Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources

Electricity Generation Sector Public Report

California Air Resources Board
Transportation and Toxics Division
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Preface

The data in this report is facility reported information dealing with potential energy efficiency-improvement actions identified by the facilities in 2011. The economic and regulatory environment for the electricity generation sector has undergone further evolution since that time. This evolving environment is expected to impact business decisions regarding these actions (e.g., run, retrofit, replace or retire). This evolving environment includes, but is not limited to:

- The State Water Board adopted Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy)
- The Emissions performance standard (EPS) jointly established by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC)
- SCAQMD’s 2013 adoption of Rule 1304.1

The State Water Board Policy applies to the 19 existing power plants (including two nuclear plants) that currently have the ability to withdraw over 15 billion gallons per day from the State’s coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). Under the State Water Board OTC Policy nearly 4,200 MW of conventional gas generation resources at existing OTC power plants in LA Basin (four out of the five of the reporting facilities in the basin) will be required to demonstrate compliance through retrofit, replacement, or retirement. In San Diego, over 900 MW of gas-fired capacity (the one reporting facility) must phase-out OTC practices through retrofit, replacement, or retirement by 2017. It is unclear at this time which compliance paths the impacted facilities will take.

The EPS, jointly established by CEC and CPUC, requires California utilities to only enter into long term contracts, purchases, or capital improvements for base load generation that emits no more than 1,100 pounds of carbon dioxide per megawatt-hour (lbs CO_2/MWh) generated. Most California gas-fired generation and gas-fired cogeneration can meet this, but less efficient natural gas-fueled facilities and coal powered facilities without carbon sequestration may not be able to comply, limiting their ability to compete as base load electricity providers. For example the coal-fired APMC Stockton Cogeneration has ceased operation since the time of data submittal, and the coal-fired ACE Cogeneration is planning to shut down soon.

Additionally, SCAQMD’s Rule 1304.1, Electrical Generating Facility Fee for Use of Offset Exemption, will impact the costs of OTC replacement generation projects in the South Coast. This is not reflected in the 2011 reported costs.

Introduction and Summary

This report summarizes the data provided to the Air Resources Board (ARB or Board) by electricity generation facilities subject to the Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation (EEA Regulation or Regulation) approved in 2010.[1] In this section, we present background information on the EEA Regulation and a short summary of the data provided by electricity generation facilities.

Following this Introduction and Summary (IS), are two sections which provide a compilation of the information submitted by the electricity generation facilities. This information is aggregated in a manner consistent with ARB regulations. The first section, Part I, gives a sector-wide summary of all the energy efficiency improvement projects identified by the electricity generation facilities, along with estimated emission reductions and costs. The second section, Part II, summarizes facility-specific information consistent with the public disclosure requirements under California Code of Regulations (CCR) §95610. Emission inventories, both on a sector-specific and facility-specific basis, are provided for the 2009 reporting year.

The following are the preliminary observations based on the information provided to ARB:

- The 14 electricity generation facilities subject to the EEA Regulation identified 129 energy efficiency improvement projects.
- The total greenhouse gas (GHG) reductions associated with these projects is estimated to be approximately 1.91 million metric tons carbon dioxide equivalent (MMTCO2e) per year.[2]
  - ✓ If fully implemented, the projects would reduce GHG emission by 16 percent.
  - ✓ Approximately 17 percent of the estimated GHG reductions (0.33 MMTCO2e) are from completed projects, with 70 percent (0.23 MMTCO2e) of these reductions from projects completed before 2010 (and therefore already accounted for in the 2009 emissions inventories) and 30 percent (0.099 MMTCO2e) of reductions from projects completed during or after 2010.
  - ✓ Approximately 83 percent of the estimated GHG reductions (1.6 MMTCO2e) are from projects that are scheduled (82 percent) or under investigation (1 percent).
- Corresponding reductions of oxides of nitrogen (NO_x) and particulate matter (PM) are 1.63 tons per day (tpd) and 0.01 tpd, respectively.

[1] Title 17, California Code of Regulations, sections 95600 to 95612.

[2] About 13 percent of the estimated reductions are from completed projects and already accounted for in the 2009 GHG Mandatory Reporting emissions inventory (70 percent of the 17 percent from completed projects). The total does not included estimated emission reductions from projects identified as “Not Implementing.” The reductions estimated for the projects not yet implemented may be more than the total possible as implementation of some projects may preclude the implementation of others that deal with the same equipment or processes.

- ✓ Approximately 96 percent of the reductions are from projects completed before 2010 and 4 percent from projects completed during or after 2010, scheduled, or under investigation.

EEA Regulation Background

On July 22, 2010, the Board approved the EEA Regulation. The Regulation requires operators of California's largest industrial facilities to conduct a one-time energy efficiency assessment. The Regulation was approved by the Office of Administrative Law and became effective on July 16, 2011. All California facilities with 2009 GHG emissions equal to or greater than 0.5 MMTCO2e per year are subject to the Regulation. Also subject to the requirements are cement plants and transportation-fuel refineries that emitted at least 0.25 MMTCO2e in 2009. Combined cycle electricity generation facilities built after 1995 were exempted from the requirements.

The Regulation requires facility managers to conduct a one-time assessment of fuel and energy consumption, and provide estimates of GHG, criteria pollutants, and toxic air contaminant (TAC or toxics) emissions. Facilities are further required to identify potential energy efficiency improvements for equipment, processes, and systems that cumulatively account for at least 95 percent of the facility's total GHG emissions. Energy Efficiency Assessment Reports (EEA Reports) were to be filed with the ARB by December 15, 2011. A total of 43 facilities were required to provide an EEA Report. [3]

To fulfill ARB's public disclosure requirements in the EEA Regulation, ARB staff developed five separate "Public Reports" for the following sectors: Refinery, Oil and Gas Production/Mineral Processing, Cement Manufacturing, Electricity Generation, and Hydrogen Production. The Public Reports summarize, by sector, the information provided in the 43 EEA Reports submitted by the facilities. The reports strike a balance between full public disclosure of the information provided to ARB and our responsibility to protect confidential business information pursuant to CCR §95610. This paper is the Public Report for the Electricity Generation Sector.

The Public Reports do not present ARB staff's findings, conclusions, or recommendations. These will be presented in a subsequent report that will include all sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Report, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014.

[3] Staff of the San Francisco State University Industrial Assessment Center is under contract to provide a third-party review of a subset of the EEA Reports. They were given nine reports to evaluate. The third-party reviews for this sector are not yet available and therefore are not reflected in this report.

Summary of EEA Report Data for the Electricity Generation Sector

Fourteen electricity generation facilities submitted EEA Reports to ARB. Summarized below are the 2009 GHG emissions from the Electricity Generation Sector, followed by a summary of the potential GHG, criteria pollutant, and TAC emission reductions from Completed/Ongoing, Scheduled, and Under Investigation energy efficiency improvement projects identified in the individual EEA Reports. Also presented are the estimated total one-time capital costs, annual costs, and annual savings associated with the projects. Additional details are provided in Parts I and II which follow this summary.

<u>GHG Emissions</u>

Table IS-I shows the 2009 GHG emissions in MMTCO2e from the 14 electricity generation facilities subject to the EEA Regulation. This estimate comes from ARB's Mandatory GHG Reporting for 2009. A number of these facilities have subsequently ceased operation or are anticipated to be replaced. The facilities that that have ceased operation are noted. As shown in the table, the Electricity Generation Sector total GHG emissions in 2009 were 12.3 MMTCO2e. These emissions are a snapshot in time of emission from only those facilities subject to the EEA Regulation. The emissions include both biogenic and non-biogenic emissions. The combination of biogenic and non-biogenic emissions was considered for determining if a facility met the applicability threshold for the EEA Regulation. This is consistent with the Mandatory Reporting Regulation. However, biogenic emissions do not have a compliance obligation under the Cap and Trade Regulation.

Table IS-I: 2009 Greenhouse Gas Emissions for Electricity Generation Facilities Subject to EEA Regulation

Electricity Generation Facility	2009 GHG Emissions (MMTCO2e)
ACE Cogeneration*	0.8
AES Alamitos	1.1
AES Huntington Beach	0.6
APMC Stockton Cogeneration*	0.5
Covanta Delano	0.6
Encina Power Plant	0.5
Kern River Cogeneration	0.8
Los Angeles Department of Water and Power (LADWP) - Haynes Generation Station	1.9
Los Angeles Department of Water and Power (LADWP) - Scattergood Generation Station	0.7
Los Angeles Department of Water and Power (LADWP) - Valley Generation Station	1.0
Midway Sunset Cogeneration	1.2
Mt. Poso Cogeneration	0.5
Sycamore Cogeneration Company	1.4
Wheelabrator Shasta	0.7
Total	**12.3**

Source: Facility EEA Reports
*No longer in operation

Energy Efficiency Projects and Estimated Potential Emission Reductions

The facility operators of California's 14 electricity generation facilities subject to the EEA Regulation identified 129 energy efficiency improvement projects and designated the project status as:

- Completed/Ongoing,
- Scheduled,
- Under Investigation, or
- Not Implementing.

For the Electricity Generation Sector, many of the projects identified by the different electricity generation facilities were similar in terms of the equipment impacted and the approach used to improve energy efficiency. Similar projects have been grouped and placed in one of the six Equipment Category listed in Table IS-2. Equipment Category refers to the equipment (i.e., boiler) or a grouping of equipment (i.e., power generation units) that are associated with the electricity generation process.

Table IS-2 summarizes, by Equipment Category, the number of projects and the estimated GHG, NO_x, and PM emission reductions associated with the projects identified in the EEA Reports. The emission reductions were estimated by the facilities. Most reductions are estimated typical reductions but the criteria reductions related to replacement units are based on manufacturer provided data which are worst case. The estimated GHG emission reductions are approximately 1.9 MMTCO2e annually; 16 percent of the total GHG emissions from these sources. The GHG reductions associated with replaced units were estimated assuming the same generation capacity as the unit being replaced. Approximately 13 percent of the GHG emission reductions identified were completed before 2010 and are reflected in the 2009 GHG totals shown in Table IS-1. Approximately 87 percent of the GHG emission reductions are from projects that were completed during or after 2010, scheduled, or under investigation and are not reflected in the 2009 GHG values shown in Table IS-1. As shown in Table IS-2, approximately 74 percent of the GHG emission reductions are from projects involving power generation units, including projects to replace these units. Conversely, about 89 percent of the NO_x reductions are associated with combustion gas turbines, including projects to install dry low NO_x combustion equipment, which have already occurred.

Table IS-2: Estimated GHG and Criteria Pollutants Emission Reductions from Potential Energy Efficiency Improvement Projects*

Equipment Category	Number of Projects	Potential GHG (MMTCO2e) per year	Potential NO_x (tons per day)	Potential PM (tons per day)
A. Boiler	21	0.33	0.072	0.053
B. Electrical Equipment	39	0.01	0.009	0.002
C. Other Equipment	30	0.04	0.019	0.005
D. Combustion Gas Turbines	7	0.07	1.454	0.008
E. Steam Equipment	15	0.04	0.050	0.015
F. Power Generation Units	6	1.42	0.028	(0.074)
Total	**118**	**1.91**	**1.63**	**0.01**

*Includes all reported projects except the 11 identified as Not Implementing

The estimates in Table IS-2 assume that all of the energy efficiency improvement projects identified in the EEA Reports would be implemented (except for those identified as Not Implementing.) However, implementation of some projects may preclude the implementation of others that deal with the same equipment or processes. Additionally, two of the facilities have ceased operation and several others are anticipated to be replaced. Therefore, these estimated reductions do not necessarily represent readily achievable on-site emission reductions.

Costs

Table IS–3 provides a summary of the estimated total one-time capital costs, annual costs, and annual savings for the 118 potential energy efficiency improvement projects identified by facility operators in the Electricity Generation Sector EEA Reports. The total potential one-time costs for all of these projects (except for those identified as Not Implementing) are estimated at about $2.9 billion with annual recurring costs of about $4 million. These projects would also result in annual saving of approximately $80 million. These estimates are preliminary. They are not based on detailed engineering and cost analysis that would be required to accurately estimate emission reductions, costs, and timing of the projects. Additionally, these costs and savings were estimated based on the regulatory and permitting rules in place and the energy costs at the time the reports were prepared in 2011. They are subject to change due to changes in local air district rules and changes in the energy market.

Table IS-3   Summary of Estimated Costs and Savings for Energy Efficiency Improvement Projects*

Number of Projects	One Time Cost (million $)	Annual Cost (million $/year)	Annual Savings (million $/year)
118	2,926	4.11	80.2

*Includes all projects identified as Completed/Ongoing, Scheduled, or Under Investigation. Does not include projects identified as Not Implementing.

