the increased costs on industry do not directly impact small businesses.

3. Cost Analysis

This section describes the sources and methodology to determine the emissions, cost, and cost per ton of our proposed regulation. In general, for each segment of the regulation, staff identified the number of devices affected, estimated the cost to comply with the regulatory provisions, estimated emissions and reductions, and accounted for any savings to be included in the cost per ton. The methodology to determine these items for each segment of the regulation is described below.

The indirect costs and economic impacts were modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. These results and analysis are included with the SRIA in Attachment E. The results helped evaluate the impact of the proposed regulation on California's economy, including business impacts, job creating, and impacts to

⁵ California Government Code Section 11342.610(b). 2016. <http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=11001-12000&file=11342.510-11342.610>

individuals. Finally, alternatives to the proposed regulation were evaluated and fiscal impacts to ARB and local air districts were estimated.

The cost estimate of the proposed regulation follows guidelines recommended by the California Environmental Protection Agency (Cal/EPA), and is consistent with the methodologies used in previous cost analyses for ARB regulations (ARB, 1999; ARB, 2000; ARB, 2004; ARB, 2005; ARB, 2007). The segments analyzed for this proposed regulation include control strategies for reciprocating compressors, centrifugal compressors, oil and water separators and storage tanks, pneumatic devices, circulation tanks for well stimulations, and a leak detection and repair (LDAR) program. Information from the 2009 Survey, of which parts were later updated by staff to account for changes since 2009, was used to form the basis of the number and types of facilities potentially impacted, number and types of equipment, and estimated emissions reduction from the standards in the proposed regulation. After the number and types of equipment impacted were identified, the direct cost to industry was estimated for each component of the regulation. Sources of data include ARB's 2009 Survey, ICF's Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Report), EPA documents including their Gas Star Program, industry groups, and communications with operators of potential control equipment, and other stakeholders.

4. Methodology

One-time costs, such as the cost for purchasing capital equipment, are amortized to reflect that businesses generally do not pay the total cost up front, and allows for annual cost to be compared to an annual emission reduction. The Capital Recovery Method for amortizing fixed costs is recommended by Cal/EPA guidelines (Cal/EPA, 1996). This method of amortizing a fixed cost was used for all capital costs of equipment, installation, and costs of testing.

The CRF is calculated as follows:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where,

CRF = Capital Recovery Factor

I = discount interest rate (assumed to be 5%)

n = project horizon or useful life of equipment

With regard to the discount rate, Cal/EPA recommends 2 percent plus the current yield for a U.S. Treasury Note of similar maturity to the project horizon and adjusted for inflation (Cal/EPA, 1996). The primary rationale for using a real discount rate of five percent is that it is equivalent to rate of return on an inflation-adjusted 10-year treasury security, (about 2 percent in the past five years) , plus the California Environmental Protection Agency recommended 3 percent risk premium. The five percent real discount rate has been used for several recent ARB regulations, and follows guidelines for economic analysis in the AB 32 Scoping Plan (ARB, 2010b). Additionally, the five percent is the average of what the US Office of Management and Budget recommends (7 percent) and what US Environmental Protection Agency has used historically for regulatory analysis.

The project horizon was chosen to reflect the expected equipment lifetime, and is based on the amortization period used by ICF when applicable (ICF, 2015). In cases when cost estimates were outside of the scope of the ICF report, the equipment lifetime is based on communications with equipment manufacturers. These values and the calculated capital recovery factors are summarized in Table B-3.

Table B-3. Equipment Lifetime and Capital recovery Factor for Control Equipment

| Equipment | Amortization Period | Capital recovery Factor |
|--|---------------------|-------------------------|
| Rod Packing for Reciprocating Compressors | 3 | 0.367 |
| Vapor Recovery for Centrifugal Compressors | 10 | 0.130 |
| No Bleed Pneumatic Devices | 7 | 0.173 |
| Vapor Recovery Equipment for Tanks and Well Stimulations | 10 | 0.130 |
| Gas Separator for Well Stimulation | 10 | 0.130 |
| Monitoring Plan Equipment | 10 | 9.130 |
| Flash Test ⁶ | 3.3 | 0.333 |

⁶ Flash tests are required on uncontrolled tank and separator systems, and controlled systems with uncontrolled water tanks every year for the first three years, and once every five years thereafter. Over 20 years, tests are conducted on average every 3.3 years.

This capital recovery factor was multiplied by all non-recurring costs, including capital costs for equipment and installation, and testing costs. This value was added to the total ongoing costs, such as labor, maintenance, recordkeeping, and fuel costs to determine the total cost per year.

$$\text{Total Cost per Year} = \text{Annualized Nonrecurring Costs} + \text{Annual ongoing Costs}$$

Where,

$$\text{Annualized Nonrecurring Costs} = \text{CRF} \times \sum (\text{Nonrecurring Costs})$$

$$\text{Annual Ongoing Costs} = \text{Labor Costs} + \text{Maintenance Costs} + \text{Fuel Costs}$$

The emissions were calculated from a combination of emission factors, survey data, and other data provided by stakeholders. There are two primary methods used to determine emissions based on the available data. The first method to determine emissions involves converting a volume of gas into a mass of CO₂e. This method was used for calculating emissions from reciprocating compressors and, centrifugal compressors. Combining this method with the appropriate conversion factors yields a mass of methane from cubic feet of gas. To perform these calculations, the following conversion factors and equations were used.

$$\text{Mass of Methane (kg)} = \frac{\text{Volume of Methane (scf)} \times \text{Molar Mass of Methane}}{\text{Conversion Factor}}$$

$$\text{Emission Reductions in MT CO}_2\text{e} = \frac{\text{Mass of Methane (kg)} \times \text{GWP}}{1000}$$

where,

$$\text{Conversion Factor} = 836.2 \text{ scf/kg mol (API, 2009)}$$

$$\text{Molar Mass of Methane} = 16.04 \text{ kg/k mol}$$

$$\text{kg} = 1000 \text{ g}$$

$$\text{Metric Ton (MT)} = 1000 \text{ kg}$$

$$\text{Global Warming Potential (GWP) of Methane} = 72$$

Additional factors used include:

$$\text{Mole Percentage of Methane in Gas from Production} = 78.8\% \text{ (API, 2009)}$$

Cubic meter = 35.13 scf

The second method to determine emissions from a given segment was to use an emission factor. These emission factors expressed emissions in either the mass of methane emitted per equipment device per unit of time for the LDAR, tank and separator systems, and pneumatic devices segments (CAPCOA, 1999; API, 2004; API, 2009), or MT CO₂e per event (WSPA, 2015) for well stimulations. Again combining this with the appropriate emission factors yields total mass of methane and CO₂e.

Emissions = Emission Factor X Number of Devices X Usage per Year

The reciprocating compressors, centrifugal compressors, LDAR, pneumatic devices and portions of the vapor recovery for tank and separator systems segments of the proposed regulation would have a corresponding increase in product with the decrease of leaks or emissions. The value of the gas saved under these segments was counted as a cost savings as a result the standards imposed by the proposed regulation. Since only the reciprocating compressors, centrifugal compressors, and pneumatic pumps had emissions that were calculated directly from a volume of gas, it is convenient to back calculate a volume of gas from the mass of CO₂e since this value is shared across all segments. In a similar fashion to how mass of CH₄ was determined from a volume of gas, the volume of gas saved was determined from the mass of CH₄.

$$\text{Volume of Methane (scf)} = \frac{\text{MT CO}_2\text{e} \times \text{Conversion Factor}}{\text{Molar Mass of Methane} \times \text{GWP} \times 1000}$$

Where,

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Molar Mass of Methane = 16.04 kg/kg mol

Global Warming Potential (GWP) of Methane = 72

Metric Ton (MT) = 1000 kg

Savings were calculated using price data obtained from the U.S. Energy Information Administration (EIA). We chose to use the average wholesale price for the period of November 2014 to October 2015. This represents the cost of gas that a utility would pay to a producer. Since this gas has higher methane content than what is typical of gas in production, this volume was

converted into an equivalent volume of gas with a composition of 94.9% CH₄ gas (EPA, 2011; PG&E, 2016).

$$\text{Volume of Gas (scf)} = \frac{\text{Volume of CH}_4 \text{ (scf)}}{.949}$$

The value of this volume of gas was determined by using the average wholesale price for California from November 2014 to October 2015 (EIA, 2016), or \$3.44 per mscf.

The cost per ton is the ratio of total dollars to be spent to comply with the standard (as an annual cost) to the mass reduction of the pollutant to be achieved by complying with that standard. In this case, we calculated the cost per ton both with and without including savings.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

The cost, emissions, savings, and cost per ton for each segment are described in detail below.

5. Recordkeeping

To comply with the proposed regulation, several provisions have recordkeeping and reporting requirements. This includes 799 facilities that are required to keep records of inspection and repair for the LDAR provisions, flash tests for 1,065 tank and separator systems, 93 liquids unloading operations that are required to keep records, 255 facilities with well casings for heavy oil production, and leak records for 979 reciprocating compressors. The recordkeeping and reporting requirements impact 272 businesses. For each of the businesses impacted, an annual report to ARB was estimated to cost \$144, or take 3 hours at \$48 per hour. A Recordkeeping event, or keeping inspection and repair records for LDAR, a flash test, a liquids unloading calculation, or a recording of a leak rate for reciprocating compressors was assigned a cost of \$48. These estimated costs of recordkeeping and reporting are in line with costs used with EPA's recordkeeping cost estimate for their proposed emission standards in the oil and natural gas sector (EPA, 2015). The total estimated cost for recordkeeping and reporting is about \$330,000 per year.

F. Vapor Recovery for Separator and Tank Systems Provision

Under the proposed regulation, systems that are currently uncontrolled and emit greater than 10 metric tons per year of methane would be subject to vapor recovery requirements.

To determine the cost and emissions from tank and separator systems, we used the ICF report, industry information, ARB's 2009 Survey, and EPA's GasSTAR Document "Installing Vapor Recovery Units on Storage Tanks" (EPA, 2006b).

According to ARB's 2009 industry survey, there are 1150 uncontrolled tank and separator systems. Of these, 317 systems at 19 facilities had emissions greater than 10 TPY of methane. Twenty six of these systems had no vapor recovery systems, and 291 had only an uncontrolled water tank.

1. Cost of the Vapor Recovery for Tanks and Separators Provision

The separator and tank systems subject to vapor recovery will need to install systems and if the gas is being routed to an existing or new combustion device, that device must meet a NO_x standard if the facility is located in a non-attainment area. Using data from ARB's survey, there are anticipated to be no new combustion devices and all impacted existing flares are expected to be in San Joaquin Valley non-attainment area.

Therefore, at each facility routing to a flare, it is anticipated that the current flare would need to be replaced by a low-NO_x incinerator.⁷ As a conservative assumption, we chose the smallest flare to be replaced. The incinerators we chose for our cost estimate range in price from \$160,000 to \$295,000, depending on size, and can operate with a capacity of up to 380,000 scf per day (Aeron, 2015a). We chose an appropriate size for each facility based on separator throughput from our survey data. It should also be noted that, through follow-up contacts, one facility was determined to be at three separate and unconnected locations, so each location would need its own incinerator and removal of a flare. Once the total throughput per day was determined, an appropriately sized incinerator was chosen from Table B-4 below. In some cases, a single facility reported to our survey was located in different physical locations. In these instances, each of the physical locations was treated as a separate facility for purposes of determining the correct size of incinerator, flare removal, and throughput.

$$\text{Throughput per Day (scf)} = \frac{\text{Volume from Newly Captured Emissions per Day} + \text{Throughput of Smallest Flare per Day}}{\text{Throughput of Smallest Flare per Day}}$$

⁷ A low NO_x incinerator is one option for meeting the NO_x standard. It is considered the most likely compliance route.

$$\begin{aligned} & \text{Volume of Newly Captured Emissions per Day (scf)} \\ &= \frac{\text{Total CH}_4 \text{ Emissions (MT)} \times \text{Conversion Factor} \times 1,000}{\text{Molar Mass of CH}_4 \times \text{CH}_4 \text{ Composition} \times 365} \end{aligned}$$

Where,

Conversion Factor = 836.2 kg/ k mol (API, 2009)

Molar Mass CH₄ = 16.04 (API, 2009)

CH₄ Composition = 78.8% (API, 2009)

Volume to Incinerator from Smallest Flare (scf/day)

$$= \frac{\text{Annual Throughput} \left(\frac{\text{scf}}{\text{year}} \right)}{365 \frac{\text{days}}{\text{year}}}$$

Table B-5 summarized the data used to choose an appropriately sized incinerator for the facilities that need to replace an existing flare. The production of one of the facilities was spread across three different locations, and this was taken into account when determining throughput for the 11 systems that would need incinerators at 9 facilities.

Table B-4. Incinerators for Tank and Separator Systems

| Uncontrolled Systems | | | | |
|---------------------------------|----------------------------------|--|------------------------------------|-----------------------------------|
| Total # of Systems | Number of Systems w/o VRS | Flare Throughput of smallest flare on site (scf/yr) | Total CH4 Emissions (MT/yr) | Total Throughput (scf/day) |
| 22 | 19 | 1,825,000 | 413.06 | 79,869 |
| 1 | 1 | 2,107,083 | 18.81 | 9,183 |
| 2 | 2 | 375,945 | 30.44 | 6,547 |
| Uncontrolled Water Tanks | | | | |
| Total # of Systems | # of Systems w/o VRS | Flare Throughput of smallest flare on site (SCF) | Total CH4 Emissions (MT/yr) | Total Throughput (scf/day) |
| 12 | 0 | 482,681 | 1372.92 | 250,169 |
| 14 | 0 | 5,660,000 | 1028.16 | 201,865 |
| 60 | 0 | 42,558,000 | 1788.00 | 440,679 |
| 3 | 0 | 48,298,000 | 76.65 | 146,216 |
| 1 | 0 | 6,780,000 | 10.40 | 20,460 |
| 3 | 0 | 31,023,000 | 46.68 | 93,455 |

Data from ARB's 2009 Survey

Table B-5. Incinerator Costs

| Operating Capacity | Capital Cost | Installation Cost | Number Required |
|---------------------------|---------------------|--------------------------|------------------------|
| Up to 36,000 scf per day | \$ 160,000 | \$ 80,000 | 6 |
| Up to 270,000 scf per day | \$ 235,000 | \$ 117,500 | 4 |
| Up to 606,000 scf per day | \$ 295,000 | \$ 147,500 | 1 |

Data from equipment manufacturer (Aereon, 2015a)

Once the number of incinerators was estimated, the cost was determined as follows:

$$\text{Cost of Incinerator} = \text{Number of Devices} \times \text{Cost per Device} \times \text{Capital Recovery Factor}$$

Where,

Capital Recovery Factor = 0.130 From Table B-3

Therefore,

Cost of 36,000 scf per day Incinerators = 6 X (\$160,000 + \$80,000) X 0.130 = \$186,480

Cost of 270,000 scf per day Incinerators = 4 X (\$235,000 + \$117,500) X 0.130 = \$182,595

Cost of 606,000 scf per day Incinerator = 1 X (\$295,000 + \$147,500) X 0.130 = \$57,304

Total Annual Cost of Incinerators = \$186,480 + \$182,595 + \$57,304 = \$426,379

In total, ARB estimates 11 flares would need to be removed and replaced with a low NOx incinerator. According to the ICF report, the cost of a flare was estimated to be about \$50,000. We assumed the cost for removing this equipment would be 50% of the capital cost, which is in line with installation costs from EPA's GasSTAR estimates (EPA, 2006b). All costs were amortized over 10 years, which was taken from the period of amortization from the ICF report for vapor recovery units and represents the expected lifetime of equipment.

Cost of Flare Replacement = Number of Flares Replaced X Cost to Replace Flare X Capital Recovery Factor

Where,

Number of Flares Replaced = 11

Cost to Replace Flare = \$25,000 (ICF, 2015; EPA, 2006b)

Capital Recovery Factor = 0.130 From Table B-3

Cost of Flare Replacement = 11 X \$25,000 X 0.130 = \$35,613

All 317 uncontrolled systems above the 10 metric tons per year threshold would need a vapor recovery system. In cases where only the water tank is uncontrolled, the new vapor recovery system for the water tank would route to the existing vapor recovery and control system. For each of these systems, an appropriately sized vapor recovery system was chosen based EPA's GasSTAR estimates (EPA, 2006b). The cost of these vapor recovery

units ranged from about \$20,000 to \$26,000 in capital costs, and about \$15,000 to \$20,000 in installation costs.

Table B-6 shows the emissions and throughput from the facilities that would need to control emissions from water tanks. This data was used to choose an appropriately sized vapor recovery system.

$$\text{Volume of Gas per Day (mscf / day)} = \frac{\text{Crude Water CH}_4 \text{ Emissions (MT/yr)} \times \text{Conversion Factor} \times 1,000 \text{ kg / MT}}{\text{Molar Mass of CH}_4 \times 365 \times \text{Number of Systems} \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}$$

Where,

Conversion Factor = 836.2 kg/ k mol

Molar Mass of CH₄ = 16.04

Table B-6. Emissions and Throughput from Water Tank

| Emissions Total # of Systems | Crude Water CH4 Emissions (MT/yr) | Volume Gas per day (mscf per day) |
|---|--|--|
| 7 | 42 | 0.9 |
| 22 | 204 | 1.3 |
| 19 | 29 | 0.2 |
| 1 | 9 | 1.3 |
| 2 | 15 | 1.1 |
| 9 | 129 | 2.0 |
| 19 | 243 | 1.8 |
| 7 | 83 | 1.7 |
| 12 | 1,373 | 16.4 |
| 14 | 1,028 | 10.5 |
| 1 | 49 | 7.0 |
| 1 | 198 | 28.3 |
| 1 | 21 | 2.9 |
| 52 | 848 | 2.3 |
| 17 | 65 | 0.6 |
| 44 | 821 | 2.7 |
| 60 | 1,788 | 4.3 |
| 25 | 444 | 2.5 |
| 3 | 77 | 3.7 |
| 1 | 10 | 1.5 |
| 22 | 32 | 0.2 |
| 3 | 47 | 2.2 |
| 317 | | |

Data from ARB's 2009 Survey

Once the throughput from water tank emissions was determined, a vapor recovery system was chosen from Table B-7. Most emissions from water tanks had throughput far below the smallest capacity vapor recovery system described in EPA's GasSTAR document "Installing Vapor Recovery on Storage Tanks" (EPA, 2006b).

Table B-7. Vapor Recovery Costs

| Design Capacity | Capital Cost | Installation Cost | Ongoing Costs | Number Required |
|------------------------|---------------------|------------------------------|--------------------------|----------------------------|
| 25 mscf / day | \$ 20,421 | \$15,316 | 7,367 | 316 |
| 50 mscf / day | \$ 26,327 | \$19,745 | 8,419 | 1 |

Data from EPA's "installing Vapor Recovery Units on Storage Tanks." (EPA, 2006b)

The total cost of vapor recovery systems for the water tank emission were determined as follows:

Cost of Vapor Recovery
= Number of Devices X (Cost per Device X Capital Recovery Factor + Ongoing Cost)

Where,

Capital Recovery Factor = 0.130 From Table B-3

Therefore,

Cost of 25 mscf per day Vapor Recovery = 316 X ((\\$20,421 + \\$15,316) X 0.130 + \\$7,367) = \\$3,790,442

Cost of 50 mscf per day Vapor Recovery = 1 X ((\\$26,327 + \\$19,745) X 0.130 + \\$8,419) = \\$14,408

Therefore,

| |
|--|
| <i>Total Annual Cost of Vapor Recovery = \\$3,790,442 + \\$14,408 = \\$3,804,828</i> |
|--|

A flash test of both the oil and water portion is required of all uncontrolled tank and separator systems with greater than either 50 bbl per day oil throughput, or 200 bbl per day of water throughput. This test is required every year for the first three years, then once every 5 years thereafter. The estimated cost for this test is \$560 each for the oil and water portion (OEC, 2016) including travel and sampling. About 1,100 facilities would need to perform this test. To account for variability in testing frequency, these costs are amortized over 3.3 years.

Testing Cost = ((Number of Oil Flash Tests + Number of Water Flash Tests) X \$560) X Capital Recovery Factor

| |
|---|
| <i>Testing Cost = ((1,065 + 1,073) X \$560) X .33 = \$395,102</i> |
|---|

2. Recordkeeping, reporting, and testing costs are estimated as follows:

Recordkeeping and Reporting Cost = Cost of Businesses Making an Annual Report + Cost of Recordkeeping for Tanks and Separators

Where,

Businesses Impacted by Tank and Separator Provision = 72

Cost of Annual Report = \$144

Number of Flash Tests for Recordkeeping = 2,138

Cost of Recordkeeping = \$48

Therefore,

$$\text{Recordkeeping and Reporting Cost} = ((72 \times \$144) + (2,138 \times \$48) \times .33) = \$37,287$$

The total cost of this provision is the sum of the previous parts of the cost estimate.

Total Annual Cost = Annual Cost for Incinerators + Annual Cost for Vapor Recovery + Amortized Cost for Flare Removal + Annual Cost for Recordkeeping and Reporting + Annual Cost for Testing

$$\text{Total Annual Cost} = \$3,804,828 + \$426,379 + \$35,613 + \$37,287 + \$395,102 = \$4,699,209$$

3. Emissions from the Vapor Recovery for Tanks and Separators Provision

To estimate emissions impacts from the implementation of the proposed regulation, staff used data from ARB's 2009 Survey. Staff used the number of separators in the Survey to determine the number of systems⁸ at each facility. Staff then used Western States Petroleum Association (WSPA, 2015) and California Air Resources Board crude and water tank flash data to determine emission factors in metric tons per barrel for methane, volatile organic compounds (VOC), and Benzene, Toluene, Ethylbenzene, and Xylene (BTEX). The emission factors were applied to the system throughputs of crude, water, and dry gas water, giving total methane, VOC, and BTEX emissions per system. The systems that will be subject to the Oil and Gas regulation are systems found to be uncontrolled with methane emissions exceeding 10 metric tons per year. A detailed description of these calculations is included in Appendix D.

⁸ For purposes of this analysis, a system is defined as a separator and associated crude oil and water tanks.

Total emissions from uncontrolled tanks and separators is estimated to be 7,865 MT of CH₄, or 566,005 MT CO₂e using a GWP of 72. Reductions are expected to be 95%, or about 537,705 MT CO₂e.

4. Savings from the Vapor Recovery for Tanks and Separators Provision

Savings are estimated to be about 2,637 MT CH₄, based on the number of facilities that staff anticipates will either route the vapor collected through a collection system or will use it on site to operate a steam generator, or other equipment. Based on data from the 2009 survey, we considered emission reductions at facilities that had a collection system without an active flare, or the ability use the collected gas for an application on site, such as for a steam generator, to go towards savings. Savings are estimated to be \$498,259.

$$\text{Volume of Gas (scf)} = \frac{\text{Mass of CH}_4 \text{ (MT)} \times \text{Conversion Factor}}{\text{Molar Mass of CH}_4 \times .949 \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}$$

Where,

$$\text{Conversion Factor} = 836.2 \text{ kg / k mol}$$

$$\text{Molar Mass of Methane} = 16.04 \text{ (API, 2009)}$$

Therefore,

| |
|---|
| $\begin{aligned} \text{Volume of Gas (scf)} &= \frac{2,637 \text{ MT CH}_4 \times 836.2 \left(\frac{\text{kg}}{\text{k}} \text{ mol}\right) \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}{16.04 \times .949} \\ &= 144,842,833 \text{ scf} \end{aligned}$ |
|---|

$$\text{Value of Gas Saved} = \text{Volume of Gas} \times \text{Cost per mscf}$$

Where,

$$\text{Cost per mscf} = \$3.44 \text{ (EIA, 2015)}$$

$$1 \text{ mscf} = 1,000 \text{ scf}$$

Therefore,

| |
|---|
| $\text{Value of Gas Saved} = \frac{144,842,833 \text{ scf} \times \$3.44}{1000 \text{ scf/mscf}} = \$498,259$ |
|---|

5. Cost per ton of the Vapor Recovery for Tanks and Separators Provision

Cost per ton is estimated to be about \$8.73 per MT CO₂e reduced, or about \$7.80 per MT CO₂e reduced with savings.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Where,

$$\text{Total Cost per Year} = \$4,699,209$$

$$\text{Savings per Year} = \$498,259$$

$$\text{Total Emissions Reductions per Year} = 537,705 \text{ MT CO}_2\text{e}$$

$$\text{Cost Per Ton} = \frac{\$4,699,209}{537,705 \text{ (MT CO}_2\text{e)}} = \$8.74 \text{ per MT CO}_2\text{e}$$

$$\text{Cost Per Ton with Savings} = \frac{\$4,699,209 - \$498,259}{537,705 \text{ MT CO}_2\text{e}} = \$7.81 \text{ per MT CO}_2\text{e}$$

G. Reciprocating Compressor Provision

The proposed regulation requires rod packings on reciprocating compressors to be replaced if the leak rate is above 2 scfm per cylinder. This applies to reciprocating compressors located at gathering and boosting compressor stations, natural gas processing plants, underground natural gas storage facilities, and transmission compressor stations.

According to ARB's 2009 Oil and Gas Industry Survey (ARB, 2013), there are 911 reciprocating compressors in the oil and gas sector in California. Also in 2009, ARB conducted a Natural Gas Transmission and Distribution Survey (ARB, 2015) which adds an additional 68 reciprocating compressors at transmission stations for a total of 979 compressors. The reciprocating compressors from the 2009 Survey include all upstream compressors. However, the proposed regulatory requirements vary by location with production compressors not subject

to the 2 scfm per cylinder requirement. In order to separate the production compressors, staff used horsepower as a proxy for location and chose to exclude compressors that were reported to operate at an average load of less than 250 hp. Using this split, staff determined there were 325 compressors that would be subject to the 2 scfm per cylinder standard. This includes all 68 compressors from the transmission and distribution survey. The remaining compressors under 250 hp were assumed to be production field compressors, and are included in the LDAR program.

To estimate the portion of the 325 reciprocating compressors that may be over our proposed standard of 2 scfm per cylinder, staff relied on data provided by industry. . The data included measurements from rod packing vents for 55 reciprocating compressors taken over a four year period. According to the data, about 14% of the measurements indicated a leak rate of over 2 scfm per cylinder. Based on the data, staff estimated that 46 out of 325 non-production reciprocating compressors would have a leak rate of over 2 scfm each year, and would require a rod packing replacement to comply with the proposed regulation. Staff estimated that for each of these 46 compressors, two of the rod packings would need to be replaced to bring the leak rate into compliance. In total, 92 rod packings would need to be replaced each year to comply with the proposed regulation.

1. Costs of the Reciprocating Compressor Provision

According to ICF's "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" (ICF, 2014), the cost of replacing a single rod packing on a reciprocating compressor is estimated to be \$6,000. This includes installation. These costs are amortized over a period of three years, which reflects methodology used by ICF, and mirrors EPA's recommended period of replacement of 26,000 hours. The total cost of 92 rod packing replacements at \$6,000 per replacement amortized over three years plus recordkeeping costs is about \$260,000 per year for all businesses, as shown below.

Cost of Rod Packing Replacement
= Number of Devices X Cost per Device X Capital Recovery Factor

Where,

Number of Devices = 92 Rod Packing Replacements per Year

Cost per Device = \$6,000 per Rod Packing Replacement (ICF, 2015)

Capital Recovery Factor = .367 from Table B-3

Therefore,

$$\text{Cost of Rod Packing Replacement} = 92 \times \$6,000 \times 0.367 = \$202,548 \text{ per Year}$$

Businesses are required to keep records of rod packing leak rates, and make an annual report to ARB.

2. Recordkeeping, reporting, and testing costs are estimated as follows:

$$\text{Recordkeeping and Reporting Cost} = \text{Cost of Businesses Making an Annual Report} + \text{Cost of Recordkeeping for Reciprocating Compressors}$$

Where,

$$\text{Businesses Impacted by Reciprocating Compressor Provision} = 55$$

$$\text{Cost of Annual Report} = \$144$$

$$\text{Number of Reciprocating Compressors} = 979$$

$$\text{Cost of Recordkeeping} = \$48$$

Therefore,

$$\text{Recordkeeping and Reporting Cost} = (55 \times \$144) + (979 \times \$48) = \$54,912$$

Total Annual Cost

$$= \text{Cost of Rod Packing Replacement} + \text{Recordkeeping and Reporting Cost}$$

$$\text{Total Annual Cost} = \$202,548 + \$54,912 = \$257,460 \text{ per Year}$$

3. Emissions for the Reciprocating Compressor Provision

Emissions were determined using the reciprocating compressor leak rate data provided by industry. According to the data, the average leak rate for all compressors is about 0.9 scfm per cylinder during pressurized operation, and about 0.45 during pressurized idle and unpressurized states. Data from our Oil and Gas Industry Survey indicates that compressors over 250 hp have an average of 3.45 cylinders and operate an average of 6,546 hours per year. Assuming this gas is 78.8% methane, the total emissions for all reciprocating compressors is estimated to be about 7,000 MT of CH₄, or about 504,000 MT CO₂e using a GWP of 72.

According to the same data from industry, the average leak rate for those compressors emitting more than 2 scfm was about 3 scfm during pressurized operation, and less than 2 scfm during pressurized idle and unpressurized states. This requires the reduction of 1 scfm for the time in pressurized operation to comply with the proposed standard, and calculating reductions

in the same fashion as overall emissions, the reduction from this measure is expected to be about 942 MT of CH₄, or about 68,000 MT CO₂e using a GWP of 72.

Total Volume of Leaked Gas (scfm)
= *Volume Leaked During Pressurized Operation*
+ *Volume Leaked During Pressurized Idle and Unpressurized States*

Volume Leaked
= *Number of Compressors X Cylinders per Compressor X Leak Rate per Cylinder*

Where,

Number of Compressors = 325 (ARB, 2013)

Cylinders per Compressor = 3.45 (ARB, 2013)

Leak Rate per Cylinder in Pressurized Operation = 0.9 scfm

Leak Rate per Cylinder in Pressurized Idle and Unpressurized State = 0.45 scfm

Therefore,

| |
|---|
| <i>Volume Leaked During Pressurized Operation = 325 X 3.45 X 0.9 = 1,009 scfm</i> |
|---|

| |
|---|
| <i>Volume Leaked During Pressurized Idle and Unpressurized State = 325 X 3.45 X 0.45 = 505 scfm</i> |
|---|

Volume of Leaked Gas per Year
= *Volume of Leaked Gas X Minutes per Hour X Hours of Operation per Year*

Where,

Minutes per Hour = 60

Hours of Pressurized Operation per Year = 6,546 (ARB, 2013)

Hours of Pressurized Idle and Unpressurized State per Year = 2,214 (ARB, 2013)

Therefore,

Volume of Leaked Gas per Year during Pressurized Operation (scfm) = 1,009 scfm X 60 minutes/hour X 6,546 hours = 396,343,935 scf per Year

Volume of Leaked Gas per Year during Pressurized Idle and Unpressurized States = 505 scfm X 60 minutes/hour X 2,214 hours = 67,026,082.5 scf per Year

$$\text{Total Volume of Leaked Gas per Year} = 397,615,433 \text{ scf} + 67,026,082.5 \text{ scf} = 463,370,018 \text{ scf}$$

$$\text{Mass of Methane (kg)} = \frac{\text{Volume of Leaked Gas X Composition of Gas X Molar Mass of Methane}}{\text{Conversion Factor}}$$

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

$$\text{Mass of Methane} = 463,370,018 \text{ scf} \times 0.788 \times 16.04 / 836.2 = 7,004,036 \text{ kg CH}_4$$

$$\text{Emissions MT CO}_2\text{e} = \frac{\text{Mass of Methane (kg)} \times \text{GWP}}{1,000 \text{ kg/MT}}$$

Where,

Conversion Factor = 1000 kg / MT

GWP = 72

Therefore,

$$\text{Emissions MT CO}_2\text{e} = \frac{7,004,036 \text{ kg CH}_4 \times 72}{1,000 \text{ kg/MT}} = 504,291 \text{ MT CO}_2\text{e}$$

4. Reductions

The reductions from the provision for reciprocating compressors is estimated to be about 68,000 MT CO₂e. According to our data, the compressors over the proposed standard of 2.0 scfm would only exceed this during pressurized operation, and reductions from pressurized idle or unpressurized states are not accounted for.

Volume Leaked (scfm)

= Number of Compressors X Cylinders per Compressor X Leak Rate per Cylinder

Where,

Number of Compressors = 46

Cylinders per Compressor = 3.45 (ARB, 2013)

Leak Rate per Cylinder Above Standard = 3.0 scfm (PG&E, 2015; Sempra, 2015)

Reduction in Leak Rate to Meet Standard = 1.0 scfm

Therefore,

| |
|--|
| <i>Volume Reduced to Comply with Standard = 46 X 3.45 X 1 = 158.7 scfm</i> |
|--|

Volume of Leaked Gas per Year

= Volume of Leaked Gas X Minutes per Hour X Hours of Operation per Year

Where,

Minutes per Hour = 60

Hours of Pressurized Operation per Year = 6,546 (ARB, 2013)

Therefore,

| |
|---|
| <i>Volume of Leaked Gas per Year = 158.7 scfm X 60 minutes/hour X 6,546 hours = 62,331,012 scf per Year</i> |
|---|

Mass of Methane (kg)

*=
$$\frac{\text{Volume of Leaked Gas X Composition of Gas X Molar Mass of Methane}}{\text{Conversion Factor}}$$*

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

$$\text{Mass of Methane (kg)} = 62,331,012 \text{ scf} \times .788 \times 16.04 / 836.2 = 942,160 \text{ kg CH}_4$$

$$\text{Reductions MT CO}_2\text{e} = \frac{\text{Mass of Methane (kg)} \times \text{GWP}}{1,000 \text{ kg/MT}}$$

Where,

$$\text{Conversion Factor} = 1000 \text{ kg / MT}$$

$$\text{GWP} = 72$$

Therefore,

$$\text{Reductions MT CO}_2\text{e} = \frac{942,160 \text{ kg CH}_4 \times 72}{1,000 \text{ kg/MT}} = 67,836 \text{ MT CO}_2\text{e}$$

5. Savings from the Reciprocating Compressor Provision

The reduction of 68,000 MT CO₂e translates to about 52 million scfm of wholesale quality gas. Reduction in leaks from rod packings directly impact losses from production, and we assume all reductions will count towards savings. Based on data from the U.S. Energy Information Administration (EIA, 2016), we estimate the value of this savings to be \$3.44 per mscf, or about \$178,000.

$$\text{Volume of Gas (scf)} = \frac{\text{Mass of CH}_4 \text{ (MT)} \times \text{Conversion Factor}}{\text{Molar Mass of CH}_4 \times .949 \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}$$

Where,

$$\text{Mass of CH}_4 = 942 \text{ MT}$$

$$\text{Conversion Factor} = 836.2 \text{ kg / k mol}$$

$$\text{Molar Mass of Methane} = 16.04 \text{ (API, 2009)}$$

Therefore,

$$\begin{aligned} \text{Volume of Gas (scf)} &= \frac{942 \text{ MT CH}_4 \times 836.2 \left(\frac{\text{kg}}{\text{k}} \text{ mol}\right) \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}{16.04 \times .949} \\ &= 51,756,415 \text{ scf} \end{aligned}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = \$3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\text{Value of Gas Saved} = \frac{51,756,415 \text{ scf} \times \$3.44}{1000 \text{ scf/mscf}} = \$178,042$$

6. Cost per Ton of the Reciprocating Compressor Provision

Dividing the cost by the emission reductions results in a cost per ton of about \$3.80 per MT CO₂e reduced. By including savings, the total annual cost of \$257,657 is reduced by \$178,042, for a net cost of about \$80,000 per year. The cost per ton with savings is estimated to be about \$1.17 per MT CO₂e.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Therefore,

$$\text{Cost Per Ton} = \frac{\$257,657}{67,836 \text{ MT CO}_2\text{e}} = \$3.80 \text{ per MT CO}_2\text{e}$$

$$\text{Cost Per Ton with Savings} = \frac{\$257,657 - \$178,042}{67,836 \text{ MT CO}_2\text{e}} = \$1.17 \text{ per MT CO}_2\text{e}$$

H. Leak Detection and Repair Provision

The proposed regulation requires facilities to implement a Leak Detection and Repair program (LDAR) on their high-methane use components, and conduct inspections on a quarterly basis. To determine the cost of this segment of the measure, staff estimated the number of components that would be inspected, and estimated the cost of performing these inspections.

To determine emissions and cost for LDAR, staff relied on a number of sources for information. Staff used the ARB's 2009 Survey for the number of components and discussions with LDAR contractors for cost information. Estimates for emissions from this segment are derived from emission factors and 'super leaker' data from CAPCOA's Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities (CAPCOA, 1999). According to ARB's Survey (ARB, 2013), there are about 1,307,831 components that will be affected by our proposed regulation. This includes components for facilities involved in natural gas processing, onshore natural gas production, natural gas transmission compressor stations, and natural gas storage. In addition to these components, reciprocating compressors are also part of the LDAR program for our proposed regulation. This represents 979 compressors according to data from our survey. Additionally, there are 20,485 well casings at heavy oil facilities that will be subject to LDAR inspection. Staff assumed there would be 11 components per compressor subject to the LDAR program and that each well casing would count as a component, so the total amount of components becomes about 1,339,185.

1. Costs of the Leak Detection and Repair Provision

The cost to inspect LDAR components was based on discussions with contractors that perform LDAR inspections and repairs. The per hour cost estimates from contractors for LDAR inspections are summarized in Table B-8. This cost is estimated to be \$60 per hour for labor, and \$1,500 per facility to account for setup costs. In order to derive an annual cost, staff needed to estimate the number of components that could be inspected in an hour. Staff contacted a number of contractors who perform LDAR work and estimated that, on average, about 34 components per hour can be inspected during an eight hour day, when travel and preparation time is accounted for. This also takes into account making a first attempt at a repair if a leak is detected. If accounting only for measurement time, approximately 50 components could be inspected per hour. Following the methodology from the ICF report, the capital cost of larger repairs is not included based upon the assumption that these repairs would need to be made regardless of an LDAR program; because the operator would repair these parts regardless of the LDAR program, the program serves to identify equipment failures sooner, benefiting the operator above and beyond the business as usual.

Table B-8. Estimated Cost from Contractors

| | Estimated Cost per Hour (\$ per hour) |
|--------------|---------------------------------------|
| Contractor 1 | 55 |
| Contractor 3 | 70 |
| Contractor 4 | 62 |

| | |
|----------------|-----------|
| Contractor 5 | 55 |
| Contractor 6 | 50 |
| Average | 60 |

Combining the average inspection rate of 34 components per hour with 2080 work hours per year yields a result of 68,250 components that can be inspected during a person year (PY). Dividing the total number of components, 1,339,185, by the number of components that are able to be inspected in a year, 68,250, yields 19.6, the number of person years needed by our proposed regulation. The total cost is estimated to be \$10 million, and is summarized below.

Cost of LDAR Program

$$= (\text{Number of PY} \times \text{Cost of PY}) + \text{Setup Cost} + \text{Recordkeeping Cost}$$

$$PY = \text{Number of Components} / \text{Components Inspected by One PY}$$

$$\text{Components Inspected by One PY} = \text{Hours per Year} \times \text{Inspection Rate per Hour}$$

Where,

$$\text{Inspection Rate per Hour} = 34$$

$$\text{Labor Hours per Year} = 2,080$$

Therefore,

$$\text{Components Inspected by One PY} = 2,080 \text{ Hours per Year} \times 34 \text{ Components per Hour} = 68,250 \text{ Components per Year}$$

Where,

$$\text{Number of Components} = 1,339,185 \text{ (ARB, 2013)}$$

$$PY = 1,339,185 / 68,250 = 19.6 \text{ PY}$$

$$\text{Annual Cost for a PY} = 2,080 \text{ Hours} \times \text{Hourly Rate}$$

Where,

Hourly Rate = \$60

Annual Cost for a Quarterly Inspection = 2,080 Hours X \$60 per Hour X 4 = \$499,200

Setup Cost = Facilities X Setup Cost X Capital Recovery Factor

Where,

Setup Cost = \$1,500

Capital Recovery Factor = 0.130

Setup Cost = 799 X \$1,500 X 0.130 = \$155,805

2. Recordkeeping, reporting, and testing costs are estimated as follows:

Recordkeeping and Reporting Cost = Cost of Businesses Making an Annual Report + Cost of Recordkeeping for Inspections

Businesses Impacted by LDAR Provision = 201 (ARB, 2013)

Facilities Impacted by LDAR Provision, Including Well Casing Facilities = 1,054 (ARB, 2013)

Cost of Annual Report = \$144

Cost of Recordkeeping = \$48 X 4 = \$192

Therefore,

Recordkeeping and Reporting Cost = (201 X \$144) + (1,054 X \$192) = \$231,505

Therefore,

*Cost of LDAR Program
= (Number of PY X Cost of PY) + Setup Cost
+ Recordkeeping Cost*

Cost of LDAR Program = (19.6 X \$499,200) + \$155,805 + \$231,505 = \$10,181,892

3. Emissions from the LDAR Provision

Emissions were estimated using emission factors from CAPCOA guidelines (CAPCOA, 1999), which also accounted for 'super leaker' components. These are components that leak at a rate several times the rate of what is

expected from a typical component, and make up the majority of emissions^{9,10,11,12}. Several studies that have reported measurements of CH₄ emissions from natural gas production sites share a common observation—the existence of skewed emissions distributions, where a small number of sites or facilities account for a large proportion of emissions. Such skewed distributions can make estimating and attributing emissions more difficult and in turn can impact the effectiveness of emission reduction policies.

Emissions are estimated to be 13,650 MT CH₄ per year, or about 982,827 MT CO₂e using a GWP of 72. According to the ICF report, a quarterly inspection program is expected to reduce emissions by 60%. Reductions for this LDAR program are estimated to be 8,190 MT CH₄ per year, or about 589,680 MT CO₂e per year using a GWP of 72.

⁹ Brandt, A. R., et al. 2014. Methane Leaks from North American Natural Gas Systems. *Science*. Vol. 343,.

¹⁰ Lamb, Brian K., et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.

¹¹ Zavala -Araiza, Daniel, et al. 2015. Reconciling Divergent Estimates of Oil and Gas Methane Emissions. *Proceedings of the National Academy of Sciences*.

¹² Zavala -Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. *Environmental Science & Technology*. Vol. 49, Pages 8167–8174.

Table B-9. Emissions from LDAR Components

| Fugitive source | | | | |
|------------------------------------|-----------------------------|-------------------------------------|------------------------|-------------------------|
| Components <10,000 ppmv | Number of Components | g CH4 per Component per Year | MT CH4 per Year | MT CO2e Per Year |
| Valves | 236,131 | 307 | 72.49 | 5,219.4 |
| Connectors | 870,766 | 105 | 91.43 | 6,583.0 |
| Flanges | 158,486 | 245 | 38.83 | 2,795.7 |
| Open end lines | 692 | 1,288 | 0.89 | 64.2 |
| Pump seals | 2,312 | 1,288 | 2.98 | 214.4 |
| Others (compressors, hatches, etc) | 21,008 | 1,288 | 27.06 | 1,948.2 |

| Components >=10,000 ppmv | | | | |
|------------------------------------|------------------|-----------|---------------|----------------|
| Valves | 5,367 | 1,217,645 | 6,534.64 | 470,494.1 |
| Connectors | 19,790 | 226,884 | 4,490.06 | 323,284.7 |
| Flanges | 3,602 | 480,924 | 1,732.27 | 124,723.2 |
| Open end lines | 16 | 1,208,880 | 19.02 | 1,369.4 |
| Pump seals | 53 | 1,208,880 | 63.53 | 4,574.4 |
| Others (compressors, hatches, etc) | 477 | 1,208,880 | 577.17 | 41,556.5 |
| Total | 1,318,700 | | 13,650 | 982,827 |

Data from ARB's 2009 Survey, and CAPCOA's California Implementation Guide for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, and API's Fugitive Hydrocarbon Emissions from Oil and Gas Operations. (ARB, 2013¹³; CAPCOA, ARB, 1999¹⁴)

4. Savings from the LDAR Provision

Since gas that is emitted from a leaking component comes directly from the process of production, transmission, processing, or storage, all reductions are counted as savings. Assuming this gas is 94.9 % CH₄, staff estimates that about 450 million cubic feet of gas will be saved with the LDAR program of our proposed regulation. Using a price of \$3.44 per mscf of gas, this results in a savings of about \$1,550,000.

$$Volume\ of\ Gas\ (scf) = \frac{Mass\ of\ CH_4\ (MT) \times Conversion\ Factor}{Molar\ Mass\ of\ CH_4 \times .949 \times 1,000 \left(\frac{mscf}{scf}\right)}$$

Where,

¹³ ARB. 2013. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.

¹⁴ CAPCOA, ARB. 1999. The California Air Resources Board Staff California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities.

Mass of CH4 = 8,190 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\text{Volume of Gas (scf)} = \frac{8,190 \text{ MT CH}_4 \times 836.2 \left(\frac{\text{kg}}{\text{k}} \text{ mol}\right) \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}{16.04 \times .949}$$
$$= 449,907,765 \text{ scf}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = \$3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\text{Value of Gas Saved} = \frac{449,907,765 \text{ scf} \times \$3.44}{1000 \text{ scf/mscf}} = \$1,547,683$$

5. Cost per Ton of the LDAR Provision

Cost per Ton is estimated to be about \$17.27, or about \$14.44 per MT CO₂e reduced with savings.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Therefore,

$$\text{Cost Per Ton} = \frac{\$10,181,892}{589,680 \text{ MT CO}_2\text{e}} = \$17.27 \text{ per MT CO}_2\text{e}$$

$$\text{Cost Per Ton with Savings} = \frac{\$10,181,892 - \$1,547,683}{589,680 \text{ MT CO}_2\text{e}} = \$14.44 \text{ per MT CO}_2\text{e}$$

I. Pneumatic Devices Provision

The proposed regulation requires continuous bleed pneumatic devices to be replaced by no bleed pneumatic devices, and to replace pneumatic pumps with electronic pumps. Staff relied on information from the ICF report, ARB's Survey, API's "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry" (API, 2004) and EPA's "Methane Emissions from the Natural Gas Industry" (EPA, 1996) to determine the number of affected devices, cost, and emissions.

According to ARB's 2009 Survey, there were 1,701 pneumatic devices relating to production, processing, and storage, and 145 pneumatic pumps. 1151 of pneumatic devices were reported to be continuous bleed devices, 405 were intermittent bleed, and 50 were low bleed. Additionally, 31 continuous bleed devices were reported in transmission and distribution, for a total of 1182 continuous bleed devices.

1. Cost of the Pneumatic Devices Provision

EPA's gas star document entitled "Convert Pneumatics to Mechanical Controls" (EPA, 2011) estimates the cost of a no bleed mechanical device to be \$3,000 per device. According to the ICF report, the cost of replacing a pneumatic pump is \$10,000 with an operating cost of \$2,000 per year. These costs were amortized over seven years to reflect the lifetime of the equipment as noted in the ICF report. The total cost to replace these devices is estimated to be about \$1.2 million per year, and is summarized below.

Cost of Pneumatic Devices

$$= \text{Number of Devices} \times \text{Cost per Device} \times \text{Capital Recovery Factor}$$

Where,

Number of Devices = 1,182 Continuous Bleed Pneumatic Devices (ARB, 2013)

Cost per Device = \$3,000 per No Bleed Pneumatic Device (EPA, 2011)

Capital Recovery Factor = .173 from Table B-3

Therefore,

$$\text{Cost of Pneumatic Devices} = 1,182 \times \$3,000 \times 0.173 = \$612,749 \text{ per Year}$$

Cost of Pneumatic Devices
= *Number of Devices X (Cost per Device X Capital Recovery Factor*
+ *Ongoing Cost per Device*

Where,

Number of Devices = 145 Pneumatic Pumps (ARB, 2013)

Cost per Device = \$10,000 per Pneumatic Pump Replacement (ICF, 2015)

Ongoing Cost per Device = \$2,000 per Year (ICF, 2015)

Capital Recovery Factor = .173 from Table B-3

Therefore,

$$\boxed{\text{Cost of Pneumatic Pumps} = 145 \times (\$3,000 \times 0.173 + \$2,000)} \\ \boxed{= \$540,560 \text{ per Year}}$$

Total Annual Cost = Cost of Pneumatic Devices + Cost of Pneumatic Pumps

$$\boxed{\text{Total Annual Cost} = \$612,749 + \$540,560 = \$1,153,309 \text{ per Year}}$$

2. Emissions from the Pneumatic Devices Provision

Emissions were calculated using emission factors used in ARB's 2009 Survey, which included factors from API's "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry" and EPA's "Methane Emissions from the Natural Gas Industry" (EPA, 1996) .

These emission factors are 3.599 tons CH₄ per year per device for a continuous bleed device (API, 2004), and 992 scf per million gallons pumped for pneumatic pumps (EPA, 2014). Using these emission factors for the 1182 continuous bleed devices and 145 pneumatic pumps in the production and transmission and distribution segments, the total emissions are 4,437 MT of CH₄ or 319,473 MT CO₂e using a GWP of 72.

Emissions for Pneumatic Devices (MT CH₄)
= *Number of Devices X Emission Factor*

Where,

Emission Factor = 3.599 MT CH₄/Year/Device (API, 2004)

$$\text{Emissions MT CH}_4 = 1,182 \times 3.599 \text{ MT CH}_4/\text{Year/Device} = 4,207 \text{ MT CH}_4$$

Emissions for Pneumatic Pumps (MT CH₄)

$$= \frac{\text{Emission Factor} \times \text{Volume Pumped} \times \text{Molar Mass of CH}_4}{\text{Conversion Factor} \times 1,000 \text{ kg/MT}}$$

Where,

Emission Factor = 992 scf CH₄ per million gallons pumped (EPA, 2014)

Volume Pumped = 11,802,226,472 Gallons (ARB, 2013)

Molar Mass of CH₄ = 16.04 (API, 2009)

Conversion Factor = 836.2 kg/k mol (API, 2009)

Therefore,

$$\begin{aligned} \text{Emissions MT CH}_4 &= \frac{992 \frac{\text{scf CH}_4}{1,000,000 \text{ Gallons}} \times 11,802,226,472 \text{ Gallons} \times 16.04}{836.2 \times 1,000 \text{ kg/MT}} \\ &= 224.6 \text{ MT CH}_4 \end{aligned}$$

and,

$$\text{Emissions MT CO}_2\text{e} = (4,207 \text{ MT CH}_4 + 224.6 \text{ MT CH}_4) \times 72 = 319,055 \text{ MT CO}_2\text{e}$$

3. Savings from the Pneumatic Devices Provision

Since these devices are no longer operated by gas, all emissions are reduced. Savings for this segment of the proposed regulation is estimated to be 243 million scf of gas. At a cost of \$3.44 per mscf (EIA, 2016), this represents a savings of about \$840,000.

$$\text{Volume of Gas (scf)} = \frac{\text{Mass of CH}_4 \text{ (MT)} \times \text{Conversion Factor}}{\text{Molar Mass of CH}_4 \times .949 \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}$$

Where,

Mass of CH₄ = 4,431 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\begin{aligned} \text{Volume of Gas (scf)} &= \frac{4,431 \text{ MT CH}_4 \times 836.2 \left(\frac{\text{kg}}{\text{k}} \text{ mol}\right) \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}{16.04 \times .949} \\ &= 243,429,070 \text{ scf} \end{aligned}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = \$3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\text{Value of Gas Saved} = \frac{243,429,070 \text{ scf} \times \$3.44}{1000 \text{ scf/mscf}} = \$837,396$$

4. Cost per ton of the Pneumatic Devices Provision

Cost per ton is estimated to be \$3.61 per MT CO₂e reduced, or \$0.99 per MT CO₂e reduced with savings.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Therefore,

$$\text{Cost Per Ton} = \frac{\$1,153,309}{319,055 \text{ MT CO}_2\text{e}} = \$3.61 \text{ per MT CO}_2\text{e}$$

$$\text{Cost Per Ton with Savings} = \frac{\$1,153,309 - \$837,396}{319,055 \text{ MT CO}_2\text{e}} = \$0.99 \text{ per MT CO}_2\text{e}$$

J. Well Stimulation Provision

For well stimulation circulation tanks, staff relied on industry information and DOGGR data. Based on data from the DOGGR website (DOGGR, 2016), we estimated there would be about 1,200 well stimulation activities during a typical year.

1. Cost of the Well Stimulation Provision

Options to mitigate emissions from a well stimulation activity include using a gas separator plus a low NOx incinerator, which was estimated to cost about \$290,000 (Voyager, 2015) and \$160,000 (Aereon, 2015a), respectively. Staff estimated that six systems would be needed for well stimulation activities throughout the state, which could be a mix of gas separators, and vapor collection systems. Existing incinerators or a bladder collection system could also be used. For this analysis, six control systems consisting of a gas separator and an incinerator are used, which represents greater cost than other alternatives.

Cost of Well Stimulation Treatment
= Number of Devices X (Capital Costs X Capital Recovery Factor)

Where,

Number of Devices = 6 Gas Separators with 6 Low NOx Incinerators

Cost per Gas Separator = \$290,000

Cost per Low NOx Incinerator = \$160,000

Installation Cost for Low NOx Incinerator = \$80,000

Capital Recovery Factor for Incinerator and Gas Separator = 0.130 from Table B-3

Therefore,

| |
|--|
| $\begin{aligned} \text{Cost of Well Stimulation Treatment} \\ &= 6 \times ((\$290,000 \times 0.130) + (\$160,000 + \$80,000) \times 0.130) \\ &= \$463,350 \text{ per Year} \end{aligned}$ |
|--|

2. Emissions from the Well Stimulation Provision

WSPA provided staff a report on emissions from well stimulation recirculation tanks (WSPA, 2015). Given the limited data set and variability within that data set, staff used the high end of the emissions estimates: 1.26 MT CO₂e

per event, based on a GWP of 21. Using a GWP of 72, this translates to emissions of about 4.32 MT CO₂e per well stimulation. Based on 1,200 well stimulation activities, total emissions are estimated to be about 5,184 MT CO₂e per year. Assuming controls are 95% effective, this translates to a reduction of 4,925 MT CO₂e per year.

$$\text{Emissions MT CO}_2\text{e} = \text{Well Stimulation Activities} \times \text{Emissions per Well Stimulation}$$

Where,

$$\text{Well Stimulation Activities} = 1,200 \text{ (DOGGR, 2016)}$$

$$\text{Emissions per Well Stimulation} = 4.32 \text{ MT CO}_2\text{e} \text{ (WSPA, 2015)}$$

Therefore,

| |
|--|
| $\text{Emissions MT CO}_2\text{e} = 1,200 \times 4.32 \text{ MT CO}_2\text{e} = 5,184 \text{ MT CO}_2\text{e}$ |
|--|

3. Savings from the Well Stimulation Provision

Although gas controlled from well stimulation activities may be used or become additional product, for the purposes of this analysis they do not count towards savings.

4. Cost per ton of the Well Stimulation Provision

Using these figures, we estimated the cost of controls for well stimulations. Cost effectiveness is estimated be \$90.93 per MT CO₂e reduced. The calculation is shown below.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Therefore,

| |
|---|
| $\text{Cost Per Ton} = \frac{\$463,350}{4,925 \text{ MT CO}_2\text{e}} = \$90.93 \text{ per MT CO}_2\text{e}$ |
|---|

K. Centrifugal Compressor Provision

The proposed regulation requires centrifugal compressors that currently use a wet seal to either convert to using a dry seal, or collect the vented gas emissions with a vapor recovery system. Staff estimated the number of centrifugal compressors with wet seals that would need a vapor recovery system or conversion to a dry seal, and relied on data supplied to us by the operator to determine the cost.

According to ARB's 2009 survey (ARB, 2013), there are 48 centrifugal compressors in California, and 28 of these are equipped with a wet seal. Staff contacted these facilities and found that 27 of these centrifugal compressors had been replaced by a compressor using a dry seal, had installed a vapor recovery system, are no longer in use, reported the wet seal in error, or were operated by a company that is no longer in business. Twenty six centrifugal compressors were reported in ARB's transmission and distribution survey, all of which had dry seals. Based on this information, staff estimated there is only one centrifugal compressor that needs to comply with the proposed regulation.

1. Cost of the Centrifugal Compressor Provision

According to the ICF report, the cost to install a vapor recovery system on a centrifugal compressor is estimated to be about \$50,000. Industry provided estimates that confirmed this figure. The cost is amortized over a period of 10 years, which matches the methodology used by ICF. The total cost of installing a vapor recovery system on this centrifugal compressor is estimated to be \$6,475 per year.

2. Emissions of the Centrifugal Compressor Provision

To determine the emissions from this compressor, staff again relied on data supplied to us by the operator of the compressor. According to the operator, the emissions measured from this compressor are 1700 scfh or about 28.4 scfm, and operates about 2,000 hours per year.

At an average of 2000 hours per year, 1700 scfh is equivalent to 3,203,520 scf of methane. Total emissions are 51.5 MT CH₄, or about 3,700 MT CO_{2e} based on a GWP of 72. According to the ICF report, a reduction of 95% is expected from a vapor recovery unit. This translates to a reduction of 48.9 MT CH₄, or about 3,500 MT CO_{2e}.

Where,

Leak Measurement = 1,700 scf per Hour

Hours of Pressurized Operation per Year = 2,000

Total Volume of Leaked Gas per Year = 2,000 Hours X 1,700 scf per Hour = 340,000 scf

Mass of Methane (kg)

$$= \frac{\text{Volume of Leaked Gas} \times \text{Composition of Gas} \times \text{Molar Mass of Methane}}{\text{Conversion Factor}}$$

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

$$\text{Mass of Methane} = \frac{340,000 \text{ scf} \times .788 \times 16.04}{836.2 \times 1,000} = 51.5 \text{ MT CH}_4$$

$$\text{Emissions MT CO}_2\text{e} = \frac{\text{Mass of Methane (kg)} \times \text{GWP}}{1,000 \text{ kg/MT}}$$

Where,

Conversion Factor = 1000 kg / MT

GWP = 72

Therefore,

$$\text{Emissions MT CO}_2\text{e} = 51.5 \text{ MT CH}_4 \times 72 = 3,709 \text{ MT CO}_2\text{e}$$

3. Savings of the Centrifugal Compressor Provision

Since the gas collected from the vapor recovery system is expected to be used or rerouted through their production line, all of the 3.4 million cubic feet of gas that is reduced will count towards savings. Based on data from the U.S. Energy Information Administration (US EIA, 2016), we estimate the value of this savings to be \$3.44 per mscf, or about \$9,000.

$$\text{Volume of Gas (scf)} = \frac{\text{Mass of CH}_4 \text{ (MT)} \times \text{Conversion Factor}}{\text{Molar Mass of CH}_4 \times .949 \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}$$

Where,

Mass of CH₄ = 48.9 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\begin{aligned} \text{Volume of Gas (scf)} &= \frac{48.9 \text{ MT CH}_4 \times 836.2 \left(\frac{\text{kg}}{\text{k}} \text{ mol}\right) \times 1,000 \left(\frac{\text{mscf}}{\text{scf}}\right)}{16.04 \times .949} \\ &= 2,689,090 \text{ scf} \end{aligned}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = \$3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\text{Value of Gas Saved} = \frac{2,689,090 \text{ scf} \times \$3.44}{1000 \text{ scf/mscf}} = \$9,250$$

4. Cost per ton of the Centrifugal Compressor Provision

Cost effectiveness is estimated to be about \$1.84 per MT CO₂e reduced, or a benefit of \$0.79 per MT CO₂e reduced with savings. The calculation is shown below.

$$\text{Cost Per Ton} = \frac{\text{Total Cost per Year (\$)}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

$$\text{Cost Per Ton with Savings} = \frac{\text{Total Cost per Year (\$)} - \text{Savings per Year}}{\text{Total Emission Reductions per Year (MT CO}_2\text{e)}}$$

Therefore,

$$\text{Cost Per Ton} = \frac{\$6,475}{3,524 \text{ MT CO}_2\text{e}} = \$1.84 \text{ per MT CO}_2\text{e}$$

$$\text{Cost Per Ton with Savings} = \frac{\$6,475 - \$9,250}{3,524 \text{ MT CO}_2\text{e}} = -\$0.79 \text{ per MT CO}_2\text{e}$$

L. Monitoring Plan

Under the proposed regulation, operators of underground natural gas storage facilities will be required to submit a plan for approval that includes daily monitoring of storage wells, and ambient air monitoring. There are a total of 14 underground natural gas storage facilities operated by six businesses that will be impacted by the provision.

There are several options available to operators of these facilities to comply with the proposed regulation. Compliance with the daily monitoring requirement can be accomplished with manual inspection using optical imaging devices, or other leak detecting equipment. Given the cost of this option, it is expected that most operators will choose to use a method of inspecting wells that involves autonomous detection of leaks, which would significantly reduce labor costs.

The cost of these devices was determined through conversations with two businesses that are expected to provide this service. According to the DOGGR website, there are 408 active natural gas storage wells located at the 14 facilities (DOGGR, 2016b). The cost was estimated from a combination of two scenarios; the first using optical imaging cameras mounted on a permanent fixture, and the second using ultrasound monitors in conjunction with optical monitors.

1. Scenario 1

Each facility would need to purchase an OGI camera, and another device capable of detecting leaks. This cost for this equipment was estimated to be \$95,000 (ARB, 2016). To conduct daily monitoring, this scenario assumed that wells are not checked manually, but rather with an automated system consisting of two ultrasonic monitors at a cost of \$18,500 each, and four IR detectors at a cost of \$11,500 each (Caltrol, 2016). These costs are amortized over 10 years.

Cost of Scenario 1 = Annual Cost of Detection Equipment + Annual Cost of Monitoring Equipment + Cost of Manual Inspections + Cost of Ambient Air Monitoring

Annual Cost of Detection Equipment = Number of Facilities X Cost of Equipment X Capital Recovery Factor

Where,

Number of Facilities = 14

Cost of Equipment = \$95,000 (ARB, 2016)
Capital Recovery Factor = 0.130

$$\text{Annual Cost of Detection Equipment} = 14 \times \$95,000 \times 0.130 = \$172,900$$

Annual Cost of Monitoring Equipment = Wells X Cost per Well X Capital Recovery Factor

Where,

Wells = 408
Cost per Well = \$83,000
Capital Recovery Factor = 0.130

Thus,

$$\text{Annual Cost of Monitoring Equipment} = 408 \times \$83,000 \times 0.130 = \$4,402,320$$

The cost of ambient air monitoring for the Monitoring Plan was based on cost estimates from ARB's Monitoring and Laboratory Division for similar applications. This was estimated to be \$84,630 in initial capital cost and \$89,500 ongoing cost for each of the 14 affected facilities (ARB, 2016b).

Cost of Ambient Air Monitoring = Number of Facilities X (Amortized Capital Cost + Ongoing Cost)

$$\text{Cost of Ambient Air Monitoring} = 14 \times ((\$84,630 \times 0.130) + \$89,500) = \$1,407,026$$

$$\text{Cost of Scenario 1} = \$172,900 + \$4,402,320 + \$1,407,026 = \$6,592,207$$

2. Scenario 2

Each facility would need to purchase an OGI camera, and another device capable of detecting leaks. This cost for this equipment was estimated to be \$95,000 (ARB, 2016). To conduct daily monitoring, this scenario assumed that wells are not checked manually, but rather with an automated system consisting of a mounted camera monitor capable of optically detecting leaks. Staff assumed one of these monitors could detect leaks at three wells, and this solution is assumed to be valid for 90% of the wells, with the remaining 10% of the wells still requiring a manual inspection. The cost of this system is estimated at \$90,000 per unit, based on conversations with the manufacturer. This cost of manual inspections is estimated at \$350 per well

per day, and is based on EPA's estimate for inspecting wells using OGI technology (EPA, 2011b). All costs are amortized over 10 years.

Cost of Scenario 2 = Annual Cost of Detection Equipment + Annual Cost of Monitoring Equipment + Ongoing Cost of Equipment + Cost of Manual Inspections + Cost of Ambient Air Monitoring

Annual Cost of Detection Equipment = Number of Facilities X Cost of Equipment X Capital Recovery Factor

Where,

Number of Facilities = 14

Cost of Equipment = \$90,000

Capital Recovery Factor = 0.130

$$\text{Annual Cost of Detection Equipment} = 14 \times \$90,000 \times 0.130 = \$172,900$$

Annual Cost of Monitoring Equipment = Wells X Cost per Well X Percentage of Applicable Wells X Capital Recovery Factor

Where,

Wells = 408

Cost per Well = \$54,000

Percentage of Applicable Wells = 90%

Capital Recovery Factor = 0.130

Thus,

$$\begin{aligned} \text{Annual Cost of Monitoring Equipment} &= \frac{408 \times \$54,000 \times 90\% \times 0.130}{3} \\ &= \$1,432,080 \end{aligned}$$

$$\text{Ongoing Cost for Equipment} = \frac{\text{Wells X Ongoing Cost X 90\%}}{3}$$

Where,

Wells = 408

Ongoing Cost = \$18,000

$$\text{Ongoing Cost for Equipment} = \frac{408 \times \$18,000 \times 90\%}{3} = 2,203,200$$

Cost of Manual Inspections
 = Wells X Cost per Well X Percentage of Applicable Wells X Frequency of Inspection

Where,
 Wells = 408
 Cost per Well = \$350
 Percentage of Applicable Wells = 10%
 Frequency of Inspection = 365 times per year

$$\text{Cost of Manual Inspections} = 408 \times \$285 \times 10\% \times 365 = \$5,212,200$$

The cost of ambient air monitoring for the Monitoring Plan was based on cost estimates from ARB's Monitoring and Laboratory Division for similar applications. This was estimated to be \$84,630 in initial capital cost and \$89,500 ongoing cost for each of the 14 affected facilities (ARB, 2016a, ARB, 2016b).

Cost of Ambient Air Monitoring = Number of Facilities X (Amortized Capital Cost + Ongoing Cost)

$$\text{Cost of Ambient Air Monitoring} = 14 \times ((\$84,630 \times 0.130) + \$89,500) = \$1,306,525$$

$$\text{Cost of Scenario 2} = \$172,900 + \$1,432,080 + \$2,203,200 + \$5,212,200 + 1,306,525 = \$10,831,367$$

Recordkeeping and Reporting Cost = Cost of Businesses Making an Quarterly Report

Businesses Impacted by Monitoring Plan = 6

Cost of Quarterly Report per Year = \$576

Therefore,

$$\text{Recordkeeping} = 6 \times \$576 = \$3,459$$

The total cost of the Monitoring Plan was estimated to be a combination of scenario 1 and scenario 2. Taking the average of the two costs yields an annual cost of about \$8,723,290.

$$\text{Cost of Monitoring Plan} = \frac{\text{Cost of Scenario 1} + \text{Cost of Scenario 2}}{2}$$

| |
|--|
| Cost of Monitoring Plan = (\$6,592,207 + \$10,831,367) / 2 + \$3,459 = \$8,723,290 |
|--|

Table B-2 summarizes the costs and reductions associated with the provisions of the proposed regulation.

M. Indirect Costs

While the direct regulatory costs of the proposed regulation can be estimated using the anticipated cost of each control strategy multiplied by the number of units that will be affected, the indirect costs and economic impacts are modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). This analysis was performed and discussed as part of the SRIA (Attachment E). Although the proposed regulation is different than the SRIA analysis, the results and conclusions of the analysis are still relevant given that the anticipated overall cost of the proposed regulation not only remains similar in magnitude to the cost used in the SRIA analysis, but the magnitude of the direct impacts of the proposed regulation as well as the SRIA are small compared to the overall size of the California economy.

N. Alternatives

Staff considered four alternatives to the proposed regulation that would be less burdensome to the affected industry. These alternatives are not the same as the alternatives in the Environmental Analysis, since those alternatives address reducing the environmental impacts of the proposed regulation while these alternatives address Administrative Procedure Act considerations. It is important to note that these alternatives are in addition to those that staff considered at the SRIA phase of this regulation, which are identified in that document. ARB staff conducted a detailed economic analysis only of options 1 and 2, since these were the most viable of the potential alternatives. The clear policy limitations and uncertain costs associated with alternatives 3 and 4 (given their flexible and unknown implementation paths) precluded a more detailed economic evaluation of those options.

1. Alternative 1: No Action. The Oil and Gas Regulation is Not Enacted

The first alternative is to not propose the regulation. Obviously, this would be less burdensome to the industry. However, this alternative does not achieve the goal of reducing methane emissions from the oil and natural gas production, processing, and storage sector. Accordingly, this alternative was rejected.

a) Costs and Benefits

Alternative 1 would impose no additional costs on consumers or manufacturers. In this scenario the impacted sectors would fall under the federal EPA guidelines of 40 C.F.R. Part 60, Subpart OOOO (Quad O).

b) Economic Impacts

Since Alternative 1 does not impose any additional costs to industries or consumers, there would be no economic impacts relative to the current conditions. Compared to the proposed regulation, there would be no changes in GSP, personal income, private investment, or other economic indicators. There would be no reduction of GHG emissions, VOCs, or other airborne toxics.

c) Cost per ton

Alternative 1 has no cost as it does not impose any fiscal costs or regulatory costs that may be associated with the development and enforcement of the proposed amendment.

d) Reason for Rejection

Alternative 1 does not sufficiently meet the goals of the proposed regulation, which is to reduce GHG emissions from the oil and gas industry. Therefore, it is not a viable alternative to the proposed amendment.

2. Alternative 2: Implement the Oil and Gas Regulation Without the LDAR Provision

The second alternative is to not propose the LDAR requirement in the regulation. This provision of the proposed regulation affects the most facilities and can be a labor intensive control measure. However, it also is the provision that achieves the largest amount of emission reductions, accounting for more than a third of the anticipated methane emission reductions. LDAR is also at the heart of catching small leaks before they become larger leaks. In addition, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that the anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

a) Costs and Benefits

If the proposal was adopted with the provisions in the SRIA, the total cost would be about \$13.8 million per year, and reduce emissions by about 0.9 million MT CO₂e. This includes savings of about \$1.5 million per year due to mitigated emissions. Benefits to businesses and individuals would be negligible and commensurate with the current proposed regulation.

b) Economic Impacts

The economic impacts are described in detail in Appendix E, which contains the SRIA and the provisions of the Proposed Regulation. Although this alternative does not include LDAR, the conclusions of the SRIA are still valid, that the proposed regulation was unlikely to significantly impact California's economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from the BAU scenario.

c) Cost per ton

The cost per ton of Alternative 2 is estimated to be about \$15 per MT CO₂e reduced, using a GWP of 72. Although this is similar to the cost per ton of the current proposal, alternative 2 does not include LDAR.

d) Reason for Rejection

In addition to being a significant source of reductions, LDAR is also at the heart of catching small leaks before they become larger leaks. Also, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that the anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

3. Alternative 3: Performance-based Standard

Staff considered a performance-standard based alternative for the proposed regulation. Specifically, staff considered a performance-based mandate to regulated entities to reduce the vented and fugitive emissions from regulated sources, as of a date certain, by an amount commensurate with the expected reductions the proposed regulation is expected to produce. Staff rejected this alternative for several reasons, but worked to incorporate flexibilities into the proposed regulation where possible to support legislative direction to avoid prescriptive regulations where possible.

Reasons for rejecting a wholesale performance standard alternative include the following points. This proposed regulation is designed to reduce venting and fugitive emissions from the sector. These emissions are, by their nature, difficult to quantify in many cases, and come from a wide range of potential sources. A flat reduction mandate would be very difficult to enforce without more accurate baseline data on current emissions from these sources, at the facility and component level, than is now available – it is, in other words, far more effective to enforce a requirement to replace a certain piece of equipment, or follow a particular LDAR procedure, than a performance-based reduction requirement from an uncertain baseline. To ensure reductions occur, therefore, staff focused on providing uniform, clear standards for equipment and processes that could reliably be measured, implemented, and enforced. Further, because emission controls focusing solely on methane reduction could have contributed to criteria pollutant emissions if poorly implemented, or failed to secure maximum co-benefits of criteria and toxic pollutants, it was important to specify particular implementation requirements to produce better results on this metric as well.

But though staff rejected a performance standard alternative as a complete option, staff made significant efforts to provide options within the rule's directive framework to provide compliance flexibilities. For instance, regulated entities have several options as to how to implement vapor control device provisions, to conduct LDAR inspections, and to address equipment replacement or retrofit decisions. These embedded options within the proposed regulation help reduce compliance burdens, thereby fulfilling the legislative intent driving consideration of performance-based alternatives, while ensuring that emission reductions happen in an enforceable and environmentally appropriate manner.

4. Alternative 4: Emission Reduction Provision

Staff also considered including an emission reduction provision that would require operators to mitigate climate impacts of large methane leaks. In evaluating whether an emission reduction provision would be appropriate, staff considered several options, including increased penalties for operators of facilities where the leak occurred and an emission reduction plan providing ton-for-ton reductions or stricter monitoring requirements. Staff concluded that stiffer monitoring requirements were the most appropriate. Increased penalties were not an effective option since all prohibited leaks violate the proposed regulation and thus every violation is potentially subject to the maximum penalties statutorily allowed. A plan for reductions was deemed inappropriate at this time, for the following reasons: first, developing generally applicable requirements for such a plan – though somewhat specified in the mitigation plan developed for the Aliso Canyon leak – is a difficult regulatory task when generalized to any potential facility, and so would likely delay the regulation and associated methane reductions.

Furthermore, ARB has considerable authority to drive appropriate mitigation via its existing enforcement authorities and settlement authority. Therefore, rigorous monitoring provisions, rigorously enforced, were deemed appropriate for this proposed regulation. ARB will continue to consider the issue, however, and may revisit this decision in future rulemakings.

O. Fiscal Impacts

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

ARB staff estimates that the regulation will require 6 PYs to implement depending on the mix of district and ARB implementation. In addition to PYs, ARB will need to purchase equipment including three IR cameras at \$85,000 each, and three toxic vapor analyzers at \$10,000 each. The costs are higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The total cost to ARB is estimated to be \$285,000 in initial costs ((3 X \$85,000) + (3 X \$10,000)), and about \$870,000 in ongoing costs (6 X \$145,000). These costs are anticipated to be imposed during the 2017/2018 fiscal year.

1. Other State Agencies

The proposed regulation does not affect other state agencies.

2. Air Districts

A local air district may decide – but is not obligated -- to be the primary agency responsible for enforcing the provisions of the Proposed

Regulation. This includes issuing permits for new control equipment, registration and inspection of equipment, and enforcing the LDAR portion of the regulation. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over \$300,000 per year in recurring costs and almost \$1,000,000 in one-time costs, primarily for permitting. Even if the districts do decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation. The costs to districts are estimated to be approximately \$1,300,000 in initial costs, and approximately \$660,000 in ongoing costs.

Although local agencies (air districts) may choose to implement this regulation, and certain aspects of it may be incorporated in permits as a matter of preexisting law, resulting in some fiscal impacts, the regulation imposes no reimbursable mandates. Air districts face no new legal requirements specific to them under this regulation. As to implementation tasks they may take on or any other costs that may result by operation of statute, air districts have legal authority under Health and Safety Code sections 40510 and 42311 to recover related costs by imposing fees. The Proposed Regulation also specifies that local air districts that choose to enforce the regulation may retain any penalty monies that result. ARB also may make arrangements to further support air districts as a voluntary matter. Thus, because the regulation applies generally to all entities operating affected sources, not the air districts, and so does not impose unique new requirements on local agencies, this is not a reimbursable mandate. (*County of Los Angeles v. State of California*, 42 Cal. 3d 46 (1987)).

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement. ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or

reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.



EDMUND G. BROWN JR. ■ GOVERNOR

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May 28, 2015

Ms. Emily Wimberger
Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Wimberger:

Thank you for submitting the standardized regulatory impact assessment (SRIA) and the summary (Form DF-131) for the proposed regulations on reducing greenhouse gas emissions from crude oil and natural gas operations, as required in California Code of Regulations, title 1, section 2002(a)(1).

Based on the April 22, 2015 draft regulations, sources at oil and natural gas production, processing, and storage facilities would be required to reduce methane in support of AB 32—Global Warming Solutions Act of 2006. Affected facilities are expected to achieve compliance through installations of equipment by 2018. Other requirements such as periodic testing, reporting, and recordkeeping of methane and hydrocarbon emissions; and timely repair of leaking components would take effect by 2017. Requirements at each facility would depend on existing equipment and local air district requirements on the same sources. While local authorities would have some flexibility, these proposed regulations are an attempt to bring all facilities up to a minimum standard.

In addition to the health and environmental benefits to individuals, industries that supply control devices benefit when the regulated facilities purchase equipment to comply with the new standards. According to the SRIA, the annualized cost of the proposed regulations peaks at \$18.8 million in 2017, assuming the affected facilities can amortize the costs. This, together with equipment spending, would result in an increase of \$54.3 million in gross state product, thus meeting the major regulations threshold of \$50 million a year. There would, however, be small reductions overall in growth rates of gross state product thereafter.

Finance, in general, concurs with the methodology used to assess the economic impact of the proposed regulation. The SRIA was particularly well constructed in relating the direct impacts of the proposed regulation to the overall impacts. However, it would be helpful to include the magnitude of the unit and total costs of devices and the geographical distribution of the affected facilities. Since the majority of retrofit costs are expected to occur in 2018, the highest direct cost and economic impact should occur in 2018, not in 2017 as described in the SRIA. While the SRIA does comply with the requirement to discuss alternatives, it would be helpful to include the direct cost of each alternative in the SRIA, rather than just the overall impacts. Finally, ARB may want to discuss how an individual facility's characteristics, such as emission rates and existing control devices, may affect the calculation of direct costs, and thus economic impacts of the proposed regulations. These existing efforts also determine the amount of emissions reductions that would be achieved.

These comments are intended to provide sufficient guidance outlining revisions to the SRIA. The SRIA, a summary of Finance's comments, and any responses must be included in the rulemaking file that is available for public comment. Finance understands that the proposed regulations may change during the notice of proposed action, after the public comment period, and following the ARB Board hearing. If any significant changes to the proposed regulations result in economic impacts not discussed in the SRIA, please note that the revised economic impacts must be reflected on the Standard Form 399 for the rulemaking file submittal to the Office of Administrative Law. Please let us know if you have any questions regarding our comments.

Sincerely,



Irena Asmundson
Chief Economist

cc: Ms. Panorea Avdis, Governor's Office of Business and Economic Development
Ms. Debra Cornez, Office of Administrative Law
Ms. Trini Balcazar, Air Resources Board
Ms. Chantel Crane, Air Resources Board
Ms. Elizabeth Scheehle, Air Resources Board
Mr. Craig Segall, Air Resources Board

Response to DOF Comments

Comment #1

It would be helpful to include the magnitude of unit and total costs of devices, and the geographical distribution of the affected facilities.

Most of the affected facilities are in the San Joaquin Air Pollution Control District. According to ARB's 2009 survey, over 60% of the affected LDAR components are located in the San Joaquin APCD. Other districts with a significant amount of affected facilities include Santa Barbara APCD, South Coast APCD, Feather River APCD, and Glen County APCD. The magnitude of unit and total costs of devices is described in detail in the cost analysis section of this Appendix.

Comment #2

Since the majority of retrofit costs are expected to occur in 2018, the highest direct cost and economic impact should occur in 2018, not in 2017.

The standards were set to be effective January 1, 2018 and it was anticipated that the capital costs would occur prior to that, in 2017. Since the effective date of the standards requiring the purchase of capital equipment has been changed to 2019, the majority of retrofit and other capital equipment is estimated to take place in 2018.

Comment #3

Include the direct cost of each alternative in the SRIA, rather than just the overall impacts.

At the time of the SRIA, the first alternative included a requirement that existing continuous-bleed pneumatic devices to be replaced with no-bleed devices. It also required an LDAR inspection program with quarterly inspections. These alternatives were eventually incorporated into the existing proposed regulation. The direct costs for this alternative were estimated to be about \$28 million per year with an emissions reduction of about 500,000 MT CO₂e. The second alternative eliminated the LDAR provision, the centrifugal compressor provision, and added a leak standard for rod packing replacement. This alternative was estimated to cost about \$20 million per year with an emissions reduction of about 450,000 MT CO₂e. Since the SRIA, better data has become available and through development of the regulation, several of the provisions have changed, and incorporated parts of each alternative. Due to these changes, a direct comparison of the costs and emissions is difficult to make.

Comment #4

Discuss how an individual facility's characteristics, such as emission rates and existing control devices, may affect the calculation of direct costs, and thus economic impacts of the Proposed Regulations.

Generally, the emission rates and number of affected devices are proportional to the estimated cost of compliance. Some facilities, which may not be subject to an existing LDAR program, may exhibit greater emissions than those that are under an existing LDAR program for VOC. These facilities may have a greater amount of emissions, or super leaking components. This would increase the cost minimally, but would be more cost effective.

Some facilities may also have an existing flare connected to a separator and tank system. In these cases, the flare would need to be removed to install a low NO_x incinerator. This would be an additional cost for these facilities. The impact is expected to be minimal. Facilities with a tank and separator system with emissions under 10 tons per year of CH₄ emissions would not be required to install vapor recovery and would have less overall cost than facilities with greater than 10 tons per year of CH₄ emissions.

State of California
AIR RESOURCES BOARD

**PUBLIC HEARING TO CONSIDER THE PROPOSED REGULATION FOR
GREENHOUSE GAS EMISSION STANDARDS FOR
CRUDE OIL AND NATURAL GAS FACILITIES**

STAFF REPORT: INITIAL STATEMENT OF REASONS

DATE OF RELEASE: May 31, 2016
SCHEDULED FOR CONSIDERATION: July 21, 2016

Location:

California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

ACKNOWLEDGEMENTS

This report was prepared with the assistance and support from many individuals within the Air Resources Board. Staff would like to acknowledge the cooperation from numerous State and local governmental agencies that have provided invaluable assistance throughout the rulemaking process. Staff would also like to acknowledge the contributions from our key stakeholders.

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EXECUTIVE SUMMARY

Background

Climate change is one of the most serious environmental threats facing the world today, and California is already feeling the effects. California has committed to take action to address the threat. Under AB 32, the California Global Warming Solutions Act of 2006, ARB was identified as the state agency charged with monitoring and regulating sources of greenhouse gas emissions that cause climate change. Methane emissions control is critical to fulfilling this mandate because these emissions are not yet declining, putting continued pressure on the GHG emissions limit, as well as on any efforts to achieve deeper reductions. Both the 2008 Climate Change Scoping Plan and the subsequent First Update to the Climate Change Scoping Plan identified the oil and gas sector as a large source of GHG emissions and include the regulation of oil and gas operations covered in the proposed regulation as a potential GHG mitigation measure to help achieve the statute's goals.

Short-lived climate pollutants (SLCP), including methane (CH₄), are among the most harmful to both human health and global climate. They are powerful climate forcers that remain in the atmosphere for a much shorter period of time than longer lived climate pollutants such as carbon dioxide (CO₂). Their relative climate forcing (or impact), when measured in terms of how effectively they heat the atmosphere, can be tens, hundreds, or even thousands of times greater than that of CO₂.¹ While reducing CO₂ emissions impacts climate change over the long term, reducing emissions of SLCPs will effectively slow the rate of climate change in the near-term; therefore, reducing these emissions can have an immediate beneficial impact on climate change.

Methane is a particularly effective SLCP and is the second largest man-made contributor to GHG emissions globally. Methane is 72 times more potent than CO₂ as a GHG when considered on a twenty year time frame. Methane is responsible for about 20 percent of current global warming and is emitted from a wide range of sources with emissions increasing globally as a result of human activities related to agriculture, waste handling and treatment.² Oil and gas systems are responsible for approximately 15 percent of methane emissions in the state. The recently proposed SLCP strategy includes a forty percent reduction of methane by 2030 with a 40-45% reduction from the oil and gas sector as a whole by 2025.

The proposed regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (proposed regulation) is designed to reduce emissions from both upstream (production, gathering and boosting stations, and processing) and some downstream facilities (natural gas storage and transmission compressor

¹ IPCC. 2007. Direct Global Warming Potentials. Chapter 2, 10.2.

² Kirschke, S. et al. 2013. Three Decades of Global Methane Sources and Sinks. Nature Geoscience.vol. 6, 813-823.

stations), which account for about four percent of statewide methane emissions.³ GHG emissions from oil and gas pipelines and related facilities are being addressed in a separate regulatory effort in partnership with the California Public Utilities Commission (CPUC)⁴.

What are we proposing?

The proposed regulation will reduce methane emissions from oil and gas production, processing, storage, and transmission compressor stations by requiring regulated entities to take actions to limit intentional (vented) and unintentional (leaked or fugitive) emissions from active and idle equipment and operations. Some methane reductions are already achieved as co-benefits of local air district regulations governing emissions of volatile organic compounds (VOC); methane is not considered to be a VOC but can be captured along with VOCs. The goal of the proposed regulation is to obtain the maximum GHG emission reductions from the sector in a technically feasible and cost-effective manner, building upon the existing regulations already being implemented by the air districts. The source categories covered under the proposed regulation currently emit approximately two and a half million metric tonnes (MMT) of CO₂e. The proposed regulation will reduce those emissions by over fifty percent. The proposal is also expected to reduce both VOC and toxic air contaminant (TAC) emissions and provide an essentially neutral NO_x impact statewide.

The provisions of the proposed regulation are:

1. Collection and use (or destruction) of methane and associated gases from uncontrolled oil and water separators and storage tanks with emissions above a set methane standard;
2. Collection and use (or destruction) of methane and associated gases from all uncontrolled well stimulation circulation tanks;
3. Leak Detection and Repair (LDAR) requirements for components, such as valves, flanges, and connectors, currently not covered by local air district rules;
4. Methane emission standards for large reciprocating compressors in addition to LDAR for the other large compressor components and smaller compressors;

³ Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations.

⁴ More information on the CPUC effort can be found at: California Public Utilities Commission (CPUC). 2015. Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M144/K999/144999228.PDF>

5. Collection and use (or destruction) of methane and associated gases from specified centrifugal compressors, or replacement of higher emitting “wet seals” with lower emitting “dry seals”;
6. Use of “No bleed” pneumatic pumps and “no bleed” continuous bleed pneumatic devices with limited exemptions and restrictions on intermittent bleed pneumatic devices; and
7. Enhanced monitoring for underground natural gas storage facilities including leak detection and ambient air monitoring.
8. Reporting requirements for liquids unloading and well casing vents

Why are we proposing this action?

Methane emissions from the oil and gas industry contribute to California’s greenhouse GHG emissions and cost-effective reduction opportunities already exist and are available for use in the sector. In addition, reducing methane emissions from this sector will help slow the rate of climate change in the near-term and have an immediate beneficial impact on climate change because methane is a powerful SLCP.

Who will be subject to the proposed regulation?

Owners and operators of equipment used in the following operations will be subject to the proposed regulation:

- Onshore and offshore crude oil or natural gas production, including well stimulation activities;
- Crude oil, condensate, and produced water separation and storage;
- Natural gas underground storage;
- Natural gas gathering and boosting stations;
- Natural gas processing plants;
- Natural gas transmission compressor stations.

Oil and gas companies, public utilities, and engineering service providers are among the largest companies that would be directly impacted.

Who will enforce the regulation?

Because stationary sources in this sector have historically been regulated by local air districts, ARB staff worked with the California Air Pollution Control Officers Association (CAPCOA) and individual air districts to design the proposal so it can be implemented and enforced by both ARB and the districts. ARB staff expects that most local air districts will choose to take the lead in implementing and

enforcing the regulation, with ARB serving as the backup agency, and it is our preference that the rule is implemented and enforced in this manner. However, ARB is prepared to take a lead implementation role in the event that the air district elects to let ARB serve in that role. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. As a result, the proposal was designed to allow local districts to enter into MOUs with ARB to define implementation and enforcement responsibilities, and to share information. The proposed regulation also provides for districts to incorporate the proposed regulation into their local rules. Upon its adoption, the proposal becomes a State regulation enforceable by ARB. This limits the ability of air districts to implement less stringent requirements. ARB anticipates continuing to work closely with local air districts to ensure adequate support for the proposed regulation's implementation and enforcement.

What are the costs of the proposed regulation?

The proposed regulation would increase costs on the complying industries, which are primarily involved with oil and gas extraction. These industries pay for control equipment and services from secondary industries but may also achieve operational cost savings through recovery of natural gas captured by the proposed control strategies. ARB staff estimates the proposed regulation will cost about \$22 million dollars per year including enhanced natural gas storage monitoring. The proposed regulation is expected to reduce GHG emissions by about 1.5 MMT CO₂e per year based on a 20-year horizon global warming potential (GWP). The cost per ton of CO₂e reduction is estimated to be about \$17 without considering savings and \$15 after savings, based on a 20-year GWP. Considering the size and diversity of the California economy, the economic impacts of the proposed regulation on the California economy are negligible, including the impact on growth of employment, investment, personal income, and production.

What are the benefits of the proposed regulation, including for Environmental Justice and Disadvantaged Communities?

Communities located in close proximity to oil and gas operations experience impacts related to these operations. Additionally, these communities are at risk for exposure to a variety of volatile organic compounds and toxics air contaminants, which are associated with oil and gas operations. Local air districts currently implement a variety of rules that reduce volatile organic compounds from the oil and gas industry with a co-benefit of methane reductions.

The proposed regulation would provide additional benefits in reductions of air pollutants including about 1.5 million metric tons of CO₂e, over 3,600 tons of VOCs, and over 100 tons of toxic air contaminants annually. The majority of all these reductions will occur in the San Joaquin Valley. Although the purpose of the regulation is to reduce methane emissions, the proposed regulation was designed

to provide co-benefits and minimize or eliminate any other potential air quality impacts. While there is an essentially neutral impact on NOx emissions statewide, there is expected to be a slight decrease in NOx emissions in the San Joaquin Valley from current conditions. The San Joaquin Valley Air Pollution Control District (SJVAPCD) has notified ARB that they are considering adopting a flare minimization rule that would achieve NOx reductions from similar sources. ARB will continue to work closely with the district to monitor the development of regulations from the plan and address any remaining NOx concerns.

Table of Contents

| | |
|--|------------|
| Table of Contents | i |
| LIST OF ACRONYMS | iii |
| I. INTRODUCTION | 1 |
| A. BACKGROUND CLIMATE CHANGE PROGRAMS | 1 |
| B. BACKGROUND – AIR DISTRICTS | 4 |
| C. CALIFORNIA’S OIL AND NATURAL GAS RESOURCES | 4 |
| D. OVERVIEW OF EMISSIONS AND REDUCTIONS | 9 |
| E. DEVELOPMENT PROCESS FOR THE PROPOSED REGULATION | 12 |
| F. ORGANIZATION OF THIS REPORT | 14 |
| II. STATEMENT OF REASONS | 15 |
| A. DESCRIPTION OF PROBLEM PROPOSAL IS INTENDED TO ADDRESS | 15 |
| B. PROPOSED SOLUTIONS TO THE PROBLEM – BACKGROUND | 15 |
| C. PROPOSED SOLUTIONS TO THE PROBLEM – CONTROL MECHANISMS | 25 |
| D. SUMMARY OF ESTIMATED EMISSION BENEFITS | 29 |
| E. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION | 31 |
| III. ALTERNATIVES TO THE PROPOSED SOLUTION. | 84 |
| A. ALTERNATIVE 1 – No Action | 84 |
| B. ALTERNATIVE 2 – Implement the Regulation without the LDAR Provision | 84 |
| C. ALTERNATIVE 3 – Performance-based Standard | 84 |
| D. ALTERNATIVE 4 - Emission Reduction Provision | 85 |
| IV. FUNDING, IMPLEMENTATION, PERMITTING AND ENFORCEMENT | 86 |
| A. FUNDING FOR IMPLEMENTING AND ENFORCING ARB’S PROPOSED OIL AND GAS REGULATION .. | 86 |
| B. PERMITTING AND ENFORCEMENT | 87 |
| V. TECHNICAL ASSESSMENT | 89 |
| A. DEVELOPMENT OF METHANE EMISSION STANDARDS | 89 |
| VI. JUSTIFICATION FOR ADOPTION OF REGULATIONS DIFFERENT FROM FEDERAL REGULATIONS CONTAINED IN THE CODE OF REGULATIONS | 109 |
| VII. AIR QUALITY | 111 |
| A. OVERVIEW | 111 |
| VIII. ENVIRONMENTAL ANALYSIS | 117 |

| | |
|--|------------|
| A. HEALTH IMPACTS | 119 |
| IX. ENVIRONMENTAL JUSTICE | 121 |
| X. ECONOMIC IMPACTS | 122 |
| A. SUMMARY OF PROPOSED COSTS AND IMPACTS | 122 |
| B. MAJOR REGULATIONS | 122 |
| C. ECONOMIC IMPACTS ASSESSMENT..... | 126 |
| D. COST EFFECTIVENESS | 126 |
| E. IMPACTS TO CALIFORNIA, STATE, OR LOCAL AGENCIES | 132 |
| XI. REFERENCES, TECHNICAL, THEORETICAL, AND/OR EMPIRICAL STUDY, REPORTS, OR DOCUMENTS RELIED UPON | 135 |
| Appendix A: Proposed Regulation Order | A-1 |
| Appendix B: Economic Analysis..... | B-1 |
| Appendix C: Environmental Analysis | C-1 |
| Appendix D: Calculation of Emissions Estimates | D-1 |
| Appendix E: Standardized Regulatory Impact Assessment | E-1 |

LIST OF ACRONYMS

| | |
|-------------------|--|
| AAQS | Ambient Air Quality Standards |
| AB | Assembly Bill |
| APCD | Air Pollution Control District |
| AQMD | Air Quality Management District |
| ARB or Board | California Air Resources Board |
| BAU | Business as Usual |
| BLM | Bureau of Land Management |
| BTEX | Benzene, Toluene, Ethylbenzene, and Xylenes |
| Cal/EPA | California Environmental Protection Agency |
| CAPCOA | California Air Pollution Control Officers Association |
| CDFW | California Department of Fish and Wildlife |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| CH ₄ | Methane |
| CO | Carbon Monoxide |
| CO ₂ | Carbon Dioxide |
| CO ₂ e | Carbon Dioxide Equivalents |
| CPUC | California Public Utilities Commission |
| CPUC | California Public Utilities Commission |
| CTG | Control Technology Guidance |
| DOF | Department of Finance |
| DOGGR | Department of Conservation, Division of Oil, Gas, and Geothermal Resources |
| EA | Environmental Analysis |
| EIA | U.S. Energy Information Administration |
| EPA | U.S. Environmental Protection Agency |
| F-gases | Fluorinated Gases |
| GHG | Green House Gas |
| GSP | Gross State Product |
| GWP | Global Warming Potential |
| H ₂ S | Hydrogen Sulfide |
| HAP | Hazardous Air Pollutant |
| HC | Hydrocarbon |
| HF | Hydraulic Fracturing |
| HFC | Hydro-fluorocarbon |
| I&M | Inspection and Maintenance |
| ICF | ICF International |
| ISOR | Initial Statement of Reason |
| LDAR | Leak Detection and Repair |
| MCF | Thousand Cubic Feet |
| MMT | Million Metric Tonnes |
| MOA | Memoranda of Agreement |
| MOU | Memorandum of Understanding |

| | |
|-----------------------|---|
| MRR | Mandatory Reporting Regulation |
| MT | Metric Ton |
| MTCH ₄ /Yr | Metric Ton of Methane per Year |
| N ₂ O | Nitrous Oxide |
| NAAQS | National Ambient Air Quality Standards |
| NG | Natural Gas |
| NGO | Non-governmental Organization |
| NO _x | Nitrogen Oxides or Oxides of Nitrogen |
| NSPS | New Source Performance Standard |
| OGI | Optical Gas Imaging |
| PM | Particulate Matter |
| PYs | Person Years |
| RACT | Reasonably Available Control Technology |
| REC | Reduced Emissions Completion |
| REMI | Regional Economic Models, Inc. |
| RWQCB | Regional Water Quality Control Boards |
| SB | Senate Bill |
| scfh | Standard Cubic Feet per Hour |
| scfm | Standard Cubic Feet per Minute |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| SLCP | Short Lived Climate Pollutants |
| SO ₂ | Sulfur Dioxide |
| SoCal Gas | Southern California Gas |
| SO _x | Sulfur Oxides or Oxides of Sulfur |
| SRIA | Standard Regulatory Impact Assessment |
| SRIA | Standardized Regulatory Impact Assessment |
| TAC | Toxic Air Contaminant |
| TPY | Tons Per Year |
| UIC | Underground Injection Control |
| USDA | U.S. Department of Agriculture |
| USFWS | U.S. Fish and Wildlife Service |
| VCS | Vapor Collection System |
| VOC | Volatile Organic Compounds |
| VRS | Vapor Recovery System |
| VRU | Vapor Recovery Unit |
| WS | Well Stimulation |
| WSPA | Western State Petroleum Association |

I. INTRODUCTION

A. BACKGROUND CLIMATE CHANGE PROGRAMS

1. AB 32

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32 (AB 32), The California Global Warming Solutions Act of 2006 (Health & Safety Code §§38500-38599). AB 32 requires a reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020 and designates the California Air Resources Board (ARB) as the lead agency for implementing AB 32. AB 32 provided direction and broad authority to create a comprehensive multi-year program to limit California's GHG emissions and initiate the transformations required to achieve the State's long-range climate objectives.

AB 32 charges ARB with achieving statewide GHG emissions targets by 2020, with maintaining that target, and with continuing the maximum technologically feasible and cost-effective GHG reductions going forward. As part of the strategy to reach and maintain the 2020 emission target, and secure continued reductions, ARB identified the oil and gas sector as a large source of GHG emissions – primarily methane. Both the 2008 Climate Change Scoping Plan and the subsequent First Update to the Climate Change Scoping Plan include the regulation of oil and gas operations covered in the proposed regulation as a potential GHG mitigation measure. Unless methane emissions, which now continue at high levels, are controlled, they will put continued pressure on the statewide GHG limit, as well as complicate any efforts to achieve deeper emissions reductions in the future. Steps therefore must be taken to control these emissions in order to fulfill AB 32's mandates.

Accordingly, this regulation covers upstream emissions (production, gathering and boosting stations, and processing) as well as natural gas storage and transmission compressor stations (collectively "oil and gas"). This regulation does not cover the petroleum refining sector. Further, GHG emissions from oil and gas pipelines and related facilities are being addressed in a separate regulatory effort in partnership with the California Public Utilities Commission (CPUC).

In 2009, ARB initiated a survey of the oil and gas industry, collecting information on sources such as compressor seals, storage tanks, valves, flanges, and connectors. The survey included combustion related emissions from equipment (equipment burning fuel for energy) as well as vented and fugitive sources, which are intentional and unintentional releases of gases to the atmosphere, respectively. The survey is the most comprehensive dataset that exists for California's oil and gas industry. No other dataset, federal or statewide, contains as much detailed information about the industry in the state. The findings from this survey provide the basis for the proposed

regulation, which reduces vented and fugitive emissions from oil and gas production, processing, storage, and transmission compressor stations. ARB has incorporated additional or supplemental data where appropriate.