The next two parts of this Public Report provide more details on the information contained in the 14 individual Electricity Generation Sector EEA Reports. The information is presented consistent with the public disclosure requirements under CCR §95610.

Part I provides sector-wide information on the 14 electricity generation facilities subject to the EEA Regulation including background information on the electricity generation sector and the electricity generation process; estimates of the GHG, criteria pollutant, and TAC emissions from the 14 facilities; and information on State, federal, and district regulations affecting electricity generation operations in California. Most importantly, Part I summarizes, on a sector-wide basis, the potential energy efficiency improvement projects identified by the facilities in their EEA Reports and provides estimates of the potential GHG, criteria pollutant, and TAC emission reductions associated with the projects. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility.

Part II provides facility-specific information about each of the 14 electricity generation facilities submitting EEA Reports. In this section, information on the 2009 emissions of GHG, criteria pollutants, and TACs from each specific facility are reported. Also provided is a summary of the potential energy efficiency improvement projects that were identified in the EEA Reports. The projects are categorized by equipment type and sub-type and provide a general description of the project. Information about cost and potential emission reductions of GHG, criteria pollutants, and TACs, summed for all the projects (by equipment type and sub-type), is provided. In compliance with CCR §95610, the specific details about the individual projects were not presented. While it is not possible to identify the specific projects at an individual facility, it is possible to get an indication of what equipment and what action(s) were considered by referring back to the sector-wide project information in Part I.

Part I – Electricity Generation Sector Summary

I.0 Introduction

The information presented in this sector-wide summary is based on EEA Reports submitted by the 14 electricity generation facilities subject to the EEA Regulation. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility. The format and level of detail of the information presented strikes a balance between full public disclosure of the information provided to ARB and our responsibility to protect confidential business information in a manner consistent with ARB regulations. This report does not present ARB staff's findings, conclusions, or recommendations. These will be presented in a subsequent report that will include all sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Reports, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014.

I.1 Electricity Generation Sector Description

The 14 electricity generation facilities that were required to provide information under the EEA Regulation are identified in Table I-1 along with the local air district in which they are located and the types of facilities. As shown in Table I-1, there are three types of electricity generation facilities, as defined by the power generation source, subject to the Energy Efficiency Audit (EEA) Regulation according to the submitted reports. Five of them are reported as cogeneration plants, eight of them are reported as steam turbine power plants. Los Angeles Department of Water and Power – Valley Generation Station (VGS) consists of one simple gas turbine unit and a combined cycle generation unit which ARB staff categorized as a gas turbine plant.

The Regulation exempted from reporting any combined cycle electricity generation facilities built after 1995, as these are considered the most energy efficient electricity generation facilities. There are 16 such facilities in California that were not required to report. Additionally, one electricity generation facility, Colmac Energy, Inc., was exempted because it is located on Native American tribal lands.

Table I-1: Electricity Generation Facilities Submitting EEA Reports, Air Districts, and Facility Type (2009)

Electricity Generation Facility	Air District	Facility Type
ACE Cogeneration*	MOJAVE DESERT AQMD	Steam Turbine Plant
Encina Power Plant	SAN DIEGO COUNTY APCD	Steam Turbine Plant
APMC Stockton Cogeneration*	SAN JOAQUIN VALLEY UNIFIED APCD	Cogeneration Facility
Covanta Delano		Steam Turbine Plant
Kern River Cogeneration		Cogeneration Facility
Midway Sunset Cogeneration		Cogeneration Facility
Mt. Poso Cogeneration		Cogeneration Facility
Sycamore Cogeneration Company		Cogeneration Facility
Wheelabrator Shasta	SHASTA COUNTY AQMD	Steam Turbine Plant
AES Alamitos	SOUTH COAST AQMD	Steam Turbine Plant
AES Huntington Beach		Steam Turbine Plant
Los Angeles Department of Water and Power (LADWP) - Haynes Generation Station		Steam Turbine and Gas Turbine Plant
Los Angeles Department of Water and Power (LADWP) - Scattergood Generation Station		Steam Turbine Plant
Los Angeles Department of Water and Power (LADWP) - Valley Generation Station		Gas Turbine Plant

* No longer in operation

California Electricity Generation Capacity

Table I-2 shows the generating capacity of the electricity generation facilities subject to the EEA Regulation. The table provides the facility nameplate capacities as well as the net summer and net winter capacities. The nameplate capacity is determined by the generator's manufacturer and the net summer and net winter capacities, typically determined by a performance test, indicate the maximum load a generator can support at the point of interconnection during the respective season. The temperature of the cooling water for thermal power plants or the ambient air for combustion turbines are the primary factors that affect or determine the difference between summer and winter capacities. (EIA, 2015) As shown in the table, the total generating capacity of these 14 facilities is approximately 8,000 MW. The individual facility generating capacity ranges from about 50 MW up to nearly 2,000 MW.

Table I-2: Generating Capacity of California Electricity Generation Facilities Subject to EEA Regulation (2009)

Electricity Generation Facility	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
ACE Cogeneration*	108	101	102
AES Huntington Beach	888	904	904
AES Alamitos	1922	1997	1997
APMC Stockton Cogeneration*	60	54	54
Covanta Delano	57	49	49
Encina Power Plant	999	964	964
Kern River Cogeneration	300	288	308
Los Angeles Department of Water and Power (LADWP) - Haynes Generation Station	1750	1524	1554
Los Angeles Department of Water and Power (LADWP) - Scattergood Generation Station	823	796	817
Los Angeles Department of Water and Power (LADWP) - Valley Generation Station	788	556	576
Midway Sunset Cogeneration	234	219	249
Mt. Poso Cogeneration	62	52	52
Sycamore Cogeneration Company	300	300	312
Wheelabrator Shasta	63	60	60
Total	8354	7864	7998

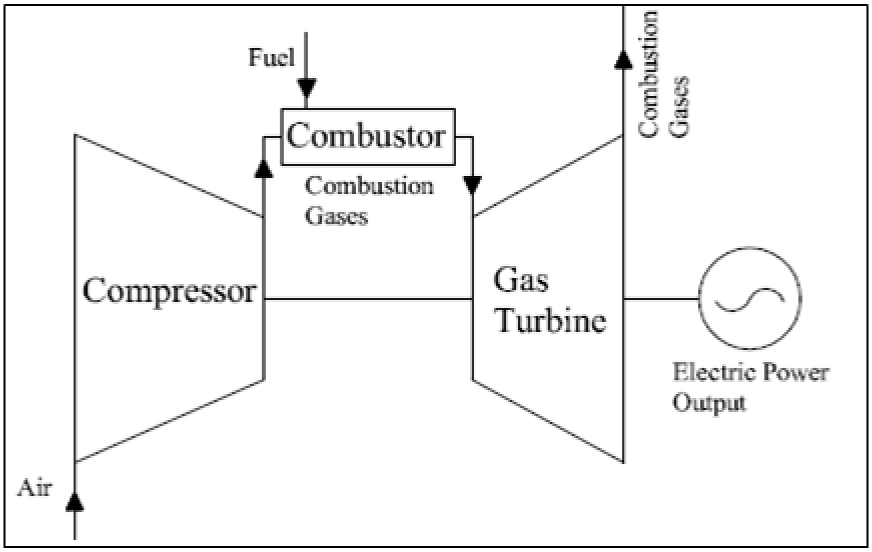
Source: http://www.eia.gov/electricity/data/eia860/ GeneratorY09.xls
* No longer in operation

Brief Description of the Electricity Generation Process

This report discusses three basic types of electricity generation processes: simple cycle, combined cycle, and cogeneration. Cogeneration may also be referred to as combined heat and power.

A simple cycle process, schematically shown in Figure I-1 below, expands the hot exhaust gas from combustion through a gas turbine providing power to drive an electrical generator. The simple cycle does not use the energy remaining in the combustion exhaust gas downstream of the turbine. A simple cycle gas turbine process is sometimes referred to as an open cycle.

Figure I-1 Simple Cycle Process



A combined cycle process, shown schematically in Figure I-2, uses the energy exhausted from the first process to produce additional electricity. Combined cycle facilities typically involve first a gas turbine, and then capturing exhaust heat to make steam for a steam turbine. The steam turbine exhaust goes to a steam condenser to be liquefied before returning to the boiler to complete the loop. Heated cooling water from the condenser either goes to a cooling tower where it is cooled and recirculated back to the condenser, or is discharged to the environment for facilities that employ once-through cooling. The system components are described in the text below Figure I-3.

Figure I-2 Simplified Combined Cycle Flow Diagram

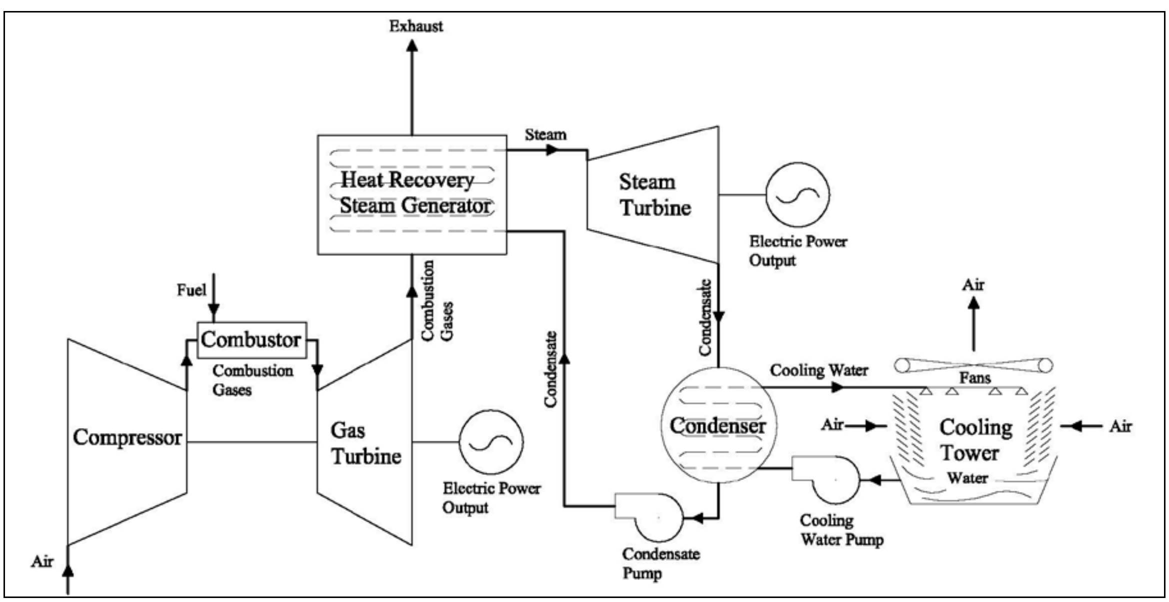
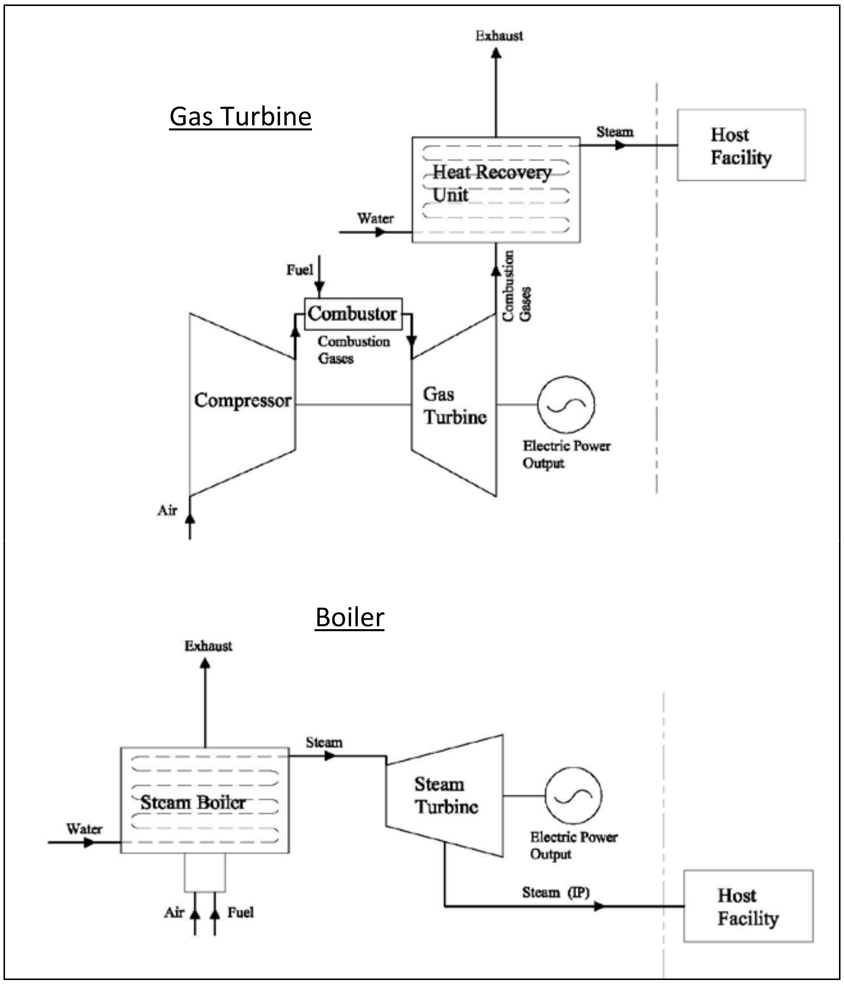


Figure I-3 shows two simplified cogeneration flow diagrams, one with a gas turbine and the other with a boiler. This figure illustrates the basic component differences between steam turbine and gas turbine systems for electricity generation. The gas turbine is powered directly by the hot combustion exhaust gas. The steam turbine is powered by steam from a boiler in which water is heated and converted to steam by the heat from the hot combustion gas. With a cogeneration process, the exhaust energy from the electricity generation process, typically in the form of steam, is exported to a host facility for another process. This exported steam is either the steam turbine exhaust or steam generated by a heat recovery unit downstream of the gas turbine.