2. Short Lived Climate Pollutants

Short-lived climate pollutants (SLCP), including methane (CH₄), black carbon (soot), and fluorinated gases (F-gases, including hydro-fluorocarbons, or HFCs), are among the most harmful to both human health and global climate. They are powerful climate forcers that remain in the atmosphere for a much shorter period of time than longer lived climate pollutants such as carbon dioxide (CO₂). Their relative climate forcing (or impact), when measured in terms of how they heat the atmosphere, (see explanation of global warming potential in footnote 10) can be tens, hundreds, or even thousands of times greater than that of CO₂.⁵ While reducing CO₂ emissions limits climate change over the long term, reducing emissions of SLCPs will help slow the rate of climate change in the near-term; therefore, reducing these emissions can have an immediate beneficial impact on climate change.

Methane has a global warming potential 72 times that of CO₂, on a 20-year timeframe, and is the principal component of natural gas⁶. Methane emissions also contribute to background ozone in the lower atmosphere. Such ground-level ozone not only contributes to ground level “smog” but ozone is also a powerful GHG.

Methane, the second largest anthropogenic, or man-made contributor to GHG emissions globally, is emitted from a wide range of fugitive sources and biological processes. Methane emissions are increasing globally as a result of human activities related to agriculture, waste handling and treatment, and oil and gas production, and are responsible for about 20 percent of current global warming.⁷ Agriculture represents the largest methane source in California, accounting for nearly 60 percent of methane emissions (Figure 1). Landfills are the next largest source of methane at 20 percent of statewide methane emissions. Oil and gas systems contribute approximately 13 percent of statewide methane emissions, with wastewater treatment and other industrial and miscellaneous sources comprising the remainder of emissions. The proposed regulation is designed to reduce methane emissions from upstream and some downstream oil and gas activities within

⁵ See footnote 1.

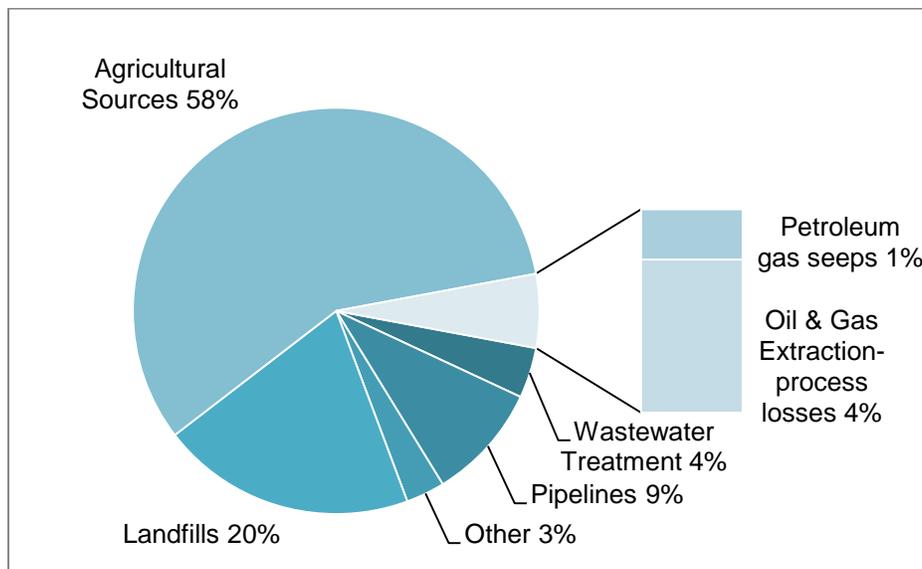
⁶ Staff used the 20 year global warming potential from the Fourth Assessment Report, which is 72. The Fifth Assessment report estimates methane is at least 84 times as potent as carbon dioxide on a 20 year timeframe. IPCC. 2008. Climate Change 2007. Synthesis Report. IPCC Fourth Assessment Report: Climate Change 2007. http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_full_report.pdf And IPCC. 2015. Climate Change 2014. Synthesis Report. IPCC Fifth Assessment Report: Climate Change 2014. http://ar5-syr.ipcc.ch/ipcc/resources/pdf/IPCC_SynthesisReport.pdf

⁷ See footnote 2.

California, which accounts for about four percent of statewide methane emissions⁸.

The regulation supports a larger, on-going, effort to reduce short-lived climate pollutants. Pursuant to Senate Bill 605 (SB 605) (Health & Safety Code § 39730), ARB is proposing a comprehensive approach to reduce methane through the proposed Short-lived Climate Pollutant Reduction Strategy.⁹ As noted in that report, ARB is proposing to reduce methane emissions from oil and gas systems (oil and gas production, processing, storage, and natural gas transmission and distribution) by 40-45 percent in 2025, matching federal commitments. Thus, the proposed regulation helps to achieve the goals identified in the proposed SLCP Reduction Strategy.

Figure 1: California 2013 Methane Emission Sources (118 MMTCO₂e)¹⁰



⁸ Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations. In Figures 6 and 7, Oil and Gas Extraction process losses includes all the upstream emissions, not just production.

⁹ ARB. 2016. Proposed Short-Lived Climate Pollutant Reduction Strategy in California.

¹⁰ See footnote 9. Using the 20-yr global warming potential from the IPCC's Fourth Assessment Report (AR4) for methane. The Intergovernmental Panel on Climate Change (IPCC) developed the concept of global warming potential (GWP) as an index to evaluate the climate impacts of different GHGs, including SLCPs. This metric provides a comparison of the ability of each GHG to trap heat in the atmosphere relative to CO₂ over a specified time horizon. Current practice in most of the world for developing GHG emission inventories, including California's GHG inventory, is to use GWP values from the 4th Assessment Report of the IPCC (AR4), which was released in 2007. California's inventory generally uses GWPs over a 100-yr timeframe. However, the use of GWPs with a time horizon of 20 years better captures the importance of the SLCPs and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO₂ emission controls. Thus, the emission inventory and estimated reductions presented later in this ISOR are calculated using 20-year GWP for methane.

B. BACKGROUND – AIR DISTRICTS

Under State law, ARB and local air districts operate within a cooperative legal framework for controlling air pollution from a variety of sources. There are 35 air districts as shown in Figure 2. Each jurisdiction's authority is based on the type of air pollutants and sources involved.

For smog-forming pollutants including volatile organic compounds, or VOCs, ARB has authority over mobile and area wide sources, such as vehicles, fuels, and consumer products, while the local districts have responsibility over stationary sources, including oil and gas operations. For portable equipment, the State shares jurisdiction with the air districts.

There are two significant exceptions to this general framework. First, with regard to greenhouse gases, AB 32 gives ARB broad authority to regulate GHGs from both mobile, stationary, and area wide sources. This regulation would be implemented under AB 32 as mentioned earlier. The other major area where ARB has authority over stationary sources involves toxic air contaminants, where the regulation of toxic air contaminants is a responsibility shared by ARB and the local districts.

For air districts with significant oil production, each district has rules aimed to reduce particulate matter less than 2.5 microns in diameter (PM_{2.5}) as well as oxides of nitrogen (NO_x) and volatile organic compound (VOC) emissions specifically from the oil and gas sector. These rules do not regulate methane directly from the sector, so the proposed regulation is designed to address those sources that are not controlled by existing district rules. ARB has used the district rules as a starting point, particularly for leak detection and repair, where districts have been implementing programs for decades.

C. CALIFORNIA'S OIL AND NATURAL GAS RESOURCES

Methane emissions from California's oil and gas sector are substantial in part because the state is a large oil and gas producer. The top crude oil producing states are Texas, North Dakota, California, Alaska, New Mexico, and Colorado, representing a combined two-thirds of the total crude oil production in the U.S in September 2015.¹¹ Texas is also the largest natural gas producer in the U.S.;¹² California is at number fifteen on the natural gas producer list, based on 2014 data. According to the U.S. Energy Information Administration (EIA), California ranked third in the nation in crude oil production in 2014, despite an overall decline in production rates in California since the mid-1980s (excluding Federal offshore areas).

¹¹ U. S. EIA. 2015. Rankings: Crude Oil Production, December 2015 (thousand barrels).

¹² U. S. EIA. 2014. Rankings: Natural Gas Marketed Production, 2014 (million cu ft).

California has nine main petroleum systems,¹³ named for the rock where the resource has been generated (source rock) that produce crude oil and natural gas (Table 1). The most prolific oil-producing area in California is the San Joaquin Basin¹⁴ in the southern half of the Central Valley; natural gas reserves and production are located primarily in geologic basins in the Central Valley, the coastal basins onshore in Northern California and offshore along the Southern California Coast. The Monterey Formation, which stretches across the lower part of the state, is the primary source of oil and gas resources in California.

Table 1: California’s main petroleum systems

| Name | Type | General Location |
|-------------|-------------|--|
| Monterey | oil | Los Angeles, Ventura, Santa Maria, and San Joaquin Basins, and Point Arena, Mendocino County |
| Eel River | gas | Humboldt Basin |
| Kreyenhagen | oil | San Joaquin Basin |
| Miocene | oil | Los Angeles, Santa Barbara, Ventura, and Santa Maria Basins Offshore |
| Moreno | oil | San Joaquin Basin |
| Forbes | gas | Sacramento Basin |
| Starkey | gas | Sacramento Basin |
| Hornbrook | gas | Sacramento Valley |
| Domengine | gas | Sacramento and San Joaquin Valleys |

Oil production in California has been occurring since before 1900, and much of the remaining reserves require additional effort to produce including enhanced oil production techniques such as steam-enhanced production, and well stimulation treatments such as acid fracturing, acid matrix and hydraulic fracturing. Oil production in California generally produces large volumes of water and may contain “associated gas” (gas dissolved in oil and produced as a byproduct of crude oil production). California also produces gas not associated with oil production, referred to as both non-associated gas and dry gas. Non-associated gas may produce some natural gas condensate, which is a gaseous hydrocarbon mixture that condenses out of the natural gas when the pressure is sufficiently reduced. The condensate includes butane, propane, and other substances.

¹³ A petroleum system includes all those geologic elements and processes that are essential for an oil and gas deposit to exist in nature. These basic elements include a petroleum source rock, migration path, reservoir rock, seal, and trap; and the geologic processes that create each of these basic elements. (USGS. 1988. Petroleum Systems of the United States.)

¹⁴ A basin is a low area in the Earth's crust, of tectonic origin, in which sediments have accumulated (USGS. 1980. Definitions for the Geologic Provinces.). Hydrocarbon generation can occur within the basin if the source rocks are rich hydrocarbon and occur at an appropriate depth, temperature, and pressure.

California has a large oil and gas industry with more than 50,000 oil and 1,500 gas wells, including offshore platforms. Figure 2 depicts the above-noted oil and natural gas producing regions of California. Each dot on the map represents a currently permitted well in operation as of February 2016. The majority of the oil wells are located in Central and Southern California with most of the gas fields located in Northern California. An extensive network of oil and gas pipelines within the State transports California’s natural gas and crude oil throughout the State.

The San Joaquin Valley Air Pollution Control District (APCD) is home to seven of the top ten largest oil fields in California. Combined, these seven oil fields produced 60 percent of the State’s total oil production in 2014.¹⁵ In addition, five fields in Kern County produced nearly 70 percent of the state’s associated gas in 2014.

California’s remaining top oil producing fields are in the South Coast Air Quality Management District (AQMD), Monterey Bay Unified APCD, and Ventura County APCD and produce 11 percent of the state’s total oil production. The top producing non-associated gas fields are located in northern California are in Yolo-Solano, Glenn, Colusa, and Feather River air districts, and produce almost 60 percent of the state’s total non-associated gas.¹⁶ The air districts and the oil and gas facility types within each district are depicted in Figure 2.

Below are the preliminary 2014 state totals for oil and gas production in California, both onshore and offshore.

Table 2: Preliminary 2014 California oil and gas production levels ¹⁷

| Oil (bbl)* | Associated gas (Mscf)** | Non-associated gas (Mscf) | Water (bbl) | Condensate (bbl) |
|-------------|-------------------------|---------------------------|---------------|------------------|
| 205,287,622 | 159,511,531 | 34,963,640 | 3,264,502,956 | 68,471 |

*Unit of volume for crude oil and petroleum products. One barrel equals 42 US gallons.

**Thousand cubic feet

¹⁵ DOGGR. 2015. 2014 Preliminary Report of California Oil and Gas Production Statistics.

¹⁶ Ibid.

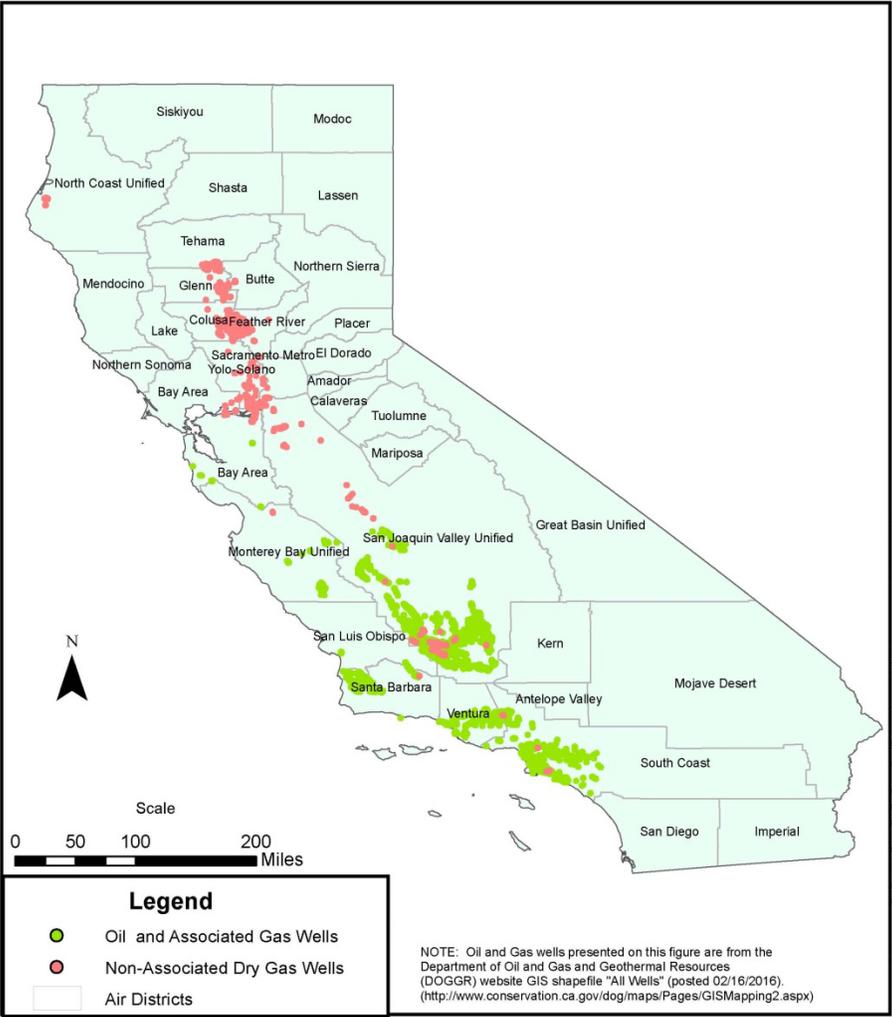
¹⁷ Ibid.

Figure 2: Oil and Natural Gas Industry Sector by Air District



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Figure 3: California Non-Associated Natural Gas Wells & Oil and Associated Gas Wells



D. OVERVIEW OF EMISSIONS AND REDUCTIONS

GHG emissions occur throughout the oil and gas sector, from production through processing and transmission and distribution. Emissions occur from intentional emissions (venting) that is part of normal operations including open tanks and equipment venting for safety or operational reasons. Emissions can also be due to unintentional leaks that occur at covered tanks, valves, or other components throughout the system. The details on the emissions covered under the proposal are outlined in the Technical Assessment chapter, as well as Appendix D.

As noted, the local air districts have rules and regulations to limit VOC and NO_x emissions because they are precursors of ground-level ozone. Many of the VOC controls also reduce methane as a co-benefit, since both VOCs and methane are found in the raw oil and gas and controlling VOCs will also reduce methane emissions. However, the district rules do not apply once the gas has been processed to the point that not many VOCs remain in the gas (generally less than 10%). For remaining gas streams that have fewer VOCs, the proposed regulation will reduce methane with a co-benefit of reducing the remaining VOCs as well. In 2015, U.S. EPA proposed additional federal measures that could address methane primarily at new oil and natural gas sources, with coverage at some existing sources, finalizing these measures in 2016. These additional actions to reduce methane from the oil and gas sector should also reduce VOC and toxic air contaminant emissions. In 2016, U.S. EPA announced efforts to consider similar measures for existing sources but that measure is in the information gathering stage.¹⁸

In recent years, there has been a significant amount of literature published on emissions from the oil and gas sector. Several studies have suggested that methane emissions are underestimated from this sector based on atmospheric studies.^{19,20} However, some recent literature supports U.S. EPA's oil and gas emissions estimates and at least one sector specific study focused on distribution pipelines found lower emissions than expected.²¹ In April 2016, U.S.EPA adjusted their GHG emission estimates for the sector with significant increases in the production sector and decrease for transmission and distribution.²² ARB staff has reviewed this recent information at a high level and believes that the proposed regulation is consistent with the revised numbers, and there is a sufficiently robust and defensible basis for this proposal. ARB's in-depth industry survey provided much more information than is available at the federal level, and U.S.EPA's estimates were similar or larger for most of the

¹⁸ U. S. EPA. 2016. Reducing Methane Emissions from the Oil and Gas Industry.

¹⁹ Brandt, A. R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.

²⁰ Miller, S. M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013

²¹ Allen, David T., et al. 2015. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.

²² U. S. EPA. 2016. U.S. Greenhouse Gas Inventory Report: 1990-2014.

sectors controlled to be under this proposed regulation, which would result in similar or more cost-effective measures.

Implementing the measures in the proposed regulation would reduce methane emissions by 40-45 percent in 2025. Additional opportunities may emerge to further reduce emissions and will be considered when they do.

1. Super Emitters

Emissions from components are not distributed uniformly throughout the sector, recent studies of natural gas facilities have shown a significant fraction of methane emissions can be attributed to a small fraction of sites or sources.^{23 24 25 26 27 28} The emissions associated with these “super-emitters” are thus important to detect and repair. Figure 4 below, illustrates one production sector example where, according to Allen et al, the top 19% of emitting pneumatic devices accounts for 95% of the emissions from pneumatics. Studies investigating methane emissions from super emitters in the natural gas system have most recently been conducted outside of California. Efforts by ARB and the California Energy Commission (CEC) are underway to investigate such emissions by using aircraft to conduct a survey of methane sources in California, including oil and gas.

²³ See footnote 19.

²⁴ See footnote 21.

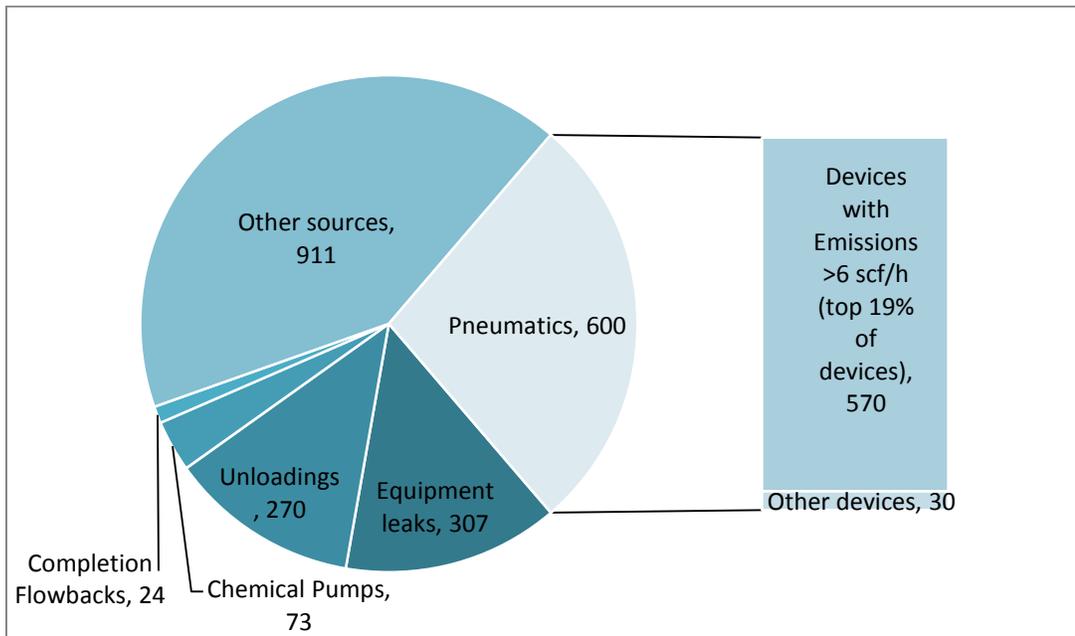
²⁵ Lamb, Brian K. et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. *Environmental Science & Technology*.

²⁶ Zavala- Araiza, Daniel, et al. 2015a. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. *Environmental Science & Technology*. Vol. 49, Pages 8167–8174. .

²⁷ Zavala- Araiza, Daniel, et al. 2015b. Reconciling divergent estimates of oil and gas methane emissions. *Proceedings of the National Academy of Sciences (PNAS)*.

²⁸ Zimmerle, Daniel J., et al. 2015. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. *Environmental Science & Technology*.

Figure 4: Methane Emission by Component, Oil and Natural Gas Systems.²⁹



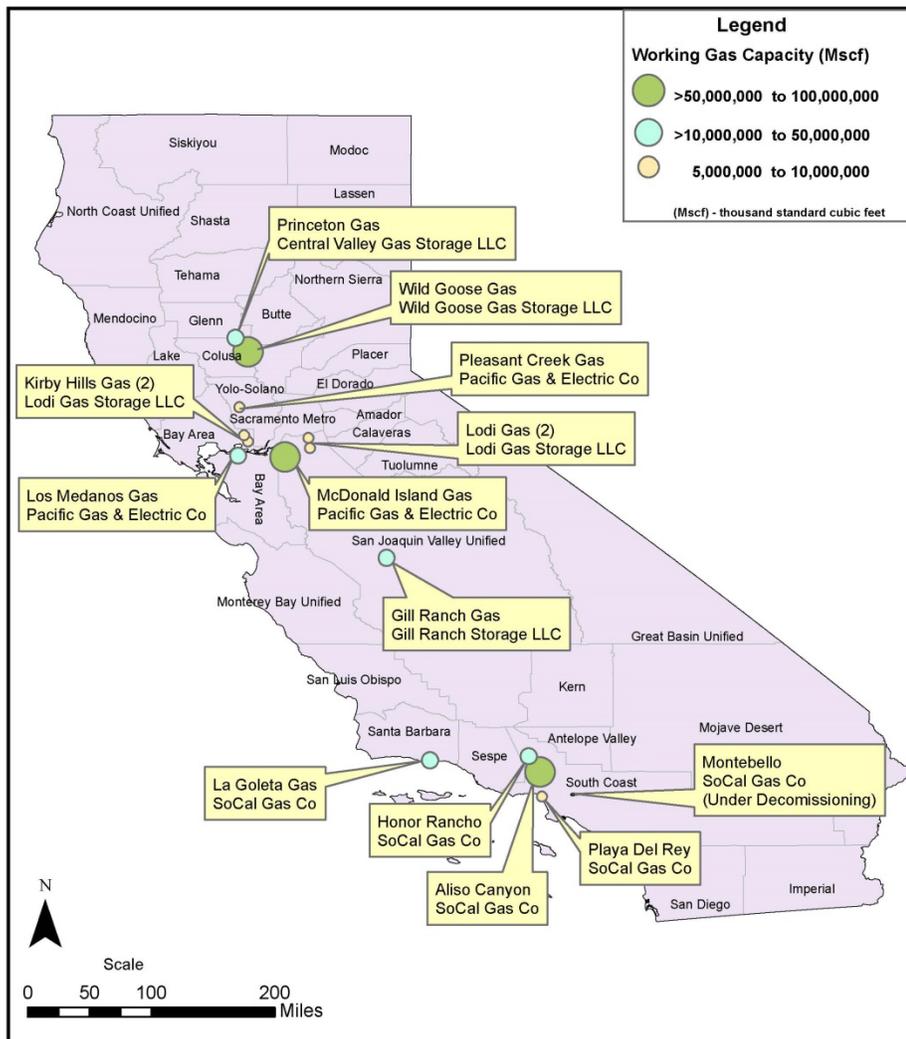
2. Aliso Canyon

In addition to super-emitters, very large unusual and unexpected leaks can occur. One recent example is the incident at Aliso Canyon. On October 23, 2015, Southern California Gas (SoCal Gas) informed the State of a natural gas leak at its Aliso Canyon natural gas storage facility. After several attempts to stop the leak, on February 11, 2016, SoCalGas temporarily controlled the leak by injecting mud from a relief well intersecting the bottom of the leaking well. February 18, 2016, state officials, including the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), confirmed the well has been permanently sealed. However, preliminary measurements suggest a total of 94,500 tons of methane was released.³⁰ Because of this incident, ARB has clarified requirements and added an additional provision to the proposed regulation specifying monitoring for the early detection of leaks.

²⁹ See footnote 21.

³⁰ ARB. 2016. Aliso Canyon Natural Gas Leak. Preliminary Estimate of Greenhouse Gas Emissions (As of April 5, 2016). http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_April_5_2016.pdf

Figure 5: California Natural Gas Storage Facilities, Operating Utility, and Air District Boundaries



E. DEVELOPMENT PROCESS FOR THE PROPOSED REGULATION

Staff evaluation of methane emissions from the oil and gas sector began with the 2009 Survey, noted earlier, with an acknowledgement of the importance of the oil and gas sector in the original Scoping Plan. Staff conducted a comprehensive, detailed survey of the industry, which provided a basis for regulatory development. During the informal rulemaking process, Staff conducted multiple public workshops and numerous meetings with individual stakeholders. Below is a timeline of the public actions taken leading to this proposal. Each of the meetings below included opportunities for public comment, which were considered when developing the proposed regulation.

Table 3: Dates of Development Meetings and Workshops

| Date | Meeting |
|------------------|--|
| April 11, 2008 | Workshop on Regulatory Concepts |
| 2009 | Conducted Survey |
| December 8, 2009 | Workshop on Survey Results |
| December 2011 | Posted Survey Results Report |
| November 2013 | Posted Revised Survey Results Report |
| August 25, 2014 | Oil and Gas Rulemaking Workshop #1 |
| December 9, 2014 | Oil and Gas Rulemaking Workshop #2 |
| April 27, 2015 | Oil and Gas Rulemaking Workshop #3 with Proposed Draft Regulatory Language (Sacramento) |
| April 29, 2015 | Oil and Gas Rulemaking Workshop #4 with Proposed Draft Regulatory Language (Bakersfield) |
| February 4, 2016 | Oil and Gas Rulemaking Workshop #5 with Proposed Draft Regulatory Language (Sacramento) |

For each of the rulemaking meetings, over 4000 individuals or companies were notified and invited to participate. Each of these meetings was well attended by a variety of stakeholders, representing oil and gas production and processing companies, natural gas storage facilities, public utilities, non-governmental organizations (NGOs), and other State agencies. Notices for the workshops and associated materials, were posted to ARB's Oil and Gas webpage at: <http://www.arb.ca.gov/cc/oil-gas/oil-gas.htm>, and emailed to subscribers of our "oil and gas" listserve. All rulemaking workshops were streamed to remote attendees by webcast.

In addition to the public meetings, staff held many meetings with stakeholders, attended relevant meetings; conducted district, industry, and NGO working group meetings, and exchanged technical information with various parties on a regular basis. The proposal benefitted from the extensive feedback based upon these communication.

Staff also conducted a Standardized Regulatory Impact Assessment (SRIA). As required by Senate Bill 617 (Chapter 496, Status of 2011), ARB conducted a

SRIA and received public feedback and comments from the Department of Finance.

As part of the SRIA process, ARB solicited public input on alternative approaches, including any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost. The SRIA summary is included as Attachment E and posted at:

http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/Major_Regulations/documents/Oil_and_Gas_SRIA.PDF

F. ORGANIZATION OF THIS REPORT

The remainder of this report is organized into 11 chapters with 5 appendices. It begins with a background chapter followed by a description of the proposed regulation with the summary and rationale, description of the implementation and funding, description of other related mandates, a technology assessment, an environmental assessment, and an economic assessment. The appendices include the proposed regulation order, economic analysis, environmental analysis, emission estimate calculations, and the standardized regulatory impact analysis (SRIA).

II. STATEMENT OF REASONS

A. DESCRIPTION OF PROBLEM PROPOSAL IS INTENDED TO ADDRESS

ARB has identified the oil and gas sector as a large source of GHG emissions. Both the 2008 Scoping Plan and the subsequent First Update to the Scoping Plan include the regulation of oil and gas operations covered as a potential GHG mitigation measure. Unless emissions from the sector are controlled, they will continue to be substantial, making it more difficult to maintain the state GHG emission limit imposed by AB 32, and will also complicate efforts to further reduce emissions, as AB 32 and multiple executive orders require. Emissions of fluorinated gases are projected to grow rapidly through 2030. Similarly, current projections indicate methane will not decline in the absence of successful methane control measures. If ARB does not take near-term action to stop methane emissions growth, it will be increasingly difficult to maintain the 2020 greenhouse gas limit, much less continue progress. Accordingly, methane emissions from the sector must be reduced. This regulation covers upstream emissions (production, gathering and boosting stations, and processing) as well as natural gas storage and transmission compressor stations. GHG emissions from petroleum refineries are not covered under this proposal, and oil and gas pipelines and related facilities are being addressed in a separate regulatory effort conducted by the California Public Utilities Commission (CPUC) in partnership with ARB.

Methane, the second largest man-made contributor to GHG emissions globally, is emitted from a wide range of fugitive sources and biological processes. Methane emissions are increasing globally because of human activities related to agriculture, waste handling and treatment, and oil and gas production. Cumulatively, methane emissions are responsible for about 20 percent of current global warming.³¹

In California, oil and gas systems are responsible for approximately 15 percent of methane emissions in the State. The proposed regulation is designed to reduce methane emissions from upstream and some downstream oil and gas activities within California, which accounts for about four percent of statewide methane emissions³².

B. PROPOSED SOLUTIONS TO THE PROBLEM – BACKGROUND

The following sections illustrate and describe, in plain English, various aspects of the oil and gas sector in California.

³¹ See footnote 2.

³² Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations.

1. Oil and Gas Processes Addressed by the Proposed Regulation

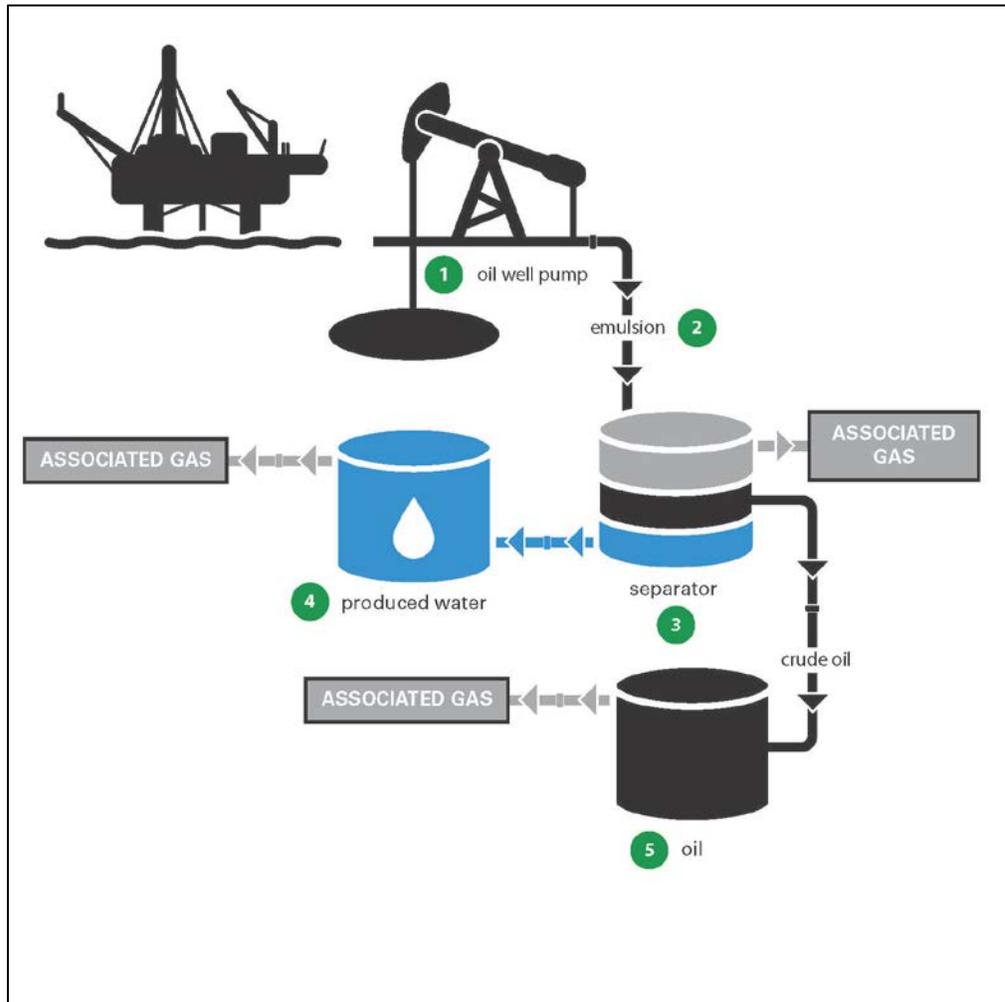
The proposed regulation addresses vented and fugitive emissions generated by processes at facilities in the following sectors:

- Onshore and offshore crude oil or natural gas production,
- Crude oil, condensate and produced water separation and storage;
- Natural gas gathering and boosting stations;
- Natural gas processing plants;
- Natural gas transmission compressor stations; and
- Natural gas underground storage.

The proposed regulation establishes emission standards for active and idle equipment and components at these facilities. Depending on the equipment or component, control mechanisms include vapor recovery, leak detection and repair (LDAR), and equipment replacement. Additionally, the proposed regulation includes monitoring at underground natural gas storage facilities for the early detection of large leaks or well failures. Storage facility monitoring provisions were added to the proposed regulation in response to the catastrophic release that occurred at the Aliso Canyon natural gas storage facility in late 2015-early 2016.

The following sections describe the crude oil and natural gas systems that are addressed in the proposed regulation and identify the equipment and components at each facility covered under the proposed regulation. These systems are further illustrated in Figures 6 through 9. Parenthetical numbers in the text refer to the figure and associated number. For example: (6, 1) refers to component 1 on Figure 6 (oil well pump), while 8-3 refers to component 3 on Figure 8 (water/condensate tank).

Figure 6: Diagram of a Crude Oil System



a) Oil and Gas Production

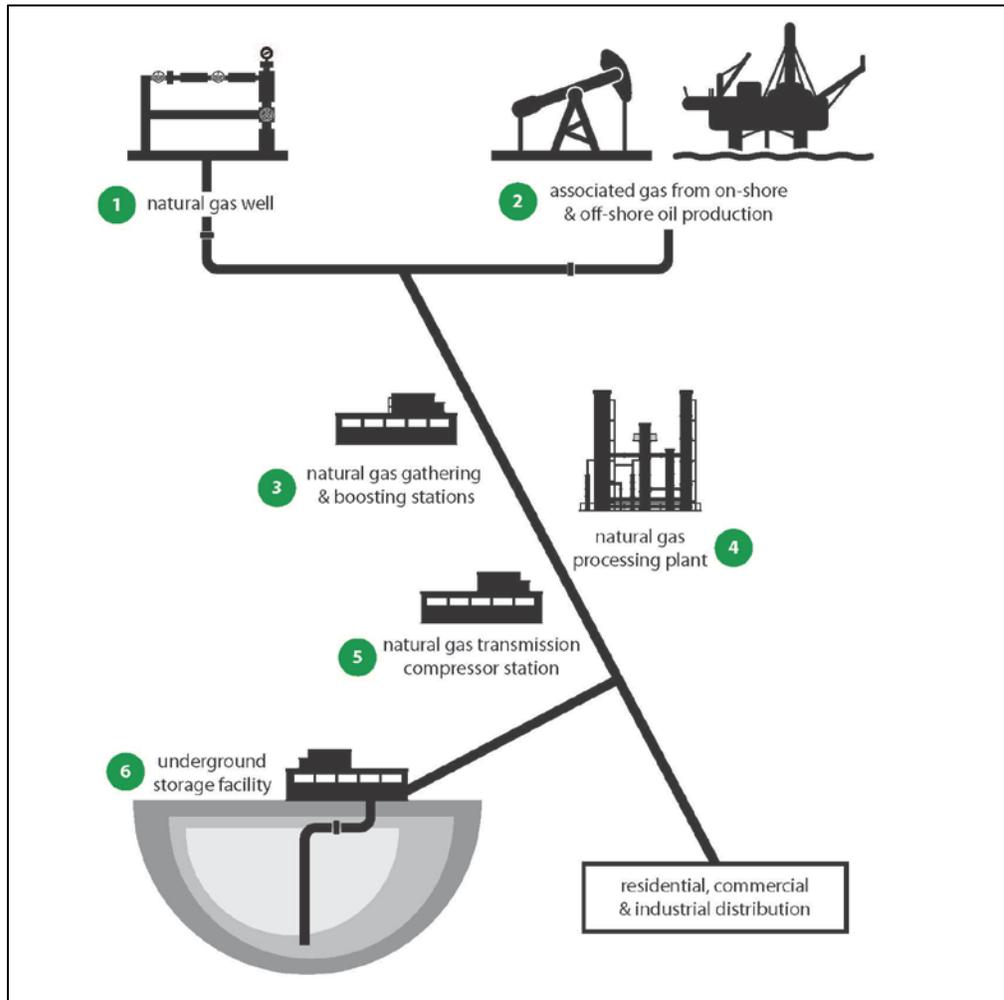
Onshore wells are drilled on a prepared surface known as a drill or production pad (6, 1). During well drilling, tanks are most commonly used to temporarily collect drilling fluids; however, a temporary pit or sump may be constructed to contain drilling fluids. Once a well has been drilled and cemented, the well completion phase begins. Well completions on a new well include casing, cementing, perforating, gravel packing, and installing a production tree. Once the casing is perforated, well stimulations such as acid fracturing, acid matrix, or hydraulic fracturing may be conducted. Well stimulation operations are performed on hydrocarbon producing wells for purposes of enhancing production by increasing the permeability of the geologic formation. These operations include the use of well stimulation fluids which can include acids such as hydrofluoric acid or a variety of other chemicals. If well stimulation occurs, a flush of the well and reservoir may recover

fluids (Figure 9) that include reservoir emulsion, well stimulation treatment fluid, additives, and produced water. Recently adopted regulations, California Code of Regulations Section 1786 (a)(4), prohibit the storage of well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment in sumps or pits; all such fluids, must be stored in containers.

The most common well stimulation treatment used in California is hydraulic fracturing. The proposed regulation would require controls on “circulation tanks” (8, 2), which are tanks or portable tanks used to circulate, store, or hold liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment. They are used to clean out sand from the system after hydraulic fracturing. The potential control methods required in the proposed regulation include a vapor recovery system, which would be subject to leak detection and repair (LDAR). Well stimulation treatments occur primarily on new crude oil production wells in California.

An oil well is completed with a pumping unit (unless it is free flowing), and connected by piping (flow lines and gathering lines) (6, 2) to production facilities that may include separators (6, 3), tanks (6, 4-5), and testing and shipping facilities. Depending on the type of recovery method used, there may also be facilities for generating and distributing steam, and injection wells for injecting steam and/or water. After an oil or gas well is put into production, an emulsion is brought to the surface. The emulsion primarily includes oil, water, and often associated gas. Flow lines or a bulk header carries the emulsion from the wellhead to a central processing facility or production platform. This combination of components is referred to as the gathering system; it will be subject to LDAR under the proposed regulation. The gathering system feeds into the oil and gas separation system.

Figure 7: Diagram of a Natural Gas System



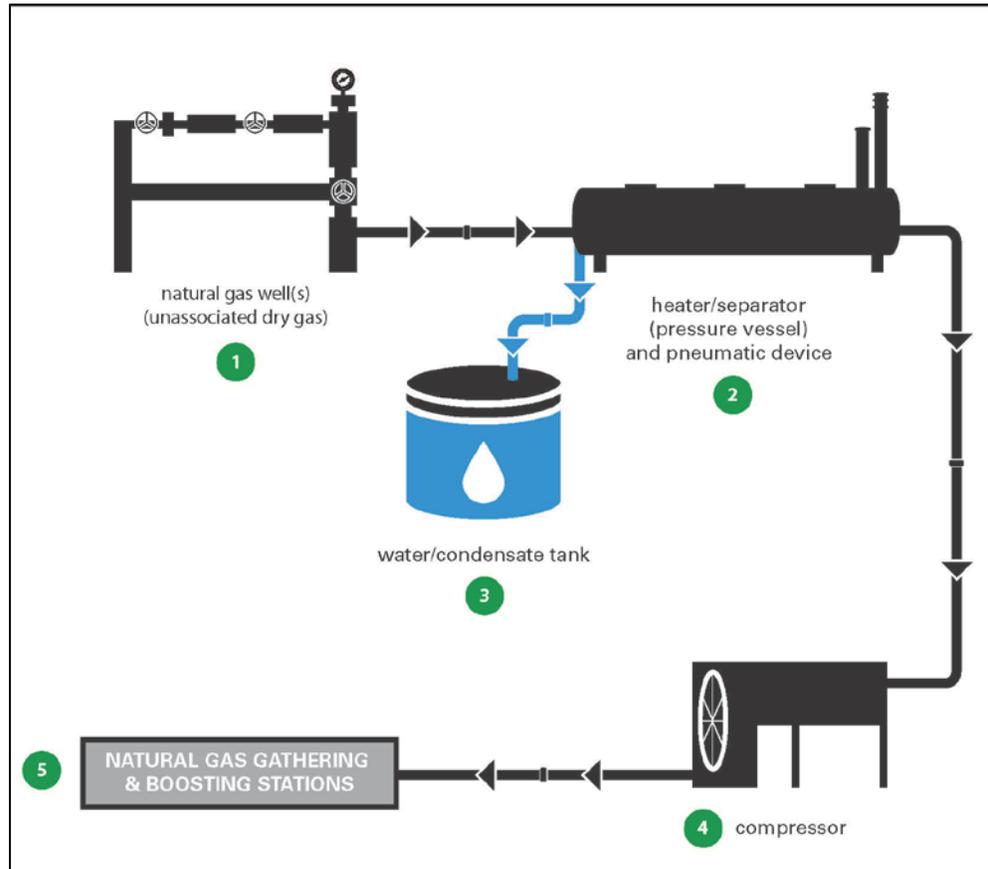
A dry gas well (8, 1) is completed with piping (flow lines and gathering lines) to a heater/separator (pressure vessel) (8, 2). The wellhead, piping and pressure vessel will be subject to LDAR under the proposed regulation. The emulsion produced from the well primarily includes gas, water, and condensate; however, in California condensate is not generally found in large volumes.

The emulsion flows from the wellhead to the heater/separator where water is separated from the gas. Emulsions from dry gas wells are often routed to one heater/separator. Piping moves wastewater to a water storage tank where, if present, residual condensate is separated out by gravity (8, 3). The gas is then routed to a compressor (8, 4) to be moved from the production facility to the gathering and boosting station (7, 3).

The wellhead, piping, pressure vessel, and compressor will be subject to LDAR under the proposed regulation. Pneumatic devices are used

for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature at gas production facilities and will also be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

Figure 8: Diagram of a Typical Natural Gas Well



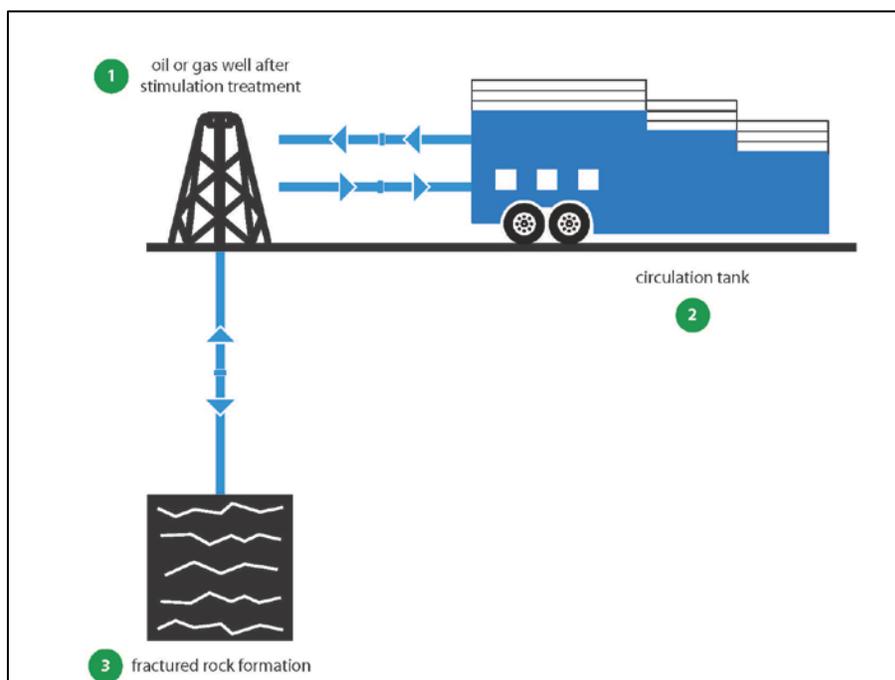
b) Liquids Unloading

Over time, dry gas wells accumulate liquids that can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production, removal of fluids (e.g., liquids unloading) is required in order to maintain production. Gas flow is maintained by removing accumulated fluids, through the use of specialized equipment installed in the well such as velocity tubing or a plunger lift system, or with the use of remedial treatments such as swabbing, soaping, or by venting the well to atmospheric pressure (referred to as “blowing down” the well)³³. The proposed regulation would require that vented natural gas from liquids unloading

³³ U. S. EPA. 2006. Installing Plunger Lift Systems in Gas Wells. Office of Air and Radiation: Natural Gas Star Program. Washington, DC.

be measured or calculated and reported, if the liquids unloading operation is not utilizing a 95% effective vapor collection system.

Figure 9: Diagram of a Circulation Tank for Well Stimulation Treatments



c) Crude Oil, Condensate, and Produced Water Separation and Storage

The purpose of the separation system is to process the emulsion into clean marketable products such as oil, natural gas, or condensates, while separating out water and other debris. For example, in crude oil production the separation system (6, 3) allows the emulsion to separate into associated gas, crude oil, and produced water. (6, 4) There are several types of separators that may be used, depending on the type of operations. They include pressure vessels, free water knockouts, gravity separators, and wash tanks.

The crude oil production separator allows for an initial separation that splits the stream into a gas component (associated gas), a liquid crude component, and a water component. This process is generally achieved through a series of vessels where associated gas is allowed to flash, or bubble out, and water to settle at the bottom, with oil taken out from the middle. Potentially large amounts of gas flash off at this point. Once the production separation has been completed, crude oil (6, 5) and associated gas are usually stored briefly onsite in order to stabilize flow between production wells and pipeline or trucking transportation sites. Produced water is either cleaned up and re-used for other purposes or stored for disposal. When stored at the production facility, crude oil, associated gas, and produced water are

kept in storage tanks or sumps (produced water only). The proposed regulation establishes an emissions standard for the separator and tank systems, which includes the separator and first water and first oil tank. The water tank could be sump for produced water.

Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. More detail on vapor collection systems and LDAR is available in section II.C.1.-2. in this document.

Pneumatic devices and pumps are widespread throughout oil and natural gas operations, including in the separator and tank systems. At crude oil production facilities, pneumatics are generally operated using compressed air or electricity; however, high-pressure natural gas may be used to operate the devices. These devices are used to maintain a process condition such as liquid level, pressure, pressure differential, and temperature. Additionally, compressors and pneumatics are used to move associated gas from the separator system along to the gas pipeline.

Natural gas operated pneumatic devices and pumps will be subject to LDAR under the proposed regulation, and in certain circumstances, may warrant replacement. Compressors will also be subject to LDAR. Pneumatic devices and pumps not operated by natural gas are not subject to the proposed regulation.

d) Natural Gas Gathering and Boosting Stations

Gathering and boosting stations collect gas from multiple wells and move it toward the natural gas processing plant. Equipment and components at these facilities include compressors to increase the pressure of gas in the pipeline from the relatively low pressure coming from the production fields to medium pressure; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate.

The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at gathering and boosting stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard.

In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded.

Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, may warrant replacement under the proposed regulation.

e) Natural Gas Processing Plants

Natural gas processing plants process raw natural gas and separate the various hydrocarbons and fluids from the raw natural gas, to produce what is known as "pipeline quality" dry natural gas. Natural gas used by consumers is composed almost entirely of methane. The raw natural gas commonly exists in mixtures with other hydrocarbons depending on the source of the natural gas (i.e. associated gas from crude oil production or dry gas) and reservoir characteristics, including: ethane, propane, butane, pentanes, the BTEX chemicals (benzene, toluene, ethylbenzene, and xylenes), water vapor, hydrogen sulfide (H₂S), carbon dioxide, helium, nitrogen, and other compounds. This process is analogous to the processing and refining of crude oil but less complicated.

The proposed regulation covers a subset of equipment at these facilities, focusing on large methane sources. The proposed regulation does include requirements for: compressors to move gas; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate, and other components. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas processing plants. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is

exceeded. Natural gas-operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation. Other components are also subject to LDAR.

f) Natural Gas Transmission Compressor Stations

Natural gas-transmission compressor stations, function to move gas further down the pipeline by either increasing the pressure of gas in the pipeline from the medium pressure coming from the gathering and boosting stations to the high pressure of the transmission pipeline or maintaining the high pressure of the transmission pipeline when pipeline flow pressure decreases. Equipment at these facilities include: compressors to increase the pressure of gas; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas transmission compressor stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. Natural gas-operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

g) Natural Gas Underground Storage

Natural gas is most commonly stored underground under pressure in three types of facilities: depleted reservoirs in oil or natural gas fields, aquifers, and salt cavern formations. In 2014, California had 14 active natural gas underground storage sites and one undergoing decommissioning.³⁴ Most of the storage is used for system balancing and as a way to maintain steady and high-utilization of pipeline capacity. The remaining storage facilities are primarily used as depositories for gas produced within the state that is not immediately

³⁴ U. S. EIA. 2015. Underground Natural Gas Storage Capacity.
http://www.eia.gov/dnav/ng/ng_stor_cap_dc_u_sca_a.htm

marketable.³⁵ The wells located at these facilities may function in both a natural gas injection and withdrawal capacity. These wells may be newly constructed or repurposed oil or natural gas production wells. Additionally, abandoned or idle wells may be located at facilities where there was previous oil or natural gas production.

The proposed regulation would require that each underground storage facility be monitored to enable the early detection of well leaks and alert operators of potentially large releases of methane, like at the Aliso Canyon facility. This includes LDAR on components at the wellhead as well as continuous ambient air monitoring at the field. Storage facility monitoring requirements under the proposed regulation built upon the DOGGR's emergency regulation requirements and will replace that leak detection protocol once the plans are fully in place.

Additionally, equipment at these facilities covered under the proposed regulation include: (1) compressors to move gas; (2) pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and (3) water knock out tanks that store water and condensate. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas transmission compressor stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

C. PROPOSED SOLUTIONS TO THE PROBLEM – CONTROL MECHANISMS

This section describes the control mechanisms used by the proposed regulation and identifies components that may be part of the control mechanism that are covered under the proposed regulation. The table below serves as a summary of the control mechanisms used in each category, for quick reference.

³⁵ U. S. EIA. 2008. Underground Natural Gas Storage.
https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrnd_storage.html#western

Table 4: Control Mechanisms by Category

| Category | Equipment | Threshold | Control Mechanism |
|--|--|--|--|
| Onshore and offshore crude oil or natural gas production | wellhead | 2 | LDAR |
| | circulation tanks and liquids components | - | vapor control; LDAR |
| | gathering system ¹ | - | LDAR |
| | pressure vessel | - | LDAR |
| | reciprocating compressor | - | LDAR |
| | pneumatics | No bleed | LDAR; replacement |
| | liquids unloading | - | reporting |
| | Crude oil, condensate, and produced water separation and storage | separator and tank system | >10 metric tonnes per year CH ₄ |
| pneumatics | | No bleed | LDAR; replacement |
| reciprocating compressor | | - | LDAR |
| components | | - | LDAR |
| Natural Gas Gathering and Boosting Stations | separator and tank system | >10 metric tonnes per year CH ₄ | vapor control; LDAR |
| | pneumatics | No bleed | LDAR; replacement |
| | reciprocating compressor | >2 scfm ³ | repair or replace; LDAR |
| | components | - | LDAR |
| Natural Gas Processing Plants | separator and tank system | >10 metric tonnes per year CH ₄ | vapor control; LDAR |
| | pneumatics | No bleed | LDAR; replacement |
| | reciprocating compressor | >2 scfm | repair or replace; LDAR |
| | components | - | LDAR |
| Natural Gas Transmission Compressor Stations | separator and tank system | >10 metric tonnes per year CH ₄ | vapor control; LDAR |
| | pneumatics | No bleed | LDAR; replacement |
| | reciprocating compressor | >2 scfm | repair or replace; LDAR |
| | centrifugal compressor | >3 scfm | vapor control; LDAR |
| | components | - | LDAR |
| Natural Gas Underground Storage | wellhead | - | LDAR and enhanced monitoring |
| | separator and tank system | >10 metric tonnes per year CH ₄ | vapor control; LDAR |
| | pneumatics | No bleed | LDAR; replacement |
| | reciprocating compressor | >2 scfm | repair or replace; LDAR |
| | components | - | LDAR and enhanced monitoring |

1. e.g., piping, flow lines, gathering lines, or bulk header

2. "-" means that there is no threshold for the control mechanisms

3. standard cubic feet per minute

1. Vapor Collection System (VCS)

Vapor collection and recovery is the process of collecting the vapors entrained in produced water from crude oil production, or vapors from produced water from natural gas production, from tanks so they do not escape into the atmosphere. Recovered vapors are sent either to the sales gas or fuel gas system, injected underground, or flared/incinerated.

The proposed regulation specifies that collected vapors be required to go into an existing sales gas system, existing fuel gas system, or an existing underground injection well. If none of these systems is available, the vapors can go to an existing flare, provided it can still meet already permitted emission limits. In absence of existing systems, a new vapor control device is required and must meet the NO_x emission standard in the proposed regulation. This could include a low-NO_x³⁶ vapor control device or other non-destructive device³⁷. In areas classified as in attainment with all state and federal ambient air quality standards, devices would not have to meet the NO_x emission standard.

Vapor collection systems include gathering lines, compressors, and pneumatic devices and pumps; the entire system will be subject to LDAR under the proposed regulation. In addition, the proposed regulation establishes an emissions standard for non-field compressors, which, if exceeded, in addition to any applicable penalties, require the compressor be repaired, replaced, or the gas must be collected and routed into the vapor collection system. Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

2. Leak Detection and Repair

Leak detection and repair, or LDAR, describes the process of locating and repairing fugitive leaks, which are the unplanned losses of methane from pipes, flanges, seals, or through the moving parts of valves, pumps, compressors, and other types of equipment and components. The air districts within the major oil producing regions of the State have had LDAR programs, or Inspection and Maintenance (I&M) programs, for decades in order to reduce volatile organic compound (VOC) emissions. However, because of the focus on VOCs, current air district I&M programs do not cover components such as valves, flanges, seals, etc., that are primarily used in natural gas service. ARB staff estimates that of all of the components in the oil and gas sector, more than 80 percent are already covered by existing air district I&M programs to prevent the release of VOC emissions, whereas the

³⁶ A device that achieves 95 percent vapor control efficiency and does not generate more than 15 parts per million by volume NO_x when measured at 3% oxygen.

³⁷ A device that achieves 95 percent vapor control efficiency and does not result in emissions of nitrogen oxides (NO_x).

LDAR component of the proposed regulation is aimed at the remaining 20 percent of components.

In addition to requiring LDAR on the major equipment and components described in the previous section (i.e., compressors, pneumatics, storage tanks and separators), the proposed regulation will also require LDAR programs to include additional components. Some examples include:

- Valves used to either restrict or allow the movement of fluids,
- Connectors and fittings used to join piping and process equipment together,
- Sampling connections utilized to obtain samples from within a process, and
- Pressure relief devices designed to protect equipment from exceeding the maximum allowable working pressure.

The LDAR program will require the repair, retrofit, or replacement of leaking equipment and components and would require implementation of improved management practices for reducing vented emissions, such as keeping hatches, or other access point on storage tanks, closed and properly sealed during normal operation, or sealing open-ended lines and valves.

3. Equipment Replacement

The proposed regulation will require some equipment be replaced when it cannot be repaired to meet the established standards. For example, continuous bleed pneumatic devices³⁸ and pumps will likely be replaced with similar devices that meet the leak-free or no venting standard established in the proposed regulation. Existing intermittent pneumatic devices emitting below 6 scfh are exempt from this requirement.

In the event that additional vapors are collected and routed into an existing vapor control system operating a vapor control device (i.e., flare), the proposed regulation will require that the existing vapor control device be replaced with a new vapor control device, (unless the existing device is compliant with the low-NO_x requirements of the proposed regulation). This could include a low-NO_x vapor control device or other non-destructive device, unless the area is classified as in attainment with all state or federal ambient air quality standards in which case any device that achieves a 95 percent vapor control efficiency of total emissions would be allowed.

³⁸ Continuous bleed controllers, used to modulate flow, liquid level, or pressure, for which gas is vented continuously.

D. SUMMARY OF ESTIMATED EMISSION BENEFITS

The proposed regulation is designed to reduce methane emissions from specified oil and gas facilities within California. The proposed regulation would result in slight CO₂ emission increases (i.e., combustion of collected vapors); however, these emissions would be in lieu of the release of methane into the atmosphere, which has a substantially higher global warming potential (GWP) than CO₂. Implementation of the proposed regulation would result in monitoring (e.g., inspections, repairs) and reporting, as well as collection and disposal of methane vapors associated with oil and gas facilities. ARB estimates statewide GHG emission benefits of approximately 1,523,000 metric tons of CO₂ equivalents per year.³⁹

Table 5: Annual Methane Emissions and Reductions using the 20 and 100 year GWP

| | Total annual emissions (MT CO ₂ e, GWP=72) | Annual reductions from proposed regulation (MT CO ₂ e, GWP=72) | Total annual emissions (MT CO ₂ e, GWP=25) | Annual reductions from proposed regulation (MT CO ₂ e, GWP=25) |
|---|---|---|---|---|
| Separators and tanks | 566,000 | 538,000 | 197,000 | 187,000 |
| LDAR | 983,000 | 590,000 | 341,000 | 205,000 |
| Pneumatics | 319,000 | 319,000 | 111,000 | 111,000 |
| Reciprocating compressors | 504,000 | 68,000 | 175,000 | 24,000 |
| Centrifugal compressors | 3,700 | 3,500 | 1,300 | 1,200 |
| Well stimulation circulation tanks | 5,200 | 4,900 | 1,800 | 1,700 |
| TOTAL from sources subject to controls in the proposed regulation | 2,381,000 | 1,523,000 | 827,000 | 529,000 |
| Other upstream oil and gas sources not subject to controls in the proposed regulation ⁴⁰ | 1,047,000 | 0 | 364,000 | 0 |
| TOTAL | 3,428,000 | 1,523,000 | 1,191,000 | 529,000 |

³⁹ Using the 20-yr global warming potential, 72, from the 2007, IPCC Fourth Assessment Report: Climate Change report, for methane. Climate Change 2007. Synthesis Report. IPCC Fourth Assessment Report: Climate Change 2007. http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_full_report.pdf

⁴⁰ The proposed regulation covers a subset of emission sources within the oil and gas upstream sector. Although large in aggregate, these are generally smaller sources. Also includes remaining emissions from sources controlled by districts. For example tank measures are 95% effective so there are 5% of the original emissions remaining.

In addition to the GHG benefits, ARB estimates that the controls and associated compliance responses from the proposed regulation will also provide substantial statewide reductions of several toxic air contaminants and criteria air pollutants, including hydrocarbons, VOC's, and the BTEX suite of chemicals. ARB also estimated the net NO_x emissions impact of the proposed regulation. This analysis is described in detail in Appendix C: Environmental Analysis. The leak detection and repair requirements will result in minor increases in vehicle emissions; however, these are offset statewide by NO_x reductions the proposed regulation is achieving through increased use of low- NO_x vapor control devices. While ARB estimates an essentially neutral impact on NO_x statewide, in the San Joaquin Valley ARB estimates a NO_x benefit of 0.46 tons/year compared to current conditions.

Table 6: Statewide Non-GHG Air Emission Benefits

| Category | Total Hydrocarbons | VOCs | Benzene | Toluene | Ethyl-Benzene | Xylenes | NOx |
|--|---------------------------|-------------|----------------|----------------|----------------------|----------------|------------|
| TOTAL non-GHG benefits from proposed regulation (tons/year) | 27,837 | 3,627 | 62 | 29 | 4.6 | 23 | (<0.1) |

E. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION

In this chapter, ARB Staff provides a brief summary of the provisions included in the proposed regulation, explaining the rationale for each requirement.

1. Section 95665. Purpose and Scope.

Summary of Section 95665

This section states that the purpose of the regulation is to establish GHG emission standards for crude oil and natural gas facilities and that the regulation has been designed to serve the purpose of the California Global Warming Solutions Act as codified in Section 38500-38599 of the California Health and Safety Code.

Rationale for Section 95665

This section establishes that the proposed regulation will reduce GHG emissions at crude oil and natural gas facilities and provide reference under applicable ARB authority. The purpose of the proposed regulation is to set emissions standards and establish requirements to control fugitive and vented GHG emissions from oil and gas facilities. Controlled emissions are composed primarily of methane. Methane is a powerful GHG with a GWP 72 times that of carbon dioxide (on a 20-year timeframe), and is found in significant quantities at oil and gas facilities.

2. Section 95666. Applicability.

Summary of Section 95666

This section specifies the types of crude oil and natural gas facilities covered by the proposed regulation. The affected facilities include (1) Onshore and offshore crude oil or natural gas production facilities; (2) Crude oil and produced water separation and storage facilities; (3) Natural gas underground storage facilities; (4) Natural gas gathering and boosting stations; (5) Natural gas processing plants; and (6) Natural gas transmission compressor stations. The section specifies that owners and operators of these facilities must ensure that their facilities, equipment, and components are in compliance with the requirements of the proposed regulation at all times, and are jointly and severally liable for doing so.

Rationale for Section 95666

This section ensures that the proposed regulation will apply to all new and existing oil and gas facilities located within California and California waters, regardless of emissions level. This section also clarifies that owners and operators are jointly and severally liable if they do not comply, and that they

must maintain compliance continuously, which is necessary to ensure compliance with the regulations.

3. Section 95667. Definitions.

Summary of Section 95667

This section establishes definitions for the terms used in the proposed regulation. Establishing definitions for key terms provides clarity and specificity in the proposed regulation.

Rationale for Section 95667

It is necessary that ARB define its terms as they apply to the proposed regulation.

4. Section 95668. Standards.

Summary of Section 95668

This section specifies that the standards apply to all facilities listed in section 95666, and that exemptions to one standard do not provide an exemption to other required standards.

Rationale for Section 95668

This section is necessary to clarify that the standards in this section apply to all listed facilities, and to make clear that any available exemptions apply narrowly, and do not compromise emission reductions required by other applicable standards.

5. Section 95668(a). Separator and Tank Systems.

Summary of Section 95668 (a)(1)

This section indicates that the flash analysis testing and vapor collection system requirements in the following section apply to separator and tank systems located at facilities listed in section 95666.

Rationale for Section 95668 (a)(1)

This section is necessary to define the types of equipment systems to which the section applies.

Summary of Section 95668 (a)(2)(A)

This section specifies that separator and tank systems that receive less than 50 barrels of crude oil and less than 200 barrels of produced water per day are exempt from the requirements of this section.

Rationale for Section 95668 (a)(2)(A)

Methane is emitted from the production of crude oil, condensate, and produced water when the fluids are produced from an underground reservoir and separated or stored on the surface. The emissions are primarily a result of depressurizing the liquids from reservoir pressure to a lower surface pressure and subjecting the liquids to changes in temperature. The analysis showed that separator and tank systems with a production level of than 50 barrels of crude oil per day and less than 200 barrels of produced water do not produce enough liquids to meet the proposed emissions standard and therefore do not warrant flash emissions testing, or a permanent vapor collection system. For more information, see Appendix D.

Summary of Section 95668 (a)(2)(B)

This section specifies that the requirements of this section do not apply to separator and tank systems that are already controlled with the use of a vapor collection system.

Rationale for Section 95668 (a)(2)(B)

Separator and tank systems that are controlled with a vapor collection system in accordance with local air district requirements are already in compliance with this regulation.

Summary of Section 95668 (a)(2)(C)

This section specifies that the requirements of this section do not apply to separators, tanks, and sumps that have not contained crude oil, condensate or produced water for at least 30 calendar days.

Rationale for Section 95668 (a)(2)(C)

Staff's analysis shows that separators, tanks, and sumps that have not contained crude oil, condensate, or produced water for at least 30 calendar days do not contain sufficient quantities of natural gas to warrant emissions control.

Summary of Section 95668 (a)(2)(D)

This section specifies that the requirements of this section do not apply to tanks used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from a newly constructed well for up to 90 calendar days following initial production from that well, provided the tank is not used to circulate liquids from a well that has undergone well stimulation.

Rationale for Section 95668 (a)(2)(D)

This exemption is necessary to provide a regulated party with the necessary time required to complete the construction of a newly drilled well using temporary tanks to store drilling fluids, emulsion, or other liquids prior to diverting production liquids into a separator and tank system. During this time period, an owner or operator will evaluate a number of characteristics, including well production rate and annual methane emissions from the produced liquids. If the annual methane emission rate is above the specified standard, the information can be used to design and construct an appropriate vapor collection system.

Summary of Section 95668 (a)(2)(E)

This section specifies that the requirements of this section do not apply to tanks used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from wells undergoing rework or inspection, for up to 90 calendar days following completion, provided the tank is not used to circulate liquids from a well that has undergone well stimulation.

Rationale for Section 95668 (a)(2)(E)

This exception is necessary to inform a regulated party that tanks used in conjunction with temporary well rework and inspection are not subject to the proposed regulation requirements. These tanks are used to hold small amounts of liquids that are expelled from a well while removing or replacing tubing or flushing small quantities of liquids from the well bore. Because the tanks are neither used in a production capacity nor used in conjunction with a well stimulation treatment, they do not warrant flash emissions testing or a permanent vapor collection system.

Summary of Section 95668 (a)(2)(F)

This section specifies that the requirements of this section do not apply to tanks that recover less than 10 gallons per day of any petroleum product from equipment, provided that the owner or operator maintains a list of the amount of liquid recovered.

Rationale for Section 95668 (a)(2)(F)

This exemption is necessary to specify that tanks used to store small quantities of waste fluids from equipment are different from tanks used in crude oil and natural gas production. These tanks are often used to clean out liquid knockout traps from large compressors or equipment but are not used in the production of crude oil or natural gas. A maximum throughput limit is specified as well as daily record keeping requirements to ensure that the tanks are used within the parameters specified.

Summary of Section 95668(a)(3)

This section specifies that existing separator and tank systems not already controlled with a vapor collection system must conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system by the effective date.

Rationale for Section 95668(a)(3)

This section ensures that, beginning on the effective date, existing separators and tank systems are controlled with a vapor collection system.

Summary of Section 95668(a)(4)

This section specifies that new separator and tank systems not already controlled with a vapor collection system must conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system within 90 days of system startup.

Rationale for Section 95668(a)(4)

This section ensures that, beginning on the effective date, new separator and tank systems have 90 days from initial startup, to conduct flash analysis testing and reporting, which is used to determine if the new separator and tank system is above the proposed methane emissions standard and requires the installation of a vapor collection system.

Summary of Section 95668(a)(5)(A)

This section specifies that flash analysis testing must be conducted in accordance with the ARB Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water as described in Appendix C to the regulation.

Rationale for Section 95668(a)(5)(A)

This section ensures that the approved method flash analysis testing will be followed by every regulated party.

Summary of Section 95668(a)(5)(B)

This section specifies that that no crude oil, condensate, or produced water may be diverted through a gauge tank that is open to the atmosphere and located upstream of the separation and system while testing is conducted.

Rationale for Section 95668(a)(5)(B)

This requirement is necessary to ensure that all flash analysis testing is facilitated in the same manner, preventing potential testing bias in facilities that might otherwise allow the products to be open to the atmosphere, before the point at which flash testing takes place.

Summary of Section 95668(a)(5)(C-D)

These sections specify that the owner or operator use the flash analysis test results provided by the laboratory to calculate the annual methane emissions for the crude oil, condensate, and produced water, adding the emissions together.

Rationale for Section 95668(a)(5)(C-D)

These requirements are necessary to ensure that each facility owner or operator is calculating the emissions and adding them together, in a consistent manner across all facilities in the state.

Summary of Section 95668(a)(5)(E-F)

These sections require that owners or operators maintain a record of flash analysis testing and report the results to ARB, per sections 95671 and 95672, respectively. Additionally, it provides for ARB to request further information or testing, if it is determined that test results are not representative of similar systems or wells.

Rationale for Section 95668(a)(5)(E-F)

These sections are necessary to provide recordkeeping requirements for flash analysis tests at a particular location or facility. Additionally, it gives ARB the ability to inquire about atypical flash analysis test results.

Summary of Section 95668(a)(6)

This section specifies that by the effective date, owners or operators of a separator and tank system with an annual emission rate greater than or equal to 10 metric tons per year of methane must control the emissions from the system as well as uncontrolled gauge tanks upstream, with a vapor collection system as specified in section 95668.

Rationale for Section 95668(a)(6)

This section is necessary to inform a regulated party with a separation and tank system with an annual emission rate greater than 10 metric tons per year of methane that the system and all uncontrolled upstream gauge tanks are subject to the vapor collection system requirement. This requirement is

necessary to ensure the separator and tank system is controlled as intended and tested while accounting for uncontrolled upstream gauge tanks that have the potential to vent emissions prior to the separator and tank system.

Summary of Section 95668(a)(7)

This section specifies that new separator and tank systems installed after January 1, 2018 with emissions that exceed the proposed regulation standard must be controlled with the use of a vapor collection system within 180 days from the date that flash analysis testing was conducted.

Rationale of Section 95668(a)(7)

This section is necessary to specify the proposed timeframe for controlling emissions from new separator and tank systems that exceed the proposed regulation standard. The proposed timeframe is intended to provide a regulated party with time necessary to design and construct a system as well as obtain the necessary local air district permits.

Summary of Section 95668(a)(8)

This section specifies that a regulated party with a separator and tank system with methane emissions measured below the proposed standard must conduct annual flash emissions testing for at least three years. If the results of three consecutive years of testing are below 10 metric tons of methane per year, the annual testing requirement may be reduced to once every five years.

Rationale for Section 95668(a)(8)

This requirement ensures that the results of flash analysis testing are accurate and then eliminates the need to conduct repetitive testing. Due to fluctuations in the liquids produced from a well or group of wells, methane emissions from each system may change slightly throughout the year. This is usually due to changes in the amount of oil or water produced. In order to provide a consistent emission baseline for each system, and to avoid the need for testing each time the system fluctuates, staff is proposing an annual testing requirement. The proposed testing requirement may be reduced to once every five years if previous results show that the emissions are consistently below the proposed standard.

Summary of Section 95668(a)(8)(A)

This section requires that the annual methane emissions must be recalculated if the crude oil, condensate, or produced water throughput increases by more than 20 percent per calendar year, after the third consecutive year of testing.

Rationale for Section 95668(a)(8)(A)

Due to the variability of fluids produced from a well or group of wells, this requirement is necessary to determine the annual methane emissions from a well with increased throughput. Methane emissions are directly related to the production rate of liquids, so an increase in the production of liquids will affect the annual methane emissions. To address daily fluctuations in volume with constant liquid composition, staff proposes that annual emissions be recalculated if there is an increase in production of crude oil, condensate, or produced water by more 20 percent per calendar year. The new methane emission rate is to be recalculated using the gas composition analysis provided during the previous year of testing along with the new volume of liquid. This will ensure that each facility maintains a current record of methane emissions for separator and tank systems while eliminating the need for extra testing.

Summary of Section 95668(a)(8)(B)

This section requires that owners or operators required to recalculate emissions with prior flash analysis testing, keep a record of the recalculations as specified. Additionally, it provides for ARB to request further information or testing, if it is determined that test results are not representative of similar systems or wells.

Rationale for Section 95668(a)(8)(B)

This section is necessary to provide recordkeeping requirements for emissions recalculation using prior flash analysis tests at a particular location or facility. Additionally, it gives ARB the ability to inquire about non-typical flash analysis test results

6. Section 95668(b). Circulation Tanks for Well Stimulation Treatments.

Summary of Section 95668(b)(1)

This section requires owners or operators of circulation tanks used in conjunction with well stimulation treatments to submit a best practices management plan designed to reduce methane emissions from circulation tanks, by the effective date listed in the regulation. Additionally, ARB's Executive Officer may approve or disapprove the plan, in whole or in part.

Rationale for Section 95668(b)(1)

This section is necessary to inform a regulated party that uses circulation tanks that they must submit a best practices management plan to ARB by the effective date specified. This requirement is necessary to ensure that a regulated party operates the uncontrolled tanks using the best practices that are available to limit the volume of emissions from the tanks while emission control equipment is designed and tested. Some best management practices that are available include using minimal amounts of water necessary to remove sand from a wellbore and minimizing the duration of circulation activity. All best practices management plans require ARB Executive Officer approval and may require modification prior to final approval, which is necessary to ensure that the plans achieve their intended purpose.

Summary of Section 95668(b)(2) and (b)(2)(A)

This section requires facilities that use circulation tanks in conjunction with well stimulation treatments to submit a written report to ARB that details the results of a technical evaluation of equipment used to control emissions from circulation tanks. The report must be provided, in writing, to ARB's Executive Officer by the effective date. The report must include testing results conducted by the owner or operator or equipment manufacturers.

Rationale for Section 95668(b)(2) and (b)(2)(A)

This section is required to inform a regulated party that uses circulation tanks that they must perform emissions testing of vapor control equipment used on a circulation tank and submit a written report of the results to ARB by the effective date specified. This requirement is necessary to provide a regulated party with time to work with circulation tank and vapor collection system equipment manufacturers to design and test emission control equipment. Examples of equipment that may be used to control emissions include a portable gas separator and a portable low-NOx incinerator to combust the collected vapors. We encourage owners or operators as well as equipment manufacturers to work with ARB during the development of the technical demonstration.

Summary of Section 95668(b)(3)

This section requires that all owners and operators of facilities that use circulation tanks during well stimulation treatments must control the methane emission with 95 percent control efficiency.

Rationale for Section 95668(b)(3)

This section is required to inform a regulated party that circulation tanks used in conjunction with well stimulation treatments by the effective date specified. This requirement is necessary to provide a regulated party with time to purchase and install vapor control equipment following the results of a successful technical demonstration specified in section 95668(b)(2).

7. Section 95668(c). Vapor Collection Systems and Vapor Control Devices.

Summary of Section 95668(c)(1)

This section specifies the types of equipment subject to the vapor collection system and control device requirements and the effective date on which the requirements apply.

Rationale for Section 95668(c)(1)

This requirement is necessary to define the types of equipment subject to the vapor collection system and control requirements and the date on which the requirements apply.

Summary of Section 95668(c)(2)

This section specifies that the vapor collection system must direct the collected vapors to one of following: (A) Existing sales gas system, (B) Existing fuel gas system, or (C) Existing gas disposal well.

Rationale for Section 95668(c)(2)

This section is required to ensure that any newly collected vapors are controlled using equipment that is already available at the facility and to minimize or eliminate ambient air quality impacts. Staff's analysis show that some oil and gas facilities have at least one of these options currently available, minimizing the cost of controlling emissions and preventing the need to install additional combustion equipment⁴¹.

⁴¹ ARB. 2013. Oil and Gas Survey. _ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.

Summary of Section 95668(c)(3)

This section specifies that if no existing sales gas system, fuel gas system, or gas disposal well is available to accept newly collected vapors, the regulated party must install a new vapor control device. New and replacement devices must meet the proposed regulation standards.

Rationale for Section 95668(c)(3)

This section is necessary to complement, and avoid interfering with, ambient air quality standards by ensuring that the installation of new combustion equipment used to reduce methane emissions avoids criteria pollutant or toxic impacts.

Summary of Section 95668(c)(3)(A)

This section specifies that a regulated party must install a new vapor control device to control newly collected vapors in the event that there is no existing vapor control device already installed at the facility.

Rationale for Section 95668(c)(3)(A)

This requirement is necessary to clarify that any existing facility without a vapor control device must install a new vapor control device in order to control the newly collected methane vapors. This alternative is only available when no existing sales gas system, fuel gas system, or underground injection well is available, and when no existing vapor control device is installed at the facility. This section is necessary to comply with the intent of the proposed regulation to control emissions of methane.

Summary of Section 95668(c)(3)(B)

This section specifies that if an existing device does not meet the standard in section 95668(c)(4), the regulated party currently operating an existing vapor control device that is subject to the proposed vapor collection system requirement must replace that existing vapor control device with a new vapor control device that meets the proposed regulation standards.

Rationale for Section 95668(c)(3)(B)

This requirement is necessary to ensure that any incremental increase in combusted methane vapors does not result in an increase of emissions that may affect attainment or local ambient air quality standards. If the existing device does not meet the standard, this alternative must be used when no existing sales gas system, fuel gas system, or gas disposal well is available, and when the facility currently operates an existing vapor control device. This section is necessary to comply with the intent of the proposed regulation to control emissions of methane without impacting local air quality.

Summary of Section 95668(c)(4)(A)

This section specifies that if a new vapor control device is to be installed in an area classified as in attainment with state or federal ambient air quality standards, the device must achieve at least 95% control efficiency and meet all applicable federal, state, and local air district requirements.

Rationale for Section 95668(c)(4)(A)

This section allows a regulated party to install any type of vapor control device that meets the specified control efficiency in a region classified as in attainment with ambient air quality standards, as long as it meets all applicable requirements. This section ensures emission controls required by the proposed regulation complements, and avoids interfering with applicable requirements for air quality.

Summary of Section 95668(c)(4)(B)

This section specifies that if a new vapor control device is to be installed in an area classified as non-attainment with state or federal ambient air quality standards the device must meet certain requirements. This requirement provides flexibility by clarifying that more than one type of vapor control device can fulfill the requirement.

Rationale for Section 95668(c)(4)(B)

This requirement is necessary to ensure that any incremental increase in combusted methane vapors does not result in an increase of emissions that may affect attainment or local ambient air quality standards.

Summary of Section 95668(c)(4)(B)1

This section specifies that a non-destructive vapor control device may be installed in an area classified as non-attainment with ambient air quality standards provided the device is at least 95% efficient in controlling emissions of methane and does not result in emissions of NO_x.

Rationale for Section 95668(c)(4)(B)1

Non-destructive control devices process collected vapors without a need for combustion. An example of such a device chills vapors to an extremely cold temperature which to turn converts the gas into liquid. The liquid may be used on-site or sold as a useable product. Although the technology is not currently employed within the oil and gas sector, manufacturers of the equipment are aware of a need for a system that can be used in this application, and ARB staff believes that the technology can be adapted for use in the oil and gas sector. This requirement is necessary to provide

flexibility in the event that the technology becomes available for future oil and gas applications.

Summary of Section 95668(c)(4)(B)2

This section specifies that a vapor control device may be installed in an area classified as non-attainment with ambient air quality standards provided it is at least 95% efficient in controlling emissions of methane and does not generate more than 15 parts per million volume of NO_x when measured at 3% oxygen and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

Rationale for Section 95668(c)(4)(B)2

This section is necessary to ensure that newly collected vapors are controlled in areas classified as non-attainment with state or federal ambient air quality standards using a device that minimizes or reduces ambient air quality impacts. Examples of such devices that can be used to meet the proposed standards include low-NO_x incinerators and microturbines. Low-NO_x incinerators use proprietary technology to efficiently burn, and otherwise destroy, all of the collected vapors. Microturbines are used to generate electricity and create a beneficial use for waste gas, which is otherwise destroyed. This requirement is necessary to provide an emissions standard that reduces emissions affecting ambient air quality while controlling newly collected vapors and allowing the regulated party to continue oil and gas production.

Summary of Section 95668(c)(5)

This section specifies that if any newly collected vapors cannot be controlled using any of the alternative options specified in section 95668(c), then any equipment subject to the proposed regulation vapor collection system requirements must be removed from service by the date specified.

Rationale of Section 95668(c)(5)

This section is necessary to inform a regulated party that they cannot operate equipment that does not meet the proposed regulation vapor collection system requirements after the effective date specified in the proposed regulation. This requirement is necessary to comply with the intent of the proposed regulation to control emissions of methane in a manner that is consistent with state and federal ambient air quality standards.

Summary of Section 95668(c)(6)

This section specifies that vapor collection systems and control devices are allowed to be out of service for a certain number of calendar days each year

for maintenance or utility power outages. Additionally, there is flexibility when replacing compliant devices, and during power outages.

Rationale of Section 95668(c)(6)

This section is required to provide a regulated party with a set amount of time, to take the vapor collection systems and control devices out of service, or to use an alternative method, to perform scheduled maintenance and to make an allowance for utility power outages.

8. Section 95668(d). Reciprocating Natural Gas Compressors.

Summary of Section 95668(d)(1)

This section specifies that reciprocating natural gas compressors used at crude oil and natural gas production facilities must comply with the proposed regulation standards.

Rationale of Section 95668(d)(1)

This section is necessary to inform a regulated party that reciprocating natural gas compressors located at the facilities listed are subject to the proposed regulation standards.

Summary of Section 95668(d)(2)

This section specifies that reciprocating compressors that operate less than 200 hours per year are exempt from the requirements of 95668(d), provided that the owner or operator keep a written record of operating hours, and can demonstrate it to ARB's Executive Officer, upon request.

Rationale of Section 95668(d)(2)

This exemption is necessary to prevent the unnecessary startup and running of a compressor in order to perform annual emissions testing. The unnecessary generation of emissions to perform emissions measurements conflicts with the proposed intent of the regulation to reduce annual methane emissions.

Summary of Sections 95668(d)(3)(A-B)

These sections are necessary to specify that components on the compressor must be tested and repaired during each inspection period according to the proposed LDAR requirements. Additionally, the rod packing or seal must also be tested in accordance with the proposed LDAR test procedure.

Rationale of Sections 95668(d)(3)(A-B)

These sections are necessary to inform a regulated party that regular emissions monitoring is required for the rod packing or seal in addition to other engine and compressor components.

Summary of Section 95668(d)(3)(C-D)

This section specifies that, by the effective date, compressor vent stacks used to vent rod packing or seal emissions shall either be controlled with the use of a vapor collection system as specified in section 95688(c) or shall be subject to measurement and, if above the minimum threshold in 95669, repaired within 30 days of the initial emissions flow rate measurement.

Rationale of Section 95668(d)(3)(C-D)

This section is necessary to specify that owners or operators have the option to control rod packing or seal emissions with the use of a vapor collection system. This section is also necessary to specify that compressors that control the rod packing or seal vent gas with the use of a vapor collection system are not required to conduct LDAR testing of the rod packing or seal. This section is also necessary to specify the repair timeframe for a rod packing or seal, which is different from other repair timeframes listed in LDAR. Due to the complexity of repairing these components, additional time is provided to allow the owner or operator to take the compressor out of service, order parts, and make all of the necessary repairs.

Summary of Section 95668(d)(3)(E)

This section specifies that the owner or operator of the reciprocating compressor shall maintain a record of rod packing leak concentration measurements that are measured above the minimum leak threshold as specified in Appendix A, Table 5. The owner or operator must also report a record of the measurements to ARB once per calendar year as specified in section 95672.

Rationale of Section 95668(d)(3)(E)

This requirement is necessary for an owner or operator to demonstrate to the ARB Executive Officer that emissions testing was conducted as specified in the proposed regulation and for ARB to maintain accurate records of emissions from these components.

Summary of Section 95668(d)(3)(F)

This section specifies that any compressor, which has been approved as a critical component, must be repaired by the end of the next process shutdown

or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(d)(3)(F)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial leak concentration measurement, whichever is sooner. All critical components must be pre-approved by the ARB Executive Officer to receive this special designation.

Summary of Section 95668(d)(4)

This section applies to reciprocating natural gas compressors at natural gas gathering and boosting stations, processing plants, transmission compressor stations, and underground natural gas storage facilities listed in section 95666 and which are not covered under section 95668(d)(3).

Rationale of Section 95668(d)(4)

This section is necessary to differentiate between compressors located at the facilities listed which are subject to different rod packing or seal testing requirements and emissions than compressors located at production facilities.

Summary of Section 95668(d)(4)(A)

This section specifies that components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.

Rationale of Section 95668(d)(4)(A)

This section is necessary to inform a regulated party that components on driver engines and compressors are subject to the LDAR testing requirements during each leak inspection.

Summary of Section 95668(d)(4)(B)

This section directs owners or operators of facilities to measure the rod packing or seal flow rate annually, and in compliance with the regulation, using one of the following methods: (1) Vent stacks must be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or (2) Vent stacks must be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making individual or combined rod packing or seal emission flow rate measurements

Rationale of Section 95668(d)(4)(B)

This section is necessary to inform a regulated party that regular rod packing or seal emission testing is required to comply with the proposed regulation, in the event that the vent stack emissions are not controlled with the use of a vapor collection system. The rod packing or seal must be measured annually using an emissions flow rate instrument. This measurement frequency was chosen because normal wear and tear on these compressors is low, and methods to measure the emissions rate are complex. In most applications, reciprocating compressors installed at the facilities specified are used to compress processed natural gas that is relatively free of contaminants that might wear out the rod packing or seal quickly. To provide flexibility with testing, owner or operator may use instrumentation, installed within the vent stack, to continuously measure the emissions flow rate or install an access port in the stack for making annual measurements.

Summary of Section 95668(d)(4)(C-E)

These sections specify that compressor vent stacks must either be controlled with the use of a vapor collection system or the rod packing must be measured annually, and any compressor with a rod packing or seal that exceeds 2 scfm (or 2 scfm times the number of rod packing cylinders), must be repaired within 30 calendar days from the date of the initial flowrate measurement. Additionally, the owner or operator must maintain a record of the flow rate measurements as specified in Appendix A, Table 7 of the proposed regulation and report the measurement result to ARB once per year.

Rationale of Section 95668(d)(4)(C-E)

These sections are necessary to specify that emissions from a rod packing or seal must either be controlled with the use of a vapor collection system or tested annually and repaired within 30 calendar days from the date of the initial flowrate measurement. These sections provide flexibility, giving an operator or operator the option to either control the emissions or perform annual measurements and make repairs as specified. The 30 calendar day repair timeframe provides time for a regulated party to take a compressor out of service, order parts, and make any necessary repairs.

Summary of Section 95668(d)(4)(F)

This section specifies that any compressor, which has been approved as a critical component by the ARB Executive Officer, must be repaired by the end of the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(d)(4)(F)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner. All critical components must be pre-approved by ARB to receive this special designation

9. Section 95668(e). Centrifugal Natural Gas.

Summary of Section 95668(e)(1)

With the exception of compressors listed in section 95668(e)(2), this section specifies that centrifugal natural gas compressors must comply with the proposed standards beginning on the date specified.

Rationale of Section 95668(e)(1)

This section is necessary to inform a regulated party that centrifugal natural gas compressors located at the facilities specified are subject to the proposed regulation requirements.

Summary of Section 95668(e)(2)

This section specifies that any centrifugal natural gas powered compressor operating less than 200 hours per calendar year is exempt from this section of the proposed regulation, provided that the owner or operator maintains a record of the operating hours per calendar year, and can provide them to ARB's Executive Officer, upon request.

Rationale of Section 95668(e)(2)

This exemption is necessary to prevent the unnecessary startup and running of a compressor in order to perform annual emissions testing. The unnecessary generation of emissions to perform emissions measurements conflicts with the proposed intent of the regulation to reduce annual methane emissions.

Summary of Sections 95668(e)(3)

This section specifies that centrifugal natural gas compressors that use wet seals or dry seals are subject to the proposed LDAR requirements.

Rationale of Sections 95668(e)(3)

This section is necessary to inform a regulated party that regular emissions testing is required for all components found on centrifugal natural gas compressors that use either a wet seal or dry seal system.

Summary of Sections 95668(e)(4)

This section specifies that centrifugal natural gas compressors with wet seals must be measured annually using one of the following methods: (A) Vent stacks shall be equipped with a meter or instrumentation to measure the wet seal emissions flow rate; or, (B) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making wet seal emission flow rate measurements.

Rationale of Sections 95668(e)(4)

This section is necessary to specify that wet seals must be measured annually to determine compliance with the proposed emission flow rate standard. This measurement frequency was chosen because normal wear and tear on these compressors is low and methods used to measure the emissions flow rate are complex. In most applications, centrifugal natural gas compressors are used to compress processed natural gas that is relatively free of contaminants that might wear out the wet seal quickly. To provide flexibility with testing, owner or operator may use instrumentation installed within the vent stack to continuously measure the emissions flow rate or install an access port in the vent stack for making annual flow rate measurements.

Summary of Section 95668(e)(5-7)

These sections specify that wet seal emissions that exceed 3 scfm (or 3 scfm times the number of seals) must either be controlled with the use of a vapor collection system or repaired within 30 calendar days from the date of the initial flowrate measurement. Additionally, the owner or operator must maintain a record of flow rate measurements as specified in Appendix A, Table 7 of the proposed regulation and report flowrate measurement results to ARB once per year.

Rationale of Section 95668(e)(5-7)

These sections are necessary to specify that owners or operators of compressors with wet seals must either control the emissions with the use of a vapor collection system or perform annual measurements and make repairs to wet seals that are measured above the flow rate standard. These sections provide flexibility, giving an operator or operator the option to either control wet seal emissions or perform annual measurements and make repairs as

specified. The 30 calendar day repair timeframe provides time for a regulated party to take a compressor out of service, order parts, and make any necessary repairs. This also provides additional time to evaluate the possibility of controlling the wet seals with the use of a vapor collection system.

Summary of Section 95668(e)(8)

This section specifies that the owner or operator of any centrifugal compressor must maintain a record of the flow rate measurements as described in Appendix A, Table 7 of the proposed regulation and report it to ARB once per year.

Rationale of Section 95668(e)(8)

This requirement is necessary for an owner or operator to demonstrate to the ARB Executive Officer that emissions testing has been conducted as specified in the proposed regulation and for ARB to maintain accurate records of emissions from these components.

Summary of Section 95668(e)(9)

This section specifies that any compressor approved as a critical component must be successfully repaired by the end of the next process unit shutdown or within 12 months of the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(e)(9)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner. All critical components must be pre-approved by the ARB Executive Officer to receive this special designation.

10. Section 95668(f). Natural Gas Powered Pneumatic Devices and Pumps.

Summary of Section 95668(f)(1)

This section specifies that natural gas powered pneumatic devices and pneumatic pumps are subject to the proposed regulation standards.

Rationale of Section 95668(f)(1)

This section is necessary to inform a regulated party that both natural gas powered pneumatic devices and natural gas powered pneumatic pumps are subject to the proposed regulation.

Summary of Section 95668(f)(2)

This section specifies that continuous bleed pneumatic devices shall not vent natural gas after the effective date specified and must comply with the leak detection and repair standards..

Rationale of Section 95668(f)(2)

This requirement is necessary to prevent the venting of methane from continuous bleed pneumatic devices. By design, continuous bleed devices continuously vent natural gas into the atmosphere. Other types of non-venting pneumatic devices are available and continuous bleed devices may also be retrofitted to use compressed air or electricity to eliminate the vented emissions.

Summary of Section 95668(f)(2)(A)1-5

These sections specify that continuous bleed pneumatic devices installed prior to January 1, 2016 that do not vent natural gas at a rate greater than 6 standard cubic feet per hour (scfh) may remain in service provided that the devices are clearly identified with a permanent tag to identify these particular devices, and the devices are tested annually using a flow rate measurement method.

Rationale of Section 95668(f)(2)(A)1-5

This section is necessary to identify a subcategory of existing continuous bleed pneumatic devices that vent small amounts of methane and were previously installed in order to comply with ARB Mandatory Reporting Regulation requirements, which required either replacing high-bleed devices with low bleed devices or metering the gas flow rate. . The requirements listed specify how an owner or operator must identify the devices for identification by inspectors, and how the devices must be tested annually to ensure that they do not vent emissions at a rate greater than 6 scfh. Similar to other devices that require emission flow rate testing, the annual measurement frequency was chosen due to the complexity of performing flow rate measurements.

Summary of Section 95668(f)(3)

This section specifies that intermittent bleed pneumatic devices must comply with the leak detection and repair requirements when they are not controlling.

Rationale of Section 95668(f)(3)

This requirement is necessary to ensure that intermittent bleed pneumatic devices do not leak or vent natural gas when they are not controlling, a state that is also known as “idle”. By design, intermittent bleed devices are designed to be sealed, and do not vent natural gas when idle. However, they may vent a predetermined volume of natural gas when controlling a process or equipment. This requirement is designed to ensure that the devices are tested consistently by an owner or operator or inspector and to ensure that the device is sealed when idle.

Summary of Section 95668(f)(4)

This section specifies that pneumatic pumps shall not vent natural gas to the atmosphere and must be tested and repaired during each inspection period according to the proposed LDAR requirements.

Rationale of Section 95668(f)(4)

This requirement is necessary to eliminate emissions of methane from pneumatic pumps that vent natural gas into the atmosphere. Other types of non-venting pneumatic pumps are available and these pumps may be retrofitted to use compressed air or electricity to eliminate the vented emissions.

Summary of Section 95668(f)(5)

This section specifies that natural gas powered pneumatic devices and pumps must be replaced or retrofitted with the use of a vapor collection system, compressed air, or electricity to prevent the venting of natural gas emissions into the atmosphere.

Rationale of Section 95668(f)(5)

This section is necessary to inform a regulated party that the proposed regulation would require the replacement of pneumatic devices or require the devices to be retrofitted. The control strategies include controlling devices with use of a vapor collection system or modifying devices to use compressed air or electricity to operate. These options are designed to provide a regulated party with flexibility to control emissions of methane from a variety of devices and pumps.

11. Section 95668(g). Liquids Unloading of Natural Gas Wells.

Summary of Section 95668(g)

This section specifies that a regulated party who vents natural gas to the atmosphere for the purpose of liquids unloading must either control the

vented natural gas with the use of a vapor collection system or measure or calculate the volume of vented gas. Regulated parties must also maintain records and report volumes of vented natural gas from liquids unloading operations and equipment installed to automatically perform liquids unloading.

Rationale of Section 95668(g)

This section is required to either (1) control emissions of natural gas that is vented as a result of liquids unloading or (2) quantify the emissions and gather information on the activity and automation equipment used to perform the operation automatically. If a regulated party chooses to control the vented natural gas, they must use a vapor collection system as specified in section 95668(c). If a regulated party chooses to measure the volume of gas that is vented they are permitted to choose from several measurement methods. A regulated party may also choose to calculate the volume of gas that is vented by using one of the specified calculation methods. If a regulated party chooses to use either one of the measurement or calculation methods, they must report the results to ARB annually. This information is necessary for ARB to accurately quantify emissions and determine the performance of automation equipment. The results will be used to determine if future modifications to the proposed regulation are necessary.

12. Section 95668(h). Well Casing Vents.

Summary of Section 95668(h)

This section specifies that by the effective date, owners or operators of wells located at facilities listed in section 95666, with a well casing vent that is open to the atmosphere shall measure the natural gas flow rate from the well casing vent annually, and according to the methods listed in the regulation. Additionally, a record of each well casing vent flow rate measurement according to Appendix A, Table 7 of the proposed regulation, should be maintained and made available to ARB's Executive Officer, annually.

Rationale of Section 95668(h)

This section is required for ARB to quantify emissions and gather information from well casing vents that are open to the atmosphere. This section is also required to notify inspectors that well casing vents that are open to the atmosphere are not subject to the LDAR standards. Each year, the owner operator must measure the volume of natural gas that is vented from each well casing vent and report the results to ARB. The results will be used to determine if future modifications to the proposed regulation are necessary.

13. Section 95668(i). Natural Gas Underground Storage Facility Monitoring Requirements.

Summary of Section 95668(i)

This section details the monitoring requirements for natural gas underground storage facilities. Operators must comply with leak detection protocols that are already in place at the effective date of this subarticle. Operators must then submit an air monitoring plan and a leak detection protocol to ARB's Executive Officer for approval. The leak detection protocol may include the daily use of Method 21, Optical Gas Imaging, or other screening instruments; or a continuous monitoring alarm system. Recordkeeping and quarterly reporting requirements are also detailed. The ambient air monitoring plan requires the use of a continuous air monitoring network. All leaks discovered must be repaired within the repair timeframes detailed in section 95669.

Rationale of Section 95668(i)

The purpose of this section is to prevent leaks in underground storage facilities from going unnoticed, neglected, or unchecked. A variety of methods to detect leaks are included in the protocol, to provide flexibility to operators in meeting requirements. Continuous ambient air monitoring is required to provide the public agencies and the public accurate exposure information.

14. Section 95669. Leak Detection and Repair.

Summary of Section 95669(a)

This section specifies the facilities that are subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(a)

This section is required to inform a regulated party of the types of facilities that are subject to the proposed leak detection and repair requirements.

Summary of Section 95669(b)

This section specifies the types of equipment that are not covered by the proposed leak detection and repair requirements.

Rationale of Section 95669(b)

This section is necessary to specify components that are not subject to the proposed leak detection and testing requirements.

Summary of Section 95669(b)(1)

This section specifies that any components that are subject to local air district leak detection and repair requirements prior to January 1, 2018 are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(1)

This section is necessary to specify that, for the purposes of this proposed regulation, all components that are already tested and repaired in accordance with local air district requirements are already in compliance with this proposed regulation.

Summary of Section 95669(b)(2)

This section specifies that components, including components found on tanks, separators, and pressure vessels used exclusively with the crude oil with API gravity less than 20 are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(2)

This section is necessary to specify that the proposed leak detection and repair testing requirements do not apply to heavy oil components. Staff's analysis of published emission factors⁴² to date show that components associated with heavy oil emit less total hydrocarbons, and therefore less methane, than other components found in gas or other liquid service.