Figure I-3 Simplified Topping Cycle Cogeneration Flow Diagram



In California, older power plants use steam turbine driven generators fed by steam from a boiler. These older facilities are being replaced with much more efficient gas turbine based systems. Several of these boilers also use once-through cooling which is being phased out to meet state and federal requirements.

Fuel Supply: In California, natural gas is the main fuel used in most electricity generation facilities. Natural gas is transported and delivered through natural gas transmission and distribution pipeline systems, primarily high-pressure underground pipes. Other fossil-type fuels (e.g., coal, petroleum coke, oil) have very limited use in California, and coal and pet coke are being phased out. Biomass fuels come from locally generated and renewable resources such as logging, wood collection facilities, mills, as well as from private property owners. Biomass fuels are typically either delivered to the power generation facility via truck or the power generation facility is located on the site where the biomass materials are produced. The 14 facilities required to submit an EEA Report all use natural gas either as primary fuel or supplemental fuel. In addition to using natural gas as a supplemental fuel for combustion stabilization, start-up, shutdown and/or refractory curing, three facilities use biomass, and three facilities use coal. However, two of the three facilities using coal are ceasing operation and the third, which previously used both coal and biomass, has ceased using coal.

Boilers: The fuels are burned to produce heat, which converts water into high temperature, high pressure steam. The combustion exhaust gases are passed through emissions control devices to remove criteria pollutants or toxic air contaminants before discharging through a stack.

Steam Turbine: High-temperature, high-pressure steam generated in the boiler enters the steam turbine, driving a generator . Low pressure steam exiting the steam turbine is condensed to water for reuse. Steam may be extracted at various points (temperatures and pressures) from a steam turbine for use in an adjacent cogeneration system, as shown in Figure I-3.

Gas Turbine: High pressure air and fuel are combusted and expanded through a gas turbine, driving a generator. Hot combustion gases can be used to raise steam for use in a steam turbine generator (a combined cycle plant) or for use in an adjacent thermal host (a toping cycle cogeneration plant).

Electrical Generation and Transmission: The shaft of the steam or gas turbine is connected to a generator that converts rotating mechanical energy into electricity.. Electricity then passes through a transformer and into the adjacent power station switchyard. Transmission lines carry the electricity from the switchyard to cities and towns.

Water Supply: The generation of electricity in power plants consumes water, generically via evaporation to cool processes and condense steam.

Cooling System: A steam turbine power plant typically uses either once-through cooling water systems or recirculating cooling water systems to condense the steam from the steam turbine generator. The recirculating water typically rejects the heat in an evaporative, or “wet” cooling tower. Most modern steam turbine generator plants in California use a dry cooling system, where the heat from the condensing steam is rejected to air. Use of cooling towers result in the loss of water to evaporation whereas dry cooling does not involve evaporation. With a wet cooling tower system, as water in the cooling tower evaporates, dissolved minerals present in the water remain behind in the system. A portion of the water must be continuously discharged, or blown down, to purge the dissolved minerals from the system. Minerals in the cooling tower water can contribute to airborne particulate matter in cooling tower drift. Make-up water is added to the cooling system to make up for the evaporative and blow down losses.

Heat Recovery Steam Generator: A heat recovery steam generator is a heat exchanger that recovers heat from an exhaust gas stream and uses that heat to generate steam from water..

Other processes/systems may include: water treatment system, fire protection system, emergency power system, demineralizer system, and emissions control systems, depending on the type of the facility and technology being implemented.

I.2 Emissions and Fuel Use

Emissions

The estimated GHG emissions from the 14 electricity generation facilities subject to the EEA Regulation are provided below. Table I-3 shows that the total GHG emissions from these 14 facilities in 2009 were 12.3 MMTCO2e. This estimate comes from ARB's Mandatory GHG Reporting for 2009. The GHG emission estimates do not include off-site emissions associated with natural gas production or electrical power imported to the facility from outside sources.

Table I-3: Electricity Generation Facilities Subject to EEA Regulation GHG Emissions (2009)

Electricity Generation Facility	2009 GHG Emissions (MMTCO2e)
ACE Cogeneration*	0.8
AES Alamitos	1.1
AES Huntington Beach	0.6
APMC Stockton Cogeneration*	0.5
Covanta Delano	0.6
Encina Power Plant	0.5
Kern River Cogeneration	0.8
Los Angeles Department of Water and Power (LADWP) - Haynes Generation Station	1.9
Los Angeles Department of Water and Power (LADWP) - Scattergood Generation Station	0.7
Los Angeles Department of Water and Power (LADWP) - Valley Generation Station	1.0
Midway Sunset Cogeneration	1.2
Mt. Poso Cogeneration	0.5
Sycamore Cogeneration Company	1.4
Wheelabrator Shasta	0.7
Total	**12.3**

Source: Facility EEA Reports
* No longer in operation

Table I-4 provides the estimated criteria pollutant emissions from the 14 electricity generation facilities subject to the EEA Regulation. The emission estimates were provided by the electricity generation facilities and are primarily based on emissions estimation methodologies used by the local air district in which each electricity generation facility is located. These are estimates of actual emissions, not the permit levels. The reporting of criteria pollutants may vary with local air district. Some facilities reported both total organic gases and reactive organic gases and others reported one or the other. The values in the table are as reported.

Table I-4: Electricity Generation Facilities Subject to EEA Regulation Criteria Pollutant Emissions (2009)

Criteria Pollutant	Total Mass Emissions (tons/day)
Total Organic Gases (TOG)	0.2
Reactive Organic Gases (ROG)	0.4
Carbon monoxide (CO)	13
Oxides of Nitrogen (NO_x)	6
Oxides of Sulfur (SO_x)	1.5
Particulate Matter (PM)	1.6

Table I-5 shows the estimated TAC emissions for the 14 electricity generation facilities subject to the EEA Regulation. The emission estimates were provided by the electricity generation facilities and are primarily based on emissions estimation methodologies used by the local air district in which each electricity generation facility is located. The TACs reported may vary by local air district, not all TACs were reported by all facilities. Also, the Air Toxics "Hot Spots" Information and Assessment Act (AB 2588), enacted in 1987, requires stationary sources to periodically provide more comprehensive reporting to the local air agency, resulting in variations in the TACs reported. These totals represent the totals of the reported values. The TACs are ranked according to potential public health impact based on the combination of mass emissions and cancer potency. The cancer potency factors (CPF) used are approved by California's Office of Environmental Health Hazard Assessment and can be found on the web at http://www.oehha.ca.gov/air/hot_spots/tsd052909.html (OEHHA, 2009)

To identify the TACs of greatest potential concern, the TACs for each facility were ranked using the reported emissions for each pollutant and their cancer potency factor. Pound for pound, not all pollutants are equal in terms of potential health impacts to the public. Specifically, the ranking (R) for each pollutant is determined by multiplying the reported emissions (E) and the pollutant-specific inhalation cancer potency factor (CPF). The equation for ranking each pollutant is: R = E x CPF.

This method for ranking pollutants is a simplistic tool used to rank the reported emissions according to potential health impacts. All of the pollutants reported for the sector were ranked using the equation above. The ten pollutants with the highest ranking are listed in Table I-5. The location of a pollutant on the list in the table is a combination of the reported emissions and the presence and/or relative magnitude of the CPF. The pollutant with the highest ranking is listed first. While the CPF is typically used in health risk assessments to estimate potential cancer risk, this ranking is not a risk assessment. The list in Table I-5 simply provides a method for placing the reported pollutants in a relative ranking based on mass and the cancer potency of the pollutant.

Mercury was reported as a TAC for the two of the facilities that use coal as a fuel. Mercury is a toxic substance with both acute and chronic toxicity factors; however, no cancer potency factor has been developed. Since the top 10 TACs are prioritized based on cancer potency factors, mercury was not included. Total mercury emissions for the two facilities is approximately 11.6 pounds per year. However, one of these facilities was retrofitted in 2011 to switch from coal to woody biomass as fuel and the other facility is ceasing operations.

Table I-5: Electricity Generation Facilities Subject to EEA Regulation Toxic Air Contaminant Emissions (2009)

Toxic Air Contaminants (TAC)*	Total Mass Emissions (pounds/year)
Formaldehyde	33,742
Chromium, hexavalent (& compounds)	<1
Benzene	2,902
Naphthalene	881
Cadmium	4
Arsenic	4
Nickel	37
Diesel engine exhaust, particulate matter (Diesel PM)	20
Acetaldehyde	2,085
Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	<1

*Listed in rank order based on mass times cancer potency.

Fuel Use

The energy required for electricity generation at these 14 facilities as described earlier, is supplied from fuel combustion. On-site fuel combustion is used to provide steam, process heat, and to produce electricity. Fuels used include natural gas, coal, biomass, and other type of fuels. The majority of GHG emissions associated with electricity generation are the result of combustion processes.

Table I-6 presents the distribution of fuels reported by the 14 electricity generation facilities subject to the EEA Regulation. The data demonstrates that most facilities are fueled by natural gas, with only 20 percent of the fuel coming from other fuel sources. At the time that these facilities reported, coal was the next largest fuel source, but only contributed 8 percent of the fuel. Coal was followed by biomass fuel at 6 percent of the fuel consumed. Other types of fuel reported by these facilities include petroleum coke, scrap rubber tires, diesel, propane, acetylene, biomethane, hydrogen, and digester gas, which make up only 5 percent of the fuel sources. These reported percentages of fuel used by the 14 facilities are a snapshot of fuel use at that time. Fuel use at these facilities has changed since the data was submitted. Coal use has dropped to zero due to the switch from coal to biomass for one facility and the cessation of operations at the other two coal-burning facilities.

Table I-6: Energy Consumption by Fuel Type for the 14 Facilities Subject to the EEA Regulation (2009)

Fuel Type	Energy Consumed (MMBtu)	Percent Total Energy Consumed
Natural Gas	166,410,000	80
Coal, underground mined, Rockies (Unitia Basin)	17,197,000	8
Biomass	13,271,000	6
Electricity*	4,216,000	2
Other Types**	5,697,000	3
Total	206,790,000	100

*Includes both purchased and internally produced electricity

**Include petroleum coke, scrap rubber tires, diesel, propane, acetylene, biomethane, hydrogen, and digester gas.

I.3 Regulatory Requirements

Electricity generation facilities subject to the EEA Regulation are also subject to a variety of State, local, and federal air pollution control regulations and emissions reduction programs. These regulations and programs are mainly designed to reduce criteria and toxic air emissions from electricity generation facilities.

Four complementary State regulations focusing on GHG emissions that electricity generation facilities are either subject to or can participate in are, the Cap-and-Trade (C&T) Regulation, the Mandatory Reporting of GHG Emissions Regulation (MRR), the Cost of Implementation Fee Regulation, and the Low Carbon Fuel Standard (LCFS) Regulation. California's air quality management and air pollution control districts develop, implement, and enforce specific criteria and toxics regulations and programs at the local level. The U.S. Environmental Protection Agency (U.S. EPA) develops criteria and toxic regulations and programs at the federal level. Below are brief summaries of the State regulations and a table of local air district regulation for the districts in which the reporting electricity generation facilities are located. Also included are web links to federal electricity generation regulations. The discussion below focuses on some of the key regulations and programs impacting electricity generation facilities. However, it is not a complete listing of all State, local, and federal regulations or programs that electricity generation facilities are required to meet. One additional program that is especially important is the State Water Resources Control Board's requirement to end once-through cooling to meet federal requirements. This is causing several coastal facilities to cease operations or replace their inefficient boilers with new, modern and efficient gas turbine based systems. This is explained more fully below.