Summary of Section 95669(b)(3)

This section specifies that components incorporated into produced water lines located downstream of a separator and tank system are not subject the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(3)

The section is necessary to specify that components used in conjunction with produced water and which are located downstream of a separator and tank system are not subject to the proposed requirements. Staff was not able to locate any published emission factors for these components which are located downstream from the point of where flashing occurs.

⁴² CAPCOA. 1999. California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities

Summary of Section 95669(b)(4)

This section specifies that natural gas distribution lines used to deliver commercial quality natural gas to a facility, and which are not owned or operated by the facility, are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(4)

This section is necessary to specify that an owner or operator is not responsible for testing or repairing components that are not owned or operated by the facility.

Summary of Section 95669(b)(5)

This section specifies that components that are buried below ground are not subject to the proposed leak detection and testing requirements and that the portion of well casing that is visible above the ground is not considered a buried component.

Rationale of Section 95669(b)(5)

This section is necessary to specify that testing is not required for buried components and prevents the need for owners or operators to uncover and test components. However, testing is required for well casing components, including the portion of well casing that is visible on the surface. In some cases it's possible for an underground well casing leak to permeate up the surface along the exterior portion of well casing. These types of leaks can be detected at well head casing on the surface and are subject to the proposed leak detection and repair requirements.

Summary of Section 95669(b)(6)

This section specifies that stainless tube fittings used in conjunction with compressed air are not subject to the proposed requirements.

Rationale of Section 95669(b)(6)

This section is necessary to prevent the need for testing components that do not contain any emissions of methane or other hydrocarbons.

Summary of Section 95669(b)(7)

This section specifies that stainless tube fittings used in conjunction with natural gas that have been tested in accordance with Method 21 do not require additional testing.

Rationale of Section 95669(b)(7)

This section is necessary to prevent the need re-testing stainless-steel tube fittings that have been previously testing. These fittings are designed with the use of a nut and ferrule locking system and are designed to not loosen or leak once tightened.

Summary of Section 95669(b)(8)

This section specifies that components operating under negative gauge pressure or below atmospheric pressure are not subject the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(8)

This section is necessary to prevent the need for testing components that do not have the ability to emit methane or hydrocarbon emissions.

Summary of Section 95669(b)(9)

This section specifies that components located downstream of a custody transfer meter and are not owned by the production facility are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(9)

This section is necessary to specify that an owner or operator is not responsible for testing or repairing components that are not owned or operated by the facility.

Summary of Section 95669(b)(10)

This section specifies that components used for general maintenance and used less than 300 hours per year are not subject to the proposed leak detection and repair requirements if the owner or operator maintains a record of the components and can provide a copy of the record at the request of the ARB.

Rationale of Section 95669(b)(10)

This section is necessary to specify that temporary components are not subject to the proposed regulation requirements. These components are used to temporarily divert liquid or gases while equipment is being constructed or modified. This requirement prevents the need to perform counting and measurements on components that are only used temporarily.

Summary of Section 95669(b)(11)

This section specifies that well casing vents that are open to the atmosphere are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(11)

This section is necessary to specify that well casing vents that are open to the atmosphere are not subject to the proposed leak detection and repair requirements. However, these components are subject to the proposed annual flow rate testing and reporting requirements. This section is necessary to prevent owners or operators or inspectors from testing these components during regular leak inspections.

Summary of Section 95669(c)

This section specifies that all components not identified in the exemptions section are subject to the proposed leak detection and repair requirements beginning on January 1, 2018.

Rationale of Section 95669(c)

This section is necessary to inform a regulated party that components located at facilities which are not identified in the exemption's section are subject to the proposed regulation requirements.

Summary of Section 95669(d)

This section specifies that the ARB Executive Officer may perform inspections at facilities at any time in order to determine compliance with the proposed leak detection and repair requirements.

Rationale of Section 95669(d)

This section is necessary to inform a regulated party that ARB may perform routine inspections at facilities at any time throughout the calendar year. These inspections may be in addition to local air district inspections. This requirement is necessary for ARB to determine compliance with the proposed regulation.

Summary of Section 95669(e)

This section specifies that owners or operators must perform daily audio-visual inspections on hatches, pressure-relief valves, well casings, stuffing boxes, and operating pump seals to look for the presence of leaks. The daily inspection frequency is reduced to weekly for unmanned facilities.

Rationale of Section 95669(e)

This section is necessary to inform a regulated party that audio-visual inspections are required for specified components. This requirement is similar to current requirements used by local air districts in major oil and gas producing regions. Each of the components listed have the potential to emit large amounts of methane so this requirement is necessary to ensure that these components do not leak for extended periods of time, or continue to leak in between routine instrument inspections. The list of components was shortened to only the most critical components so that an owner or operator has the ability to perform simple audio-visual checks when they visit the facilities.

Summary of Section 95669(e)(1)

This section specifies that all pipes installed at a facility must be audio-visually checked at least once every 12 months.

Rationale for Section 95669(e)(1)

This section is necessary to inform a regulated party that audio-visual inspections are required for all pipes located at a facility at least once every twelve months. This requirement is similar to current requirements used by local air districts in major oil and gas producing regions. This requirement is necessary to ensure that all gathering pipes used at a facility are inspected. Although pipes are designed not to leak emissions, they are also not routinely inspected with the use of Method 21 which is primary used for measuring connections. This requirement is necessary to ensure that pipes are checked for damage and repaired within 24 hours or tested with the use of Method 21 and repaired within the specified timeframes.

Summary of Section 95669(f)

This section specifies that any audio-visual inspection that indicates a leak that cannot be repaired within 24 hours must be measured with the use of Method 21 and then repaired within the timeframe specified for the resulting leak concentration measurement. Provisions have been made to clarify the testing requirement for leaks discovered over weekends or holidays.

Rationale for Section 95669(f)

This section is necessary to specify resulting actions that are required by an owner or operator if a leak is discovered during an audio-visual inspection. In many cases leaks can be repaired immediately, but some leaks require more complex repairs. The measurement requirement is necessary to identify the leak concentration which is used to determine the repair timeframe.

Summary of Section 95669(g)(1)

This section specifies that components must be tested in accordance with EPA Reference Method 21 at least once each calendar quarter and that the quarterly inspections may be reduced to annual inspections if a facility maintains compliance for five consecutive calendar quarters. The annual inspection frequency will revert back to quarterly if the facility fails to maintain compliance with the proposed requirements.

Rationale of Section 95669(g)(1)

This section is necessary to specify the proposed test method and the proposed leak inspection frequency. The EPA Reference Method 21 provides a reliable means of quantifying leaks and is currently in use by local air districts in major oil and gas producing regions. Accurately quantifying leaks is critical to determining compliance with the specified leak thresholds and repair timeframes. This section is also necessary to specify criteria that determine the leak inspection frequency after five consecutive calendar quarters. The proposed option for compliant facilities to conduct annual inspections is similar to current requirements used by local air districts in major oil and gas producing regions. This option provides an incentive for facilities to find and repair leaks quickly and also prevents the need for unnecessary instrument-based inspections at compliant facilities. In the event that a facility is determined to be out of compliance with the proposed requirements, either by way of an ARB or local air district inspection or by way of an inspection conducted by the owner or operator, the facility must revert back to quarterly inspections.

Summary of Section 95669(g)(2)

This section specifies that Optical Gas Imaging (OGI) instruments may be used to screen for leaks at a facility if they are approved for use by the local air district and used by a technician with minimum Level II Thermographer training. All leaks detected with these instruments must be measured with the use of Method 21 within the timeframes specified in order to quantify the leak concentration and determine the appropriate repair timeframes.

Rationale of Section 95669(g)(2)

This section is necessary to specify that OGI instruments may be used as a screening device to locate leaks if all of the specified conditions are met. Some owners or operators may find it useful to use these instruments in order to assist with leak inspections or to locate leaks in hard to reach places. Special provisions have been included that require local district approval and the need for specialized OGI instrument training. The training requirement is necessary because there are special conditions required for using OGI instruments and reading the images that they create. This section is also

necessary to specify that all leaks detected with the use of an OGI instrument must be tested with the use of Method 21. This requirement is necessary to accurately determine the component leak concentration and repair timeframe.

Summary of Section 95669(h) and (i)

These sections specify the proposed leak thresholds and repair timeframes that apply to regulated facilities subject to the proposed regulation. Under this proposal, leaks that are measured with a total hydrocarbon concentration above the leak threshold are required to be repaired within the designated timeframe. Two different minimum leak threshold standards are required under this regulation proposal. Beginning January 1, 2018, the minimum leak threshold is greater than or equal to 10,000 parts per million by volume (ppmv), and beginning January 1, 2020, the minimum leak threshold is greater than or equal to 1,000 ppmv. The proposed repair time periods are the same for each minimum leak threshold providing 14 calendar days for a regulated party to make repairs. These proposed repair time periods do not apply to critical components which are provided additional time to make repairs.

Rationale of Section 95669(h) and (i)

These requirements are necessary to eliminate methane emissions from components such as valves, flanges, and fittings. Emissions from these components may occur from the effects of weathering when bolts may naturally loosen or when components wear out. The proposed leak thresholds and repair timeframes are similar to those used by local air districts for oil and gas facilities in major oil and gas producing regions. The minimum leak threshold between the 2018 and 2020 calendar years are intended to provide owners or operators with time to repair any large leaks found at their facilities. These minimum leak thresholds are higher than similar leak thresholds used by local air districts. After January 1, 2020, facilities must comply with lower leak thresholds which resemble those currently used by local air districts.

Summary of Section 95669(j)

This section specifies how a leaking component must be identified with a weatherproof tag, which identifies the date that the inspection was conducted and the leak concentration measurement. The tag must remain affixed to the component until it has been repaired and retested to verify that it is no longer leaking above the minimum leak threshold standard.

Rationale of Section 95669(j)

This section is required so that a regulated party and inspectors can track component leaks measured above leak concentration thresholds, and reduces the possibility that a leaking component will be double-counted

during any inspection period. Each tag is required to remain affixed to the component until it has been fully repaired and tested to demonstrate it does not leak above the proposed minimum leak threshold.

Summary of Section 95669(k)

This section specifies that a regulated party must maintain a record of each leak detection and repair inspection including the leak concentration measurement and repair date(s) or components. It also requires that regulated parties must report this information to ARB once per calendar year, as well as making records available to the Executive Officer upon request.

Rationale of Section 95669(k)

This section is necessary to document the results of the leak detection and repair inspections and components awaiting repairs. This allows both the regulated party and inspectors to verify compliance with the proposed regulation and to ensure that all components are repaired within the timeframes.

Summary of Section 95669(l)

This section specifies that hatches must be closed at all times except during sampling, process material, or attended maintenance operations.

Rationale of Section 95669(l)

This requirement is necessary to ensure that unattended pressure vessels, separators, and tanks do not emit methane emissions. The emissions may occur as a result of an automated process, such as when liquids are automatically transferred to a tank or vessel, or when liquids are stored for an extended period. The requirement allows for hatches to be open during routine activities so that a regulated party may enter a vessel to perform routine maintenance or sampling.

Summary of Section 95669(m)

This section specifies requirements for open-ended lines or valves located at the end of lines used at facilities subject to the proposed regulation requirements.

Rationale of Section 95669(m)

This requirement is necessary to prevent the release of methane from open ended lines or valves that have one side of a valve seat open to the atmosphere. This requirement is designed to ensure that all valves are sealed as intended and do not solely rely on the valve seat to prevent the release of

emissions. Provisions are included to allow the owner or operator to use the valve as intended, but the valve must be sealed when not being used.

Summary of Section 95669(n)

This section specifies that components or component parts that incur five repair actions within a continuous 12 month period must be replaced.

Rationale of Section 95669(n)

This section is necessary to ensure that documented faulty or defective components are replaced to eliminate methane emissions. In some cases, these components may emit methane in between regular leak detection and repair inspections. This requirement is necessary to address faulty components that cannot be repaired by simple adjustment, such as tightening bolts that have loosened due to weathering.

Summary of Section 95669(o)

This section specifies that a regulated party must comply with all of the proposed leak detection requirements specified in the proposed regulation, and specifies the beginning compliance dates, leak thresholds, and percentage of leaks that are allowed during each compliance period. Failure to meet the requirements shall constitute a violation of the proposed regulation requirements.

Rationale of Section 95669(o)

This section is necessary to specify the leak detection and repair standards and to notify a regulated party that failure to meet any of the requirements constitutes a violation of the proposed regulation. Table 3 identifies the proposed compliance requirements for the first year of leak detection and testing, and Table 4 identifies the requirements beginning January 1, 2019 and thereafter.

15. Section 95670. Critical Components.

Summary of Section 95670(a)

This section specifies that by the proposed date, or within 180 days from installation, critical components must be pre-approved by ARB.

Rationale of Section 95670(a)

This section is necessary to inform a regulated party that all critical components must be pre-approved by ARB. Critical components are those that receive additional time to make repairs, which can be up to 12 months

from the date of initial leak detection or the next time that the equipment is shut down or removed from service.

Summary of Section 95670(b)

This section specifies that a regulated party must provide sufficient documentation demonstrating that a critical component is part of critical process unit and that removing the component within the proposed repair timeframes would result in excessive methane emissions or would impact the safety or reliability of the system.

Rationale of Section 95670(b)

This requirement is necessary so that a regulated party can adequately demonstrate that a critical component is part of a critical process unit.

Summary of Section 95670(c)

This section specifies that requests for critical components are made by submitting records and documentation to ARB as specified.

Rationale of Section 95670(c)

This section is necessary to provide a regulated party with instructions for submitting a request for a critical component designation.

Summary of Section 95670(d)

This section specifies that a regulated party must maintain a record of all critical components installed at the facility and must be able to make the record available upon request by the ARB or local air district inspector.

Rationale for Section 95670(d)

This section is necessary to inform a regulated party that records of critical components must be maintained at the facility and made available upon request by ARB or the local air district inspector. These records are necessary to provide documentation for use in determining compliance with the proposed leak repair timeframes.

Summary of Section 95670(e)

This section specifies that all critical components must be identified with a weatherproof, readily visible tag, indicating that they are pre-approved ARB critical components.

Rationale of Section 95670(e)

This section is necessary to inform a regulated party that all critical components must be clearly identified. This requirement is necessary so that ARB or local air district inspectors can easily verify these components during routine inspections and determine compliance with the proposed leak repair timeframes.

Summary of Section 95670(f)

This section specifies that approval of critical components may be granted if all of the requirements listed in Section 95670 are met, and that ARB reserves discretion to deny a critical component approval.

Rationale of Section 95670(f)

This section is necessary to inform a regulated party that ARB may deny a request for critical component approval. This requirement is needed to provide ARB with the discretion to evaluate, and re-evaluate if needed, all critical components to ensure that they are the part of a critical process unit and that repairing such component within the proposed repair timeframes would result in excessive methane emissions or would impact the safety or reliability of the system.

16. Section 95671. Record Keeping Requirements.

Summary of Section 95671(a)(1)

This section specifies that a record of flash analysis testing, including a sketch or drawing of the separator and tank system, laboratory reports, calculations, and field testing forms must be maintained for five years.

Rationale of Section 95671(a)(1)

This section is necessary to list all of the information required to adequately document the results of flash analysis testing and to document any changes in the system configuration or annual methane emissions. This information is also used by ARB or a local air district inspector to determine compliance with the proposed regulation standard.

Summary of Section 95671(a)(2)

This section specifies that a record of each leak concentration measurement for a reciprocating compressor rod packing or seal that is measured above the minimum leak threshold is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(2)

This requirement is necessary to list information that is required to adequately document the results of emissions testing. This information is required by ARB to maintain accurate records of leak concentration measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(3)

This section specifies that a record of each reciprocating compressor rod packing or seal emission flow rate measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(3)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(4)

This section specifies that a record of each centrifugal compressor wet seal emission flow rate measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(4)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(5)

This section specifies that a record of each pneumatic device emission flow measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(5)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(6)

This section specifies that each liquids unloading measurement or calculation must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(6)

This requirement is necessary to list information that is required to adequately document the results of liquids unloading activities. This information is required by ARB to maintain accurate records of liquids unloading activities and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(7)

This section specifies that a record of each well casing flow measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(7)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(8)

This section specifies that a record of each leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and subsequently measured above the minimum leak threshold is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(8)

This requirement is necessary to document leaks that have been identified during daily inspections or identified by a continuous monitoring system and demonstrate that they have been tested and repaired within the proposed repair timeframes. This information is required by ARB to maintain accurate records of leak concentration measurements and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(9)

This section specifies that a record of the number of leaks identified during inspections for each leak threshold category is recorded as specified in Appendix A, Table A4 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(9)

This requirement is necessary to document the number of leaks identified during a leak inspection for each leak threshold category in order to determine compliance with the proposed regulation requirements,

Summary of Section 95671(a)(10)

This section specifies that a record of each leak initial and final leak concentration and repair date is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(10)

This requirement is necessary to document all components that have been measured above the minimum leak threshold. This information is required by ARB to maintain accurate records of leak concentration measurements and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

17. Section 95672. Reporting Requirements

Summary of Section 95672(a)(1)

This section specifies that within 90 days of performing flash analysis testing or recalculating annual methane emissions, the results must be reported to ARB as specified in Appendix A, Table A1 of the proposed regulation.

Rationale for Section 95672(a)(1)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(2)

This section specifies that a record of each rod packing or seal leak concentration measurement that is above the minimum allowable leak threshold must be reported to ARB annually as specified in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(2)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(3)

This section specifies that a record of each rod packing or seal emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(3)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(4)

This section specifies that a record of each centrifugal compressor wet seal emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(4)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(5)

This section specifies that a record of each pneumatic device emission flow rate measurement for devices with a designed flow rate of less than 6

standard cubic feet per hour must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(5)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(6)

This section specifies that the measured or calculated volume of natural gas that is vented to perform liquids unloading must be reported to ARB annually as specified in Appendix A, Table A3 of the proposed regulation.

Rationale for Section 95672(a)(6)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(7)

This section specifies that a record of each well casing emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(7)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(8)

This section specifies that within 24 hours of identifying a leak that is measured above the maximum allowable leak threshold at each underground injection/withdrawal well wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead, the regulated party must contact ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

Rationale for Section 95672(a)(8)

This requirement is necessary to notify ARB and other appropriate agencies of a leak concentration measurement found at or near a wellhead assembly that exceeds the maximum allowable standard and potentially signals a well

failure. This requirement is necessary to ensure that all appropriate agencies are notified promptly so that appropriate action may be taken.

Summary of Section 95672(a)(9)

This section specifies that within 24 hours of receiving an alarm signaled by an air monitoring system that detects levels of natural gas that exceed more than 10 percent of baseline conditions that the regulated party must contact ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

Rationale for Section 95672(a)(9)

This requirement is necessary to notify ARB and other appropriate agencies of an alarm that exceeds baseline conditions and potentially signals a well failure. This requirement is necessary to ensure that all appropriate agencies are notified promptly so that appropriate action may be taken.

Summary of Section 95672(a)(10)

This section specifies that a record of all leaks identified during daily inspections or identified by a continuous leak monitoring systems and that are measured above the minimum leak threshold must be reported to ARB quarterly as specified in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(10)

This information is required by ARB to maintain accurate records of leaks identified at or near an underground injection/withdrawal well wellhead assembly and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(11)

This section specifies that the results of leak detection and repair inspections conducted during each calendar quarter must be reported to ARB annually as specific in Appendix A, Table A4 of the proposed regulation.

Rationale for Section 95672(a)(11)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(12)

This section specifies that the initial and final leak concentration measurement for each leak measured above the minimum allowable leak

threshold must be reported to ARB annually as specific in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(12)

This information is required by ARB to maintain accurate records leak inspection activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(b)

This section specifies the mailing address and electronic mailing address for ARB.

Rationale for Section 95672(b)

This section is necessary to provide contact information so that reports can be submitted to ARB.

18. Section 95673. Implementation.

Summary of Section 95673(a)(1)

This section specifies that the requirements of the proposed regulation are provisions of state law that are enforceable by both ARB and local air districts, and that a regulated party must pay fees required by a local air district to implement and enforce the proposed requirements, including fees associated with enforcement penalties. Enforcement action penalties secured by local air districts may be retained by the district.

Rationale for Section 95673(a)(1)

This section is necessary to clarify that the proposed regulation is enforceable by both ARB and the local air districts, and that a local air district may charge fees associated with implementing or enforcing the requirements, that regulated parties are responsible for paying the fees, and that local air districts may retain the funds.

Summary of Section 95673(a)(2)

This section specifies that the ARB Executive Officer may enter into an agreement with a local air district to further define implementation and enforcement requirements or to establish formal information sharing procedures.

Rationale for Section 95673(a)(2)

This section is necessary to make clear that ARB and local air districts may enter into formal written agreements, such a Memorandum of Understanding or Agreement, which may further define the implementation or enforcement procedures. Providing for such agreements is necessary to implementing the regulation in a flexible and cost-effective manner, and supports efficient use of ARB and air district resources. These agreements can be developed to provide a formal process for sharing confidential information such as registration or permit records, inspection or enforcement records, or collected test data.

Summary of Section 95673(a)(3)

This section specifies that implementation and enforcement by a local air district may not result in a standard, requirement, or prohibition that is less stringent than any of the requirements listed in the proposed regulation.

Rationale for Section 95673(a)(3)

This section is necessary to specify that the proposed regulation sets the minimum standards and requirements for regulated parties. In no instance may a local air district issue a registration or permit used on less stringent standards or requirements or adopt rules that result in less stringent standards or requirements, which are less stringent than the proposed requirements. This is necessary to ensure that this statewide regulation is implemented in a uniform manner, ensuring consistent emissions benefits and costs for regulated entities.

Summary of Section 95673(a)(4)

This section specifies that implementation and enforcement of the proposed regulation by a local air district does not waive or limit ARB's authority to implement or enforce any of the requirements specified. It further specifies that a facility's permitting or registration status does not otherwise limit the ability of a local air district to enforce applicable requirements.

Rationale for Section 95673(a)(4)

This section is necessary to clarify that both ARB has the ability to implement and enforce each of the provisions specified in this proposed regulation. It is also necessary to clarify that facilities subject to compliance with this article may be subject to local air district enforcement regardless of permitting or registration status.

Summary of Section 95673(b)(1)

This section specifies that a regulated party currently required to maintain a local air district permit for a facility or equipment due to federal, state, or local requirements must apply for these permits to be amended to include the terms specified in the proposed regulation and that future local air district requirements do not alter these provisions.

Rationale for Section 95673(b)(1)

This section is necessary so that a regulated party, as well as other federal, state, and local entities, understand that the terms and conditions of this proposed regulation must be included in any existing permit that covers affected facilities or equipment and that future changes to those permits do not alter the proposed regulation requirements.

Summary of Section 95673(b)(2)

This section specifies the registration requirements for facilities or equipment covered by the proposed regulation, which include registration with ARB, unless a local air district collects the required information and enters into an agreement to share it with ARB.

Rationale for Section 95673(b)(2)

This section is necessary to specify that facilities or equipment covered by the proposed registration must register equipment with ARB. This section specifies all required information. This section is also necessary to make clear that air districts may take on the registration program, obviating the need for separate registration with ARB.

Summary of Section 95673(b)(3)

This section specifies that owners and operators subject to the proposed regulation must comply with all of its requirements, even if they have not complied with any of the permitting and registration requirements of section 95673.

Rationale for Section 95673(b)(3)

This section is necessary to make clear that even if permitting and registration requirements are not fulfilled, the substantive standards and requirements of the proposed regulation still apply. This will ensure that any confusion over these compliance requirements does not act as an excuse to compromise emission reductions.

19. Section 95674. Enforcement.

Summary of Section 95674

This section specifies the types of violations that may occur under this proposed regulation. Subsection (a) specifies that each violation at each individual piece of equipment constitutes a separately enforceable violation. Subsection (b) specifies that each day or portion of a day that compliance is not maintained is a separate violation. Subsection (c) specifies that each metric ton of methane emitted in violation of the proposed regulation will constitute a separately enforceable violation. Subsection (d) specifies that failure to submit any required report will constitute a violation, and that each day a report is late will constitute a violation. Subsection (e) specifies that failures to retain required records and failures to produce records will constitute violations for each record, and for each day production is late. Subsection (f) specifies that producing inaccurate information is a violation of the proposed regulation. Subsection (g) specifies that submitting or producing false information is a violation of the proposed regulation.

Rationale for Section 95674

This section is required to specify that failure to comply with any of the proposed requirements is subject to enforcement action. Each enforcement provision is clearly specified so the proposed regulation is not interpreted in such a way to mean that a regulated party is not subject to enforcement action.

20. Section 95675. No Preemption for More Stringent Air District or Federal Requirements.

Summary of Section 95675

This section specifies that the proposed regulation does not preempt more stringent federal or local requirements.

Rationale for Section 95675

This section is required so that the proposed regulation is not interpreted in such a way to mean that any more stringent federal or local requirement do not apply to an entity subject to this proposed regulation.

21. Section 95676. Severability.

Summary of Section 95676

This section specifies that each part of the proposed regulation is severable.

Rationale for Section 95676

This section is necessary so that the proposed regulation is not interpreted in such a way to mean that a future determination, which invalidates any part of the proposed regulation, does not invalidate any of the other requirements.

22. Appendix A.

Summary of Appendix A, Table A1

This table specifies data that must be recorded at the time each flash analysis test is conducted.

Rationale for Appendix A, Table A1

This table is required to document the results of flash analysis testing and to adequately describe the separator and tank system at the time of testing. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

Summary of Appendix A, Table A2

This table specifies data that must be recorded each time a liquids unloading activity is conducted.

Rationale of Appendix A, Table A2

This table is required to document the results of liquids unloading activities. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

Summary of Appendix A, Table A3

This table specifies the minimum amount of information that must be provided to ARB each time an owner or operator makes a request for a critical component designation.

Rationale of Appendix A, Table A3

This table is required to submit information to ARB for critical component approval request. This table is used by a regulated party and ARB or local air district inspectors to maintain records of all critical components located at a facility and verify component repair timeframes.

Summary of Appendix A, Table A4

This table specifies test data that must be recorded during each leak detection and repair inspection.

Rationale of Appendix A, Table A4

This table is required to list the number of leaks found in each leak threshold category in order to determine compliance with the proposed leak detection and repair requirements.

Summary of Appendix A, Table A5

This table specifies the initial and final leak concentration measurements of each component that is found leaking above the minimum leak threshold.

Rationale of Appendix A, Table A5

This table is necessary to document components that are found leaking above the minimum leak threshold and to verify that the leak is either awaiting repairs or has been repaired and re-tested to verify that the component is not leaking above the minimum leak threshold.

Summary of Appendix A, Table A6

This table specifies the data that is required to register equipment at facilities with ARB.

Rationale of Appendix A, Table A6

This table is required to provide the ARB with adequate information to maintain records of equipment installed at facilities. This information will be used to assist ARB with conducting routine inspections and provide AB with accurate records of equipment installed at facilities.

Summary of Appendix A, Table A7

This table specifies the data that is required when conducting emission flow rate measurements.

Rationale of Appendix A, Table A7

This data is required to adequately document the results of emission flow rate measurements. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

23. Appendix B.

Summary of Appendix B

This section specifies the approved methodology for determining vented natural gas volume from liquids unloading of natural gas wells.

Rationale for Appendix B

This appendix is necessary to provide owners and operators with the calculation specified in the proposed regulation.

24. Appendix C.

Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water

Summary of Section 1

This section specifies that the intended purpose of the test procedure is to quantify emissions from crude oil, condensate, and produced water and that it is applicable for use on separator and tank systems.

Rationale of Section 1

This section is required to inform a regulated party of the intended purpose and applicability of the test procedure.

Summary of Section 2

This section describes the test procedure and specifies that testing is conducted by gathering pressurized liquid samples upstream of a separator and tank system. The intent of the test procedure is to replicate flashing inside of a separator and tank system. Therefore, samples must be gathered upstream of the system before emissions can flash from the liquid. After the samples are gathered, they are taken to a laboratory for conducting liquid and gas analyses in accordance with specified test methods and procedures. After the laboratory completes the analyses, the annual methane emissions are calculated using the laboratory results and a calculation methodology.

Rationale of Section 2

This section is required to provide a summary of the test procedure so that a regulated party can understand the test procedure concept.

Summary of Section 3

This section proposes definitions to the terms used in the test procedure.

Rationale of Section 3

It is necessary that ARB defines its terms as they apply to the test procedure.

Summary of Section 4

This section provides a list of each item that may create a bias, or errors, in the final reported results. A bias in the reported results can be introduced by using an incorrect sampling method, gathering samples from the wrong location or type of vessel, using the wrong type of sampling cylinder, or using un-calibrated equipment.

Rationale of Section 4

This section is necessary to inform a regulated party with a list of each bias that has been identified with the procedure so they can avoid errors that will affect the final reported results.

Summary of Section 5

This section provides a list of minimum equipment specifications for equipment that is used to take measurements from liquid that is collected from a pressurized separator.

Rationale of Section 5

This section is required so that all field measurements are performed using instruments that provide a minimum degree of accuracy and provide consistency in the final reported results.

Summary of Section 6

This section specifies the minimum equipment specifications required to gather liquid samples from a pressurized separator. The equipment includes pressure and temperature gauges, sampling cylinders, and high pressure rated fittings. This section also specifies the need for a portable pressurized separator in the event that no pressurized separator is installed within the separator and tank system. The portable pressurized separator is optional if a pressurized separator is installed and located immediately upstream of the separator and tank system.

Rationale of Section 6

This section is required so that a regulated party can obtain all equipment necessary to conduct the liquid sampling procedure.

Summary of Section 7

This section specifies that a sampling technician must be provided with specific information by the owner or operator at the time of liquid sampling. A list of the required information is provided which includes a system

identification number, the daily crude oil and produced water throughput, number of wells in the system, and the days of operation per year.

Rationale of Section 7

This section is required to inform a regulated party that information must be provided to the sampling technician at the time of liquid sampling. The information is required at the time of sampling because the characteristics of a separator and tank system can change daily, and any change in the parameters will affect the final reported results. Failure to provide the technician with the required information at the time of sampling will prevent the laboratory from conducting its analysis and will not provide the information necessary to calculate the annual methane emissions and report the final results.

Summary of Section 8

This section specifies procedures for using a Double Valve sampling cylinder to collect samples of crude oil or produced water. Depending on the liquid gathered, the cylinder is pre-filled with the specified liquid and sample liquid is introduced in the orientation as shown. Prior to gathering a sample, liquid must be purged through the sampling train into a suitable waste container to prevent filling the cylinder with air or other containments and to ensure that representative liquid is gathered.

Rationale of Section 8

This section is required to instruct a sampling technician on the proper method used for collecting crude oil or produced water using a Double Valve cylinder. This section is intended to provide detailed instructions to prevent sample collection bias and to prevent errors in final the reported results.

Summary of Section 9

This section specifies procedures for using a Piston Cylinder to collect samples of condensate or produced water. The Piston Cylinder may only be used to collect light hydrocarbon liquids or water because heavy crude oil can solidify and damage the cylinder, which will also prevent the laboratory from extracting the liquid. Prior to gathering a sample, liquid must be purged through the sampling line into a suitable waste container to prevent filling the cylinder with air or containments, and to ensure that representative liquid is gathered.

Rationale of Section 9

This section is required to instruct a sampling technician on the proper method used for collecting condensate or produced water using a Piston

Cylinder. This section is intended to provide detailed instructions to prevent sample collection bias and to prevent errors in final the reported results.

Summary of Section 10.1

This section specifies the laboratory quality control and quality assurance requirements required to conduct the test procedure. Each day of sampling, the laboratory must gather at least one sample duplicate. This way the lab can ensure consistency with their instruments and ensure that samples are collected in accordance with the test procedure. All deviations in measurements must be documented by the laboratory to provide a record of the deviation and explain discrepancies in reported results. Each laboratory must train its technicians on the sampling methods contained in the test procedure and must maintain records associated with sampling.

Rationale of Section 10.1

This section is required to maintain consistency in reported results from each of the separator and tank systems measured and to maintain consistency amongst the different laboratories performing the test procedure.

Summary of Section 10.2

This section lists the equipment specifications and practices required to conduct the flash analysis procedure. The minimum reporting limit for a gas chromatograph system is 100ppm for hydrocarbon and fixed gases. This provides for sufficient accuracy when reporting annual methane emissions. The equipment must be able to heat samples to the same temperature of the separator and tank system and have the ability to measure gas volume, temperature, and pressure.

Rationale of Section 10.2

This section is required to provide consistency amongst laboratories performing the laboratory flash analysis procedure. These specifications can accommodate different instruments, system configurations, and procedures used by different laboratories while ensuring consistency in final reported results

Summary of Section 10.3

This section specifies how a laboratory conducts the flash analysis procedure required to calculate the gas to oil or gas to water ratio. This includes procedures for how to heat and depressurize a sampling cylinder, collect flash gas, and analyze the gas for methane and other gaseous compounds. The procedure also includes a requirement that at least 0.20 cubic feet of gas is required to conduct test methods specified in the test procedure. After a flash analysis procedure is completed, the laboratory

must completely drain the cylinder and measure the volume of liquid to calculate the gas to oil or gas to water ratio.

Summary of Section 10.3

This section is required to ensure consistency among different laboratories conducting the flash analysis procedure. A minimum gas volume is required so that all of the instruments can be purged of air or contaminants and eliminates error in the final reported results. The minimum gas volume requirement is listed in this section because this is the point when a laboratory will discover how much gas is entrained in the liquid.

Summary of Section 10.4

This section specifies the calculation methodology used by the laboratory to calculate a gas to oil or gas to water ratio.

Rationale of Section 10.4

This section is necessary to specify the calculations that must be used by a laboratory to calculate a gas to oil or gas to water ratio. This section is required to ensure consistency in reported results.

Summary of Section 10.5

This section specifies the laboratory methods required to conduct the test procedure.

Rationale of Section 10.5

This section is necessary to specify laboratory methods required to conduct the test procedure and to ensure consistency in reported results.

Summary of Section 11

This section specifies the calculation methodology required to calculate the annual methane emissions using a gas to oil or gas to water ratio and a gas composition analysis provided by a laboratory in conjunction with the separator and tank system throughput obtained at the time of liquid sampling.

Rationale of Section 11

This section is necessary to specify the calculations required to calculate the annual methane emissions and ensure consistency in reported results.

Summary of Section 12

This section specifies records that must be compiled and maintained by a laboratory conducting the test procedure. These records include a field data collection form for each sample gathered, a sketch or diagram of the separator and tank systems, laboratory reports, and other information necessary to support the reported results.

Rationale of Section 12

This section is necessary to properly document all records associated with conducting the test procedure. In the event that the reported results do not represent the results of similar systems, the ARB Executive Officer or the owner or operator can contact the laboratory to evaluate the reported results and investigate possible sources of discrepancy.

Summary of Section 13

This section specifies that the test procedure must be conducted as specified and that alternative test procedures or laboratory methods used to report annual methane emissions must receive ARB Executive Officer approval. Any alternative procedures or methods will be evaluated by ARB on a case-by-case basis and a record of any approval will be maintained by ARB and made available upon request.

Rationale of Section 13

This section is necessary to specify that the test procedure must be conducted as specified and that alternative procedures or methods cannot be used without prior ARB Executive Officer approval. This section is required to ensure consistency in reported results.

Summary of Form 1

This section specifies the laboratory methods or procedures required to conduct the test procedure.

Rationale of Form 1

This section is necessary to document all applicable test methods and procedures used to conduct the test procedure and to ensure consistency in reported results.

III. ALTERNATIVES TO THE PROPOSED SOLUTION

Staff considered four alternatives to the proposed regulation that would be less burdensome to the affected industry. These alternatives are not the same as the alternatives in the Environmental Analysis, since those alternatives address reducing the environmental impacts of the proposed regulation while these alternatives address Administrative Procedure Act considerations. It is important to note that these alternatives are in addition to those that staff considered at the SRIA phase of this regulation, which are identified in that document.

A. ALTERNATIVE 1 – No Action

The first alternative is to not propose the regulation. Obviously, this would be less burdensome to the industry. However, this alternative does not achieve the goal of reducing methane emissions from the oil and natural gas production, processing, and storage sector. Accordingly, this alternative was rejected.

B. ALTERNATIVE 2 – Implement the Regulation without the LDAR Provision

The second alternative is to not propose the LDAR requirement in the regulation. This provision of the proposed regulation affects the most facilities and can be a labor intensive control measure. However, it also is the provision that achieves the largest amount of emission reductions, accounting for more than a third of the anticipated methane emission reductions. LDAR is also at the heart of catching small leaks before they become larger leaks. In addition, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that they anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

C. ALTERNATIVE 3 – Performance-based Standard

Staff considered a performance-standard based alternative for the proposed regulation. Specifically, staff considered a performance-based mandate to regulated entities to reduce the vented and fugitive emissions from regulated sources, as of a date certain, by an amount commensurate with the expected reductions the proposed regulation is expected to produce. Staff rejected this alternative for several reasons, but worked to incorporate flexibilities into the proposed regulation where possible to support legislative direction to avoid prescriptive regulations where possible.

Reasons for rejecting a wholesale performance standard alternative include the following points. This proposed regulation is designed to reduce venting and fugitive emissions from the sector. These emissions are, by their nature, difficult to quantify in many cases, and come from a wide range of potential sources. A flat reduction mandate would be very difficult to enforce without more accurate baseline data on current emissions from these sources, at the

facility and component level, than is now available – it is, in other words, far more effective to enforce a requirement to replace a certain piece of equipment, or follow a particular LDAR procedure, than a performance-based reduction requirement from an uncertain baseline. To ensure reductions occur, therefore, staff focused on providing uniform, clear standards for equipment and processes that could reliably be measured, implemented, and enforced. Further, because emission controls focusing solely on methane reduction could have contributed to criteria pollutant emissions if poorly implemented, or failed to secure maximum co-benefits of criteria and toxic pollutants, it was important to specify particular implementation requirements to produce better results on this metric as well.

But though staff rejected a performance standard alternative as a complete option, staff made significant efforts to provide options within the rule's directive framework to provide compliance flexibilities. For instance, regulated entities have several options as to how to implement vapor control device provisions, to conduct LDAR inspections, and to address equipment replacement or retrofit decisions. These embedded options within the proposed regulation help reduce compliance burdens, thereby fulfilling the legislative intent driving consideration of performance-based alternatives, while ensuring that emission reductions happen in an enforceable and environmentally appropriate manner.

D. ALTERNATIVE 4 - Emission Reduction Provision

Staff also considered including an emission reduction provision that would require operators to mitigate climate impacts of large methane leaks. In evaluating whether an emission reduction provision would be appropriate, staff considered several options, including increased penalties for operators of facilities where the leak occurred and an emission reduction plan providing ton-for-ton reductions or stricter monitoring requirements. Staff concluded that stiffer monitoring requirements were the most appropriate. Increased penalties were not an effective option since all prohibited leaks violate the proposed regulation and thus every violation is potentially subject to the maximum penalties statutorily allowed. A plan for reductions was deemed inappropriate at this time, for the following reasons: first, developing generally applicable requirements for such a plan – though somewhat specified in the mitigation plan developed for the Aliso Canyon leak – is a difficult regulatory task when generalized to any potential facility, and so would likely delay the regulation and associated methane reductions. Furthermore, ARB has considerable authority to drive appropriate mitigation via its existing enforcement authorities and settlement authority. Therefore, rigorous monitoring provisions, rigorously enforced, were deemed appropriate for this proposed regulation. ARB will continue to consider the issue, however, and may revisit this decision in future rulemakings.

IV. FUNDING, IMPLEMENTATION, PERMITTING AND ENFORCEMENT

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are interested in building on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

A. FUNDING FOR IMPLEMENTING AND ENFORCING ARB'S PROPOSED OIL AND GAS REGULATION

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation provides for the local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

To aid enforcement, operators must register their facilities with ARB (unless the district takes on this task via MOU) and update relevant permits for permitted facilities. Permit updates can occur on whatever frequency now in use at a district; registration with ARB (or the district) is required by January 1, 2018.

Implementing and enforcing this regulation does not come without costs. Local air districts have the legal authority to raise fees paid by the regulated community to support additional programs such as this regulation, which will help to address these costs, but likely need board approval, which is uncertain. The rule also makes clear that districts may retain penalties secured from rule enforcement. ARB continues to explore opportunities to further assist the air districts.

ARB staff, with district input, estimate that the regulation will require on the order of 5-6 PYs to implement depending on the mix of district and ARB implementation. The costs are going to be higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over \$300,000 per year in recurring costs and almost \$1,000,000 in one-time costs, primarily for permitting. Even if the districts

decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation.

B. PERMITTING AND ENFORCEMENT

The proposed regulation addresses enforcement, permitting, and registration requirements for covered equipment and facilities in several ways:

- Operators with equipment and facilities that are already covered by local air district permitting programs must include the proposed regulation requirements as part of their submission, ensuring compliance with the proposed regulation. This submission will aid enforcement by ensuring that applicable requirements are gathered in operating and construction permits, but limits local air district workload because it does not require that any new permits be issued to otherwise unpermitted facilities or equipment. In addition, permits can be updated upon scheduled renewal timelines, to avoid unduly increasing district workload. New covered equipment and facilities (including wells) must include this in their submission at the time they are permitted.
- All equipment and facilities covered by this proposed regulation would also be required, by January 1, 2019, to be registered with ARB, to ensure that ARB enforcement personnel have the information necessary to effectively enforce the regulation. However, if the local air district is also collecting this information, and has entered into an MOU with ARB to share the information with ARB, then this requirement may not apply, depending on the MOU details.

In sum, the proposed regulation is designed so that its requirements can be folded into existing permitting programs, where they exist, and to ensure that critical enforcement and compliance information reaches ARB, with minimum duplication of local air district efforts. Local air districts are free to expand or establish permitting or registration programs to support enforcement, but are not required to do so.

ARB anticipates working closely with the local air districts to support implementation and enforcement. The proposed regulation thus contains several provisions to support further ARB/air district cooperation on enforcement and implementation. It makes clear, first, that both ARB and local air districts may enforce and inspect to ensure compliance. ARB anticipates entering into MOUs with interested local air districts to ensure that these shared responsibilities are undertaken in a coordinated way. To further support local air districts in their efforts, the proposed regulation also provides that districts may incorporate the terms of the regulations into their local rule, that owners and operators must be subject to fee increases imposed by air districts to implement the proposed regulation, and that local air districts may retain penalties they collect enforcing the regulation.

To support statewide uniformity and rigorous enforcement, the proposed regulation is clear that no local air district may implement or enforce it in ways that reduce its stringency; similarly, local air district decisions, and permitting and registration decisions, do not in any way waive or limit ARB's own enforcement authority. Conversely, the proposed regulation is also clear that it does not preempt any local air district requirements that are more stringent, or substitute for compliance any applicable federal requirements.

Finally, the proposed regulation defines potential violations to provide clarity. Individual violations for which enforcement consequences may result include: (1) failure to comply with its requirements with regard to each individual piece of covered equipment, (2) each day or portion thereof out of compliance, (3) each metric ton of methane emitted in violation, (4) failure to submit any required report and each day or portion thereof the report is late, (5) failure to retain and failure to produce any record required by the regulation, (6) falsifying any information or record, and (7) producing inaccurate records or information.

V. TECHNICAL ASSESSMENT

A. DEVELOPMENT OF METHANE EMISSION STANDARDS

In developing the proposed regulation, Staff analyzed the impact of applying control measures to the different components affected by the regulation's provisions.

1. Crude Oil and Produced Water Separator and Tank Systems

Separator and tank systems are used to separate and store crude oil, condensate, and produced water. Based on ARB site visits to production facilities and conversations with industry, Staff identified several types of separator and tank system configurations. In crude oil production, the most common system consists of a separator, which allows emulsion to gravimetrically separate, and two tanks, one of which is used to hold the separated crude oil and one which is used to hold the produced water. There may be further oil tanks and produced water tanks downstream of these first two for further separation and treatment of the oil and produced water. However, for purposes of the proposed regulation, "separator and tank system" means the first separator in a crude oil or natural gas production system and only the tanks directly connected to the separator, which typically is no more than two – one for oil and one for produced water.

In dry natural gas production, the most common system consists of a heated separator used to heat the gas to remove liquids, and a single tank used to store produced water and small amounts of condensate, which is typically a mixture of very light hydrocarbons.

Each of the system configurations vary slightly due to factors such as the number of wells in the system, type of oil produced, and the amount of gas entrained in the crude oil or produced water.

Staff evaluated emissions from separator and tank systems based on the results of flash analysis testing. Emissions from flashing are primarily a result of depressurizing liquids from underground reservoir pressure to atmospheric pressure at the tanks. Staff used test data to derive average emission factors for crude oil and produced water, and then applied the factors to counts of separators and tanks and to oil and produced water throughputs, both obtained from the ARB Oil and Gas Industry Survey, to estimate annual methane emissions⁴³. The results of the analysis and test data are provided in Appendix D.

The flash emission test data show that methane is emitted in varying quantities from each well or group of wells that serve each separator and tank system. The amount of methane emitted is a function of the percentage of

⁴³ See footnote 41. ARB. 2013. Oil and Gas Survey. ARB 2007 Oil and Gas Industry Survey Results

methane contained in the gas, the volume of gas entrained in the liquid (the Gas Oil Ratio or the Gas Water Ratio), and the total oil and water throughput. This means that emissions can be different for each separator and tank system. As shown in the data in Appendix D, both heavy oil and light oil contain methane and may have similar volumes of gas entrained in the liquid. In some case, the only difference in methane emissions is due to the oil and water throughput.

a) Limited Throughput Exemption

Staff is proposing a limited exemption from flash analysis testing and vapor collection system requirements for small producers of oil and natural gas. The proposed exemption is based on an analysis of the flash test data as outlined in Appendix D to determine if there are production levels below which no systems are expected to exceed the proposed methane standard. The analysis shows that a separation and tank system will not exceed the proposed standard if both the crude oil production is below 50 barrels per day and the produced water production is below 200 barrels per day. This exemption applies to both crude oil and natural gas separator and tank systems. Owners or operators with systems meeting both of these requirements will not need to conduct flash analysis testing or control a separator and tank system with the use of a vapor collection system. ARB Staff estimates this will exempt approximately 1,500 smaller separator and tank systems from the proposed regulation requirements, resulting in lower costs for smaller producers without an expected impact on emission reductions.

b) Methane Standard

To develop the proposed emission standard, Staff analyzed impacts for a range of methane standards between 0 and 40 MTCH₄/Year for uncontrolled separator and tank systems. The proposed 10 MTCH₄/Year standard was chosen to achieve approximately 90% annual methane. Standards of 0 or 5 MTCH₄/Year were also considered, although those standards would have required vapor controls on significantly more systems while achieving only limited additional methane reductions. The results of the analysis are shown below in Table 7.

Table 7: Impact of Different Annual Methane Standards on Uncontrolled Systems⁴⁴

| Category | O&G System Threshold | | | | | | | | |
|---|----------------------|-------|-------|-------|-------|-------|-------|-------|-------|
| | 0 MT | 5 MT | 10 MT | 15 MT | 20 MT | 25 MT | 30 MT | 35 MT | 40 MT |
| # of Systems Controlled | 1,072 | 38 | 29 | 29 | 26 | 7 | 5 | 4 | 4 |
| # of Water Tanks Controlled | 1,432 | 303 | 294 | 289 | 281 | 252 | 224 | 168 | 99 |
| System CH ₄ Emission Reductions (MT) | 1,217 | 929 | 871 | 871 | 821 | 408 | 350 | 316 | 316 |
| Water Tank CH ₄ Emission Reductions (MT) | 8,132 | 7,445 | 7,424 | 7,390 | 7,344 | 7,116 | 6,744 | 5,897 | 4,631 |
| Total CH ₄ Emission Reductions (MT) | 9,349 | 8,374 | 8,295 | 8,261 | 8,165 | 7,524 | 7,094 | 6,213 | 4,947 |
| % of Total Emissions Captured | 100.00% | 90% | 89% | 88% | 87% | 80% | 76% | 66% | 53% |

While evaluating different methane standards, Staff also considered the US EPA New Source Performance Standards (NSPS) Subpart OOOO⁴⁵ for new or modified tank systems used at crude oil and natural gas production facilities. The NSPS sets an emissions limit of 6 tons of VOC per year for new or modified systems to require vapor recovery. This analysis was conducted to ensure that the proposed methane standard would be at least as stringent as the standard required by EPA. As described in Appendix D, the analysis shows that 6 tons per year of VOC is equivalent to approximately 36 metric tons per year of methane, which means that the proposed methane standard is more stringent than the current US EPA NSPS as it relates to VOCs. Therefore, the proposed methane standard will not result in emissions that exceed the current US EPA NSPS requirements and will provide significant reductions.

2. Circulation Tanks for Well Stimulation Treatments

Well stimulation treatments (WSTs) are performed on crude oil or natural gas wells to increase the production of gas or fluids. The different types of well stimulation treatments used at crude oil and natural gas production facilities

⁴⁴ Does not include emissions from tanks currently controlled under district rules.

⁴⁵ U. S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012.

include hydraulic fracturing, acid fracturing, and acid matrix stimulation. A WST is performed after a drilling operation has been completed, but before the well is put into final production. After a WST has been completed, the surface equipment used to conduct the operation is removed from the well pad and replaced with a circulation tank (see Figure 8) and other support equipment to remove drilling plugs and excess sand from the wellbore. During the circulation process, water is injected into the wellbore where it mixes with other hydrocarbon liquids found in the reservoir. The sand, contained within the water and hydrocarbon mixture, is then forced back up to the surface where it is transported to the circulation tank to remove the sand from the liquid mixture. This process is conducted to prevent sand from entering the separator and tank system where it can clog or damage equipment. Staff visited several different WST operations that used a circulation tank to circulate sand from a wellbore. In all cases, the tanks were open to the atmosphere. This allows methane to vent to the atmosphere during the circulation process.