<u>California GHG Regulations</u>

<u>Cap-and-Trade Program</u>

Cap-and-Trade is one of the strategies California will use to reduce GHG emissions. The program will help California meet its goal of reducing GHG emissions to 1990 levels by 2020. Under Cap-and-Trade, an overall limit on GHG emissions from capped sectors has been established by the Cap-and-Trade Program and facilities subject to the cap will be able to trade compliance instruments (allowances and offsets). Electricity generation facilities are subject to the Cap-and-Trade Regulation and will have to either reduce on-site GHG emissions or obtain GHG compliance instruments equal to their compliance obligation. For more information about the Cap-and-Trade Program, please go to http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

Mandatory Reporting of GHG Emissions (title 17, CCR, sections 95100 to 95157)

In January 2012, amendments to the Mandatory Reporting of GHG Emissions Regulation became effective. The 2012 amendments implemented minor but necessary revisions to the reporting regulation. Neither major changes to GHG reporting requirements nor added reporting obligations for new industrial sectors were proposed. The Mandatory Reporting Regulation was amended in 2013 to further support benchmarking, allocation of allowances, and the covered emissions calculation under the Cap-and-Trade Regulation, as well as to ensure that reported GHG emissions data is accurate and complete in order to support California's other climate and GHG reduction programs. These amendments became effective January 1, 2014. Operators are required to report stationary combustion and process emissions as well as amounts of carbon dioxide captured and transferred off-site. Operators are required to sample feedstock (other than natural gas) daily, but solid and liquid samples can be composited to produce a monthly sample for carbon content analysis. For more information about the Mandatory Reporting of GHG Emissions regulation, please go to http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm/.

Cost of Implementation Fee Regulation (title 17, CCR, sections 95200 to 95207)

The AB 32 Cost of Implementation Fee Regulation was finalized on June 17, 2010 and became effective on July 17, 2010. Amendments were adopted in 2011 and 2012 to better align it with the Mandatory Reporting Regulation and the Cap-and-Trade Regulation. AB 32 authorized ARB to adopt a schedule of fees to be paid by sources of GHG emissions. Money collected from these fees will be used to fund the State's costs of implementing AB 32. Entities subject to these fees include large natural gas distributors and large users of natural gas including refineries, suppliers and importers of gasoline and diesel fuel, electricity importers and in-state generating facilities, facilities that combust coal and petroleum coke, and cement manufacturers. There are approximately 300 facilities subject to this fee.

Fees are determined based on the annual budget for the program and the cost to repay start-up loans. The regulation is designed so that invoices are sent after the budget is approved ensuring that each year ARB collects only the amount authorized to run the program and repay the startup loans. The fees are based on a uniform cost for each metric ton of carbon dioxide subject to the regulation. This uniform cost is referred to as the Common Carbon Cost (CCC) and is calculated as the total amount of funding to be collected divided by the total number of emissions subject to the regulation. For more information about the Cost of Implementation Fee Regulation, please go to: http://www.arb.ca.gov/cc/adminfee/adminfee.htm.

Low Carbon Fuel Standard Regulation

The LCFS regulation is designed to reduce GHG emissions associated with the lifecycle of transportation fuels used in California. The lifecycle includes the emissions associated with producing, transporting, distributing, and using the fuel. The regulation reduces lifecycle greenhouse gas emissions by assessing a "carbon intensity" score to each transportation fuel based on that fuel's lifecycle assessment. For more information about the LCFS regulation, please go to http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

The LCFS defines electricity as a low-carbon transportation fuel that is key to reducing carbon emissions created by the state's vehicle fleet. While no specific reductions are stipulated for electricity producers, the LCFS's credit trading aspect creates an economic incentive to pursue lower carbon emissions. Further carbon reductions would generate more credits to be traded in the LCFS's credit market. Purchasing these credits and actively supporting the integration of electricity's use in transportation is an avenue for more carbon-intensive fuel providers to offset their own carbon emissions.

<u>Other California Policies and Programs</u>

Once-Through Cooling Water Policy

The Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling was adopted by the State Water Resources Control Board on May 4, 2010, and became effective October 1, 2010. It was subsequently amended on July 19, 2011 and June 18, 2013. This policy establishes uniform, technology-based standards to implement the federal Clean Water Act section 316(b), which requires that the location, design, construction, and capacity of cooling intake structures reflect the best technology available for minimizing adverse environmental impact. California is allowed to adopt a policy that is more stringent than the federal rule requires. This policy applies to existing electricity generation facilities located along the California coast that withdraw coastal and estuarine water for cooling purposes using a single-pass system known as once-through cooling. Five electricity generation facilities subject to ARB's EEA Regulation, Los Angeles Department of Water and Power (LADWP) – Haynes Generation Station, LADWP – Scattergood Generation Station, AES Alamitos, AES Huntington Beach, and Encina Power Plant are also subject to this once-through cooling water policy. Section 316(b) is implemented through the National Pollutant Discharge Elimination System permits issued by Regional Water Quality Control Boards. For more information on this policy please go to: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

Senate Bill (SB) 1368 Emission Performance Standards

SB1368 (Perata, Chapter 598, Statutes of 2006) limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the California Energy Commission (CEC) and the California Public Utilities CommissionCPUC. The established standard for baseload generation owned by, or under long-term contract to publicly owned utilities, is a limit of 1,100 lbs CO2 per megawatt-hour (MWh). This will encourage the development of power plants that meet California's growing energy needs while minimizing their emissions of greenhouse gases.

California Renewable Energy Program

In 2002, California established its Renewables Portfolio Standard Program, with the goal of increasing the percentage of renewable energy in the state's electricity mix to

20 percent by 2017. The Energy Commission's 2003 Integrated Energy Policy Report recommended accelerating that goal to 2010, and the 2004 Energy Report Update urged increasing the target to 33 percent by 2020. Governor Schwarzenegger, the Energy Commission, and the California Public Utilities Commission (CPUC) endorsed this enhanced goal for the State. Achieving these renewable energy goals became even more important with the enactment of AB 32 (Núñez, Chapter 488), the California Global Warming Solutions Act of 2006. This legislation sets aggressive GHG reduction goals for the state and its achievements will depend in part on the success of renewable energy programs. For more information about this program, please go to: http://www.energy.ca.gov/renewables/index.html.

Local Air District Criteria and Toxics Emission Reductions Regulations and Programs

Table I-7 below lists the key local district criteria regulations affecting electricity generation facilities. In addition, electricity generation facilities are subject to local district permitting regulations and air toxics reporting programs. A recently adopted SCAQMD rule, Rule 1304.1, Electrical Generating Facility Annual Fee for use of Offset Exemption, may significantly impact the cost of scheduled projects to replace power generation units in the SCAQMD. This rule creates an annual fee for electrical generating facilities that replace power generation units and use the offset exemptions described in SCAQMD Rule 1304(a)(2). Facilities have advised us that this rule significantly increases certain project fees beyond those reported in their original submittals. The cost estimates presented in this report do not account for any cost increases that may be associated with Rule 1304.1.

Table I-7: District-Specific Rules Affecting Electricity Generation Facilities

District	Local Rules	Subject	Rule
Bay Area AQMD	Rule 2-3	Permits	Power Plants
	Rule 9-11	Inorganic Gaseous Pollutants	NO_x and CO From Utility Electric Power Generating Boilers
Mojave Desert AQMD	R475	Prohibitions	Electric Power Generating Equipment
	R476		Steam Generating Equipment
San Diego County APCD	R69	Prohibitions	Electrical Generating Steam Boilers, Replacements Units, and New Units
	Regulation X	Standards of Performance For New Stationary Sources	Subpart Da - Standards of Performance For Electric Utility Steam Generating Units Constructed After 9/18/78
San Joaquin Valley APCD	see General Rules		

District	Local Rules	Subject	Rule
Shasta County AQMD	see General Rules		
	Rule 3:26		Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; Oxides of Nitrogen Control Measure
South Coast AQMD	Rule 475	Prohibitions	Electric Power Generating Equipment
	Regulation IX	Standards of Performance for New Stationary Sources (NSPS)	
	Regulation X	National Emission Standards for Hazardous Air Pollutants (NESHAPS)	
	Rule 1134		Emissions of Oxides of Nitrogen from Stationary Gas Turbines
	Rule 1135	New Source Review	Emissions of NO_x From Electric Power Generating Systems
	Rule 1135.1	New Source Review	Controlling Emissions of Oxides of Nitrogen from Electric Power Generating Equipment
	Rule 1304	New Source Review	Exemptions
	Rule 1304.1	New Source Review	Electrical Generating Facility Fee for Use of Offset Exemption
	Rule 1401	Toxics and Other Non-Criteria Pollutants	New Source Review of Toxic Air Contaminants
	Rule 1402	Toxics and Other Non-Criteria Pollutants	Control of Toxic Air Contaminants from Existing Sources
	Rule 1470.	Toxics and Other Non-Criteria Pollutants	Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines
	Regulation XVII	Prevention of Significant Deterioration	
	Regulation XXVII	Climate Change	
	Regulation XXX	Title V Permits	
	Regulation XXXI	Acid Rain Permit Program	

Federal Regulations

Federal regulations affecting power plant air emissions can be accessed via the following links:

http://www.epa.gov/mats/powerplants.html

http://www.epa.gov/lawsregs/sectors/electric.html

http://www.epa.gov/air/caa/

http://www2.epa.gov/carbon-pollution-standards

I.4 Energy Efficiency Improvement Opportunities

The information provided in the Tables I-9 through I-14 was compiled by staff using information provided in the EEA Reports prepared by the 14 electricity generation facilities subject to the EEA Regulation. All projects that were identified as Completed/Ongoing, Scheduled, or Under Investigation are included in the tables. Projects that were identified as Not Implementing were not included. Each table covers a broad category of equipment or processes identified by the table title and referred to as “Equipment Category”. The “Equipment Category” for each table is listed in Table I-8 along with a brief description of the type of projects in the specific category.

Note that many of the facilities are either closing due to market conditions or being replaced. This may have been part of the owners’ consideration of type and scope of energy efficiency improvement opportunities and their cost effectiveness.

Table I-8: Listing of Equipment Categories and Projects Descriptions of Types of Projects

Table Number	Equipment Category	Description of Types of Projects
Table I-9	Boiler	Projects associated with boilers and auxiliary equipment used for cogeneration and power generation.
Table I-10	Electrical Equipment	Projects dealing with electric motors powering air compressors, pumps, fans, and other types of electrical equipment, such as hog motors and variable frequency drives.
Table I-11	Other Equipment	Projects dealing with coal feeder, condenser, feedwater heater, cooling tower, turbine-generator, and plant control systems.
Table I-12	Combustion Gas Turbines	Projects involving stationary gas turbines.
Table I-13	Steam Equipment	Projects dealing with steam turbines, and steam traps.
Table I-14	Power Generation Units	Projects dealing with repowering units, and unit related issues.

Within each table, the projects are assigned to an “Efficiency Improvement Method” group (column 1). The Efficiency Improvement Method is the approach, action, or mechanism that would result in energy efficiency improvements, and are identified as follows:

- Change in operation of equipment
- Change in maintenance practices
- Change in management systems
- Process control
- The same but more efficient technologies
- Investment in new technologies

The information associated with each “Efficiency Improvement Method” represents numerous identified projects. A more detailed description of the types of projects associated with the “Efficiency Improvement Method” is provided in Tables I-9 through I-14 under the column entitled “Project Description.” The emissions and cost data provided are a summation of the data provided for all the projects under the specific “Efficiency Improvement Method” grouping. The estimated GHG emission reductions associated with the projects, capital costs, annual costs, and annual savings estimated by the electricity generation facilities are also provided. These estimated benefits were usually based on the fuel savings realized. These costs and savings were estimated based on the regulatory and permitting rules in place and the energy costs at the time the reports were prepared in 2011.