Staff initially relied on US EPA estimates for emissions from hydraulically fractured oil wells⁴⁶; however, industry conducted additional testing on wells located in California⁴⁷. Although the industry testing is limited, Staff believes it is more representative of California data since WST is very different in other parts of the country. Due to the limited number of tests, Staff chose the upper limit of the range for the estimates. The data did not include information on other constituents in the vapor coming from the tanks other than methane. However, since the well stimulation process uses a variety of chemicals, there is potential for reductions in other pollutants such as toxic air contaminants.⁴⁸ A recent meta-analysis showed 87 percent of studies on unconventional natural gas development indicated increased air emissions compared to conventional natural gas development⁴⁹. For this reason, and due to the fact that both the US EPA and California industry studies show that uncontrolled emissions of methane are associated with hydraulically fractured oil and gas wells, Staff is proposing emissions controls for all circulation tanks used in conjunction with well stimulation treatments.

During the development of the proposed regulation, Staff received feedback from industry⁵⁰ indicating that it may be difficult to collect small volumes of natural gas from some hydraulically fractured oil wells, or that although the

⁴⁶ U. S. EPA. 2014. Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production.

⁴⁷ WSPA. 2015. Recirculation Tank Emissions Testing. October 2015.

⁴⁸ CCST. 2015. An Independent Scientific Assessment of Well Stimulation in California Volume I, Well Stimulation Technologies and their Past, Present, and Potential Future Use in California. Sacramento, CA

⁴⁹ Hays J., Shonkoff SBC. 2016. Toward an Understanding of the Environmental and Public Health Impacts of Unconventional Natural Gas Development: A Categorical Assessment of the Peer-Reviewed Scientific Literature, 2009-2015.

⁵⁰ WSPA. 2016. Meetings, Attachment 2. http://www.arb.ca.gov/cc/oil-gas/meetings/WSPA_attachment2_03042016.pdf

gas may be able to be collected, it may not be feasible to inject the gas into an existing vapor collection system. Staff contacted one manufacturer of circulation tanks to inquire about using their equipment to recover both small and large quantities of natural gas from circulated liquids. Through subsequent discussion, the manufacturer reported that their equipment is commonly used in other states outside of California for collecting gas from wells that are subject to US EPA NSPS requirements, and that their equipment can be used to collect any volume of natural gas liquids, including low volumes as used in circulation tanks⁵¹.

Additional discussions with industry suggested that even if gas is collected from circulation tanks, it would be difficult to route the gas to an existing vapor collection system and that the gas may be of unsuitable quality for use in on-site equipment. Staff contacted one manufacturer of Low-NOx incinerators to determine if such a device could be used in this type of application^{52 53}. The manufacture reported that their devices are used for destroying low quality waste gas, and for situations where only a small amount of gas is collected, they may be able to temporarily store gas in what is called a “bladder” until a volume is large enough volume of gas is collected for incineration.

Based on initial discussions with industry and equipment manufacturers, Staff is proposing that facilities using circulation tanks in conjunction with WSTs develop a best management practices plan to reduce emissions from the tanks and provide ARB with the results of a technical demonstration of vapor control equipment by the date specified in the proposed regulation. This will provide time for industry and equipment manufacturers to work together to develop and test all necessary equipment, and help to ensure that industry is taking steps to reduce emissions while the equipment is being designed and tested.

For the purposes of estimating costs and emissions associated with controlling circulation tank emissions, Staff relied on cost estimates provided by manufactures of Low-NOx incinerators and costs to install a vapor collection system as described in Appendix B. To estimate the number of tanks that would be subject to the vapor control requirements, Staff estimated that 6 circulation tanks would be subject to the proposed requirements. This estimate is based the assumptions that only a limited number of circulation tanks are used in California. In practice, circulation tanks are portable and frequently moved from one job site to another, and the duration of a circulation job typically lasts no more than 48 hours. The calculations used to estimate the costs and emissions can found in Appendix B.

⁵¹ SandX. 2015. Phone conversation.

⁵² Tim Egan. 2015. Email from Timothy Egan of Aeron to Joe Fischer of ARB. July 2.

⁵³ Aeron. 2015. Phone conversations.

3. Vapor Collection Systems and Control Devices

Vapor collection systems are used to control emissions for separator and tank systems, circulation tanks, and other types of equipment. The systems are used to collect and route vapors to equipment for use as a fuel source or underground injection, or to send the vapors to a control device that may thermally or non-thermally destroy the collected vapors. The collection systems are typically comprised of vapor collection piping and a compressor, although some systems operate without a compressor by using natural gas pressure.

Currently, vapor collection systems are used at crude oil and natural gas facilities for controlling VOC emissions from pressure vessels, tanks, separators, and other types of equipment such as natural gas compressors. After vapor is collected, it must be controlled with 95% efficiency. This level was chosen to align with the U.S. EPA NSPS requirements. The vapors are often sent to a sales gas or fuel gas system, but they may also be re-injected into an injection well or combusted with the use of a vapor control device. Vapor control devices, such as a flare or incinerator, are used to destroy collected vapors. However, destroying vapors with the use of these devices can also result in the formation of nitrogen oxides or NO_x emissions, which also contribute to the formation of ozone and particulate matter⁵⁴.

To develop the proposed vapor control device standards, Staff considered NO_x emission impacts in regions classified as nonattainment for federal and State ambient air quality standards. Staff is concerned with NO_x because it is an ozone precursor, and creating more of it in ozone impacted areas would have a negative effect on the air quality in those regions. These nonattainment areas are California air basins described in the Environmental Analysis, Appendix C to this document. Staff focused on designing methane emission controls that would complement and avoid interfering with efforts to address these important criteria pollutants, while protecting communities (including low-income and disadvantaged communities) living in these areas. Staff is proposing a systematic approach for handling any newly collected vapors, which results in reduced NO_x emission from business as usual.

The proposal is designed to take a tiered approach with regard to collecting and disposing of methane vapors. The first tier of the proposal requires any newly collected vapors to be directed to an existing sales gas system, fuel gas system (where they are combusted as fuel in equipment), or sent to an existing gas disposal well for underground injection. This systematic approach to handling newly collected methane vapors is designed to use existing systems that have no impact on NO_x, since even the newly collected vapors used in a fuel gas system will displace natural gas that would have been purchased.

⁵⁴ U. S. EPA. 1999. Nitrogen Oxides (NO_x), Why and How They Are Controlled.

If the facility does not have these options, the second tier is to use a new non-combustion vapor control device. During the regulatory development process, Staff contacted one non-combustion technology manufacturer that uses this type of equipment to reduce VOC emissions to determine if the technology could be used in oil and gas applications⁵⁵. This type of technology rapidly cools and condenses vapors into a liquid. The manufacturer reported that condensing gaseous carbon dioxide along with methane can cause equipment problems and is not currently feasible. However, Staff has included an option to use a non-combustion technology if they become feasible in the future.

If the facility cannot use an existing sales gas, fuel gas, or injection system, or a non-combustion vapor control device, the facility can consider a newly installed or existing vapor control device. A new vapor control device must meet the proposed NO_x standard of 15 ppmv and must not use supplemental fuel gas to operate, aside from gas required to run a pilot. Table 8 compares average values of NO_x emissions from different types of combustion equipment. As shown, a low- NO_x incinerator and microturbine provide the lowest NO_x emission rates compared to other types of combustion equipment, including regular flares and rich burn internal combustion engines.

If a facility has newly collected vapors and an existing flare, and needs to use a combustion control device due to this proposed regulation, then the facility will have to replace an existing higher-NO_x flare with a low-NO_x incinerator or other device that meets the 15 ppmv NO_x standard. As shown in Appendix D, replacing existing flares with low-NO_x incinerators will more than make up for the resulting new NO_x emissions from the combustion of newly collected vapors, resulting in a NO_x benefit of approximately 1.6 tons per year of NO_x.

Table 8: NO_x Emission Comparison of Equipment

| Equipment Type | NO _x Emissions (lb/MMBtu Input) |
|---------------------------------|---|
| Rich Burn IC Engine | 0.170 ⁵⁶ |
| Flare | 0.068 ⁵⁷ |
| NG Turbine | 0.040 ¹⁸ |
| Low-NO _x Incinerator | 0.018 ⁵⁸ |
| Microturbine | 0.015 ¹⁸ |

⁵⁵ Air Products and Chemicals Inc. 2015. Phone conversation.

⁵⁶ U. S. EPA, Combined Heat and Power Partnership. 2015. Catalog of CHP Technologies. Section 1. Introduction. March.

⁵⁷ U. S. EPA. 2015. AP 42, Fifth Edition, Volume I Chapter 13: Miscellaneous Sources. Section 13.5 Industrial Flares. <https://www3.epa.gov/ttnchie1/ap42/ch13/>

⁵⁸ Aeron. 2015. Certified Ultra Low Emissions Burner, Sheets CEB 50 through CEB 1200. <http://www.aereon.com/enclosed-combustion-systems/certified-ultra-low-emissions-burner-ceb>

4. Reciprocating Natural Gas Compressors

Reciprocating compressors are used to compress natural gas by using a piston driven by crankshaft, connected to an engine or electric motor. Rod packing systems are the mechanism used to create a seal around a moving crankshaft, to contain the gas inside of the compressor. Due to the design of these systems, a rod packing or seal may leak a small amount of natural gas during normal operation, and have the potential to vent large amounts of gas if the rod packing or seal becomes damaged or wears out.

In order to develop the proposed emissions standard for reciprocating compressors, Staff reviewed the most current local air district rules for compressors, (see LDAR section below), the US EPA NSPS, information provided by rod packing manufacturers, and owners and operators of reciprocating compressors.

The current US EPA NSPS requires new or modified compressors used at gathering and boosting stations and natural gas processing plants to replace rod packing systems within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing⁵⁹. There are no other requirements for compressors installed at the other types of facilities. ARB Staff reviewed current local air district rules for requirements pertaining to natural gas compressors. They found that some compressors installed within major oil and gas producing regions are subject to regular leak inspection requirements over and above the NSPS standards. These requirements are included within the local air district leak detection and repair programs and require owners and operators to measure concentration from the vent area around the rod packing or seal and other compressor components on a regular basis.

In addition to evaluating the current federal and local requirements, ARB Staff also contacted a manufacturer of reciprocating compressors to gather information and manufacturer guidelines for replacing faulty or defective rod packing systems. The guidelines provided below, are described in terms of a natural gas flow rate of emissions from the vent near the piston rod-packing on the reciprocating compressor. Table 9 identifies the manufacturer's recommended guidelines for repairing or replacing rod packing systems. These guidelines apply to one compressor manufacturer that produces compressors for use at natural gas transmission and underground storage facilities where the compressor uses a driver engine or motor with greater than 250 rated horsepower.

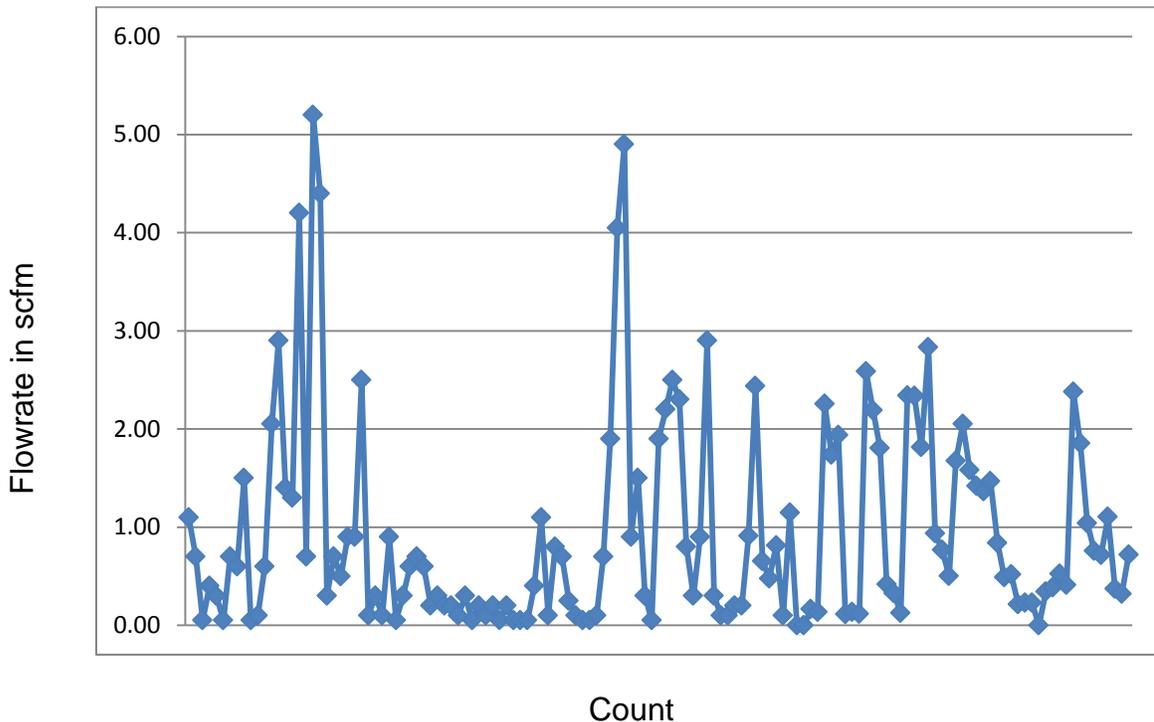
⁵⁹ U.S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012

Table 9: Manufacturer Rod Packing Guidelines⁶⁰.

| Condition | Rod Packing Flow Rate measured in standard cubic feet per minute (scfm) | Rod Packing Flow Rate measured in standard cubic feet per hour (scfh) |
|--------------|---|---|
| Excellent | 0.02 | 1.2 |
| Good | 0.05 | 3.0 |
| Normal | 0.10 | 6.0 |
| Fair | 0.50 | 30.0 |
| Poor (Alarm) | 2.00 | 120.0 |
| Very bad | 3.00 | 180.0 |
| Dangerous | 4.00 | 240.0 |
| Failure | 100.00 | 6000.0 |

Staff also used natural gas emission flow rate data provided by industry. The industry provided data included measurements from 55 reciprocating compressors taken over a four year period. According to the data, about 14% of the measurements indicated a leak rate of over 2 scfm per cylinder. Figure 10 below depicts the industry provided flow rate measurements.

Figure 10: Measured Rod Packing Flow Rate (scfm)



Most of the measurements in Figure 10 are below 2 standard cubic feet per minute (scfm), or 120 scfh, which is below the manufacturer’s “poor” guideline

⁶⁰ Dresser-Rand. 2014. Email from Matt Gilbert of Dresser Rand to Christian Hurley of ARB. December 17, 2014.

rating. However, several were measured above 2 scfm, and would be considered dangerous or as a rod packing failure according to the manufacturer's guidelines shown in Table 9.

Using the manufacturer's and industry data, Staff is proposing a 2 scfm standard for rod packing emissions from compressors used at natural gas transmission compressor stations, underground storage facilities, gathering and boosting stations, and processing plants. This standard was designed to correspond with the manufacturer's recommended guidelines for heavy duty compressors used at these types of facilities, regardless of the amount of time the compressor has been in use. Because many of these compressors use elevated vents stacks, ARB Staff also proposes that each compressor is outfitted with an access port installed at ground level to ensure that both the operators and inspectors can make regular flow rate measurements without specialized equipment. In addition, these compressors are subject to the LDAR requirement for all components other than the rod packing. Any newly installed or modified compressor must still comply with the NSPS as well as the proposed regulation.

Staff believes that the NSPS standards do not conflict with ARB's proposed emissions standards. In the event that a rod packing is measured in accordance with the proposed testing requirements prior to the EPA NSPS timeframe, the rod packing may not require repair or replacement, which does not interfere with the NSPS standards. However, in the event that a rod packing is measured above the proposed emissions standards, the rod packing would require repair or replacement sooner than the NSPS timeframe, which will result in fewer methane emissions. In addition, the NSPS only applies to compressors found at gathering and boosting stations and natural gas processing plants, whereas this proposed regulation's rod packing standard also applies to compressors at underground natural gas storage facilities and transmission compressor stations.

The remaining compressors identified in the ARB survey are located at oil and natural gas production facilities. ARB proposes that compressors used at production facilities undergo LDAR testing to check the rod packing or seal in order to provide for a simple leak concentration measurement. ARB is also proposing that all other components on production compressors be subject to LDAR. Staff considered using the same flow rate measurement standard as proposed for compressors used at other types of facilities, as well as the simpler LDAR test method and emission standard. During site visits, Staff found that nearly all production facility compressors are uncovered and can be reached from ground level. Further, many of the production facility compressors are already subject to local air district LDAR requirements, which is an effective, easier test method to perform. In order to integrate with local air district programs and provide a simpler form of testing for the majority of compressors located in California, staff is proposing to use the Method 21 test method (detailed further in the LDAR section) combined with a 30-day

repair timeframe for a rod packing or seal that is measured above the minimum LDAR leak threshold. The 30 calendar day repair timeframe is intended to provide time for the owner or operator to remove the compressor from service and make the necessary repairs.

3. Centrifugal Natural Gas Compressors

Centrifugal compressors use a rotating disk or impeller to pressurize natural gas for use in a transmission pipeline or underground storage applications. Similar to reciprocating compressors, centrifugal compressors also use a mechanism, referred to as either a wet seal or a dry seal, to create a seal around a moving crankshaft, which contains the gas inside of the compressor. Wet seals use pressurized oil circulated around the moving shaft to form a barrier and contain the natural gas inside of the compressor. Unlike wet seals, dry seals do not use high pressure oil to create the sealing barrier. Instead, dry seals use a very tight tolerance fit to contain the gas inside of the compressor. Methane emissions from wet seals are higher than the emissions from dry seals because normal operation causes natural gas to become entrained into the seal oil, which is circulated through the oil pump system, and emitted.

To develop the proposed wet seal emissions standard, Staff reviewed the current NSPS⁶¹, the EPA Natural Gas STAR recommended technologies and practices⁶², and data collected as part of the ARB survey⁶³. Staff also conducted several site visits to natural gas transmission and underground storage facilities and visited a centrifugal compressor manufacturing facility to verify wet seal and dry emissions rates, and learn about compressors and common maintenance practices, including retrofitting.

Current NSPS requirements state that all new or modified compressors installed at oil and gas production facilities must control 95% of the wet seal emissions. There are no NSPS requirements for compressors installed at transmission compressor stations or underground storage facilities. Staff contacted each of the facilities reporting centrifugal compressors in the 2007 ARB survey. Staff confirmed that there is only one uncontrolled wet seal centrifugal natural gas compressor currently operating in California. The compressor is not subject to EPA NSPS requirements.

To develop the proposed emission standard, Staff referred to the US EPA Natural Gas STAR recommended technologies and practices. The Gas STAR program is a voluntary partnership that encourages oil and natural gas companies to adopt cost-effective emission reduction technologies. According to the Gas STAR data, wet seals are estimated to emit 50 scfm

⁶¹ U. S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012.

⁶² U. S. EPA. 2014. Natural Gas Star. Wet Seal Degassing Recovery System for Centrifugal Compressors.

⁶³ See footnote 41.

(3000 scfh) per seal while dry seals emit 3 scfm (180 scfh) per seal. Because both the wet seal and dry seal emission estimates are provided in terms of flow rate, Staff concluded that measuring the wet seal emission flow rate is feasible, as long as the operator or inspector has access to the wet seal vent stack for making measurements.

Staff developed the 3 scfm emission standard because this is the equivalent of an average dry seal emission rate and similar to a 95% vapor control for the average wet seal emission rate. Staff also proposes that an access port for making flow rate measurement be installed at ground level.

Two alternative means to meet this standard are also proposed. One option is for the operator to control the emissions from wet seals with at least 95% control efficiency using a vapor collection system. It is identical to the NSPS for centrifugal compressors installed at production facilities. The second alternative allows the operator to replace the wet seals with dry seals by January 1, 2020. This provides additional time for the operator to modify California's only wet-seal reciprocating compressor due to the high cost of replacing a wet seal compressor with a dry seal compressor, if controlling the emissions with the use of a vapor collection system is not possible.

4. Natural Gas Powered Pneumatic Devices and Pumps

Pneumatic devices are used for maintaining a process at an oil or natural gas facility such as liquid level, pressure, or temperature. While pneumatic devices are commonly used at crude oil production facilities, most devices use compressed air or electricity to operate and therefore do not vent natural gas or methane emissions. However, gas powered pneumatic devices are commonly found at natural gas production and midstream facilities such as natural gas transmission compressor stations or underground storage facilities where natural gas is readily available. These devices use pressurized natural gas to operate and can be classified into three primary types;

- Continuous bleed devices vent natural gas to the atmosphere on a continuous basis.
- Intermittent bleed devices also vent natural gas to the atmosphere but only do so when they control a process, or more specifically, when the actuators spin to open or close or control a process; and
- No bleed devices do not vent natural gas while idle or when they actuate.

a) Continuous Bleed Devices

Continuous bleed devices, as the name implies, are designed to continuously vent natural gas into the atmosphere in order to operate.

The devices are commonly referred to as either high bleed or low bleed depending on the volume of gas that is vented,

- High Bleed devices vent more than 6 scfh;
- Low Bleed devices are those that vent less than 6 scfh;

Due to advances in technology, the use of electronic control instrumentation has been increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. Mechanical devices are another alternative to high bleed pneumatic devices that are widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. However, use of the mechanical devices is limited because they need to be in close proximity to the process measurement⁶⁴.

Staff contacted one manufacturer of continuous bleed pneumatic devices to discuss retrofitting existing high bleed devices with electric or mechanical devices⁶⁵. The manufacturer reported that they provide retrofit kits for a number of their units for converting the devices to use electricity, and they also supply retrofit kits to convert units to low bleed⁶⁶.

Staff also considered recently installed low bleed devices as several operators recently choose to change out high bleed devices with low bleed devices instead of installing metering in order to be compliant with ARB's Mandatory Reporting Regulation. Requiring these low bleed devices to be changed to no bleed devices would place a burden on facilities, but the amount of methane emissions reduced by replacing those previously installed low bleed devices is small when compared to the total methane emissions from continuous high bleed natural gas powered pneumatic devices.

Accordingly, Staff is proposing that continuous bleed pneumatic devices be converted to no bleed devices, except where high bleed devices have been recently changed out to low-bleed devices pursuant to ARB's Mandatory Reporting Regulation.

⁶⁴U.S. EPA. 2014. Options for Reducing Methane Emissions from Pneumatic Devices in The Natural Gas Industry.

⁶⁵ Emerson Process Management. 2015. Phone conversation.

⁶⁶ Emerson Process Management. 2016. Electro-Pneumatic Transducers.

<http://www2.emersonprocess.com/en-US/brands/fisher/FieldInstrumentation/valveaccessories/Electro-PneumaticTransducer/Pages/FisherElectro-PneumTrans.aspx>

b) Intermittent Bleed Devices

Intermittent bleed devices vent natural gas only when they control a process, and the frequency of the controlling depends upon the size of the device and the particular operation. Since intermittent bleed devices are designed to prevent natural gas from venting while idle, Staff proposes for these devices to be subject to LDAR and should be tested while idle to ensure no unintended leakage. This ensures that industry, ARB, and local air district inspectors conduct consistent testing among all of the different devices.

c) Pneumatic Pumps

Pneumatic pumps, commonly referred to as “Kimray” pumps, are often found at natural gas production well sites and used in conjunction with glycol dehydrators. There are two types of gas powered pumps: piston and diaphragm. Both types have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm in order to draw liquid into the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered using a vapor collection system⁶⁷.

In contrast to gas powered pumps, electric motor driven pumps do not use pressurized gas to operate and therefore do not vent emissions to the atmosphere. Using electric pumps as an alternative to gas powered pumps provides significant benefits. First, electric powered pumps provide a financial return on the gas that is otherwise vented into the atmosphere. Second, worn O-rings in gas powered pumps can cause contamination of lean glycol in the dehydrator, reducing system efficiency and requiring an increase in the glycol circulation rate, compounding the methane emissions. Finally, replacing gas powered pumps often results in lower annual maintenance costs because the O-rings in gas powered pumps must be replaced when they begin to leak, typically every 3 to 6 months. The need for this replacement is eliminated when electric pumps are employed⁶⁸.

Staff has provided several options that owners or operators can use to comply with the proposed regulation standard of not venting gas, including replacing gas powered pumps with electric pumps, collecting the vented gas with the use of a vapor collection system, or using compressed air to operate. Staff performed the cost analysis assuming that all pumps would be replaced with electric powered

⁶⁷ U. S. EPA. 2014: Oil and Natural Gas Sector Pneumatic Devices.

⁶⁸ U. S. EPA. 2006. Replacing Gas-Assisted Glycol Pumps with Electric Pumps.

pumps as described in Appendix B. However, it is possible that some owners or operators may use one of the other available options.

5. Liquids Unloading of Natural Gas Wells

Staff proposes to require that owners or operators of natural gas wells vented to the atmosphere for the purpose of liquids unloading, collect the vented gas using a vapor collection system; measure the volume of vented gas by direct measurement; or calculate the volume of vented gas. There are currently no rules that apply to the unloading of liquids from natural gas wells and the purpose of this provision is to gather data about liquids unloading activity in California. This data will inform ARB Staff, in modifying these rules for additional emission reductions.

6. Well Casing Vents

Staff is proposing that owners or operators of crude oil or natural gas wells with well casing vents that are open to atmosphere perform annual flow rate emissions testing of each casing vent and submit the results to ARB annually. The purpose of this provision is to gather equipment and emissions data which will inform ARB Staff if future emissions controls are necessary.

7. Natural Gas Underground Storage Facility Monitoring Requirements

A large natural gas leak was discovered at a natural gas storage facility in Southern California on October 23, 2015 (Aliso Canyon). Numerous initial attempts to stop the leak failed, and on January 6, 2016, Governor Brown issued a state of emergency. The leak was plugged on February 18, 2016. This event highlighted the need to require monitoring at all natural gas storage facilities. The Division of Oil and Gas and Geothermal Resources (DOGGR) responded by adopting an emergency regulation for gas storage facilities (Cal. Code Regs., tit. 14, s 1724.9, subd. (e)) that requires operators of storage facilities to submit an inspection and leak detection protocol to DOGGR for review and approval.⁶⁹ The protocol is required to include inspection of the wellhead, attached pipelines, and area within a 100 foot radius of the wellhead at least daily. The operator is required to select and use gas leak detection technology such as infrared imaging that takes into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. DOGGR staff is currently working with operators to finalize and approve leak detection protocol for each facility.

⁶⁹ DOGGR. 2016. Requirements for Underground Gas Storage Projects. Final Text of Emergency Regulations.

DOGGR anticipated including the leak detection protocol requirements in their final regulation expected to be adopted in early 2017. As DOGGR and ARB have agreed that the monitoring requirements are more appropriately located in ARB's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, staff has included them in the proposed regulation.

Storage facility monitoring requirements under the proposed regulation will replace the leak detection protocol under DOGGR's regulation. In developing the requirements, ARB staff was cognizant of investments facility operators may have made to acquire leak detection instruments and systems and to assure that they would qualify for use under the proposed regulation. The area around the wellhead to be included in leak screening has been expanded under the proposed regulation to 300 feet in response to the detection of leaking gas in this area at Aliso Canyon.⁷⁰

The proposed regulation requires natural gas storage facility owners and operators to develop and submit to ARB a plan to provide continuous ambient air monitoring at the facility and to screen for surface leaks at least daily. Continuous air monitoring is included in response to community concern with exposure to pollutants that resulted from the leak at Aliso Canyon. To provide data transparency to the public, the monitoring system is required to be accessible remotely by the ARB and other state or local agencies specified by the ARB Executive Officer.

8. Leak Detection and Repair

The proposed leak detection and repair (LDAR) requirements are used to locate and measure leaks at facilities. Local air districts in the major oil producing regions of California currently implement LDAR programs at crude oil production facilities. These programs, as originally designed and intended, reduce emissions of VOC gases but do not cover components used in natural gas service including those found in dry natural gas production, underground storage, or transmission compressor facilities. This is because methane is not considered a major contributor to ground level ozone, so it has not been counted as a VOC. Using ARB's 2007 Survey data, ARB Staff estimates that current local air district programs cover about 80% of all components used at crude oil and natural gas facilities throughout California⁷¹. Implementing LDAR will be used to prevent the release of powerful greenhouse gas emissions found at these facilities. It could also reduce product losses, increase safety for workers, and decrease the exposure of the surrounding community. In the following sections Staff details the development of the three major provisions of ARB's proposed LDAR requirement.

⁷⁰ South Coast Air Quality Management District. 2016. SCAQMD/DOGGR Joint Inspection. <http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/air-sampling/scaqmd-doggr-joint-inspection>

⁷¹ See footnote 41.

a) Test Method Requirement

To develop the proposed LDAR requirement, Staff evaluated current local air district rules and the US EPA Method 21⁷² test method, and Optical Gas Imaging (OGI) technologies. Each of the local air districts that currently have LDAR programs require Method 21 in combination with specified leak concentration thresholds^{73 74 75 76 77}. The leak measurement is then used to determine the timeframe in which a facility must make repairs to fix the leaking component. Method 21 is the only test procedure currently in use by the local districts at oil and gas facilities. This method is favored because it has the ability to quantify leak concentrations. Quantifying the concentration of leaks gives air districts the ability to define leak thresholds and thereby specify repair timeframes, with the largest leaks having the shortest repair timeframe. This approach provides the districts with the ability to enforce the leak standards if measured concentrations exceed specified thresholds.

OGI is an alternative to Method 21 measurements, but is used to view leaks from various sources including hard-to-reach and unsafe locations. While traditional OGI cannot measure leak concentrations and there are no US EPA adopted test methods available for using these instruments, Staff discovered that there are new OGI technologies that are evolving and are being designed to quantify emissions. This technology is currently untested; however ARB is open to future testing for use of this new type of OGI measurement technology, including comparative testing with Method 21 instrumentation.

For this rulemaking, ARB proposes the use of Method 21 to implement a US EPA-approved test method along with a set of leak thresholds and repair timeframes that are similar to current local air districts. Both the local air districts and facility operators can use their existing instruments to implement the same or similar standards at facilities that are not currently subject to a LDAR program. Although Staff proposes

⁷² CFR. 2016. Method 21 - Determination of Volatile Organic Compound Leaks. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr60_main_02.tpl

⁷³ San Joaquin Valley Air Pollution Control District. 2011. Rule 4401: Steam-Enhanced Crude Oil Production Wells.

⁷⁴ San Joaquin Valley Air Pollution Control District. 2005. Rule 4409: Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities.

⁷⁵ Ventura County Air Pollution Control District. 1998. Rule 74.10: Components at Crude Oil and Natural Gas Production and Processing Facilities.

⁷⁶ Santa Barbara Air Pollution Control District. 1991. Rule 331: Fugitive Emissions Inspection and Maintenance.

⁷⁷ South Coast Air Quality Management District. 2009. Rule 1173: Control of Volatile Organic Compound Leaks and Releases From Components at Petroleum Facilities and Chemical Plants.

Method 21 as the required test method, the proposed regulation will not prohibit the use of OGI technologies. Some local air districts and oil and natural gas facilities currently use OGI as a means to perform leak screening surveys, with Method 21 used to determine compliance with the leak thresholds and repair timeframes. Staff believes the same type of work practice will continue with the adoption of the proposed LDAR program, and ARB encourages the use of alternative leak detection instruments including the use of OGI technologies. ARB has a contract nearing completion to compare different LDAR technologies and determine correlation equations, if feasible, but results are not currently available for evaluation.

b) Leak Threshold and Repair Times

This proposed rule includes requirements for leak thresholds and repair time periods for components at oil and natural gas facilities. Detected leaks must be repaired within a specific time period depending on the leak concentration, with larger leaks requiring the quickest repair times. Staff developed a phased in approach with higher concentration thresholds in the first two years. The final thresholds and repair times are as follows:

Table 10: Repair Time Periods on or after January 1, 2020

| Leak Threshold | Repair Time Period |
|------------------------|-----------------------------------|
| 1,000-9,999 ppmv | 14 calendar days |
| 10,000-49,999 ppmv | 5 calendar days |
| 50,000 ppmv or greater | 2 calendar days |
| Critical Components | Next shutdown or within 12 months |

In the proposed regulation, 1,000 ppmv is the lowest leak threshold defined. Staff chose this threshold to be consistent with the majority of districts with oil and gas LDAR regulations. District regulations vary on the threshold but 1,000 ppmv is the most common across the districts. In addition, staff chose to lower the threshold from 10,000 ppmv after two years to 1,000 ppmv simply to ensure that more leaks are being detected. The thresholds and repair times assure that leaks are repaired once found and that the largest emitting sources are prioritized. The quickest leak repair time period is 2 calendar days for leaks measuring 50,000 ppmv or greater.

c) Leak Inspection Frequency

To develop the proposed leak inspection frequency, Staff reviewed existing LDAR programs currently in use by California local air districts, then contacted enforcement Staff and management at the Santa Barbara, Ventura, South Coast, and San Joaquin Valley air districts to further discuss the minimum inspection frequency requirements in detail. The districts require daily inspections for specific types of components that have the potential for substantial emissions, such as pressure relief valves. These inspections are audio or visual based and do not require instrument testing. Each district also has provisions for unmanned or remote facilities that allow operators to inspect those facilities on a less than daily basis. ARB believes these are appropriate and in line with recent findings that open tank hatches can be a significant source of methane.⁷⁸

The Method 21 instrument-based inspection frequency is also similar among each of the different air districts. For example, in South Coast, Santa Barbara, Ventura, and the San Joaquin Valley (for gas and light crude oil), the minimum inspection frequency is quarterly for a minimum number of inspection quarters. If a facility meets a specified set of criteria, they may convert to annual inspections. The criteria for converting from a quarterly to annual inspection frequency is based upon the number of leaks found during each inspection period and does not prevent the district from conducting random leak inspections. At any time during a calendar year, the local district may enter a facility and conduct random leak inspections in order to determine if the facility is in compliance with district LDAR rules. If at any time a district discovers leaks that exceed the LDAR requirements, or finds leaks that may exceed a maximum leak threshold, the annual inspection frequency reverts to quarterly. This approach is similar to the approach currently used by several local air districts.

Quarterly LDAR achieves approximately a 60 percent reduction in methane emissions from leaking components, whereas annual LDAR achieves only about a 40 percent reduction.⁷⁹ In addition, quarterly inspections will result in more opportunities to detect “super-emitting” components, the source of the majority of component emissions, according to several studies.^{80 81 82 83 84 85}

⁷⁸ ACS Publications. 2016. Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites. Environmental Science & Technology. Publication Date (Web): 05 Apr 2016.

⁷⁹ ICF International. 2014. Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries.

⁸⁰ See footnote 19.

⁸¹ See footnote 21.

⁸² See footnote 25.

⁸³ See footnote 26.

Based on the information gathered, ARB Staff proposes a quarterly instrument-based inspection frequency with an option for compliant facilities to convert to annual inspections after passing a minimum of five quarterly inspections. In addition, ARB's regulation will require a daily audio-visual inspection requirement for facilities that are visited on daily basis, and weekly audio-visual inspection requirement for unmanned or remote facilities. The audio-visual based inspections are required for all accessible pumps, compressors, and automatic pressure relief valves located at each facility. These requirements are designed to integrate with the proposed Method 21 test method, leak thresholds, and repair timeframes, and to integrate with existing local air district rules.

⁸⁴ See footnote 27.

⁸⁵ See footnote 28.

VI. JUSTIFICATION FOR ADOPTION OF REGULATIONS DIFFERENT FROM FEDERAL REGULATIONS CONTAINED IN THE CODE OF REGULATIONS

Oil and gas operations are also subject to the federal Clean Air Act, including its permitting requirements. They are subject to U.S. EPA performance standards for oil and gas operations. These regulations, 40 C.F.R. Part 60, Subpart OOOO (Quad O), limit emissions of volatile organic compounds from new equipment installed at crude oil and natural gas operations. Corresponding air toxics standards for certain pieces of oil and gas equipment are also codified in 40 C.F.R Part 63. In 2015, EPA committed to reduce methane emissions in the U.S. by 40 percent below 2012 levels by 2025 from the oil and gas sector. As part of this effort, EPA has proposed additional NSPS requirements for new and modified sources in the oil and gas sector and suggested Control Technology Guidance for existing sources in non-attainment areas. EPA finalized its rules in May 2016. On March 10, 2016, President Obama announced steps to reduce emissions from all existing oil and gas facilities but that process is in the information gathering stage. ARB staff anticipate that controls proposed in this regulation would aid in (and may suffice entirely for) compliance with any federal standards developed.

California has authority to set its own standards to reduce emissions further to meet federal and state ambient air quality standards and climate change requirements and goals, and to require additional and separate reporting. The proposed regulation addresses existing facilities and equipment where Quad O does not, and is more restrictive. The differing state requirements proposed are authorized by law (AB 32, as discussed above) and are necessary to achieve additional benefits for human health, public welfare, and the environment, and are justified by these benefits, as envisioned by authorizing legislation, as this section explains.

ARB's proposed regulation covers more facilities in California compared to EPA's NSPS, because it will apply to existing and new facilities, including offshore oil and natural gas production facilities. EPA's New Source Performance Standards (NSPS) applies to onshore oil and gas facilities newly constructed, reconstructed, or modified after August 23, 2011 (or after September 2015, in certain cases to which the May 2016 final federal rule applies). The types of facilities subject to the NSPS, are natural gas well sites, oil well sites, production gathering and boosting stations, natural gas processing plants, and natural gas compressor stations (transmission and storage).

The Bureau of Land Management (BLM) has also recently proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas operations on federal and tribal lands. (43 CFR 3162 and 3179) These proposed regulations are consistent with EPA's NSPS rules and would apply to sources not covered in those rules. ARB's proposed regulation does not apply to tribal lands; it does apply to federal lands, in which case ARB may develop an MOU with BLM to coordinate enforcement.

In addition to direct federal regulations, many air districts with significant oil production have rules aimed to reduce PM_{2.5} as well as NO_x and VOC emissions specifically from the oil and gas sector in order to meet federal ambient air quality requirements. The district rules do not cover methane specific sources and the proposed regulation generally addresses emissions from equipment and processes not already controlled by those existing district rules. ARB has used the district rules as a starting point, particularly for leak detection and repair, where districts have been implementing programs for decades.

ARB staff carefully reviewed existing and proposed regulations as this proposed regulation was developed. Because EPA's rule was finalized as this proposed regulation was being issued, review of modifications made to that rule during finalization is ongoing. However, because that rule covers only new sources, and follows the basic structure of EPA's proposal, it does not obviate the need for more rigorous, and far broader, source coverage in this proposed regulation. Indeed, EPA makes clear that its final rules are intended to complement state efforts, rather than supplant them. The proposal is designed to be as strong as, or stronger than, existing rules in other jurisdictions and in certain California air districts, and to extend strong elements of those rules. The proposal is also designed to integrate well with regulatory efforts for other aspects of the sector, as well as to provide a complementary basis for compliance with potential proposed federal rules.

VII. AIR QUALITY

A. OVERVIEW

This chapter describes the expected emissions, air quality, and health impacts associated with the proposed regulation. Furthermore, this chapter reports on the potential effects of the proposed regulation on environmental justice and local communities. The purpose of the proposed regulation is to establish GHG, primarily methane, emission standards for the oil and gas operations and facilities covered under the proposed regulation. Additionally, the Draft Environmental Analysis in Appendix C identifies the reduction of volatile organic compounds and toxic air contaminants as a co-benefit of the proposed control strategies.

1. Air Quality

ARB's Draft Environmental Analysis (Draft EA) in Appendix C, describes the long-term operations resulting from compliance with the proposed regulation. These operations could include the combustion of methane vapors as a management option for captured methane gas and increased vehicle use as a result of inspections, equipment replacement and repairs, and transporting compressed vapor. These compliance responses, if not properly constrained as they have been in the proposed regulation, have the potential to increase emissions from the pollutants for which national and state ambient air quality standards have been established.

The proposed regulation is designed to require the cleanest combustion devices, consequently reducing any potential additional air quality emission impacts to below significance in nonattainment areas and would not affect areas currently in attainment. Specifically, though some newly-collected vapors may be combusted, the proposed regulation requires that inefficient combustion devices already in use be replaced with cleaner devices before they can be used for compliance. The result of this design ensures that no significant emission increases would occur in nonattainment areas, and could result in a net reduction of emissions for some areas and pollutants.

Table 11 displays the estimated statewide GHG emission benefits from the proposed regulation by category. These benefits are described in further detail in Chapter 4.8 of the Draft EA, Appendix C. In addition to the benefits identified in Table 12, the proposed regulation would also provide a reduction in risk of large, catastrophic methane releases (similar to the events at Aliso Canyon) from the proposed enhanced monitoring at natural gas underground storage facilities.

Table 11: Estimated Statewide GHG Emission Reductions (MT CO₂e/year).*

| Category | Reductions |
|---|-------------------|
| Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard | 538,000 |
| Control of vapors from uncontrolled well stimulation circulation tanks | 4,900 |
| Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules | 590,000 |
| Inspection and repair requirements for reciprocating natural gas compressors | 68,000 |
| Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting “wet seals” with lower emitting “dry seals” | 3,500 |
| Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances | 319,000 |
| TOTAL from proposed regulation | 1,523,000 |

*Using 20 year GWP, AR4

Table 12 displays ARB’s estimated statewide emissions reductions of toxic air contaminants and criteria air pollutants from implementation of the proposed regulation. ARB’s detailed description on the emissions calculations is found in Appendix D of this ISOR. Generally, the emissions were calculated from a combination of emission factors, survey data, and other data provided by stakeholders based on likely compliance responses to each of the provisions in the proposed regulation. ARB’s detailed description of the air quality impacts of the proposed regulation is found in the Draft EA in Appendix C, Chapter 4.3 of this ISOR.

Reductions in emissions from vapor collection on uncontrolled oil and water separators, tanks, and sumps all occur in the San Joaquin Valley Air Basin, since ARB’s analysis showed that facilities in other oil and gas production regions would either not exceed the methane standard or already have vapor collection installed. As noted in Table 12, ARB estimates statewide NO_x benefits of approximately 1.6 tons per year from vapor collection tanks, separators and sumps. This is a result of the design of the proposed regulation which requires the use of a complaint vapor control device (e.g., low-NO_x combustion device). However, ARB’s analysis of vehicle emissions associated with LDAR results in an estimated statewide increase in NO_x of approximately 1.6 tons per year. Therefore the proposed regulation results in

an estimated statewide net increase in NOx of less than 0.1 tons per year. A detailed description of these emissions can be found in the Draft EA.

Table 12: Estimated Statewide Emission Reductions of Toxic Air Contaminants and Criteria Air Pollutants (tons/year)

| Category | Total Hydrocarbons | VOCs | Benzene | Toluene | Ethyl-Benzene | Xylenes | NOx |
|--|--------------------|--------------|-----------|-----------|---------------|-----------|--------------------|
| Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard ¹ | 10,458 | 1,362 | 23 | 11 | 1.7 | 8.5 | 1.6 |
| Control of vapors from uncontrolled well stimulation circulation tanks | 96 | 12 | 0.2 | 0.1 | <0.1 | <0.1 | <0.1 |
| Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules | 9,698 | 1,264 | 22 | 10 | 1.5 | 7.9 | (1.6) ² |
| Inspection and repair requirements for reciprocating natural gas compressors | 1,318 | 172 | 3.0 | 1.4 | 0.21 | 1.1 | NA |
| Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting "wet seals" with lower emitting "dry seals" | 68 | 9 | 0.2 | <0.1 | <0.1 | <0.1 | NA |
| Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances | 6,199 | 808 | 14 | 6.5 | 1.0 | 5.0 | NA |
| TOTAL (benefits from proposed regulation) | 27,837 | 3,627 | 62 | 29 | 4.6 | 23 | (<0.1) |
| ¹ All estimated emission reductions from this category are occurring in the San Joaquin Valley Air Basin. ² ARB estimates that increased LDAR will result in increased NOx from vehicle emissions by 1.6 tons/year. | | | | | | | |

In addition to the statewide emission benefit evaluation, ARB completed an emissions impacts analysis at the district level as part of the Draft EA in

Appendix C. ARB staff completed this analysis for the following districts: Bay Area AQMD, Butte County AQMD, Colusa County APCD, Feather River AQMD, Glenn County APCD, Monterey Bay Unified APCD, North Coast Unified AQMD, Santa Barbara County APCD, South Coast AQMD, SJVAPCD, Sacramento Metropolitan AQMD, Tehama County APCD, Ventura County APCD, and Yolo-Solano AQMD. ARB's analysis identified negligible emission impacts (less than 0.1 tons per year) for ROG, TOG, CO, NOx, PM10, PM2.5, and SOx for all air districts evaluated except for SJVAPCD. ARB reports these emission impacts as negligible since the analysis contains too much uncertainty in the analysis to accurately quantify such small increases. For SJVAPCD, ARB staff estimates net reductions of 0.5 tons per year of NOx and 30.1 tons per year of CO, and negligible reductions in SOx. Conversely, ARB has identified emission increases of 0.9 tons per year of PM10 and 0.3 tons per year of PM 2.5 in the SJVAPCD. The design of the proposed regulation ensures that emission impacts are well below any applicable CEQA significance thresholds for direct and cumulative impacts. The regulation decreases NOx emissions below existing levels in the San Joaquin Valley and provides substantial emission benefits of VOCs as well as smaller benefits of the BTEX suite of chemicals.

As previously stated, ARB's analysis shows a net NOx decrease of 0.5 tons per year and net increases of PM10 and PM2.5 of 0.9 and 0.3 tons per year, respectively, in the SJVAPCD. ARB's analysis uses the current baseline (i.e., emissions from current vapor control devices). The SJVAPCD has published a study of the potential to reduce NOx from existing flaring, as required by a commitment in the 2015 State Implementation Plan (SIP) for the 1997 PM2.5 Standard. In an update to the SJVAPCD Governing Board (SJVAPCD 2016), district staff state that the low-NOx vapor control devices, as required under the Proposed Regulation, will be required under the district's upcoming SIP therefore ARB must not "take credit" for NOx reductions from these devices.

Pursuant to CEQA, the baseline to be used in an environmental analysis is the physical environmental conditions as they exist at the time environmental review is commenced. ARB staff disagree that undeveloped future rules are properly considered part of the CEQA baseline. However, in an effort to fully address SJVAPCD's concerns, ARB has conducted a further analysis against a hypothetical future baseline where all existing vapor control devices are already low-NOx vapor control devices. In such a scenario, there would be no NOx benefit attributed to the Proposed Regulation for replacing current vapor control devices with low-NOx vapor control devices. Under that scenario, the Proposed Regulation would result in a NOx emissions increase in the SJVAPCD of 4.1 tons per year, CO emissions increases of 1.6 tons per year, and a negligible SOx emissions increase. PM10 and PM2.5 emissions would not change. All estimated emissions increases under this alternative scenario are below the CEQA significance threshold for the SJVAPCD of 10 tons per year for NOx, 5 tons per year for PM10, and 15 tons per year for PM 2.5. The SJVAPCD does not define CEQA significance thresholds for CO and SOx.

However, as noted above, the proper CEQA baseline for this project is existing environmental conditions, as analyzed above.

The change in NO_x emissions that might occur as a result of the proposed regulation was estimated separately by staff of the SJVAPCD. The SJVAPCD analysis was limited to emissions from tanks only. For context, when comparing against this hypothetical future baseline, ARB staff estimates an additional 2.9 tpy NO_x from the tank measure only. SJVAPCD staff estimates an additional 20.2 tpy NO_x, an order of magnitude greater than the ARB staff estimates.

ARB staff believes these high estimates are not accurate for several reasons. SJVAPCD made assumptions on tank coverage, assumed all gas at a lease would go into one large system, assumed all recovered gas would go to a flare, and included supplemental fuel (which is not allowed in the current version of the regulation). ARB used the robust data contained within the oil and gas survey results to determine the amount of gas going to each tank system (not each facility), the number of systems above our standard, which systems were already controlled, the disposal method for each system, and did not assume supplemental fuel use since low NO_x incinerators can handle waste gas. More detailed information can be found in the Draft EA.

Although the regulation decreases NO_x compared to current levels, ARB staff recognizes some of the ARB's proposed NO_x reduction approaches in this rule may be required in the future by the district and ARB is committed to spurring innovation in, and application of, NO_x control strategies. Staff suggests following the development of the related SJVAPCD rules and exploring options to address any remaining concerns through, among other options, consideration of innovative NO_x technologies or funding or implementation of NO_x reduction projects.

Additionally, implementation of the proposed regulation would consist of modifications to existing facilities such as installation of vapor collection systems, and replacement or repair of leaking equipment resulting in the installation or replacement of gathering lines and piping, flanges, valves, low NO_x combustion devices pneumatic devices and pumps, and other components. Any proposed modifications to facilities would require having local or State land use approvals secured prior to their implementation. Part of the development review and approval process for projects located in California requires environmental review consistent with California environmental laws (e.g., CEQA) and other applicable local requirements (e.g., local air quality district rules and regulations). The environmental review process would include an assessment of whether or not implementation of such projects could result in air quality impacts. As described in ARB's Draft EA in Appendix C, ARB expects any construction-related impacts to air quality to be less-than-significant due to the limited nature of the modifications and upgrades to oil and gas facilities that could be

required under the Proposed Regulation, consisting of activities such as installation of piping, gathering lines, tanks, valves, and hatches.