They are subject to change due to changes in local air district rules and changes in the energy market. One example is SCAQMD Rule 1304.1, which was adopted in September 2013. We have been advised by facility owners that this local rule will significantly impact certain project costs that they included in their report. The cost estimates presented in this report do not account for any cost increases that may be associated with Rule 1304.1. Where projects have been grouped, the reported values are a summation of all the projects represented by the listing. In addition, estimates of the NO_x and PM co-benefits are provided. These estimates provide a general idea of what co-benefits might be achieved by implementing the reported projects. The information is arranged so as to provide the maximum transparency of the information reported and at the same time protect the confidential business information the facilities provided.

The information provided in Tables I-9 through I-14 is preliminary and not based on detailed engineering and economic analyses for all the projects.

Boiler Projects

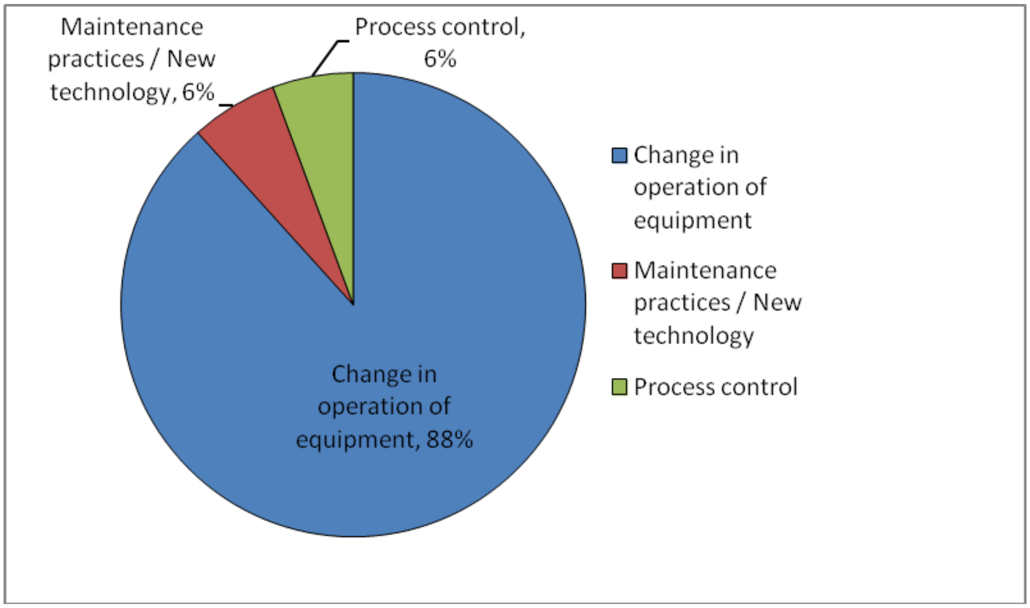
Table I-9 provides information on identified energy efficiency improvement projects related to boilers at the electricity generation facilities. A total of 21 projects related to boilers were identified by the facilities. The total estimated GHG emission reductions for these projects – provided in the third column of the table - are about 0.3 MMTCO2e. The total estimated NO_x and PM reductions associated with these projects would be 0.07 tons/day for NO_x and 0.05 tons/day for PM. Total one-time capital costs, associated annual costs, and associated annual savings are also presented in this table. The total estimated one-time costs for implementing these projects are $24 million with annual costs estimated at about $1.0 million. These projects would also result in an annual saving of approximately $16 million.

Table I-9: Boiler Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Staff operation of equipment	Reduce minimum load, Reduce fuel use and steam output via output optimization, install auxiliary steam boiler system	293,609	7,751,000	944,000	11,519,000	0.052	0.048
Maintenance practices / New technology	Clean convection section of boiler, replace air preheater baskets, annual boiler tune-ups, Inject Kaolin Clay into fluidized bed boiler	20,180	8,156,000	12,000	2,337,000	0.009	0.002
Process control	Improve fly ash management, replace boiler controls, install new air injection nozzles	18,750	8,445,000	88,000	1,714,000	0.012	0.003
	total	**332,539**	**24,352,000**	**1,044,000**	**15,570,000**	**0.072**	**0.053**

The greatest GHG reductions from boiler-related projects would come from changes in the operation of equipment. Projects related to change in operation of equipment include: reducing minimum load, reducing fuel use and steam output via output optimization, and installation of auxiliary steam boiler system. Projects related to maintenance practices/new technology include: cleaning the convection section of the boiler, replacing air preheater baskets, annual boiler tune-ups. Projects related to process control include: improving fly ash management, replacing boiler controls, and installing new air injection nozzles. Figure I-4 shows the distribution of estimated GHG emission reductions by efficiency improvement method.

Figure I-4: Boiler Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Electrical Equipment Projects

Table I-10 below provides information on identified energy efficiency improvement projects related to electrical equipment at the electricity generation facilities. A total of 39 projects related to electrical equipment were identified by the facilities. The vast majority of these projects (37 projects) were categorized as a combination of the efficiency improvement methods of the same but more efficient technologies and maintenance practices. Only two projects were categorized as either new technology or process control. Consequently, it was necessary to aggregate these two projects with the other projects in order to protect confidential business information. The total estimated GHG emission reductions for the electrical equipment projects would be nearly 10,000 metric tons annually. The total estimated NO_x and PM reductions associated with these projects would be 0.009 tons/day for NO_x and 0.002 tons/day for PM. Total one-time capital costs for implementing these projects is about $3.1 million, with annual costs of $92,000. These projects would also result in an annual savings of nearly $1.4 million.

Table I-10: Electrical Equipment Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Same but more efficient technologies / Maintenance practices / New technology / Process control	Replace air compressors / instrument air motors / air supply motors / nitrogen supply motors, replace hog motors, add VFDs, replace pumps & fans, retrofit steam and acoustic blower, install control valve to pumps	10,104	3,112,000	92,000	1,394,000	0.009	0.002

The greatest GHG reductions from electrical equipment projects would come from the use of the "Same but more efficient technologies/Maintenance practices". Projects related to "Same but more efficient technologies/Maintenance practices" include: replacing inefficient motors, fans and pumps, and the addition of variable frequency drives (VFD) on the motors powering this equipment. An example of a new technology project includes retrofitting steam and acoustic blower for soot. An example of a process control project includes installing automatic control valves on pumps.

<u>Other Equipment Projects</u>

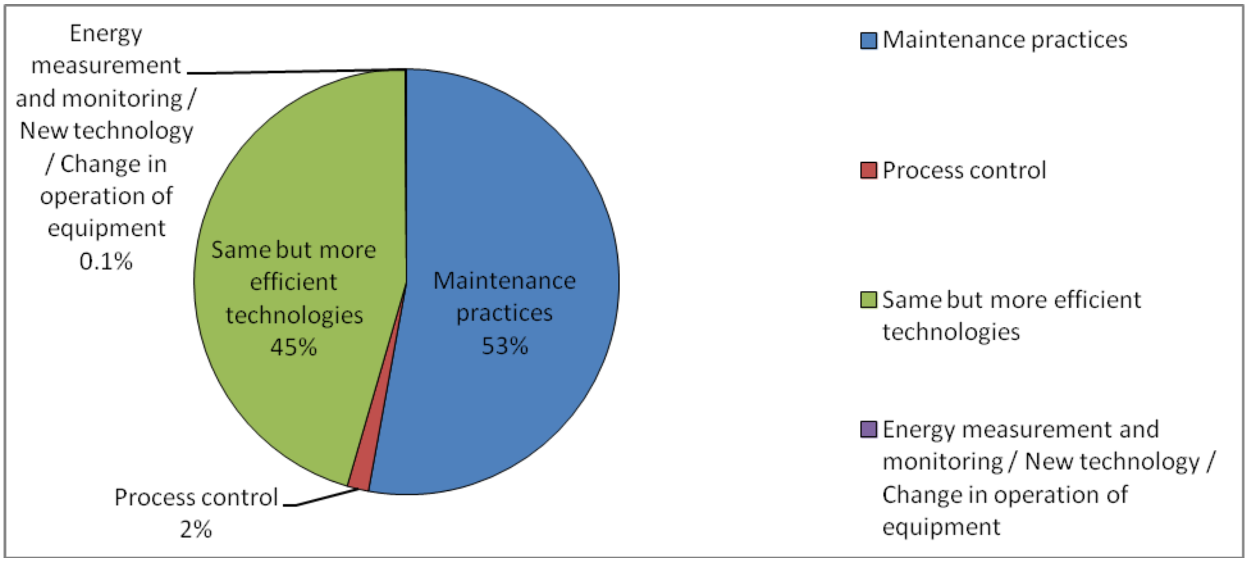
Table I-11 provides information on identified energy efficiency improvement projects related to other equipment type projects at electricity generation facilities. There were 30 projects identified for equipment categorized as "Other Equipment". Other equipment includes a variety of equipment types such as coal feeders, condensers, feedwater heaters, cooling towers, turbine-generators, and plant control systems. The total estimated GHG emission reductions for these projects, provided in the third column of the table, are about 42,000 metric tons annually. The total estimated NO_x and PM reductions associated with these projects would be 0.019 tons/day for NO_x and 0.005 tpd for PM. Total one-time capital costs, associated annual costs, and associated annual savings are also shown in the table. The total estimated one-time costs for all of these projects are about $44 million with annual costs of about $364,000. These projects would also result in an annual saving of about $4 million.

Table I-11 Other Equipment Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Maintenance practices	Condenser "plug-and-shoot" cleaning, clean condenser tubes, repair vacuum leaks in condenser, repair leaks in feedwater heater, clean cooling tower, overhaul turbine-generator	22,325	28,124,000	114,000	1,703,000	0.0098	0.0026
Same but more efficient technologies	Replace feedwater heaters	19,158	15,551,000	-	1,760,000	0.0023	0.0026
Process control	Improve coal fuel feed, improve condensing capacity	690	400,000	250,000	460,000	0.0070	0.0001
Energy measurement and monitoring / New technology / Staff operation of equipment	Revise hardware and software, retrofit fluorescent fixtures, recommission feed water heater	48	414,000	-	173,000	0	0
	Total	42,221	44,489,000	364,000	4,096,000	0.019	0.005

The greatest GHG reductions in this category would come from those projects categorized as “Maintenance Practices” and “Same but more efficient technologies”. Projects involving maintenance practices include: cleaning condensers, repairing leaks in condensers and feedwater heaters, cleaning cooling towers, and overhaul of turbine-generators. Projects involving using the same but more efficient technologies involve replacing feedwater heaters. Figure I-5 below illustrates the distribution of estimated GHG emissions reductions by efficiency improvement method.

Figure I-5 Other Equipment Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Combustion Gas Turbine Projects

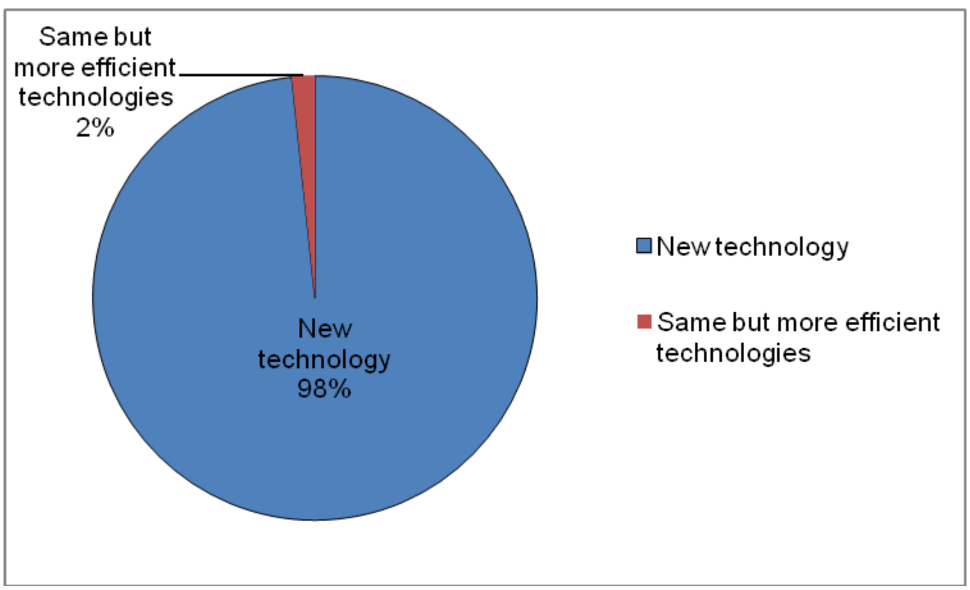
Table I-12 below provides information on identified energy efficiency improvement projects related to combustion gas turbines at electricity generation facilities. A total of seven projects related to combustion gas turbines were identified by the facilities. The total estimated GHG emission reductions for these projects, provided in the third column of the table, are about 66,000 metric tons annually. The total estimated NO_x and PM reductions associated with these projects would be 1.45 tpd for NO_x and 0.008 tpd for PM. Total one-time capital costs, associated annual costs, and associated annual savings are also shown in the table. The total estimated one-time costs for all of these projects are about $89 million with annual costs of about $2.6 million. These projects would also result in an annual saving of about $5.5 million.

Table I-12 Combustion Gas Turbine Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
New technology	Install dry low NO_x combustion equipment	65,086	70,940,000	2,600,000	5,400,000	1.45	0.008
Same but more efficient technologies	Install second stage nozzle, install third stage buckets and nozzles	1,105	17,990,000	-	85,000	0	0
	Total	66,191	88,930,000	2,600,000	5,485,000	1.45	0.008

The greatest GHG reductions from combustion gas turbine-related projects would come from new technology. Projects involving new technology include installation of dry low NO_x combustion equipment. Projects related to “Same but more efficient technology” include: installation of second stage nozzles, and installation of third stage buckets and nozzles. Figure I-6 shows the distribution of estimated GHG reductions by efficiency improvement method.

Figure I-6 Combustion Gas Turbine – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Steam Equipment Projects

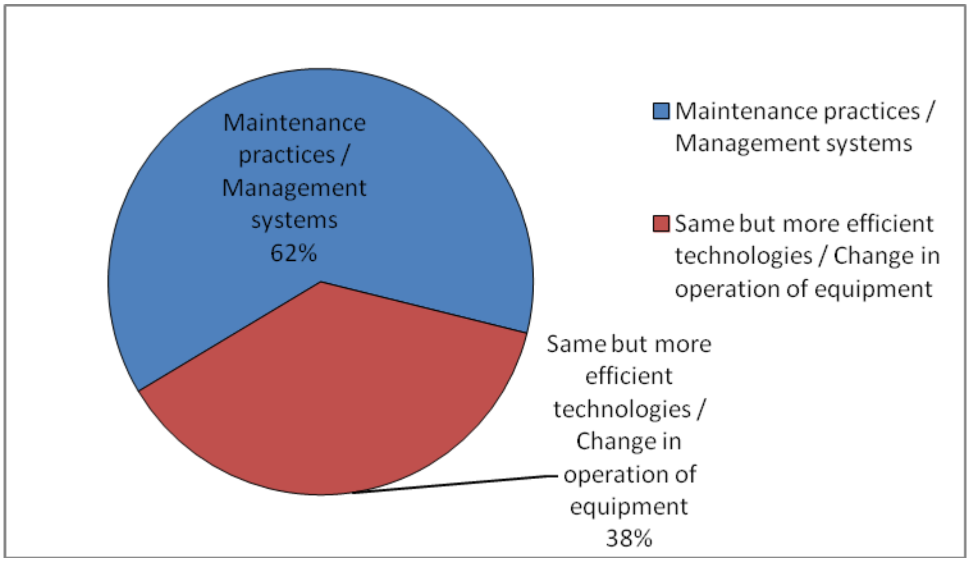
Table I-13 below provides information on identified energy efficiency improvement projects related to steam equipment at electricity generation facilities. There are 15 projects identified for equipment categorized as "Steam Equipment". The total estimated GHG emission reductions for these projects, provided in the third column of the table, are about 44,000 metric tons annually. The total estimated NO_x and PM reductions associated with these projects would be 0.05 tpd for NO_x and 0.015 tpd for PM. Total one-time capital costs, associated annual costs, and associated annual savings are also shown in the table. The total estimated one-time costs for all of these projects are about $45 million with annual costs of about $10,000. These projects would also result in an annual saving of about $1.6 million.

Table I-13 Steam Equipment Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Maintenance practices / Management systems	Turbine overhaul, steam path audit, steam traps maintenance, reduce steam leaks	27,613	25,757,000	10,000	742,000	0.049	0.015
Same but more efficient technologies / Change in operation of equipment	Upgrade steam turbine seals, upgrade low pressure rotor, maximize steam superheat temperature to turbine	16,569	19,500,000	-	857,000	0.001	0.0002
	Total	44,182	45,256,000	10,000	1,598,000	0.050	0.015

The greatest GHG reductions in this category would come from those projects in the maintenance practices/management systems category. Examples include preventive maintenance activities to identify and repair steam leaks in the distribution piping, implementation of a steam trap maintenance program, overhaul of steam turbines, and steam path audits. Projects involving using the same but more efficient technologies and change in operation of equipment were also identified. These projects involved upgrades on steam turbine seals, low pressure motors, and maximization of steam superheat temperature to turbine. Figure I-7 shows the distribution of estimated GHG reductions by efficiency improvement method.

Figure I-7 Steam Equipment Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Power Generation Units

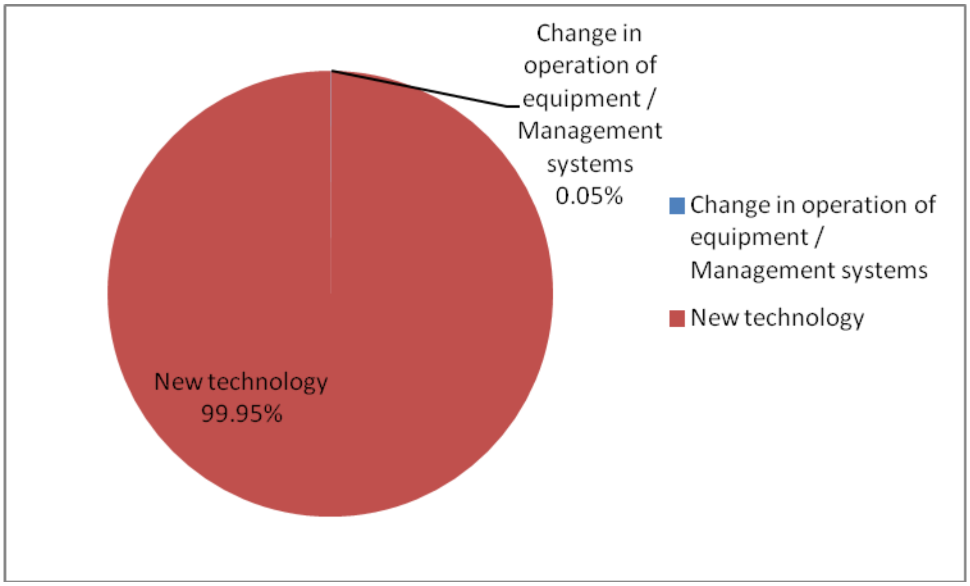
Table I-14 below provides information on identified energy efficiency improvement projects related to power generation units at electricity generation facilities. There are six projects identified for equipment categorized as "Power Generation Units". The total estimated GHG emission reductions for these projects, provided in the third column of the table, are nearly 1.4 MMTCO2e annually. The total estimated NO_x impact associated with these projects would be a reduction of 0.028 tpd. PM emissions are estimated to increase by 0.07 tpd. The PM emissions for the project are based on BACT and manufacturer-provided pollutant stack concentration data, which would represent the worst-case concentration. However, the project emissions are being compared to baseline emissions for the current configuration that represent typical and not worst-case concentrations. Consequently, the apparent PM increase is most likely due to the nature of the inconsistent data available for comparison and does not represent an actual emissions increase. Total one-time capital costs, associated annual costs, and associated annual savings are also shown in the table. The total estimated one-time costs for all of these projects are \$2.7 billion and would result in energy cost savings for electricity generation facilities of \$52 million annually.

Table I-14 Power Generation Units Projects – Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Change in operation of equipment / Management systems	Improve and follow the management philosophy, stabilize operations with visual control, continuous improvement training	651	50,000	-	100,000	0.00033	2.7E-05
New technology	Replace the current boiler and steam turbines configuration	1,418,876	2,720,000,000	-	52,000,000	0.027	(0.074)
	Total	1,419,527	2,720,050,000	-	52,100,000	0.028	(0.074)

The greatest GHG reductions from power generation units-related projects would come from the implementation of new technology. Projects involving new technology include replacing the current boiler and steam turbine configuration with combined cycle configuration. These large reductions in GHG emissions are estimated on the basis of the current power generation level. If generation capacity is increased, emissions will similarly increase. However, if the increased capacity replaces less efficient generation at other facilities, reductions are still realized. Improvements due to change in operation of equipment/management systems represent only 0.05% of total GHG reductions for these projects. Projects involving change in operation of equipment/management systems include those which would improve and follow management philosophy, stabilize operations with visual control, and provide continuous improvement training for employees. Figure I-8 shows the distribution of estimated GHG reductions by efficiency improvement method.

Figure I-8 Power Generation Units Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



<u>Summary</u>

Table I-15 summarizes, by "Equipment Category," the number of projects and the estimated GHG, NO_x, and PM emission reductions associated with the energy efficiency improvement projects identified in the EEA Reports. The estimated GHG emission reductions are approximately 1.9 MMTCO2e annually.

Table I-15: Estimated GHG and Criteria Pollutants Emission Reductions from Energy Efficiency Improvement Projects Identified in EAA Reports*

Equipment Category	Number of Projects	GHG Reductions (MMTCO2e per year)	NO_x Reductions (tons per day)	PM Reductions (tons per day)
A. Boiler	21	0.33	0.072	0.053
B. Electrical Equipment	39	0.01	0.009	0.002
C. Other Equipment	30	0.04	0.019	0.005
D. Combustion Gas Turbines	7	0.07	1.454	0.008
E. Steam Equipment	15	0.04	0.050	0.015
F. Power Generation Units	6	1.42	0.028	(0.074)
Total	**118**	**1.91**	**1.63**	**0.01**

*Includes all reported projects except those identified as Not Implementing

Figure I-9 shows pictorially the relative contribution of each equipment category to the total GHG reductions. As shown in the figure, the equipment categories with the greatest potential GHG emission reduction are "Power Generation Units," "Boiler," and "Combustion Gas Turbines."

Figure I-9 Potential Electricity Generation Facilities GHG Emission Reductions by Equipment Category

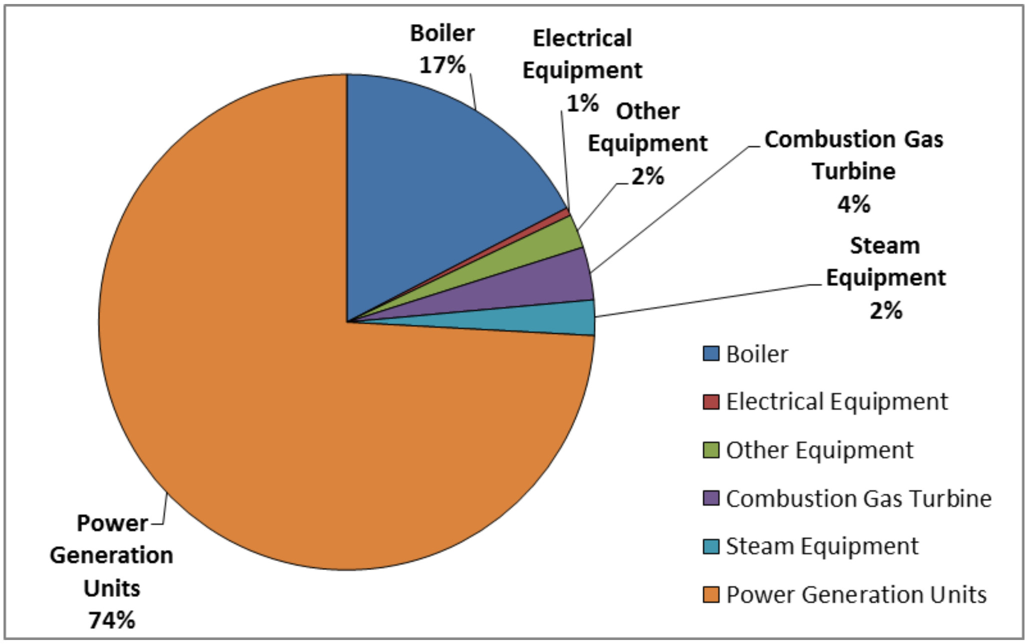


Table I-16 provides a summary of the estimated total one-time capital costs, annual costs, and annual savings for the 118 potential energy efficiency improvement projects identified in the EEA Reports. The total estimated one-time costs for all of these projects (except for those identified as "Not Implementing") are $2.9 billion with annual cost of about $4.1 million. These projects would also result in a net annual saving of approximately $80.2 million. These estimates are preliminary. They are not based on detailed engineering and cost analysis that would be required to accurately estimate emission reductions, costs, and timing of the projects.