VIII. ENVIRONMENTAL ANALYSIS

The Air Resources Board (ARB), as the lead agency for the proposed regulation, has prepared an environmental analysis under its certified regulatory program (17 CCR 60000 – 60008) to comply with the requirements of the California Environmental Quality Act (CEQA). ARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (14 CCR 15251(d)). ARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report to comply with CEQA (17 CCR 60005).

The Draft Environmental Analysis (Draft EA) for the proposed regulation is included in Appendix C to this Staff Report. The Draft EA provides an environmental analysis, which focuses on reasonably foreseeable potentially significant adverse and beneficial impacts on the physical environment resulting from reasonably foreseeable compliance responses taken in response to implementation of the proposed actions within the proposed regulation. The Draft EA is intended to disclose potential adverse impacts and identify potential mitigation specific to the proposed regulation.

Implementation of the proposed regulation would require regulated entities to take actions to limit vented and fugitive methane emissions from equipment and operations. The Draft EA states that implementation of the proposed regulations would result in beneficial impacts to GHGs through reductions in methane emissions from oil and gas operations in California. The Draft EA states that the proposed regulation would result in less-than-significant long term impacts to air quality but with reductions in VOCs. The Draft EA also states the proposed regulations could result in less-than-significant or no impacts to aesthetics, agriculture resources, air quality, biological resources (long term), energy demand, greenhouse gases (short term), geology and soils (long term), hazards and hazardous materials, hydrology and water quality (long term), land use planning, transportation and traffic, mineral resources, noise, population and housing, public services, recreation, and utilities and service systems; and potentially significant and unavoidable adverse impacts due to short term construction related impacts to biological resources (short term), cultural resources (short term), geology and soils (short term), and hydrology and water quality (short term) that are reasonably foreseeable as a result of the proposed regulation.

Written comments on the Draft EA will be accepted starting June 3, 2016 through 5 p.m. on July 18, 2016. The Board will consider the Final EA and responses to comments received on the Draft EA before considering adoption of the proposed regulation.

Table 13: Summary of Potential Environmental Impacts

| Resource Area Impact | Significance Finding |
|---|-----------------------------|
| Aesthetics | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Agriculture Resources | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Air Quality | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Biological Resources | |
| Short-Term Construction-Related Impacts | Potentially significant |
| Long-Term Operational Impacts | Less-than-significant |
| Cultural Resources | |
| Short-Term Construction-Related Impacts | Potentially significant |
| Energy Demand | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Geology, Soils and Minerals | |
| Short-Term Construction-Related Impacts | Potentially significant |
| Long-Term Operational Impacts | Less-than-significant |
| Greenhouse Gas Emissions | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Beneficial impact |
| Hazards and Hazardous Materials | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Hydrology and Water Quality | |
| Short-Term Construction-Related Impacts | Potentially significant |
| Long-Term Operational Impacts | Less-than-significant |
| Land Use and Planning | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Mineral Resources | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |

| Resource Area Impact | Significance Finding |
|---|-----------------------------|
| Noise | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Population and Housing | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Public Services | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Recreation | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Transportation and Traffic | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |
| Utilities and Service Systems | |
| Short-Term Construction-Related Impacts | Less-than-significant |
| Long-Term Operational Impacts | Less-than-significant |

A. HEALTH IMPACTS

California experiences some of the highest concentrations of PM_{2.5} in the nation.⁸⁶ The majority of California’s population lives in areas that exceed the national and state PM_{2.5} air quality standards.^{87 88} These standards are set based upon assessments of scientific studies that link exposure to PM_{2.5} to health effects, including hospitalization due to respiratory and cardiovascular illness, and premature death from cardiopulmonary disease.^{89 90} The U.S. EPA has determined that exposure to PM_{2.5} plays a “causal” role in premature death, meaning that a substantial body of scientific evidence shows a relationship between PM_{2.5} exposure and increased mortality, a relationship that persists when other risk factors such as smoking rates and socioeconomic factors are taken into account.⁹¹ NO_x emissions impact human health because photochemical reactions convert some NO_x into ammonium nitrate aerosol, a

⁸⁶ U. S. EPA. 2012. Fine Particle Concentrations Based on Monitored Air Quality from 2009 – 2011

⁸⁷ ARB. 2013. Area Designations for State Ambient Air Quality Standards PM_{2.5}.

⁸⁸ ARB. 2013. Area Designations for National Ambient Air Quality Standards PM_{2.5}.

⁸⁹ ARB. 2010. Estimate of Premature Deaths Associated with Fine Particle Pollution (PM_{2.5}) in California Using a U.S. Environmental Protection Agency Methodology.

⁹⁰ U. S. EPA. 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.

⁹¹ U. S. EPA. 2009. 2009 Final Report: Integrated Science Assessment for Particulate Matter.

component of PM_{2.5}, and convert some NO_x to ozone, a major constituent of smog and a potent lung irritant.

There are no expected associated health impacts.

IX. ENVIRONMENTAL JUSTICE

Government Code section 65040.12(e) defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to supporting the achievement of environmental justice. In 2001, the Board adopted a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law.⁹² Although ARB's environmental justice policies apply to all communities in California, they recognize that environmental justice issues have been raised more often in the context of low-income and minority communities.

As a result of ARB's work with the public, the business sector, local government, and air districts, California's ambient air is the cleanest since air quality measurements have been recorded.⁹³ However, large numbers of Californians live in areas that continue to experience episodes of unhealthy concentrations of ozone and PM_{2.5}.

Communities located in close proximity to oil and gas operations are already experiencing the impacts of those operations including, but not limited to, odors, noise, and vehicle traffic. Additionally, these communities are at risk for exposure to a variety of volatile organic compounds and toxics, including the BTEX suite of chemicals, which are associated with oil and gas operations. Local air districts currently implement a variety of rules that reduce volatile organic compounds from the oil and gas industry. The purpose of the proposed regulation is to reduce methane emissions from the covered oil and gas operations and facilities covered with the reduction of additional volatile organic compounds and toxic air contaminants as a co-benefit of the proposed control strategies. The proposed regulation was designed to minimize or eliminate any potential air quality emission impacts in nonattainment areas and minimize potential emissions well below significance levels in attainment areas. Specifically, though some newly-collected vapors may be combusted, the proposed regulation requires that inefficient combustion devices already in use be replaced with cleaner devices before they can be used for compliance. The surrounding communities will benefit from the proposed regulation to the extent that the proposed control strategies provide reductions in emissions of volatile organic compounds and toxic air contaminants. There will be no adverse impact to the surrounding communities due to the oil and gas regulation.

⁹² ARB. 2001. Policies and Actions for Environmental Justice.

⁹³ ARB. 2014. History of Air Resources Board.

X. ECONOMIC IMPACTS

A. SUMMARY OF PROPOSED COSTS AND IMPACTS

The proposed Regulation for the Reduction of Greenhouse Gas (GHG) Emissions from Crude Oil and Natural Gas Operations (proposed regulation) is intended to reduce GHG emissions from oil and gas production, processing, storage and transmission compressor stations. The economic impacts of the proposed regulation are discussed in this section, and include impacts and benefits to businesses, individuals, and government agencies. This section also includes a discussion of the estimated cost of the proposed regulation.

B. MAJOR REGULATIONS

For a major regulation proposed on or after January 1, 2014, a Standardized Regulatory Impact Assessment (SRIA) is required. A major regulation is one “that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars (\$50,000,000), as estimated by the agency.” (Govt. Code Section 11342.548) Further, the Health and Safety Code Section 57005(b) defines a “major regulation” as any regulation that will have an economic impact on the state’s business enterprises in an amount exceeding ten million dollars (\$10,000,000), as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a) of Section 11346.3 of the Govt. Code.

When amortized, the proposed regulation will cost \$23 million with the enhanced underground storage monitoring plan and \$14 million per year without that provision; however, the largest expenditures will be in 2018 when most of the capital equipment is expected to be purchased. This upfront cost is estimated to be over \$40 million in direct costs, and over \$50 million in overall economic impact. Due to the estimated economic impact of compliance exceeding \$50 million in a 12 month period during 2018, the proposed regulation was determined to be a major regulation and required a SRIA. A SRIA was submitted to the Department of Finance (DOF) on February 20, 2015 and a revised version on April 29, 2015. On May 28, 2015, ARB received a letter from the DOF acknowledging the status of a major regulation, and commenting on the information presented in the SRIA. These comments are addressed in Appendix B to this document.

Since the submittal of the SRIA, the proposed regulation has undergone several changes. In addition to changes in the standards, there have been changes to the methodology of estimating the cost and emissions for provisions of the proposed regulation due to the availability of updated data and feedback from industry representatives and other stakeholders. Although these changes have been made after the submittal of the SRIA, staff believes the conclusions of the

SRIA continue to be accurate, since the overall annual cost, emission, reductions, and impacted industries are similar.

In addition to changes made to the standards of the proposed regulation, ARB is now using the 20 year AR4 value (72) of GWP instead of the 100 year AR4 value (25) to determine the reductions in CO₂e. Also, the value assigned to gas saved changed from \$4.10 per mscf to \$3.44 per mscf. This value was changed to reflect the most recently available data and is the average wholesale price that is specific to California over the last 12 months of available data, from November 2014 to October 2015.⁹⁴ Also, the compliance dates for the regulation have changed from starting January 1, 2017, to starting January 1, 2018.

In addition to the changes discussed above, some of the methodologies of estimating the potential costs and emission have changed. This is due to the availability of better data, stakeholder comments, as well as the continued development of the proposed regulation. These changes are described in detail below. All SRIA emissions use a GWP of 25, and all current emissions use a GWP of 72 in the descriptions.

1. Changes from SRIA

a) Reciprocating Compressors

In the SRIA version of the proposed regulation, all reciprocating compressors would need to replace a rod packing after three years of use. In the current version of the proposed regulation, compressors at production facilities are no longer subject to a rod packing leak standard, but instead are required to meet an LDAR standard. Many of the compressors at production facilities are smaller, may be portable, and handle a different composition of gas than compressors at processing, storage or transmission facilities. In addition, most of the available data concerning leak rates and rod packing cost and performance are from larger compressors that are typically not found at production facilities. The provision to exclude production type compressors eliminated over 600 of almost 1000 compressors from this segment, for determining cost and emissions. In addition, industry provided data on the leak rate by compressor for a large subset of the remaining compressors. This new data was used in place of the emission factors previously used. With the reduction in number of compressors, the change from a time based standard to a performance based standard, and using measurement data instead of emission factors, the estimated reduction of emissions has changed from 143,000 MT CO₂e to about 68,000 MT CO₂e. Based on the

⁹⁴ U. S. EIA. 2016. U.S. Natural Gas Citygate Price (Dollars per Thousand Cubic Feet).

decrease of compressors potentially impacted by the standard for rod packing leaks, the estimated cost of compliance has decreased from about \$600,000 per year to about \$260,000 per year.

b) Centrifugal Compressors

In the SRIA version of the proposed regulation, 25 centrifugal compressors with wet seals were anticipated to need a vapor recovery system or to be converted to a dry seal. In an effort to verify this data from ARB's 2009 Survey, staff contacted the facilities that would be impacted by this provision in the proposed regulation. All centrifugal compressors, except for one, were reported with wet seals in error, are no longer in use, have been replaced with a compressor with a dry seal, or now have a vapor recovery system installed to control emissions. In addition, measurement data taken directly from this single compressor was used in place of the emission factors used to generate the emissions and reductions for the SRIA. Due to the updated number of impacted units, the emissions dropped from about 20,000 MT CO₂e to about 3,700 MT CO₂e and the reduction estimates dropped from about 10,000 MT CO₂e to about 3,500 MT CO₂e. The associated cost of compliance decreased from about \$375,000 per year to about \$6,000 per year.

c) LDAR

In the SRIA version of the proposed regulation, the emissions did not include a small percentage of super emitter components, which are responsible for the majority of emissions. In addition, the LDAR program was changed from an annual inspection to a quarterly inspection requirement. These changes were made to address stakeholder comments, and ensure emissions were determined with the best available data. The estimated emissions reduction has changed from about 1,200 MT CO₂e to about 590,000 MT CO₂e, and the estimated cost has changed from about \$2 million per year to about \$10 million per year.

d) Pneumatic Devices

At the time of the SRIA, all continuous bleed pneumatic devices were required to change to a low bleed pneumatic device. Based on stakeholder feedback, this has been changed to require a no bleed pneumatic device in the current proposed regulation to maximize emission reductions with no increased cost. Also, after a review of the data, the count of continuous bleed devices was overestimated by about 170. The anticipated emissions reduction from this segment have changed from about 124,000 MT CO₂e to about 320,000 MT

CO₂e, and the estimated cost has changed from about \$1.3 million per year to about \$1.2 million per year.

e) Tank and Separator Systems

The provisions for tank and separator systems have changed from requiring a vapor recovery system for all uncontrolled systems, to require vapor recovery and comply with a NO_x emission standard, but only for uncontrolled systems that are anticipated to have over 10 MT per year of CH₄ emissions. Due to this change, the estimated number of systems impacted changed from over 600 to about 300. It is now assumed that a low NO_x incinerator will be used to comply with the NO_x emission standard in place of a flare. The emissions are now calculated with the throughput to the separators instead of limited, reported emissions data from the 2009 ARB survey. The estimated emissions reductions have changed from about 252,000 MT CO₂e to about 540,000 MT CO₂e. The estimated cost has changed from about \$16 million per year to about \$4.7 million per year.

f) Well Stimulations

The current proposal uses emission factors from WSPA⁹⁵ to estimate emissions from well stimulations. These emission factors became available after the submittal of the SRIA when the best available data projected much greater emissions. The estimated emissions reduction from this segment of the proposed regulation has changed from about 24,400 MT CO₂e to about 5,000 MT CO₂e. The estimated cost has changed from about \$200,000 per year to about \$460,000 per year due better cost data becoming available and inclusion of additional compliance equipment.

g) Liquids Unloading

The requirement for controls for liquids unloading were removed for the proposed regulation, and replaced with a reporting requirement. The estimated reductions of about 350 MT CO₂e have been eliminated, and the expected cost of \$450,000 per year has been replaced with a cost of about \$6,000 for reporting and recordkeeping.

h) Monitoring Plan

The proposed regulation now includes a monitoring plan, which requires operators of natural gas storage facilities to monitor gas wells on a daily basis, and install a system for ambient air monitoring. This was not included in the SRIA. The cost of this provision is estimated to be about \$8.7 million per year.

⁹⁵ WSPA. 2015. Recirculation Tank Emissions Testing, Source Test Report.

C. ECONOMIC IMPACTS ASSESSMENT

The proposed regulation encourages the use of more efficient and potentially cost-saving technology to ensure maximum production of natural gas. Much of the capital equipment purchased, such as vapor recovery for tanks, have lifetimes that far exceed the pay-off period. Though at some point the primary industries no longer are making payments for the capital required for compliance, they continue to enjoy the natural gas savings that are provided by that capital. Therefore, the primary industries oil and gas extraction and natural gas distribution, are required to make minor changes to their production facilities, these modifications include increases in efficiency that may result in net benefits to regulated parties in the long run. Secondary industries face increased product demand, resulting in increased output and employment in those industries.

The proposed regulation was analyzed using generally high estimates and GHG emission reduction estimates; thus, the analysis may serve as an upper bound of anticipated impacts. To the extent there are greater cost savings due to increased product capture, the economic impacts of the proposed regulation would be less negative in all years, and likely show a benefit to the economy. This result would persist in later years and the primary industries, having made a large initial investment in the capital necessary to prevent substantive leaks, would continue to see savings long after the payments for the capital are finished.

The proposed regulation is unlikely to significantly impact California's economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from Business as Usual (BAU).

D. COST EFFECTIVENESS

1. Cost Analysis and Costs per Ton

This section describes the sources and general methodology to determine the emissions, cost, and cost per ton of the proposed regulation. In general, for each segment of the regulation, staff identified the number of devices affected, estimated the cost to comply with the regulatory provisions, estimated emissions and reductions, and accounted for any savings to be included in the cost per ton. Cost per ton is the dollars spent to reduce a unit mass of a specified pollutant, in this case methane. The general methodology to determine these items for each segment of the regulation is described below and is described in more detail in Appendix B. Costs are based on best estimates at the time of preparation.

The indirect costs and economic impacts were modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-

by-year estimates of the total regional effects of a policy or set of policies. These results and analysis are included with the SRIA in Attachment C. The results helped evaluate the impact of the proposed regulation on California's economy, including business impacts, job creating, and impacts to individuals. Finally, alternatives to the proposed regulation were evaluated and fiscal impacts to ARB and local air districts were estimated. The cost estimate of the proposed regulation follows guidelines recommended by the California Environmental Protection Agency (Cal/EPA), and is consistent with the methodologies used in previous cost analyses for ARB regulations (ARB, 1999; ARB, 2000; ARB, 2004; ARB, 2005; ARB, 2007). The segments analyzed for this proposed regulation include control strategies for reciprocating compressors, centrifugal compressors, oil and water separators and storage tanks, pneumatic devices, circulation tanks for well stimulations, and a leak detection and repair (LDAR) program. Information from this survey, of which parts were later updated by staff to account for changes since 2009, was used to form the basis of the number and types of facilities potentially impacted, number and types of equipment, and estimated emissions reduction from the standards in the proposed regulation. After the number and types of equipment impacted were identified, the direct cost to industry was estimated for each component of the regulation. Sources of data include ARB's 2009 Survey, ICF's Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Report), EPA documents including their Gas Star Program, industry groups, and communications with operators of potential control equipment, and other stakeholders. Appendix B details the methodology and calculations by sector.

Table 14: Summary of Cost, Emissions, and Cost per Ton using the 20 year and 100 year GWP respectively

| Provision | Annual Cost | Annual Savings | Reductions using 20 year GWP (MT CO ₂ e) | Cost per Ton using 20 year GWP (\$ / MT CO ₂ e reduced) | Cost per Ton using 20 year GWP with Savings (\$ / MT CO ₂ e reduced) | Cost per Ton Using 100 year GWP (\$ / MT CO ₂ e reduced) | Cost per Ton with Savings Using 100 year GWP (\$ / MT CO ₂ e reduced) |
|---------------------------|--------------|----------------|---|--|---|---|--|
| VRU for Tanks | \$4,700,000 | \$500,000 | 540,000 | \$ 9 | \$ 8 | \$25 | \$23 |
| Reciprocating Compressors | \$260,000 | \$180,000 | 68,000 | \$ 4 | \$ 1 | \$11 | \$3 |
| LDAR | \$10,000,000 | \$1,500,000 | 590,000 | \$ 17 | \$ 14 | \$49 | \$41 |
| Pneumatic Devices | \$1,200,000 | \$840,000 | 320,000 | \$ 4 | \$ 1 | \$10 | \$3 |
| Well Stimulations | \$460,000 | \$0 | 5,000 | \$ 91 | \$ 91 | \$262 | \$262 |
| Centrifugal Compressors | \$6,000 | \$9,000 | 3,500 | \$ 2 | \$ (1) | \$5 | \$(2) |
| Monitoring Plan | \$8,700,000 | \$0 | 0 | NA | NA | NA | NA |

| | | | | | | | |
|--------------|---------------------|--------------------|------------------|-------------|-------------|-------------|-------------|
| Total | \$25,400,000 | \$3,000,000 | 1,500,000 | \$17 | \$15 | \$48 | \$42 |
|--------------|---------------------|--------------------|------------------|-------------|-------------|-------------|-------------|

All Figures are in 2015 dollars

2. Direct Costs

a) Direct Costs on Individuals

For 2017, the baseline projected outputs for oil and gas extraction and natural gas distribution industries are approximately \$25 billion and \$19 billion respectively. The ratio of compliance cost to total output is less than 0.5 percent for both industries, making it likely that pass-through of costs would be unnoticeable. However, to the extent that any potential costs are passed on to individual consumers, minor increases in the price of natural gas and electricity may occur.

b) Direct Costs on Typical Businesses

Any business involved with crude oil or natural gas extraction, natural gas storage, crude oil processing excluding refineries, natural gas processing (including gas plants), crude oil tank farms (excluding tank farms at refineries), or transmission of natural gas will potentially be impacted by the proposed regulation. In February 2009, ARB conducted an Oil and Gas Industry Survey for crude oil and natural gas production, processing, and storage facilities in California.⁹⁶ The survey was completed by 325 companies representing over 1,600 facilities and approximately 97 percent of the 2007 crude oil and natural gas production in California. Out of these companies, 272 companies that responded to the survey are expected to be impacted by the provisions in the proposed regulation.

ARB estimates the direct cost to industry for the proposed regulation to be approximately \$25 million per year. This includes the amortized cost of capital equipment, and annual costs for labor, maintenance, reporting and recordkeeping. ARB generally used high estimates throughout for estimating emissions, costs, and reductions. The average impact each of the 272 businesses is expected to be about \$100,000 per year. The typical businesses are not small because the primary industries are ineligible to be classified as small under government code.⁹⁷ Therefore, the increased costs on industry do not directly impact small businesses.

The proposed regulation will impact some businesses that would have otherwise been classified as a small business. Small businesses with estimated annual revenue of less than \$10 million per year, but greater

⁹⁶ ARB. 2013. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.

⁹⁷ Government Code Section 11342.610(b). 2016. Small Business Procurement and Contract Act. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=14001-15000&file=14835-14843_

than \$2.5 million per year, as estimated by annual gas and oil production from ARB's survey (ARB, 2013) are expected to incur costs of about \$16,000 per year to comply with the provisions in the proposed regulation. These businesses have average revenue of about \$5.2 million, and the estimated costs account for less than 0.5% of the estimated annual revenue. Microbusinesses are businesses with annual revenue of less than \$2.5 million per year. Based on ARB's survey (ARB, 2013), these businesses have an average revenue of about \$780,000 and will incur costs of about \$3,700 annually. This accounts for less than 0.5% of the estimated annual revenue.

3. Cost Analysis

a) Benefits

The proposed regulation is anticipated to deliver environmental benefits that include an estimated annual reduction in GHG emissions, beginning in 2018, of about 1.5 million MT CO₂e per year from oil and gas related operations in California. In addition, the proposed regulation is expected to save primary industries about 800 million standard cubic foot (scf) per year of industrial natural gas through reductions of leaks and vapor recovery systems⁹⁸. This will result in a savings of about \$3 million per year, assuming the value of this gas is \$3.44 per Mscf. The cost per ton of the proposed regulation is estimated to be approximately \$15 per MT CO₂e reduced. These estimates use the 20-year GWP for methane (i.e., 72) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4).

Using the 20-year GWP shows the impact of reducing methane in the short term when compared to carbon dioxide. Reducing SLCPs, such as methane, can produce near term results that deliver immediate and tangible climate, air quality, economic, and health benefits while longer-term changes are being implemented.

The proposed regulation is also expected to provide co-benefits of reductions in emissions of VOCs and toxic air contaminants that are emitted from uncontrolled oil and water storage tanks and released from well stimulation circulation tanks. The estimated reduction in VOCs is approximately 3,630 tons per year, or about 10 tons per day statewide. There was the potential for NO_x increases for vapor recovery units if the facility used a flare. However, since the proposed regulation would impose a NO_x standard in these cases where none or a less stringent one applied before, the overall impact is a small but

⁹⁸ This assumes gas is 94.9% CH₄.

beneficial with a reduction of about 1.6 metric tons per year, but there are NO_x impacts from LDAR leading to an overall impact that is neutral for the state as a whole. Table 12, above, summarizes reductions of all pollutants, and detailed calculations are in Appendix D.

b) Benefits to Individuals

The proposed regulation will not directly affect individual consumers; however, as a result of the anticipated decrease in methane emissions, VOCs, and other toxic air contaminants, the proposed regulation will provide health and climate benefits.

Like emissions of other GHGs, emissions of methane due to human activities (anthropogenic emissions) have increased markedly since pre-industrial times. Of the GHGs emitted as a result of human activities, methane is the second most important GHG after carbon dioxide (CO₂), accounting for 14 percent of global GHG emissions in 2005. Though methane is emitted into the atmosphere in smaller quantities than CO₂, its global warming potential (i.e., the ability of the gas to trap heat in the atmosphere) is 72 times that of CO₂, resulting in methane's stronger influence on warming during its atmospheric life time.⁹⁹

California experiences some of the highest concentrations of PM_{2.5} in the nation.¹⁰⁰ The majority of California's population lives in areas that exceed the national and state PM_{2.5} air quality standards.^{101 102} These standards are set based upon assessments of scientific studies that link exposure to PM_{2.5} to health effects, including hospitalization due to respiratory and cardiovascular illness, and premature death from cardiopulmonary disease.^{103 104} The U.S. EPA has determined that exposure to PM_{2.5} plays a "causal" role in premature death, meaning that a substantial body of scientific evidence shows a relationship between PM_{2.5} exposure and increased mortality, a relationship that persists when other risk factors such as smoking rates and socioeconomic factors are taken into account.¹⁰⁵ NO_x emissions impact human health because photochemical reactions convert some NO_x into ammonium nitrate aerosol, a component of PM_{2.5}, and

⁹⁹ GMI. 2016. About Methane. <https://www.globalmethane.org/about/methane.aspx>

¹⁰⁰ U. S. EPA. 2012. Fine Particle Concentrations Based on Monitored Air Quality from 2009 – 2011

¹⁰¹ ARB. 2013. Area Designations for State Air Quality Standards.

¹⁰² ARB. 2013. Area Designations for National Air Quality Standards.

¹⁰³ ARB. 2010 Estimate of Premature Deaths Associated with Fine Particle Pollution (PM_{2.5}) in California Using a U.S. Environmental Protection Agency Methodology.

¹⁰⁴ U. S. EPA. 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.

¹⁰⁵ U. S. EPA. 2009. 2009 Final Report: Integrated Science Assessment for Particulate Matter. DC, EPA/600/R-08/139F, 2009.

convert some NO_x to ozone, a major constituent of smog and a potent lung irritant.

The PM_{2.5} and NO_x emission changes due to the proposed regulation are expected to be negligible, and so there are no expected associated health impacts.

c) Benefits to California Businesses

The proposed regulation requires the oil and gas industry to purchase, retrofit, and service capital equipment. The requirements of the regulation would increase the demand for these services and increase business opportunities for secondary industries both within and outside of California. Additionally, the proposed regulation is designed to reduce industrial natural gas leakage, which will result in cost savings for the regulated parties. For example, many of the proposed control strategies are designed such that natural gas can be recovered and either used on site as energy or captured for sale. These savings are estimated to be about \$ 3 million per year. While the primary industries are not small businesses, by definition, some of the secondary industries contain small businesses. If these businesses were able to meet the increased demand and provide the capital equipment and services to the primary industries for compliance, small businesses would see increased demand, output and, likely, employment.

ARB estimates that more than \$25 million each year will be spent on control equipment and inspection services. This includes over \$10 million complying with the LDAR provisions in the proposed regulation. Companies involved in LDAR inspections may see an increase in business or expansion. In areas of the state that previously did not have an inspection program, there will be new demand for a previously unneeded service, which may result in new businesses being created.

In areas without existing VOC based regulations for LDAR or higher pressure natural gas systems, LDAR is likely to be more cost effective. Also, staff believes that with the advent of newer technologies, the efficiency of LDAR inspections will improve.

While direct costs to the primary industries exceed \$40 million in the first year of implementation, these industries achieve savings of about \$3 million annually from leakage prevention strategies within the proposed regulation. Secondary industries also achieve benefits, as demand for their equipment, services, or other products such as natural gas increases yielding positive economic benefits.

E. IMPACTS TO CALIFORNIA, STATE, OR LOCAL AGENCIES

1. Fiscal Impacts

a) ARB and Air Districts

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

A local air district may decide – but is not obligated -- to be the primary agency responsible for enforcing the provisions of the proposed regulation. This includes issuing permits for new control equipment, registration and inspection of equipment, and enforcing the LDAR portion of the regulation. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over \$300,000 per year in recurring costs and almost \$1,000,000 in one-time costs, primarily for permitting. Even if the districts do decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation. The costs to districts are estimated to be approximately \$1,300,000 in initial costs, and approximately \$660,000 in ongoing costs.

Although local agencies (air districts) may choose to implement this regulation, and certain aspects of it may be incorporated in permits as a matter of preexisting law, resulting in some fiscal impacts, the

regulation imposes no reimbursable mandates. Air districts face no new legal requirements specific to them under this regulation. As to implementation tasks they may take on or any other costs that may result by operation of statute, air districts have legal authority under Health and Safety Code sections 40510 and 42311 to recover related costs by imposing fees. The Proposed Regulation also specifies that local air districts that choose to enforce the regulation may retain any penalty monies that result. ARB also may make arrangements to further support air districts as a voluntary matter. Thus, because the regulation applies generally to all entities operating affected sources, not the air districts, and so does not impose unique new requirements on local agencies, this is not a reimbursable mandate. (*County of Los Angeles v. State of California*, 42 Cal. 3d 46 (1987)).

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement. ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

ARB staff estimates that the regulation will require 6 PYs to implement depending on the mix of district and ARB implementation. In addition to PYs, ARB will need to purchase equipment including three IR cameras at \$85,000 each, and three toxic vapor analyzers at \$10,000 each. The costs are higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The total cost to ARB is estimated to be \$285,000 in initial costs ((3 X \$85,000) + (3 X \$10,000)), and about \$870,000 in ongoing costs (6 X

\$145,000). These costs are anticipated to be imposed during the 2017/2018 fiscal year.

b) Other State Agencies

The proposed regulation does not affect other state agencies.

XI. REFERENCES, TECHNICAL, THEORETICAL, AND/OR EMPIRICAL STUDY, REPORTS, OR DOCUMENTS RELIED UPON

The numbered “Explanatory footnote” used below are not references, they are place holders used throughout the document to add comments or explain text.

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GPA 2286

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February 19, 2016
Jim Nyarady
Manager, Oil & Gas Section
California Air Resources Board
1001 I. Street
Sacramento, CA 95814
Jim.nyarady@arb.ca.gov

Dear Mr. Nyarady:

Please accept these comments on behalf of Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council and Sierra Club. We greatly appreciate the opportunity to comment on the California Air Resources Board's ("CARB") draft regulation for methane pollution from oil and gas facilities. We commend CARB for proposing a strong draft that, in particular, directly regulates methane from new and existing sources, and applies to a broad suite of facilities across the natural gas supply chain. We are particularly supportive of those provisions that require, or prioritize, the capture of methane, over combustion, and the broad applicability of the leak detection and repair requirement to multiple pieces of equipment and components. That being said we believe there is room for improvement and offer below some suggestions to this end.

A. Leak Detection and Repair

We commend CARB on proposing that operators inspect facilities quarterly. As we have documented in prior comments, frequent inspections are critical to ensuring leaks and emissions are minimized and promptly remediated.¹ They are also highly cost effective.² We do, however, believe the leak detection and repair provisions can and should be improved. Specifically, we strongly recommend the following:

- While maintaining the quarterly inspection frequency in the draft proposal, remove the provisions allowing operators to adjust frequency based on the number or percentage of leaking components identified in prior surveys, which are not rationally tied to the emissions performance of a facility, and misaligns incentives for operators;
- Allow for the use of optical gas imaging and other equally effective advanced technologies to detect leaks. This, coupled with Method 21 compliant devices capable of quantifying methane, will ensure that inspections efficiently detect the full suite of leaking components at a site, while still quantifying emissions from leaking components.
- Remove the exemptions in Section 95669(e)(1), (6) and (4) and narrow the exemption in (8); and
- Decrease the lowest allowable leak threshold from 10,000 ppm to 500 ppm, consistent with other leading states.

¹ May 15 Letter to CARB from EDF; May 15 Letter to CARB from Sierra Club, et al.

² *Id.*

1. *Eliminate Provisions Allowing for Reduction in Inspection Frequency*

We strongly advise eliminating provisions allowing operators to adjust frequency based on the number or percentage of leaking components identified in prior surveys, neither of which is rationally tied to the future leak performance of a facility. Moreover, such an approach misaligns incentives for operators.

As we have explained in prior comments, studies suggest that past leak emissions are not a good predictor of future leak emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random events play in overall leak emissions.³ Numerous studies have found that leaks, in particular very large leaks or “super emitters,” are largely unpredictable and shift over time. In particular, a series of studies undertaken in the Barnett Shale found that abnormal operating conditions, such as improperly functioning equipment, could occur at different points in time across facilities.⁴ As a result, one of the study’s authors concluded that inspections need “to be conducted on an ongoing basis” and “across the entire population of production sites.”⁵ Accordingly, we recommend that CARB propose an LDAR standard based on fixed frequencies.

Data from operators collected as part of Colorado’s rulemaking further supports a fixed inspection requirement. Colorado’s recently adopted leak detection and repair program requires that operators inspect for leaks at all but the smallest sites on a continuous annual, quarterly, or monthly basis.⁶ Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, “Encana’s experience shows leaks continued to be detected well into the established LDAR program.”⁷ Encana’s data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, operators continue to find leaks during every subsequent survey because leaks re-occur on an ongoing basis at facilities.⁸ This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak inspection data from a number of

³ May 15 Letter to CARB from EDF.

⁴ Harriss et al., (2015) “Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary,” *Environ. Sci. Technol.*, 2015, 49 (13), available at <http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305><http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305><http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305> (providing a summary of the 12 studies that were part of the coordinated campaign).

⁵ Zavala-Araiza, et al., (2015) “Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites,” *Environ. Sci. Technol.* 2015, 49, 8167–8174, available at <http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133>

⁶ 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014).

⁷ Rebuttal Statement of Encana Oil and Gas (USA) Inc., p. 10, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9., on file with EDF.

⁸ *Id.* at 10-11.

well production facilities and compressor stations.⁹ Carbon Limits found that inspectors continued to find leaks in frequent repeat inspections on the same facility. Additionally, Carbon Limits found that the cost-effectiveness of the leak inspections, expressed in dollars per metric ton of VOC abatement, did not significantly rise over several years after regulations were put in place requiring LDAR at facilities in Alberta.

CARB's proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities.¹⁰ EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."¹¹ The report recommends that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies should monitor more frequently.¹²

We strongly recommend that CARB maintain the quarterly inspection frequency and remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. However, if CARB retains the provisions that allow for decreased inspections, we urge CARB to strengthen these by adding a provision that explicitly prohibits a decrease in monitoring if the facility is in violation of any aspect of the LDAR provisions, and requires a return to quarterly at those facilities conducting annual surveys upon the finding of a violation of any of the the LDAR provisions. This is the approach taken by Ventura County, San Joaquin Valley, and Santa Barbara air districts, and we maintain this is an important element to ensuring that reductions in frequency only occur at those facilities in compliance with the CARB rule.¹³

2. CARB Should Allow for the Use of OGI and other Emerging Technologies Demonstrated to be Equally or More Effective, yet Less Costly, than Method 21.

Optical gas imaging (OGI) systems have rapidly advanced to the forefront of leak detection technology, primarily because of the speed and comprehensiveness with which these technologies can detect leaks, as well as other important advantages over Method 21 or non-instrument based methods. In addition, the methane leak detection landscape is innovating

⁹ Colorado Department of Public Health and Environment. Index of /apc/aqcc/Oil & Gas 021914-022314/REBUTTAL STATEMENTS, EXHIBITS & ALT PROPOSAL REVISIONS/Conservation Group. Supplemental Testimony of David McCabe. Pg 734-736. Available at: <ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB%20Exhibits.pdf>.

¹⁰ U.S. EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007. Pg 1. Available at <http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf>.

¹¹ *Id.* at 23.

¹² *Id.*

¹³ Ventura County Air Pollution Control District R. 74.10.D.8.b and 74.10.9; San Joaquin Valley Air Pollution Control District R. 4409.5.2.9 and 4409 5.2.10; Santa Barbara County Air Pollution Control District R. 331.F.2.c.

rapidly and we urge CARB to include an alternative compliance pathway that allows operators to use methods demonstrated to be equally or more effective at detecting methane leaks as Method 21 or OGI. Importantly, these benefits not only enhance the effectiveness of inspections in detecting leaks, but also reduce costs. Coupled with Method 21, OGI offers an efficient, comprehensive method to detect, quantify and help repair leaks:

- **Speed.** Optical gas imaging can be used to quickly and comprehensively scan an entire facility for leaks, accurately detecting almost any leaking equipment from safe vantage points. The Colorado Air Pollution Control Division estimates operators can scan a facility for leaks twice as quickly using an IR camera as they can using a Method 21 compliant device.¹⁴ Some suggest that this is a conservative estimate of the time savings associated with the use of IR cameras, and that IR camera scans can be performed even more efficiently.¹⁵ BLM estimates OGI can identify up to 2,100 components per hour while portable analyzer can only identify 30-40.¹⁶ A recent presentation by Target Emission Services similarly notes that OGI is capable of surveying 1000-5000 components per day versus only 250-600 using Method 21.¹⁷
- **Comprehensive Inspection.** Moreover, optical gas imaging technology with infrared cameras is proven to enable efficient and accurate site-level assessments, including difficult to access components.¹⁸ A clear illustration of this is that operators can detect leaks atop storage tanks using an IR camera that would otherwise go undetected unless an inspector climbed to the top of the tank.¹⁹ As we have previously noted, thief hatches are a very significant source of leaks, as documented by various EPA Region 8 and Colorado inspections and enforcement actions.²⁰ This allows open thief hatches or other similar leaks to be promptly addressed once detected, without requiring an inspector to climb the tank on every leak survey. OGI allows operators to safely but effectively monitor components and equipment that may be unsafe to monitor with Method 21, and also

¹⁴ Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) at 20, on file with EDF.

¹⁵ ICF International, “Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries,” March 2014, at 3-10 to 3-11, available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

¹⁶ U.S. Bureau of Land Management, Regulatory Impact Analysis for: Revisions to 43 CFR 3100, 3600 and Additions of 43 CFR 3178 and 43 CFR 3179, at 103, available at http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

¹⁷ Target Emission Services. “LDAR Case Study: Comparison of Conventional Method 21 vs. Alternative Work Practices (Optical Gas Imaging).” (Hereinafter “Target Presentation”). Presentation at 2015 Gas Technology Institute Conference. Slide 8. Available at: <http://www.gastechnology.org/CH4/Documents/13-Terence-Trefiak-CH4-Presentation-Oct2015.pdf>.

¹⁸ Consent Decree *U.S. v. Noble Energy*, (No. 1:15 cv 00841, D. CO., April 22, 2015), available at http://www.justice.gov/sites/default/files/enrd/pages/attachments/2015/04/23/lodged_consent_decree.pdf; see also EPA Compliance Alert, “EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities,” Sept. 2015, available at <http://www2.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf>.

¹⁹ See *Id.* See also Mitchell, A.L., et al., (2015), “Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results,” *Environ. Sci. Technol.*, 2015 49 (5), pp 3219-3227. DOI: 10.1021/es5052809, available at <http://pubs.acs.org/doi/abs/10.1021/es5052809>.

²⁰ May 2015 Letter to CARB from EDF.

allows operators to detect leaks such as pinhole corrosion leaks in tanks, which operators are very unlikely to find with Method 21.

- **Accuracy and Efficacy.** Although technologies such as OGI do not currently quantify leaks, detection is of primary importance since most leaks are cost effective to repair once detected.²¹ The quantitative comparisons that exist indicate that OGI is as effective as Method 21 in detecting all but the smallest leaks.²² There is also data indicating that OGI can be more accurate for identifying the source of specific leaks.²³
- **Compliance Monitoring and Enforcement.** OGI technologies allow operators to record and save videos of leaks. These records can help CARB or district inspectors confirm compliance with the LDAR requirements. While we urge CARB to remove the provisions allowing operators to decrease inspection frequency based on past performance, if these provisions remain, records of the leaks detected will become even more important and strict recordkeeping requirements should be adopted.

The use of OGI-based LDAR programs is a central feature of many leading and federal state standards. Five states – Colorado, Pennsylvania, Ohio, Utah and Wyoming – have adopted LDAR requirements for oil and gas facilities that allow the use of OGI instruments as a means of compliance.²⁴ Since 2011, Subpart W of EPA’s Greenhouse Gas Reporting Program has allowed the use of OGI cameras to detect leaking components at above-ground facilities in natural gas processing, transmission, storage, and distribution, as well as LNG import/export facilities.²⁵ EPA and the Bureau of Land Management’s recent proposals to limit pollution from oil and natural gas facilities both propose to allow for the use of OGI as the primary leak detection method.²⁶

Many leading operators have also deployed OGI to help detect and repair leaks. Companies such as Shell, Anadarko Petroleum Corporation, and Noble Energy have indicated that they are utilizing infrared cameras for leak detection and repair purposes.²⁷ More specifically, Jonah

²¹ Letter from Jonah Energy LLC to Steven A. Dietrich, Administrator, Wyoming Department of Environmental Quality, Dec. 10, 2014 at 2 (discussing its voluntary LDAR program and stating that “the estimated gas savings from the repair of leaks identified exceeded the labor and materials cost of repairing the identified leaks.”), on file with EDF; Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, CL-13-27 (Mar. 2014), available at http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf, at 16.

²² EDF, Oil and Natural Gas Sector Leaks Peer Review Responses of Environmental Defense Fund, June 16, 2014 at 15-16; Target Presentation, supra note 17.

²³ Target Presentation, supra note 17.

²⁴ Co. Dep’t of Pub. Health & Env’t Reg. No. 7 (5 CCR 1001-9), See 5 C.C.R. § 1001-9 XVIII (2009). Available at <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=2772&fileName=5%20CCR%201001-9>; Pa. Dep’t of Env’tl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5) Section H (1/2015); Ohio Env’tl. Prot. Agency, General Permit 12.1(C)(5)(c)(2), 12.2(C)(5)(c)(2); Wyo. Dep’t of Env’tl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised Sept. 2013); Utah Department of Environmental Quality, Division of Air Quality, Approval Order: General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery, II.B.10 (June 5, 2014).

²⁵ EPA, Greenhouse Gas Reporting Program (GHGRP), Subpart W, available at <http://www.epa.gov/ghgreporting/reporters/subpart/w.html>

²⁶ 80 FR 56593, 56596 (Sept. 18, 2015); 81 FR 6616, 6647 (Feb. 8, 2016)

²⁷ EDF, Oil and Natural Gas Sector Leaks Peer Review Responses of Environmental Defense Fund, June 16, 2014 at 9.

Energy's Enhanced Direct Inspection & Maintenance (EDI&M) Program in Wyoming has been ongoing for the last five and a half years, employing a *monthly* leak detection and repair program using instrument-based surveys (IR camera technology). This program has resulted in over 16,000 inspections and thousands of repaired leaks identified by IR camera technology and a reported overall control effectiveness in excess of 75%.²⁸

We are aware that Air Districts with existing inspection and maintenance programs require quantification of leaks. To the extent that CARB retains the requirement in the proposal that operators quantify leaks, we urge allowing operators the flexibility to couple their OGI inspections with a device capable of quantification. This would take advantage of many of the benefits of OGI while also ensuring quantification. Under this approach, operators would be required to first scan the facility with OGI, thus ensuring that difficult or unsafe to monitor components are scanned. Operators would then only be required to measure the leaks detected with the OGI camera. Since OGI operators can conduct OGI inspections more quickly than Method 21, this approach would result in a lower overall inspection time and therefore inspection costs, and still ensure that any detected leaks are quantified. Colorado allows operators to utilize this approach.²⁹

As we have previously indicated, the methane leak detection technology landscape is advancing rapidly and the draft rule should support such innovation. Accordingly, we strongly urge the agency to allow operators to utilize approved devices other than Method 21 and OGI that have been demonstrated to be equally or more effective at detecting methane leaks. This is the approach allowed in Colorado.

3. LDAR Exemptions Should be Removed or Narrowed to Improve the Protectiveness of the Rule and Increase Emission Reductions

The LDAR provisions contain numerous exemptions that undermine the protectiveness of the rule and are not supported by LDAR requirements adopted or proposed in other jurisdictions. To ensure that this LDAR program results in the greatest degree of emission reduction feasible, we suggest removing or narrowing the following exemptions:

- Section 95669(e)(1). This provision exempts “components at a facility upstream of a transfer of custody meter used exclusively for the delivery of commercial quality natural gas to the facility.” We understand that this exemption is intended to exempt the facility receiving commercial quality natural gas from responsibility for conducting LDAR on components that handle gas that does not belong to them. The problem with this approach is that it leaves components with the potential to leak unregulated. Regardless of who owns the gas, all components at facilities listed in Section 95666 should be subject to LDAR if the rule is to achieve the maximum feasible emission reductions. No other state with an LDAR program, nor the local District inspection and maintenance programs in California, contain this exemption. We urge CARB to remove this overly broad exemption, or otherwise clarify what entity is responsible for addressing leaks from the components identified in Section 95669, if it is not the entity receiving the commercial quality natural gas.

²⁸ Jonah Energy LLC, presentation at the WCCA Spring Meeting, May 8, 2015, on file with EDF.

²⁹ 5 C.C.R. § 1001-9 XVII.F.6.e.

- Section 95669(e)(6). This provision exempts “components and piping located downstream from the point where crude oil, condensate, or natural gas transfer custody occurs, including components and piping located outside the facility boundaries of natural gas compressor stations and underground storage facilities.” Like the exemption in Section 95669(e)(1), this exemption is overly broad and threatens to exempt components located at numerous facilities. No other state with an LDAR program, nor the local District inspection and maintenance programs in California, contain this exemption. Custody transfer occurs at numerous points between the production, gathering and boosting, processing, storage and transmission segments, and therefore there are countless components potentially exempt under this provision. We urge CARB to remove this provision, or narrowly cabin it to certain limited, clear instances where CARB explains the basis for this exemption.
- Section 95669(e)(4). This provision exempts “one-half inch and smaller stainless steel tube fitting including those used for instrumentation. No other state LDAR program contains this exemption. Nor does the South Coast Air District inspection and maintenance rule 1173. We are not aware of any data that indicates that these types of fittings do not leak. In fact, to the contrary, other local Air District inspection and maintenance rules require these types of fittings to be included in LDAR unless demonstrated to be leak free.³⁰ We urge CARB to remove this exemption, or at a minimum, only allow it if operators demonstrate such fitting to be leak free.
- Section 95669(e)(8). This provision exempts components that are “unsafe to monitor when conducting Method 21 measurements and as documented in a safety manual or policy approved by the ARB Executive Officer.” First off, we note that if CARB were to allow the use of OGI, the need for and use of this exemption would be significantly lessened, as operators can scan many components that may be unsafe to monitor using Method 21 (see above). Second, while we understand the need for safety exceptions, such exceptions should be narrowly tailored. We thus recommend that CARB require unsafe to monitor components be inspected within a certain timeframe. This is the approach taken by a number of the local Air Districts. Ventura County Air District requires operators inspect unsafe to monitor components at least once a year³¹ and San Joaquin Valley requires such components be inspected “during each turnaround” or within two years of the date when five major leaks within a year have been detected, whichever is sooner.³² We urge CARB to include similar provisions in its rule, specifically requiring inspection of such components at least every 6 months, during each turnaround, or when the component becomes safe to inspect, whichever happens earliest.

³⁰ Ventura County Air Pollution Control District R. 74.10.G.2.b; San Joaquin Valley Air Pollution Control District R.4409.4.2.10; Santa Barbara County Air Pollution Control District R. 331.B.c.

³¹ Ventura County Air Pollution Control District R. 74.10.D.5.a

³² San Joaquin Valley Air Pollution Control District R.4409.5.3.7.6

4. *CARB Should Require All Leaks of 500 ppm be Repaired Upon Rule Implementation*

The proposal sets the lowest leak threshold at 10,000 ppm for the first year of the rule's implementation, and then lowers this to 1,000 in year two. A 10,000 ppm leak is a large leak, and we are not aware of any technical or other justification for allowing smaller leaks that can be detected to go unmitigated. Method 21 and OGI are both capable of detecting leaks smaller than 10,000 ppm. Moreover, other leading states with LDAR programs that contain quantitative leak thresholds such as Colorado and Pennsylvania require operators repair much smaller leaks of 500 ppm.³³ U.S. EPA uses a leak threshold of 500 ppm for a number LDAR requirements for new facilities under NSPS Subpart OOOO.³⁴ We therefore urge CARB to lower the initial leak threshold to 500 ppm to be consistent with these other states and EPA to reflect what is technically feasible.

B. Pneumatic Devices and Pumps

We believe that CARB intends to regulate pneumatic devices in the following ways:

- Prohibit venting of natural gas from *continuous*-bleed pneumatic devices and pumps after 1 January 2018, as provided for in §§ 95668(f)(3) and (6);
- Include continuous-bleed, intermittent bleed pneumatic devices and pneumatic pumps in LDAR, as provided for in §§ 95668(f)(3)-(5); and
- Prohibit intermittent bleed devices from venting natural gas when not actuating after January 1, 2018, as provided for in § 95668(f)(4).

We commend CARB for proposing these provisions. No other jurisdiction prohibits venting from new continuous bleed devices or pumps located at the suite of facilities subject to this proposal, nor includes all pneumatic devices, including intermittent bleed devices, in leak detection and repair requirements. These provisions will go a long way towards reducing emissions from new continuous-bleed pneumatic devices and pumps, and malfunctioning intermittent and continuous-bleed devices and pumps.

1. CARB Should Phase Out Existing Low-Bleed Continuous Devices

That said, for continuous-bleed pneumatic devices, the draft regulation is significantly weaker than the 22 April 2015 draft regulation. We understand the proposal as allowing for the use of continuous-bleed pneumatic devices installed before 1 January 2015, provided operators adhere to the monitoring provisions in draft § 95668(f)(2), which requires operators to regularly check that these devices are not emitting more than six standard cubic feet per hour (scfh), and to fix or replace them if they do emit over this threshold. This “grandfather” clause that allows for the *indefinite* use of continuous bleed devices is not warranted.