Table I-16 Summary of Estimated Costs and Savings for Energy Efficiency Improvement Projects*

Number of Projects	One Time Cost (million $)	Annual Cost (million $/year)	Annual Savings (million $/year)
118	2,926	4.11	80.2

* Includes all projects identified as Completed/Ongoing, Scheduled, or Under Investigation. Does not include projects identified as "Not Implementing"

I.5 Implementation Status of Energy Efficiency Improvement Opportunities

Many of the projects identified in Section I-4 have already occurred or will occur over the next few years. Electricity Generation facilities subject to the EEA Regulation identified 129 energy efficiency improvement projects and assigned these projects to one of four categories:

- Completed/Ongoing
- Scheduled
- Under Investigation or
- Not Implementing

Eleven of the 129 projects were identified as not being implemented. Table I-17 shows the estimated GHG, NO_x, and PM emission reductions associated with the energy efficiency improvement projects identified in the EEA Reports as completed, ongoing, scheduled, or under investigation, by project status. The reductions associated with the Completed/Ongoing projects were divided into two subcategories based on if the projects were completed before 2010 or during/after 2010. This was done to avoid double counting of GHG emission reductions since reductions occurring before 2010 should already be reflected in the 2009 GHG Mandatory Reporting.

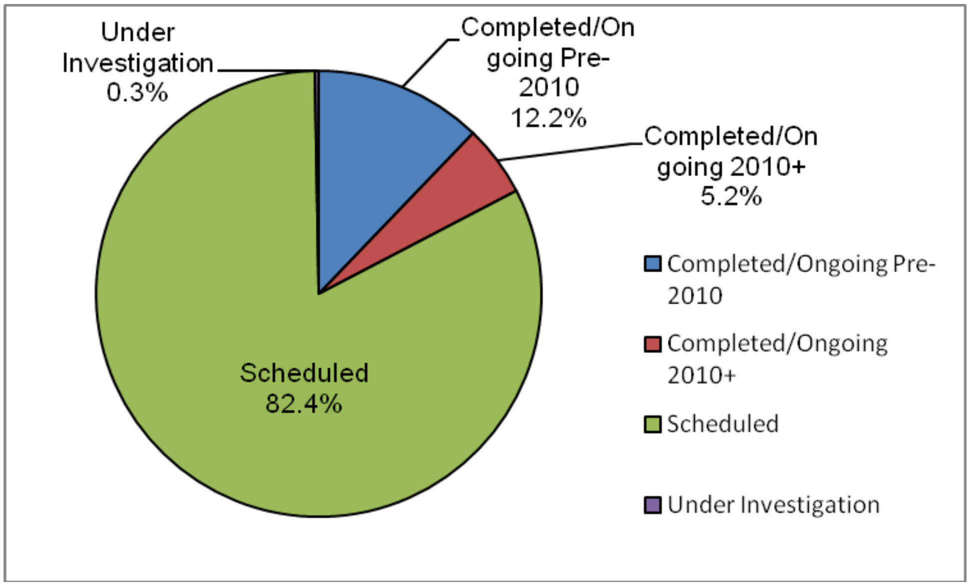
Table I-17: Estimate GHG, NO_x, and PM Emission Reductions by Project Status

Project Status	**GHG Reductions** MMTCO2e/year (% of total)	**NO_x Reductions** tons/day (% of total)	**PM Reductions** tons/day (% of total)
Completed/Ongoing Pre-2010	0.23	1.56	0.046
Completed/Ongoing 2010+	0.099	0.025	0.016
Subtotal C/O	0.33 (17%)	1.58 (98%)	0.06 (259%)
Scheduled	1.58 (82%)	0.039 (2%)	-0.045 (N/A)
Under Investigation	0.0054 (1%)	0.002 (0.01%)	0.0002 (1%)
Subtotal Pre-2010	0.23 (13%)	1.56 (96%)	0.06 (100%)
Subtotal 2010+	1.68 (87%)	0.06 (4%)	-0.02
Total	1.91	1.63	0.018

Note: numbers may not add due to rounding

Two things in Table I-17 to note are that 17 percent of the estimated GHG reductions come from Completed/Ongoing projects and that about 13 percent of all estimated GHG reductions occurred before 2010. Approximately 82 percent of identified GHG reductions come from scheduled projects. This is shown pictorially in Figure I-10. Based on the projects that were reported, the vast majority of these GHG reductions are due to the replacement of power generation units, as illustrated in Table I-14. However, it is unclear at this time how the recent adoption of SCAQMD Rule 1304.1 will impact the implementation of these projects. For the NO_x emission reductions, 98 percent are associated with projects that are either completed or ongoing, and an estimated 96 percent of the identified emission reductions are thought to be reflected in the reported 2009 emissions inventories.

Figure I-10 Estimated GHG Reduction by Project Status



It should be noted, that the estimated reductions assume that all of the energy efficiency improvement projects identified in the EEA Reports will be implemented, except for those identified as "Not Implementing." This assumption is accurate for projects that were reported as Completed/Ongoing, which make up about 17 percent of the estimated GHG reductions. However, implementation of some projects reported as Scheduled or Under Investigation may preclude the implementation of other projects that deal with the same equipment or processes. Therefore, these estimated reductions do not necessarily represent actual achievable on-site emission reductions. As stated in the Introduction and Summary, ARB staff will be developing a subsequent report that will include all of the sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Report, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014.

Reference:

(EIA, 2015) What is the difference between electricity generation capacity and electricity generation? http://www.eia.gov/tools/faqs/faq.cfm?id=101&t=3 , March 2015.

(OEHHA, 2009) Technical Support Document for Cancer Potency Factors: Methodologies for derivation, listing of available values and adjustments to allow for early life stage exposures, California Environmental Protection Agency Office of Environmental Health Hazard Assessment Air Toxicology and Epidemiology Branch, May 2009.

Part II - Facility Specific Information for Electricity Generation Facilities

II.0 Introduction

Part II of this report provides facility-specific information about each of the 14 electricity generation facilities submitting EEA reports. Each electricity generation facility has a separate section that provides information on the current (2009, or 2010 in a few cases) emissions for GHG, criteria pollutants, and TACs from the specific facility and a summary of the potential energy efficiency improvement projects that electricity generation facility staff identified in their EEA report. The projects are grouped by timing (Completed/Ongoing, Scheduled, or Under Investigation). The projects are then listed by Equipment Category and Equipment Sub-type. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility.

Equipment Sub-type provides a general description of the types of equipment affected by the improvement project but does not provide a detailed explanation of each of the 129 projects identified or facility-specific variations from the general description. Information about cost and potential emission reductions of GHG, criteria pollutants, and TACs, summed for all the projects (by Equipment Category and Equipment Sub-type), is provided. In compliance with the confidentiality requirement under CCR §95610, the specific details about the individual projects were not presented. While it is not possible to identify the specific details for each project a facility has identified, it is possible to get a good indication of what equipment, what action(s), and timeframe were considered by referring back to the sector-wide project information in Part I and specifically Tables I-9 through I-14.

II.1 ACE Cogeneration

General Information

ACE Cogeneration is a coal and petroleum-fired cogeneration facility that is owned by a partnership consisting of DCO Energy, ArcLight Capital and Northern Star. ACE is operated by Trona Operating Partners in Trona, California (San Bernardino County) that has been operating since 1990. Coal is fired in a boiler that makes steam for a steam turbine generator. The total power output from the facility is 108 MW. The facility also provides steam to the adjacent Searles Valley Minerals plant. Nearly all of the emissions from the facility are from the coal-fired boiler system. The facility operator has decided to shut down this facility.

Emissions

Table II-1 provides the 2010 GHG emissions reported by ACE Cogeneration in compliance with ARB's GHG Mandatory Reporting Regulation. ACE Cogeneration contributes seven percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation.

Table II-1: ACE Cogeneration 2010 Greenhouse Gas Emissions

Pollutant	2010 Annual Emissions (MMTCO2e)
GHG	0.85

Note: This facility elected to provide 2010 criteria pollutant and toxic air contaminant emissions. The 2009 GHG emissions for this facility are 0.81 MMTCO2e.

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-2.

Table II-2: ACE Cogeneration 2010 Criteria Pollutant Emissions

Criteria Pollutant (CP)	2010 Annual Emissions (tpd)
Reactive Organic Gases (ROG)	0.01
Carbon Monoxide (CO)	0.48
Oxides of Nitrogen (NO_x)	1.1
Oxides of Sulfur (SO_x)	0.76
Particulate Matter (PM)	0.06

Table II-3 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-3: ACE Cogeneration 2010 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2010 Annual Emissions (lbs/year)
Chromium, hexavalent (& compounds)	<1
Dibenzofurans (chlorinated)	<1
Nickel	15
Polychlorinated Biphenyls (PCB)	6
Formaldehyde	315
Cadmium	<1
Dibenz [a,h] anthracene	<1
Arsenic	<1
Benzene	26
1,3 Butadiene	4

*Listed in rank order based on toxics cancer potency.

Mercury was reported as a TAC for this facility. Mercury is a toxic substance with both acute and chronic toxicity factors; however, no cancer potency factor has been developed. Since the top 10 TACs are prioritized based on cancer potency factors, mercury was not included. Total mercury emissions for this facility were reported to be 0.37 pounds per year.

Energy Efficiency Improvement Options

Table II-4 provides information on the 11 energy efficiency improvement projects identified in ACE Cogeneration's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

ACE Cogeneration reported that it has implemented and identified 11 projects as Completed/Ongoing. These projects, either completed or with expected completion in the 2000 to 2011 time frame, are estimated to reduce GHG emissions by 24,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.038 and 0.005 tpd, respectively. The Completed/Ongoing projects are estimated to cost approximately $700,000 in one-time costs, with an additional $301,000 in annual costs. ACE Cogeneration has estimated that these projects will save approximately $1.8 million annually.

Table II-4: ACE Cogeneration Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Electrical Equipment / Steam Equipment / Power Generation Units	Electric motors - pumps & fans / Steam traps / Power generation units	3	9,852	90,000	1,000	329,000	0.009	0.001
	Other Equipment	Feedwater heater / Cooling tower / Coal feeder / Plant control system	5	4,038	600,000	250,000	523,800	0.014	0.001
	Boiler	Boiler for power generation	3	10,560	7,000	50,000	938,000	0.015	0.003
Total			11	24,450	697,000	301,000	1,791,000	0.038	0.005

There were no projects identified as not being implemented for this facility.

II.2 AES Alamitos

General Information

AES Alamitos, operates the Alamitos Station, which is a nominal 1,950 megawatt (MW) power plant. The facility is located in Long Beach, California within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). The facility currently consists of 6 separate generation units (Units 1, 2, 3, 4, 5, and 6) utilizing a total of 6 natural gas boilers, 18 steam turbines, and 10 generators. Boilers are the primary GHG emissions source in this plant. This facility has a once-through cooling system with an intake canal off the Los Cerritos Channel and outfall to the San Gabriel River. To comply with the statewide Once-Through Cooling Water Policy (OTC Policy) adopted by California State Water Resources Control Board, AES Alamitos plans to replace up to 1,340 MW from these units with a combination of combined-cycle gas turbine technology, open cycle gas turbine technology, and battery energy storage systems. The remaining units would be permanently retired. This replacement is included in the projects identified for this facility.

Emissions

Table II-5 provides the 2009 GHG emissions reported by AES Alamitos in compliance with ARB's GHG Mandatory Reporting Regulation. AES Alamitos contributes nine percent of the total GHG emissions from electricity generation facilities subject to EEA Regulation.

Table II-5: AES Alamitos 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	1.07

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-6.

Table II-6: AES Alamitos 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Total Organic Gases (TOG)	17.6
Carbon monoxide (CO)	906.5
Oxides of Nitrogen (NO_x)	55.7
Oxides of Sulfur (SO_x)	5.9
Particulate Matter (PM)	15.2

Table II-7 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-7: AES Alamitos 2009 Top Prioritized Toxic Air Contaminant Pollutant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Benzene	36
Formaldehyde	73
1,3-Butadiene	<1

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-8 provides information on the two energy efficiency improvement projects identified in AES Alamitos's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

AES Alamitos identified two projects as Scheduled. No specific cost or GHG benefit data are provided for the Power Generation Units or Other Equipment individually as to protect the confidential nature of the data. However, these projects were included in the full list of possible projects in Tables I-9 through I-14.