³³ 5 C.C.R. § 1001-9 XVII.F.6.b;

Pa. Dep't of Env'tl.

Prot., Air Quality Permit Exemptions, No. 275-2101-003, <http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf>.

³⁴ See 77 F.R. at 49,498.

As we detailed in our May 2015 comments, there are numerous ways to eliminate emissions from pneumatic devices that bleed natural gas to the atmosphere.³⁵ Compressed air can be used instead of natural gas to drive devices. EPA’s 2012 OOOO NSPS standards require all pneumatic controllers at processing plants to be zero emitting,³⁶ and EPA presumes that most operators will use compressed air systems to comply with this regulation.³⁷ For sites with numerous pneumatic devices, compressed air is a cost-effective and feasible approach to eliminate emissions from pneumatic devices – including any intermittent-bleed devices on site, and also most pneumatic pumps – especially when electric power is readily available. Oil and gas production in California occurs largely in areas with increased access to electric power. Many centralized production sites and compressor stations have numerous pneumatic devices.

Other “zero-bleed” technologies exist beyond compressed air to eliminate emissions from pneumatic devices. These include:

- generating low-cost electric power on-site which can be used to power electrical valve controllers and actuators, or potentially to compress air, including devices which generate electricity from compressor waste heat;
- solar / battery systems which can be used with electric controllers and actuators; and
- “closed-loop” actuator systems which use natural gas to control and actuate valves but capture that gas on the low-pressure side of a system so it is not vented.

These systems are described in more detail and documented in our comments to US EPA on Proposed NSPS Subpart OOOOa.³⁸

In addition to using equipment that is not designed to bleed in the first place, emissions from pneumatic devices can be captured and utilized, sold, or controlled, as CARB’s proposal recognizes. These options apply well to the “low-bleed” continuous-bleed pneumatic devices that CARB’s proposal would grandfather. Since many of these devices are on sites that have, or will have, a vapor collection system, the cost of connecting a device to the vapor collection system is very low.

We thus recommend that CARB remove the provision allowing “low-bleed” continuous-bleed pneumatic devices that were in operation on 1 January 2015 to continue operating. If CARB concludes that such devices must be allowed to continue venting gas into the atmosphere, despite the numerous options operators have to eliminate these emissions, CARB must limit the period over which operators are allowed to continue these harmful emissions to at most a few years. Indefinite grandfathering is not warranted.

2. *Control Emissions from Intermittent-bleed Pneumatic Devices*

CARB has significantly strengthened its proposal for intermittent-bleed pneumatic devices, by adding specific testing requirements to ensure that these devices do not leak gas into the air when

³⁵ May 15, 2015 CATF et al Comments to CARB at 8-9.

³⁶ 40 C.F.R. § 60.5390(b)(1).

³⁷ See EPA, TSD for the Proposed NSPS Subpart OOOO, 5-22 (July 2011).

³⁸ Dec. 4 CATF et al, Comments to EPA on Proposed OOOOa at 90-91, Ex 1.

not actuating. Draft § 95668(f)(4). However, we reiterate our concern that, beyond this provision, the draft regulation, like the April 2015 draft, does not limit emissions from these devices. These devices are a very significant source of emissions. Oil and gas producers reported over 850,000 metric tons of methane emissions nationwide in 2014 from intermittent-bleed devices to US EPA's GHGRP, far higher than the 161,000 metric tons of methane they reported from continuous-bleed devices (both high-bleed and low-bleed).³⁹ In California, oil and gas producers reported over 4,100 tons of methane in 2014 from intermittent-bleed devices, while reporting no emissions at all from continuous-bleed devices.⁴⁰ Alarming, reported emissions from intermittent-bleed devices are increasing, both nationwide and in California.⁴¹

Similar to continuous-bleed devices, there are numerous options to limit or eliminate emissions from intermittent-bleed pneumatic devices. Many high-emitting intermittent-bleed pneumatic controllers can be replaced with lower emitting, or even zero-emitting, equipment. The zero-emitting technologies described above can all be applied to intermittent-bleed devices, and in the case of compressed air systems, a single system can readily be used to run a mix of continuous-bleed and intermittent-bleed devices. Even where venting natural gas-driven pneumatic devices are used, lower-bleed intermittent pneumatic devices are available. Properly designed intermittent bleed devices can emit below 6 scfh in many applications.⁴² The emissions factor for intermittent bleed pneumatics in natural gas transmission is 2.35 scfh,⁴³ well below 6 scfh. In a recent study of the methane abatement opportunities from oil and gas, ICF International estimated that 25% of high emitting intermittent-bleed controllers in oil and gas production can be replaced with low-emitting devices.⁴⁴ Wyoming requires *all* pneumatic controllers to be low emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.⁴⁵

While CARB's proposal would reduce emissions from intermittent-bleed devices by ensuring that devices that leak continuously are fixed or replaced, the emissions from properly operating devices will remain high without additional standards.

It may be useful to consider that not all intermittent-bleed devices actuate frequently – but some actuate very frequently, and therefore emit large amounts of natural gas. For example, Allen *et*

³⁹ US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_PNEUMATIC_DEVICE_TYPE. Converted from metric tons carbon dioxide equivalent to metric tons of methane using a GWP of 25.

⁴⁰ *Id.*

⁴¹ *Id.*

⁴² In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. American Petroleum Institute, "Technical Review of Pneumatic Controllers," at 7 (Oct. 14, 2011), available as Attachment K to American Petroleum Institute, Comment on OOOO New Source Performance Standards (Nov. 30, 2011), <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266>.

⁴³ 40 C.F.R. Pt. 98, subpart W, Table W-3.

⁴⁴ ICF International. (2014) "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," p. B-6. Available at: http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

⁴⁵ This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers (email from Mark Smith, WDEQ, to David McCabe, 22 September 2014), Ex. 2.

al. (2015) observed that controllers for emergency shut-off devices made up 12 percent of the population of controllers that they studied.⁴⁶ These devices will actuate very rarely, if at all. It may be reasonable to exclude some intermittent-bleed devices from control requirements for vent gas, if operators can demonstrate that actuation is very uncommon. (If facilities have instrument air installed, however, the costs of connecting that air supply to every intermittent-bleed controller are very low, and in general that should be required.)

In contrast, some intermittent-bleed devices actuate very frequently. Of the 377 devices studied by Allen *et al.* (2015), 24 were intermittent-bleed devices that actuated at least 10 times during the sampling period, which was typically 15 minutes. Four actuated over fifty times while sampled.⁴⁷ These devices can emit at high levels – five of the forty highest emitting devices studied by Allen *et al.* (2015) are intermittent-bleed devices that were assessed to be operating properly.⁴⁸ Devices with specific functions, such as level controllers on separators, are likely to actuate frequently.

While specific treatment of intermittent-bleed devices that very rarely actuate may be warranted, the fact that some controllers very rarely actuate cannot be used to justify inaction for the entire class of intermittent-bleed controllers.⁴⁹ Since there are available approaches to avoid these emissions, CARB must issue appropriate standards to address emissions from intermittent-bleed controllers that are operating properly (not continuously emitting) and that have high emissions.

We suggest that CARB require emissions from intermittent-bleed devices be routed to a vapor collection system; if such a system is not available or operators can demonstrate that such routing is not feasible, operators must ensure that the intermittent-bleed device does not emit natural gas continuously or emit over six scfh, as is required in Wyoming.⁵⁰

As we discussed and documented in our May 2015 comments, these requirements will produce abatement at a reasonable cost. This is particularly true for California, where most facilities will have vapor collection systems, so the costs of routing emissions from intermittent-bleed devices to these systems should be quite low (like the costs of routing emissions from continuous-bleed controllers to these control devices, as ARB proposes).

Finally, we commend CARB’s proposal to require capture of all emissions from natural gas-driven pneumatic pumps.

C. Compressors

⁴⁶ Allen D.T. *et al.* (2015), “Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers,” *Environ. Sci. Technol.* 49, 633–640.

⁴⁷ Derived from analysis of table S4-1 in Allen *et al.* (2015) supplemental information.

⁴⁸ See Allen *et al.* (2015), Supporting Information, section S-8. Temporal profiles of emissions from the 40 highest-emitting controllers sampled in the study are shown. Controllers LB01-PC01, LB07-PC01, LB04-PC01, LB06-PC05, and LB04-PC03 – five of the forty highest emitting controllers – are clearly intermittent devices which were assessed to be “operating as expected.”

⁴⁹ Since some intermittent-bleed devices actuate very rarely, their emissions are low. These devices bring the average emissions factor for intermittent-bleed devices down.

⁵⁰ Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6(f).

1. *Reciprocating Compressors*

We support CARB's approach to require operators to either capture and control all emissions from rod packing on reciprocating compressors, or to monitor rod packing emissions at the vent point and repair them when they exceed thresholds. We commend CARB's draft proposal for requiring control of rod packing emissions from compressors at wellpads, which EPA has failed to require or propose for even new equipment to date, and for requiring measurement of actual emissions from "midstream" compressors – those at natural gas gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities.

However, the draft regulation should be strengthened. Since even new, properly installed rod packing seals allow some natural gas to escape past the seals, emissions from reciprocating compressors – even those that are monitored closely – are inevitable if the natural gas that escapes is not captured and directed to a vapor collection system (VCS). Therefore directing gas to a VCS should be required whenever possible. The alternative approach of monitoring emissions and requiring repair when emissions rise above a threshold should only apply when directing gas to a VCS is somehow not feasible. Even if used to control emissions with a vapor control device as described in draft §95668(c)(3) – (c)(4), instead of directing vapors to a sales, fuel, or reinjection line, collecting vapors with a VCS is superior to monitor and repair. CARB should strengthen the draft by requiring the use of a VCS whenever feasible.

The draft standards magnify this problem by only requiring annual monitoring for midstream compressors, which would be regulated under draft §95668(d)(2), when those compressors do not have vapor collection systems in place. Furthermore, the emissions standard for these compressors – two standard cubic feet per minute (scfm) per cylinder (draft §95668(d)(2)(E)) – is much higher than appropriate, since rod packing replacement can cost-effectively reduce emissions at levels far below 2 scfm per cylinder, as we show below.

We commend CARB for requiring measurement of the volumetric or mass flow rate from rod packing vents for midstream compressors, as opposed to measuring the hydrocarbon concentration at the access port. Measuring the volumetric or mass flow rate from an access port with high volume sampling, bagging, or calibrated flow measuring instruments gives a real value for emissions, while hydrocarbon concentration is only weakly correlated with emissions.⁵¹ Some leak-detection service providers routinely measure emissions from leaks with high volume samplers, indicating that the cost of these measurements is quite reasonable.⁵² The routing of all emissions through an access port will make such measurements particularly accurate and feasible. Therefore, CARB should retain the requirement for measuring actual flow in this manner for midstream reciprocating compressors, but on a quarterly instead of annual basis, as discussed above. If measurements are only required on an annual basis, as in the current draft, two problems arise. First, elevated emissions can and will continue over a longer period than if quarterly measurements are required. Second, the lax annual requirement encourages operators

⁵¹ Clearstone Engineering *et al.* (2006) *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*, at 3. Available at http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf.

⁵² Carbon Limits (2014), *supra* note 21 at 10.

of midstream compressors to monitor emissions rather than direct natural gas from reciprocating compressor seals to a VCS.

Further, CARB must strengthen the proposal by reducing the threshold at which repair of rod packing is required. Draft §95668(d)(2)(E) requires repair or replacement of rod packing when emissions per cylinder reach two scfm. However, since the natural gas that escapes from rod packing and is vented to the air is a salable product, and repair / replacement of rod packing keeps more natural gas in the system and therefore increases revenues for operators, repair / replacement of rod packing is cost-effective when emissions are far lower than 2 scfm. In comments we recently filed on US EPA's 2015 proposed New Source Performance Standard Subpart OOOOa, we used US EPA figures for the costs of rod packing replacement to show that replacement is cost-effective when emissions per cylinder reach 20 to 25 standard cubic feet *per hour*, over a factor of four lower than the 2 scfm threshold in draft §95668(d)(2)(E).⁵³ For example, using cost figures from US EPA documents (converted to 2015 dollars) and a \$4 per MCF price of natural gas, we showed that the net abatement cost of replacing rod packing when emissions per cylinder reach 20 scf per hour is \$538 per short ton of avoided methane pollution; if the threshold were 25 scf per hour, the net cost would drip to \$232 per short ton of abated methane.⁵⁴ Accordingly, CARB must reduce the threshold at which replacement or repair of rod packing is required. It is important to consider that operators have other options for control; specifically, the option of using a vapor collection system. Indeed, commercial systems to direct rod packing emissions to fuel systems for compressors are available,⁵⁵ and in general these emissions can be routed to a VCS which directs gas into a sales line such as a vapor recovery unit on a tank. We also note that the Ohio EPA has released a draft general permit that requires operators to capture all emissions from reciprocating compressor rod packing and direct those emissions to sales, fuel lines, or 98% control.⁵⁶

Finally, CARB should consider requiring measurement of actual flow, in the manner required for midstream compressors, for compressors at wellpads and other oil and gas production sites, as opposed to measuring hydrocarbon concentration as currently required in draft § 95668(d)(1)(B). At a minimum CARB should seek comment and cost data on this approach for these compressors. Wellpad compressors can be large and, given the low cost of actual emissions measurements, it is not appropriate to require the less accurate concentration measurement at all of these compressors.

2. Centrifugal Compressors

We believe that the approach taken by CARB in the previous (22 April 2015) draft of the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities was more appropriate than the approach taken in the current draft. The April 2015 draft would have required operators of centrifugal compressors with wet seals to “collect the wet seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device.” April 2015 Draft at § 95213(f)(1)(B). In contrast, the

⁵³ Joint comments at 101-102.

⁵⁴ *Id* at 102.

⁵⁵ *Id* at 98.

⁵⁶ Ohio EPA, General Permit 17.1 Template, C.(1)(b)(1)(d), available at <http://epa.ohio.gov/dapc/genpermit/permitsec.aspx>

current Draft Proposal allows operators of centrifugal compressors with wet seals to opt out of installing a vapor collection system, and instead to monitor emissions from the wet seals and, if they rise above three scfm, to “minimize” emissions and after several years, to install dry seals. Draft regulation at § 95668(e)(3) – (e)(8). This is an odd approach.

First, it is generally very feasible and cost effective to install vapor collection systems that route wet seal degassing emissions to the suction side of the compressor, another beneficial use, or a control device. EPA has published literature through its Natural Gas STAR program describing how these systems — consisting of seal oil/gas separators, demisters/filters for both high and low-quality gas, and necessary piping and instrumentation — are cost effective and can largely eliminate vented gas from wet seal compressors.⁵⁷ EPA literature presents four different options for using gas that is captured through these devices: 1) return it to compressor suction; 2) route high-pressure gas to a combustion turbine for electricity generation; 3) route low-pressure gas to a heater or boiler to use as fuel; and 4) send the captured gas to a control device.⁵⁸ EPA notes that at least one operator has configured its system to use all four of these options.⁵⁹ Based on experience from about one hundred installations, BP has reported that systems that return seal gas to compressor suction (the first option) are “simple, broadly flexible, and reliable,” and generate “positive cash flow in less than a month.”⁶⁰ EPA requires that operators of new and modified wet-seal centrifugal compressors at gathering and boosting compressor stations and gas processing plants use these vapor collection systems to capture seal oil degassing vapors and route emissions to a process or 95% control,⁶¹ and has proposed extending this requirement to new and modified transmission and storage segment wet-seal centrifugal compressors.⁶²

Second, according to US EPA, “Methane emissions from wet seals typically range from 40 to 200 standard cubic feet per minute.”⁶³ The minimum of this range is an order of magnitude above the threshold above which CARB would require operators to “minimize” emissions. Draft regulation at § 95668(e)(6) – (e)(7). Simply put, wet seal centrifugal compressors without vapor collection systems in place cannot meet this standard.

Recognizing this, many operators may choose to simply install vapor collection systems, which is a comparatively simple modification, not requiring years of lead time. However, in addition to increasing the complexity of the rule, the option to monitor and “minimize” emissions instead of installing a vapor collection system may be detrimental. First, since the word “minimize” in draft § 95668(e)(7) is not defined, and a wet seal unit operating normally typically emits at least 40 scfm, the provision may be interpreted by some operators as allowing them to operate wet

⁵⁷ See EPA, *Wet Seal Degassing Recovery System for Centrifugal Compressors* (2014), available at <http://www3.epa.gov/gasstar/documents/CaptureMethanefromCentrifugalCompressionSealOilDegassing.pdf>; see also Reid Smith, BP, and Kevin Ritz, BGE, *Centrifugal Compressor Wet Seals Seal Oil De-gassing & Control*, presentation delivered at 2014 Natural Gas STAR Annual Implementation Workshop (May 2014), available at http://www3.epa.gov/gasstar/documents/workshops/2014_AIW/Experiences_Wet_Seal.pdf, at 7—19.

⁵⁸ *Id.* at 3.

⁵⁹ *Id.*

⁶⁰ *Id.*

⁶¹ 40 C.F.R. § 60.5380.

⁶² Proposed 40 C.F.R. § 60.5380a (80 F.R. 56,593.)

⁶³ See EPA, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors* (2006), at 1. Available at: http://www3.epa.gov/gasstar/documents/ll_wetseals.pdf.

seal compressors uncontrolled, emitting well over three scfm, until January 1, 2020. Second, it is not clear how the critical component provision in draft 95668(e)(8) will operate, and whether operators of designated-critical wet seal centrifugal compressors will enact controls.

As such, CARB should revert to the simpler and clearer approach to wet seal centrifugal compressors in the April 2015 Draft regulation.

Finally, CARB should ensure that components on driver engines and compressors for *dry seal* centrifugal compressors are subject to the LDAR provisions of §95669. We believe that this would reflect CARB's intent. However, since 95668(e)(2) specifically requires this for wet seal compressors but the draft is silent on dry seal compressors in this regard, we are concerned that some operators may misinterpret the draft regulation as not requiring LDAR for dry seal compressors.

D. Crude Oil, Condensate, and Produced Water Separation and Storage

CARB should clarify and tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems (where the measured annual flash emission rate is greater than 10 metric tons per year).

1. Testing Should Occur Earlier and Controls be Installed Sooner

We remain concerned that the draft rule may allow new vessels to operate without any emission controls for the first year of operation. Section 95668(a)(4) provides that owners and operators of new and existing separators and tank systems that are not controlled for emissions with the use of a vapor collection system must conduct annual flash analysis testing of the crude oil, condensate, or produced water – with no requirement to actually control emissions unless this analysis demonstrates emissions in excess of ten metric tons of methane per year. (Section 95668(a)(2)(B) exempts tanks from the requirements of this subsection entirely if they are “used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from any newly constructed well for up to 30 calendar days following initial production,” so long as the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.)

Section 95668(a)(4) clarifies that this annual flash analysis testing must be conducted “[b]eginning January 1, 2017 and by no later than September 1, 2017.” Though the draft states that this requirement applies to “new and existing” systems, it appears to apply to separator and tanks systems that are in place prior to January 1, 2017 (and possibly to those that become operational between January 1, 2017 and September 1, 2017). For such systems, CARB should require that owners and operators conduct testing by a date certain that is earlier than September 1, 2017. Furthermore, CARB should clarify that this means that the first test must be done prior to that date (as opposed to that date commencing a year-long period during which testing may occur).

For separator and tank systems that start operation between January 1 and September 1, 2017, or after September 1, 2017, it is unclear when flash analysis testing must commence. For example, because the measurement is only required annually, it is possible that an owner or operator of a system that starts operation after September 1, 2017 may choose to conduct testing on the last day of the first year of a tank's operation. Because section 95668(a)(5) only requires control

once methane emissions have been measured to exceed 10 metric tons per year, the draft regulation does not plainly require control within the first year.

CARB should also specify how soon controls must be installed once emissions are measured in excess of 10 metric tons. Section 95668(a)(5) specifies that the requirement to control emissions begins January 1, 2018 (“Beginning January 1, 2018, owners or operators of separator and tank systems with a measured annual flash emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system with the use of a vapor collection system as specified in section 95668(c)”). It is unclear when vapor collection systems must be installed (i.e., how soon after the measurement greater than 10 metric tons), particularly for systems that exceed the 10 metric tons per year threshold after January 1, 2018. Section 95668(a)(8) further states that flash analysis testing “shall be conducted *within one calendar year* of adding a new well to the separator and tank system since the time of previous flash analysis testing” (emphasis added). With a full year to conduct testing and no firm date to realize control of the vessel, we are concerned that operators may delay installation for long periods of time *after* testing, leading to excessive periods without control.

Other jurisdictions have successfully implemented regulations that require control of tanks in the months after production begins at a well. US EPA requires that emissions from new and modified storage vessels that have potential to emit six tons of VOC or more per year must control emissions from those vessels by 60 days after the vessel goes in service.⁶⁴ As discussed below, Colorado requires operators to assess whether emissions will be significant from tanks – and if so, to control vessels from the date of initial production at the well. In light of these precedents, CARB’s proposal is clearly insufficiently protective.

As noted in our prior comments, a regulation that had the effect of allowing vessels to operate without controls for the first year is problematic because emissions are likely to be highest during the first year. Oil and gas well production generally sharply declines during the first year of operation. Throughput of materials (oil, produced water, and other substances) in vessels tracks production, meaning that potential vessel emissions follow this curve as well. Thus, the draft regulation may not only have the effect of allowing uncontrolled vessel emissions for a year—it could allow emissions without control during the time when those emissions will be highest. This concern is heightened because operators may be incentivized to delay testing until the end of the year, because if production has dropped enough to reduce potential emissions below the 10 metric ton per year threshold, the vessel will not need control.

As noted in our May 2015 comments, in crafting emission control requirements for vessels, the Colorado Air Pollution Control Division expressed concern that even allowing operators to wait *ninety days* after commencement of production to install controls on vessels would allow significant and avoidable air pollution.⁶⁵ Colorado determined that it would be cost effective to

⁶⁴ See 40 C.F.R. §60.5395(d)(1)(i). “For each Group 2 storage vessel affected facility [that is, vessels constructed after 12 April 2013], you must achieve the required emissions reductions by April 15, 2014, **or within 60 days after startup**, whichever is later.” Emphasis added.

⁶⁵ Colorado Air Pollution Control Division, Final Economic Impact Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 5 (5 CCR 1001-9), pages 8-9 (Jan 30, 2014), available at [ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Air%20Pollution%20Control%20Division%20\(APCD\)/APCD%20REB%20R7.finalEIA.pdf](ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Air%20Pollution%20Control%20Division%20(APCD)/APCD%20REB%20R7.finalEIA.pdf)

require controls to be installed on all crude oil and produced water tanks immediately, allowing operators to remove controls from a tank once testing demonstrated that the tank's uncontrolled emissions would fall below the applicable threshold. A presumption of control has the added benefit of providing operators with an incentive to test emissions promptly. ARB should follow Colorado's lead and assume that vessels require emission controls unless and until operators demonstrate otherwise.

At bare minimum, CARB should clearly indicate 1) when annual flash analysis testing must commence (including for systems that become operational after the dates specified in 95668(a)(4)), and 2) for systems with a measured annual flash emission rate greater than 10 metric tons per year, the mandatory timeline for installing a vapor collection system.

We suggest that testing should be carried out within 30 days of initial production, and that CARB require that controls be in place within 60 days after initial production for tanks that have potential emissions above the threshold, in line with the Federal standards (note that the Federal standards have a different, VOC-based threshold than the draft CARB standard). CARB should also consider requiring control from the day of initial production when emissions from the tank can be anticipated to exceed 10 metric tons per year, in accordance with the Colorado approach.

CARB must also ensure that for new wells, the Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water properly assesses annual emissions. It is critical that operators assess potential emissions rapidly after operation of a tank begins, so that the tank can be controlled if needed. CARB must also ensure that operators do not use a simple extrapolation of low production in the first days after production begins to conclude that potential emissions from the vessel will be less than the 10 metric ton per year threshold. Such extrapolation would be inappropriate because for new wells, particularly wells that were hydraulically fractured, production can rise dramatically over the initial weeks after production begins. CARB thus must ensure that operators use liquid throughput values in Equation 1 of Section 11 of the Test Procedure that are appropriate for yearly averages for new wells.

2. Provisions Requiring Clarification or Strengthening

CARB should also clarify or strengthen the following provisions:

- 95668(a)(4)(D): "Demonstrate that the results of the flash analysis testing are representative of the crude oil, condensate, and produced water processed or stored in the separator and tank system. The ARB Executive Officer may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems." It is unclear how the owner or operator would demonstrate that the test results are representative, or how the ARB Executive Officer would determine whether the test results "reflect representative results of similar systems."
- 95668(a)(7): "... If the results of flash analysis testing are less than or equal to 10 metric tons per year of methane using three consecutive years of test results the owner or operator may reduce the frequency of testing and reporting to once every five years."

Testing once every five years is too infrequent to effectively determine if emissions have increased above 10 metric tons per year.

- 95668(a)(9): “Flash emissions shall be recalculated if the annual crude oil, condensate, or produced water throughput increases by more than 10 percent since the time of the previous flash analysis testing” (provided that the increase in throughput is not a result of adding a new well to the separator and tank system which requires additional flash analysis testing as specified in section 95668(a)(8)). This provision should specify how soon after the throughput increase the flash emissions must be recalculated.

3. Comparison of CARB Proposal to Colorado Requirements

The following section compares the requirements and timelines in the CARB draft rule to those in the Colorado methane rule (emphasis added):

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control and monitoring requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

*XVII.C.1.b. Owners or operators of storage tanks with uncontrolled actual emissions of VOCs **equal to or greater than six (6) tons per year based on a rolling twelve month total** must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.*

XVII.C.1.b.(i) Control requirements of Section XVII.C.1.b. must be achieved in accordance with the following schedule:

*XVII.C.1.b.(i)(a) A storage tank constructed on or after May 1, 2014, must be in compliance **within ninety (90) days of the date that the storage tank commences operation.***

XVII.C.1.b.(i)(b) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

*XVII.C.1.b.(i)(c) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(a) or XVII.C.1.b.(i)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must be in compliance **within sixty (60) days of discovery of the emissions increase.***

XVII.C.1.c. Control requirements within ninety (90) days of the date of first production.

*XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment **during the first ninety (90) calendar days after the date of first production.** The air pollution control equipment must achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after the date of first production.*

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section XVII.C.1.b.

...

XVII.C.2. Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section XVII.C.2.b.(ii).

...

XVII.C.2.b.(ii) Owners or operators must achieve the requirements of Sections XVII.C.2.a. and XVII.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule:

*XVII.C.2.b.(ii)(a) A storage tank constructed on or after May 1, 2014, must comply with the requirements of Section XVII.C.2.a. **by the date the storage tank commences operation.** The storage tank must comply with Section XVII.C.2.b. and implement the approved instrument monitoring method inspections **within ninety (90) days of the date that the storage tank commences operation.***

XVII.C.2.b.(ii)(b) A storage tank constructed before May 1, 2014, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 2015. Approved instrument monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty

(30) days for storage tanks with uncontrolled actual VOC emissions greater than 50 tons per year.

*XVII.C.2.b.(ii)(c) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(a) or XVII.C.2.b.(ii)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. and implement the required approved instrument monitoring method inspections **within sixty (60) days of discovery of the emissions increase***

E. Catastrophic Leaks

We commend CARB for considering this important issue, particularly in light of the disastrous natural gas leak at the Aliso Canyon underground storage facility and the regulatory gap it exposed. Given the current regulatory framework applicable to California's fourteen underground gas storage facilities and the age and condition of the state's oil and gas infrastructure, the potential for large and catastrophic leaks is a critical safety and environmental problem. We also note, however, that this is a complicated new undertaking with many complex topics that must be carefully considered. While we urge CARB to move forward with developing a mitigation framework to address any future major leaks as expeditiously as possible, we request that ARB not delay the current rulemaking schedule in order to do so.

In developing mitigation requirements, we request that CARB consider the following:

- Regulatory Authority. CARB should reserve for itself broad authority to ensure emissions from large and catastrophic leaks are fully mitigated. Criteria for determining which leaks are subject to mitigation requirements should not be narrowly limited to predetermined emissions thresholds. Site-specific conditions should be taken into account when determining whether any particular leak qualifies for regulation under this new program, including but not limited to volume, proximity to sensitive receptors, potential health and environmental threats, leak duration, and others.
- Accounting Framework for Quantifying Leaks. CARB must develop a scientifically rigorous framework for quantifying leak volume. The exact accounting method may vary depending on the nature of the leak and site-specific conditions and CARB should therefore ensure that the framework provides sufficient flexibility to respond to different leak sources and types, while also relying on proven and scientifically defensible measurement and estimation methods.
- Preventative Measures. CARB should prioritize measures that could help prevent large or catastrophic leaks from occurring in the first place, for example requiring facilities to develop an assessment of the threat of such leaks and steps that could be taken to minimize those threats. To the extent that agencies other than ARB have jurisdiction over the sorts of preventative measures that could prevent large or catastrophic leaks from occurring, CARB should coordinate with those agencies to help ensure they have everything they need to put such measures in place.

- Mitigation Requirements. Detailed and specific criteria need to be developed that can serve as the foundation for required mitigation of large and/or catastrophic leaks. At a minimum, the following should be addressed:
 - Stringency. CARB should require that leaks be repaired as expeditiously as possible and that the entire volume of leaked methane be remediated.
 - Accuracy. As discussed above, a site-specific and scientifically rigorous method must be developed to determine the total leak volume.
 - Credibility. CARB itself, in addition to local air districts, should approve and independently verify reductions using scientifically proven methods.
- Penalties and Compensation. CARB should consider options such as fines based, for example, on the volume and duration of the leak, and compensation for people negatively affected by the leak. It should also ensure that costs associated with the leak will not be passed on to ratepayers.
- Emergency Authorization. ARB should also consider including provisions analogous to section 303 of the federal Clean Air Act, 42 U.S.C. § 7603, which authorizes EPA to bring suit in federal court to stop or prevent pollution that poses an imminent and substantial endangerment to the public health and welfare, or to issue enforceable orders where necessary. An analogous provision in CARB's regulations could grant APCDs/AQMDs or any other appropriate agency authority to bring suits against, or issue binding orders to, any source that is responsible for a large or catastrophic leak limited in time and scope to measures that would remove any imminent and substantial endangerment posed by the leak.
- Notification Procedures. The rules should include specific timeframes in which leaks must be reported to CARB, local air districts, other regulatory agencies with jurisdiction over the leaking facility, potentially impacted members of the public, and other relevant stakeholders.
- Emergency Planning. CARB should require facilities to prepare and submit emergency response plans for large and catastrophic leaks. These plans should be reviewed and approved in conjunction with other regulatory agencies with jurisdiction over the facilities, (e.g. DOGGR, CPUC, etc.). Such plans should be periodically reviewed and updated at a fixed frequency and/or when necessitated by material changes in operations at the subject facility.

We greatly appreciate the opportunity to comment on this important proposal and look forward to working with CARB as it develops the next iteration of this regulation.

Respectfully submitted,

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July 21, 2016

Elizabeth Scheehle
Chief, Oil and GHG Mitigation Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Pacific Gas and Electric Company's Comments on the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear Ms. Scheehle,

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the Air Resources Board's (ARB) Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities¹ (Proposed Regulation), which was released on May 31, 2016.

I. GENERAL COMMENTS

PG&E is committed to delivering safe, reliable and affordable natural gas to our 15 million natural gas customers. Spanning 70,000 square miles, the company's system serves one in 20 Americans, provides 970 billion cubic feet per year of volume, and consists of thousands of miles of pipelines in addition to compressor stations, boosting stations, storage facilities, and other supporting infrastructure.

PG&E is also committed to helping California achieve its ambitious climate goals. Many of the improvements that PG&E has made in recent years to increase the safety and reliability of the natural gas system, including implementing one of the nation's most aggressive pipeline modernization programs and adopting the latest innovative leak-detection technologies, also serve to reduce methane emissions. Additionally, PG&E has upgraded its measurement, monitoring, and data management systems to improve the accuracy of greenhouse gas (GHG) data reported to the United States Environmental Protection Agency (EPA) and ARB in support of the Mandatory Reporting Regulation (MRR).

PG&E respectfully submits the following comments on the Proposed Regulation. An overview of PG&E's comments includes:

¹ Air Resources Board, May 2016. Proposed Regulation Order: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.

- More time is required for stakeholder analysis and input regarding the new storage requirements.
- Accurate leak measurement is critical to reducing emissions.
- Critical component exemptions can be appropriately considered at the facility level.
- Performance criteria limiting the number of leaks based on component population counts should be eliminated.

B-10-1

II. STORAGE REQUIREMENTS MERIT ADDITIONAL PUBLIC DISCUSSION

The May 31 Proposed Regulation includes substantial new provisions related to natural gas storage.² Unlike the other requirements, the proposed language in 17CCR§95668(h), *Well Casing Vents* and 17CCR§95668(i), *Natural Gas Underground Storage Facility Monitoring Requirements* have not been addressed in public workshops. In light of the fact that the other requirements of this regulation were developed with substantial stakeholder engagement over the course of multiple years, PG&E respectfully requests that the underground storage requirements be excluded from the regulation until more thorough stakeholder review and public discussion can be conducted. Additional public process regarding the storage requirements is also important in light of the Division of Oil, Gas and Geothermal Resources (DOGGR) discussion draft storage regulation and the associated risk for duplicative regulatory requirements.

B-10-2

At this time, PG&E notes that the 200 foot radius well-head monitoring requirement conflicts with the 100 foot radius well-head monitoring requirement contained in the DOGGR discussion draft. PG&E recommends this inconsistency be corrected. Additionally, a well-head radius of 200 feet would include within it components from other types of equipment at certain PG&E facilities. PG&E recommends that the radius be reduced to 100 feet to avoid inadvertently making non-storage components subject to the storage regulations.

III. ACCURATE LEAK MEASUREMENT IS CRITICAL TO REDUCING EMISSIONS

PG&E supports reduction of leak emissions but recommends that further consideration be given to the measurement basis in the Proposed Regulation's Leak Detection and Repair (LDAR) requirements. The LDAR requirements are a key emission reduction provision of the Proposed Regulation, as noted in the Staff Report: Initial Statement of Reasons.³ Leak repair timelines are driven by measurement of leak concentration using EPA Reference Method 21 testing, with higher concentration leaks requiring speedier repair. In this way, "large" leaks would ostensibly be repaired quickly so as to limit emissions.

B-10-3

However, it is well understood that Method 21, as a concentration-based measurement, does not correlate well to volume-based leak rates. This can result in inaccurate characterization

B-10-4

² Air Resources Board. May 2016. Proposed Regulation Order: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. 95668(i).

³ California Air Resources Board. May 31, 2016. Staff Report: Initial Statement of Reasons. P 84.

of actual emissions from leaks. Even after strictly following Method 21 procedures, external factors like wind speed, probe orientation, and screening speed introduce measurement uncertainties that can cause any single leak rate estimate to vary by a factor of 1000. ARB's own documentation regarding Method 21 recognizes the issue: "This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources."⁴ The lack of correlation between concentration-based measurements and actual leak emissions can lead to the misclassification of minor leaks as severe.

B-10-4
Cont.

Accurate leak measurement is critical for cost-effective emissions reduction. For one, understanding the true severity of leaks allows for proper repair prioritization. Additionally, making repairs on the timelines mandated by the Proposed Regulations will often require equipment blowdowns, which may result in emissions many times greater than the leak that is being repaired. Accurate leak measurement allows for informed analysis of the tradeoffs between repair and blowdown over a given timeframe.

PG&E recognizes that Method 21 offers practical advantages for local air districts that have historically used concentration-based measurement. These advantages include familiarity of use, and avoided cost of purchasing new equipment and training personnel. However, since the purpose of this regulation is to reduce methane emissions, the language should allow operators to use volume-based measurements, such as high-flow sampler devices to confirm any high concentrations measured prior to initiating leak repairs. These records would be retained and made available for inspection.

Finally, with regard to the LDAR provisions that are driven by concentration-based leak measurement, PG&E reiterates that variance provisions to repair time frames be developed to protect against increased emissions. Due to the scope of this regulation and the variety of equipment and station designs that it covers, it is impossible to give consideration to every repair scenario. This regulation may inadvertently force the repair of a leak that will create a net increase in emissions when the repair blowdown volume is considered. Variance provisions which enforce reasonable repair timelines while allowing operators to bundle repairs will help the regulation achieve its emission reduction goals.

B-10-5

IV. FACILITY LEVEL CRITICAL COMPONENT EXEMPTIONS

PG&E facilities subject to the Proposed Regulation play key roles in the operation of the natural gas system and the provision of safe, affordable, and reliable energy to customers. PG&E supports the critical component exemption included in the Proposed Regulation, which recognizes that LDAR requirements for certain components may need to be delayed in cases where shutting down the component would result in greater emissions, or would impact the safety or reliability of the natural gas system.⁵

B-10-6

PG&E recommends that the regulation specifically allow system or facility level exemptions. A single PG&E compressor may have hundreds of individual components, the

⁴ California Air Resources Board. July 1, 1999. *Method 21 Determination of Volatile Organic Compound Leaks.*

⁵ Air Resources Board. May 2016. *Proposed Regulation Order: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.* 95670(b).

majority of which would require taking the compressor out of service to repair. Preparing a critical component exemption for each compressor component would be onerous and require developing a specific naming convention and catalog for each component in a way that could be understood by both the operator and regulators. Since the compressor as a whole unit is critical to safely operating the facility, a system-level exemption would be appropriate for this location.

B-10-6
Cont.

PG&E agrees that the critical component exemption should not be used to avoid routine maintenance and standard repairs that can be conducted without taking a critical component/facility out of service. Requiring tightening, lubrication or adjustment (TLA) repairs on a timeframe consistent with the Proposed Regulation's LDAR requirements (subject to variance provisions) could be a stipulation of critical component status in facility-level cases.

B-10-7

V. PERFORMANCE CRITERIA LIMITING THE ALLOWABILITY OF LEAKS BASED ON COMPONENT POPULATION COUNTS SHOULD BE ELIMINATED

The Proposed Regulation includes criteria specifying the number of allowable leaks based on the number of components at a given facility.⁶ PG&E's natural gas underground storage and transmission compressor facilities operate under varying pressures that can range from <1 psig to 2160 psig. While manufactured components have an estimated service life, system operations, environmental factors, and other variables make it very difficult for operators to predict when a component will fail and leak. PG&E currently implements a condition-based maintenance program to ensure the safety and reliability of equipment and components within a facility. In order to comply with the proposed regulation, PG&E will need to develop and implement a prescriptive, aggressive, and costly component replacement schedule. This would likely yield little emission reduction benefit, as a majority of the components would be replaced prior to their service life.

B-10-8

Additionally, this prescriptive requirement is counter to the objective of the LDAR program which is designed to detect and repair leaks on an on-going basis. Adding punitive performance criteria for the discovery of leaks detected through compliance with the LDAR program is at odds with the broader mission of leak detection, repair, and emissions avoidance.

B-10-9

PG&E also notes that starting in 2020, any leak detected with a concentration measurement of 50,000 ppmv or greater constitutes a violation of the regulation. PG&E interprets this requirement as intending to limit "super-emitting" leak sources; however, as noted in Section III, a high concentration measurement does not necessarily correlate to a high-emission leak. Unless volume-based measurement is instituted and agreement is reached on what constitutes a zero-allowability, super-emitting leak by volume, PG&E recommends this stipulation be removed.

B-10-10

⁶ *Ibid.* 95669(o)

Finally, the Proposed Regulation contains provisions which require the replacement of components which require five repair actions within a 12 month period.⁷ In addition to the quarterly LDAR requirements, this stipulation provides a backstop against operators that may choose to perform minimal repairs. Given the multiple repair requirements prescribed in the Proposed Regulation, PG&E again recommends removing the leak allowability criteria.

B-10-11

VI. CONCLUSION

Thank you for the opportunity to submit these comments on the ARB Proposed Regulation.

Sincerely,

/s/

Nathan Bengtsson

Cc: Chair Mary Nichols (mary.nichols@arb.ca.gov)
Executive Director Richard Corey (Richard.corey@arb.ca.gov)
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⁷ Ibid. 95669(n)



To: California Air Resources Board
 From: Seth Shonkoff, Executive Director, PSE Healthy Energy
 Date: July 16, 2016
 Re: California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10
 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for
 Crude Oil and Natural Gas Facilities

Thank you for accepting these comments on California Air Resource Board's (CARB) proposed Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. In light of the recent Aliso Canyon gas leak disaster, the recommendations of the California Council on Science & Technology's (CCST) Independent Scientific Study of Well Stimulation (Long et al. 2015), and the national commitment made by the Obama Administration to reduce methane leakage from the oil and gas sector by 40-45% below 2012 levels by 2025, these regulations are an important step forward to reducing the powerful greenhouse gas pollutant, methane, and working to stabilize the climate.

We submit these comments on behalf of PSE Healthy Energy, a national energy science and policy institute that supports the adoption of responsible evidence-based energy policies that aim to protect the climate, public health, and the environment. Our organization is composed of physicians, scientists, and engineers who work to fill data gaps and promote scientific understanding of modern energy resources and production.

PSE Healthy Energy strongly supports CARB's proposed standards for crude oil and natural gas facilities. We especially appreciate CARB's leadership in proposing standards simultaneously for both new and existing sources. In conjunction with local, state, and federal regulatory requirements, these standards will prevent the waste of hydrocarbon resources and reduce the environmental, social, and economic costs of methane and other co-emitted air pollutant emissions. We encourage swift implementation of these standards to mitigate climate change and protect the health of Californians.

B-11-1

In addition to our support for these new regulations, we submit the following comments as additions and revisions that we would like to see in the final regulations.

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General Comments

Overall, we support the adoption of these regulations with minimal additions or deletions. These go a long way toward reducing the leakage of methane pollution into the atmosphere.

CARB should make some improvements to this proposal to ease public participation in the regulatory process, especially with respect to the LDAR program as described below.

First of all, CARB should not take a “step-down” approach to enforcement. CARB should maintain a consistent standard for inspection frequency. Under this proposal, failing to discover leaks can lead to eased requirements and less frequent inspections. This approach is flawed for two reasons. First, the absence of a leak reveals nothing about the probability of a future leak. Second, if failing to detect leaks can result in reduced requirements for inspections, companies are incentivized to encourage less rigorous inspections. Operators may find it in their best interest to not find leaks rather than repair them. This approach also sets a poor regulatory precedent as methane leakage is regulated in other states and at the federal level, and for regulations of other pollutants.

B-11-2

In addition to the draft regulations, we also urge CARB to engage in community-scale air quality monitoring to ensure that community exposures to air toxics attributable to oil and gas development are not elevated beyond thresholds for health.

B-11-3

We also recommend that CARB consider the implementation of minimum surface setbacks as recommended in the California Council on Science & Technology (CCST) Independent Scientific Study of Well Stimulation (Long et al. 2015).

B-11-4

95668(i) Natural Gas Underground Storage Facility Monitoring Requirements

PSE Healthy Energy applauds CARB's attention to underground storage with special monitoring requirements. We are currently in the process of conducting an extensive nationwide review of best practices for underground natural gas storage, and are pleased to see strong requirements in these draft regulations.

We note and are supportive of CARB's taking over LDAR implementation from the Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR). The proposal to have the ability to remotely access readings from the continuous monitoring of ambient air from underground natural gas storage facilities by



2018 will be important in reducing future leakage, and this data will greatly benefit the public.

We are aware that some groups have suggested that CARB augment this remote access monitoring system with a simple function allowing the public to upload monitoring data of its own, submitting citizen complaints with OGI video compliant with 95668(i)(B) that can trigger the 95669 inspection and repairs. As discussed below, a cooperative LDAR approach involving industry, government, and the public will most efficiently reduce emissions, save money, and ease compliance. We would like to see language included that would ensure that the upload of such data would trigger inspection by either a state agency or a certified third-party operator within a short timeframe, such as one week, in order to catch existing leaks not detected by infrequent inspections.

B-11-5

In addition, we support the proposal (95668 (i)(c)(6)) to require operators to maintain and make available records of their monitoring system to CARB upon request. We urge CARB to similarly require operators to also make those records available to the public.

B-11-6

95669. Leak Detection and Repair.

The Optical Gas Imaging (OGI) from the leak at the Aliso Canyon facility helped bring to the national spotlight the dangers associated with methane emissions. The infrared plumes also highlighted the contributions citizen science can bring to the enforcement of this rule. Ultimately, regulations mean nothing without proper enforcement mechanisms like an effective LDAR program.

To ease both compliance and implementation, CARB should create a single publicly accessible and searchable web based portal. This platform will first assist the regulated community by allowing electronic submission of recordkeeping and inspection reports. It will also benefit the public by allowing for online streaming of the continuous monitoring data CARB will receive under 95668(i)(1)(A).

B-11-7

Nothing in this above approach should be construed to replace or supersede the inspection, recordkeeping, and reporting requirements detailed under this proposed regulation.

95669(b)(1) PSE Healthy Energy encourages CARB to collaborate with local air districts on implementing an LDAR program that standardizes inspections, monitoring, recordkeeping, and reporting. Accordingly, local air districts should maintain the flexibility to impose additional LDAR requirements. In no circumstance should some districts have weaker LDAR requirements than CARB.

B-11-8



95669(b)(4) PSE Healthy Energy opposes CARB's proposal to exempt natural gas distribution pipelines not owned by the operator of the crude oil production facility. Pipelines can be a significant source of methane emissions and, regardless of ownership, operators should have LDAR obligations for all components of the system within their sphere of influence.

B-11-9

95669(g)(1) PSE Healthy Energy supports regular inspections of all 95668 components. However, we are concerned about CARB's proposal to reduce the frequency of inspections simply because the operator finds no leaks or only low-level leaks. This approach provides a disincentive to find and repair leaks, by rewarding operators for not detecting them. Furthermore, past leak performance is not indicative of future performance. If anything, older components should receive greater scrutiny.

B-11-10

95672 Reporting Requirements.

95672(a)(8-12) We support CARB's proposals to require operators to report leaks within specified timeframes and to report the results of inspections conducted pursuant to section 95669. Similarly, we urge CARB to require operators to make these reports available to the public upon request; and create a publicly accessible and searchable web based platform where operators must submit these records.

B-11-11

Conclusion

We are pleased to see these draft rules addressing both existing and new infrastructure moving forward in California, and we encourage swift adoption of the final rules. CARB will achieve important public health, economic, safety and climate benefits with the implementation of this rule. But as with all rules, enforcement is key. We look forward to the revision and adoption of this rule, followed by strong and swift implementation of these monitoring programs.

B-11-12

Air Resources Board

PUBLIC MEETING AGENDA July 21, 2016

Agenda Item # - 16-7-2: to tracy.jensen@arb.ca.gov

Testimony detailed content by Elias Tobias, P.Eng. Safety Scan USA (safetyscan.org) on behalf of EDF (environmental defence fund)

- Safety Scan specializes in Gas Leak Detection using state of the art infrared optical gas imaging (OGI). Quantification using hi-flow sampler technology. Emissions management program support for LDAR programs and GHG emissions reporting deployed on an encrypted cloud based system
- There was a study made by Colorado State University and Carnegie Mellon University found out recently that Natural Gas facilities in the US alone lose about 100 billion cubic feet of gas every year. That is 8x the estimates that the EPA uses. Big leakers
 - Compressor Stations (transmission and storage). (Fugitive) 22%
 - Underground pipelines. (Fugitive) 16%
 - Vented accounts for 30%
 - Total just here 68%
 - Facilities inspected = 4,549
- Although OGI costs more per hour because we can inspect a facility usually 20x to 100x faster than the traditional method 21 most of the time. At the end of the day our services will cost less. This sometimes is a paradigm that needs some work. As an

example for a private underground natural gas storage facility in northern California (we visited most after the emergency proclamation was signed by governor Brown) our inspection will take between 1/2 h to 4 h on a starting rate of \$265. At the end of the day our inspection will probably cost less than the regular old method 21

- OGI can be extremely helpful in detecting gas leaks at an early stage. Methane for example has a detection limit at 3 gr / h or 0.1oz / h. Imagine a regular cigarette lighter gas flow, this technology will detect that level of leak at a proper distance
- OGI makes the leak visible to the human eye producing an undeniable proof from a safe distance with encrypted GPS and date stamp
- We can deploy our OGI camera from the ground, helicopter, airplane or a military / industrial grade drone if necessary
- Porter Ranch leak videos from almost 3 miles showed the seriousness of that event and we have produced over 20 optical gas imaging videos with very "dramatic" imaging for our own scientific study purposes
- And because gas leaks are unpredictable we support the removal of the ARB step down rule
- There is also a recent very modern technology that uses spectral imaging based on the combination of an infrared spectrometer with a single element detector and a scanner system that can qualify and quantify over 400 types of compounds (methane included).
- Qualify = it can tell what gases are leaking, and the system will identify all of them

- Quantification = with the proper ground installation the gas leak plums information can provide that quantity of gases leaked into the atmosphere. The technology available can be deployed from 2 km or 1.25 miles away from the leak
- Quantification from an airborne helicopter is know to be in development at the present moment
- Many of the technologies presented here can be automated on a 24/7 option connected to a control room and/or scada for automatic alarms as soon as the leaks reach the detection limits that can sometimes be adjusted

For and example if we were to deploy this new technology while the Aliso Canyon leak was happening we could have identified all the compounds that were being emitted into the atmosphere and also had a very strong chance to scientifically quantify the concentration of all gases being leaked into the atmosphere on a 24/7 real time monitoring with spectral images videos as a proof

B-12-1

Sincerely,

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