Table II-8: AES Alamitos Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of projects	Estimated GHG Reduction (metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Scheduled	Power Generation Units	Power Generation Units	1	CBI	CBI	CBI	CBI	CBI	CBI
	Other Equipment Type	Turbine-Generator	1	CBI	CBI	CBI	CBI	CBI	CBI

CBI - Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.3 AES Huntington Beach

General Information

AES Huntington Beach, LLC, operates the Huntington Beach Generation Station, which is located in Huntington Beach, California within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). At the time that the EEA Report was submitted, the facility was a nominal 880 MW power plant and consisted of four separate generation units (Units 1, 2, 3, and 4.) Units 3 and 4 were permanently retired on October 31, 2012, and converted to synchronous condensers providing 290 mega volt amperes reactive (MVars) of voltage support at AES Huntington Beach. As of October 2012, the facility has 450 MW of generating capacity and consists of two separate generation units (Units 1, 2) utilizing two natural gas-fired boilers, four steam turbines, and four generators. However, the emissions reported in this chapter are consistent with the 2009 facility configuration which included four separate generation units. The facility's primary GHG emission sources are the natural gas-fired boilers. This facility has a once-through cooling system with an offshore intake and outfall from and to the Pacific Ocean. To comply with the statewide Once-Through Cooling Water Policy (OTC Policy) adopted by California State Water Resources Control Board, AES Huntington Beach plans to replace the facility with a combination of combined-cycle gas turbine technology and open cycle gas turbines. This replacement is included in the projects identified for this facility.

Emissions

Table II-9 provides the 2009 GHG emissions reported by AES Huntington Beach in compliance with ARB's GHG Mandatory Reporting Regulation. Note that these reported emissions were from the four units operating in 2009 and that the facility has since been reduced in size. AES Huntington Beach contributed five percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation in 2009.

Table II-9: AES Huntington Beach 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.63

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-10.

Table II-10: AES Huntington Beach 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	Not Reported
Carbon Monoxide (CO)	169.8
Oxides of Nitrogen (NO_x)	30.3
Oxides of Sulfur (SO_x)	4.7
Particulate Matter (PM)	21.4

Table II-11 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-11: AES Huntington Beach 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Benzene	27
Formaldehyde	57
1,3 Butadiene (not from boilers)	4

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-12 provides information on the three energy efficiency improvement projects identified in AES Huntington Beach's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

AES Huntington Beach reported that it has identified two projects as Completed/Ongoing, and one project as Scheduled. No specific cost or GHG benefit data are provided for the listed projects. The data were aggregated for all projects to protect the confidential nature of the data. Additionally the projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report. These projects are estimated to reduce GHG emissions by 220,000 metric tons annually. In addition, these projects are estimated to reduce NOx by approximately 0.006 tpd. However, the PM emissions are estimated to increase by approximately 0.007 tpd. The PM emissions for the project are based on BACT and manufacturer-provided pollutant stack concentration data, which would represent the worst-case concentration. However, the project emissions are being compared to baseline emissions for the current configuration that represent typical and not worst-case concentrations. Consequently, the apparent PM increase is most likely due to the nature of the inconsistent data available for comparison and does not represent an actual emissions increase. The Completed/Ongoing and Scheduled projects are estimated to cost approximately $1 billion in one-time costs. AES Huntington Beach has estimated that these projects will save approximately $20 million annually.

Table II-12: AES Huntington Beach Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boiler	Boiler for power generation	1	CBI	CBI	0	CBI	CBI	CBI
	Steam Equipment	Steam turbine	1	CBI	CBI	0	CBI	CBI	CBI
Scheduled	Power Generation Units	Power generation units	1	CBI	CBI	0	CBI	CBI	CBI
Total			3	220,000	1,014,000,000	0	20,097,000	0.0062	-0.0068

CBI – Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.4 APMC Stockton Cogeneration

General Information

The Air Products Manufacturing Corporation (APMC) Stockton Cogeneration Plant is located in Stockton, California. It began operation in 1988 and was shutdown in July 2012. Air Products has determined that it is no longer profitable for the facility to operate. This fluidized bed coal-fired facility consisted of a single 60MW circulating fluidized bed (CFB) boiler; a 178 MMBtu/hr steam auxiliary boiler; a single turbine with high pressure side and low pressure side. Since the facility has been sold for scrap value, there is no intention of operating the CFB boiler.

The CFB boiler was the main source of emissions. During its operation, it had two to three major overhauls in which extensive turbine work was required. The facility would annually take a maintenance outage to perform preventive inspection and corrective maintenance.

The facility was located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). It was operated on approximately nine acres and employed approximately 43 persons at one time.

Emissions

Table II-13 provides the 2009 GHG emissions reported by Stockton Cogeneration in compliance with ARB's GHG Mandatory Reporting Regulation. Stockton Cogeneration contributed four percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation in 2009.

Table II-13: APMC Stockton Cogeneration 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.54

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-14.

Table II-14: APMC Stockton Cogeneration 2009 Criteria Air Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Total Organic Gases (ROG)	0.8
Carbon monoxide (CO)	71.2
Oxides of Nitrogen (NO_x)	98.4
Oxides of Sulfur (SO_x)	106.8
Particulate Matter (PM)	8.3

Table II-15 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-15: APMC Stockton Cogeneration 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Benzene	<1
Formaldehyde	<1

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

APMC Stockton completed an EEA report prior to ceasing operations in 2012. The projects and benefits identified in the report are provided below. These projects are of interest in terms of what could be done at similar type facilities; however, since the facility is no longer in operation, no additional projects are anticipated to be completed.

Table II-16 provides information on the 9 energy efficiency improvement projects identified in Stockton Cogeneration's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

The APMC Stockton Cogeneration reported that it has identified 4 projects as Completed/Ongoing. These projects, completed and expected completion in the time 2011 to 2012, were estimated to reduce GHG emissions an estimated 1,800 metric tons annually. In addition, these projects were estimated to reduce NOx and PM by approximately 0.0009 and 0.00008 tpd, respectively. The Completed/Ongoing projects were estimated to cost approximately $50,000 in one-time costs, with an additional $20,000 in annual costs. APMC Stockton Cogeneration has estimated that these projects would save approximately $0.4 million annually.

The APMC Stockton Cogeneration also identified two projects as Scheduled. No specific cost or GHG benefit data are provided for the two projects listed as Scheduled. These data could not be aggregated in such a way as to protect the confidential nature of the data. However these projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report.

The APMC Stockton Cogeneration also identified three projects as Under Investigation. The Under Investigation projects were estimated to reduce GHG emissions by 4,000 metric tons annually and NOx and PM by 0.002 and 0.000018 tpd respectively.

Table II-16: APMC Stockton Cogeneration Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Power Generation Units / Steam Equipment / Other Equipment	Power generation units / Steam turbine / Cooling tower / Feedwater heater	4	1,838	50,000	20,000	400,000	0.00092	0.00008
Scheduled	Boiler / Steam Equipment	Boiler for cogeneration / Steam traps	2	CBI	CBI	CBI	CBI	CBI	CBI
Under Investigation	Electrical Equipment / Boiler / Steam Equipment	Electric motors - pumps & fans / Boiler for cogeneration / Steam turbine	3	4,281	650,000	10,000	770,000	0.00214	0.00018
Total for all Completed/Ongoing projects			4	1,838	50,000	20,000	400,000	0.00092	0.00008

CBI – Confidential Business Information pursuant to CCR §95610

APMC also identified two projects as not being implemented due to the cost effectiveness. These projects are listed in Table II-17. The Equipment Category, Equipment Sub-type, number of projects, and a brief description of the reason the projects were not being implemented are also listed in Table II-17.

Table II-17: APMC Stockton Cogeneration Energy Efficiency Improvement Options Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Projects Not Being Implemented
Not Being Implemented	Electrical Equipment	Electric motors – fans / other (conveyer motor)	2	Not cost effective

II.5 Covanta Delano

General Information

Covanta Delano is located in Delano, CA within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). Covanta owns and operates this biomass power generation facility that processes approximately 1,200 tons of biomass materials each day, generating up to 50 megawatts of electricity. The Covanta Delano facility currently burns biomass materials from locally generated and renewable resources such as agricultural crop residue, orchard prunings and removals, stone fruit pits, nut shells, cotton gin trash, cotton stalks, vineyard prunings, cull logs, eucalyptus logs, bark, lawn yard and garden clippings, leaves, silvicultural residue, tree and brush pruning, wood, wood chips, and wood waste (including clean, chipped wood products, plywood, particle board, fiberboard and wood products manufacturing wastes, wood based construction demolition materials, pallets, crates and boxes). The plant operates two fluidized bed boilers which are the primary emissions sources.

Emissions

Table II-18 provides the 2009 GHG emissions reported by Covanta Delano in compliance with ARB's GHG Mandatory Reporting Regulation. Covanta Delano contributes five percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation. Note that the Covanta Delano GHG emissions from biomass fuel, which constitute about 99 percent of their emissions, are exempt from compliance with the ARB Cap and Trade Regulation per CCR section 95852.2.

Table II-18: Covanta Delano 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.58

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-19.

Table II-19: Covanta Delano 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpd)
Carbon monoxide (CO)	98.4
Oxides of Nitrogen (NO_x)	221.5
Oxides of Sulfur (SO_x)	14.0
Particulate Matter (PM)	40.2

Table II-20 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-20: Covanta Delano 2008 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2008 Annual Emissions (lbs/year)
Cadmium	2
Arsenic	2
Beryllium	1
Formaldehyde	85
Acetaldehyde	159
Lead	17
Naphthalene	2
Methylene chloride {Dichloromethane}	28
2-Methyl naphthalene	1
Acrolein	45

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-21 provides information on the 18 energy efficiency improvement projects identified in Covanta Delano's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

The Covanta Delano facility reported that it has identified 17 projects as Completed/Ongoing, and one project as Under Investigation. No specific cost or GHG benefit data are provided for the two Steam Equipment and Other Equipment projects. The data for the two Steam Equipment projects and the single project identified as Under Investigation could not be aggregated in such a way as to protect their confidential nature of the data and consequently are not shown. However, these projects were included in the list of possible projects in Tables I-9 through I-14. The Completed/Ongoing projects, either ongoing or completed in 2011, are estimated to reduce GHG emissions approximately 1,600 metric tons annually. In addition, these projects are estimated to reduce NOx and PM emissions of approximately 0.0004 and 0.0002 tpd, respectively. These projects are estimated to cost approximately $1.4 million in one-time costs, with an additional $35,500 in annual costs. Covanta Delano has estimated that these projects will save approximately $278,000 annually.

Table II-21: Covanta Delano Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Type	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Electrical Equipment	Electric motors - pumps & fans / air compressors	15	1,613	1,445,000	35,500	278,000	0.00038	0.00017
	Steam Equipment	Steam turbine	2	N/A	N/A	N/A	N/A	N/A	N/A
Under Investigation	Other Equipment Types	Feedwater heaters	1	N/A	CBI	N/A	N/A	N/A	N/A
Total for Completed/Ongoing projects			17	1,613	1,445,000	35,500	278,000	0.00038	0.00017

N/A - Unable to Accurately Quantify

CBI - Confidential business Information pursuant to CCR §95610

Covanta Delano also identified six projects as not being implemented due to the cost effectiveness. These projects are listed in Table II-22. The Equipment Category, Equipment Sub-type, number of projects, and a brief description of the reason the projects were not being implemented are also listed in Table II-22.

Table II-22: Covanta Delano Energy Efficiency Improvement Options Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Projects Not Being Implemented
Not Being Implemented	Electrical Only Equipment	Electric motors-pumps & fans	6	Not cost effective

II.6 Encina Power Plant

General Information

Encina Power Plant is located in Carlsbad, California, about 32 miles North of San Diego. San Diego Gas and Electric (SDG&E) built the plant in the 1950's and operated it until 1999. In May 1999 SDG&E sold the plant to Cabrillo Power, a joint venture between Dynegy and NRG. In 2006, NRG acquired Dynegy's interests in Cabrillo Power and now wholly owns and operates Cabrillo Power.

The 965-megawatt plant has five generation units; all are conventional steam boiler units. The plant also has a 15-megawatt gas turbine. All five boiler units burn natural gas, and could fire fuel oil as back up fuel during gas curtailments to the San Diego area. The plant's 138-kV and 230-kV switchyards deliver the plant's power to the power grid.

Unlike most power plants, Encina houses its steam units inside a building. The building protects the units from corrosive sea air and conceals the plant's industrial-scale equipment. Flue gas from all five units exhausts through one exhaust stack. The units also share one water intake, which channels seawater from the Agua Hedionda Lagoon to the condensers for cooling. This facility's coastal once-through cooling system causes it to be subject to the statewide Once-Through Cooling Water Policy (OTC Policy) adopted by California State Water Resources Control Board in 2010. Compliance with this policy is covered by one of the projects included for this facility.

The gas turbine unit was designed to generate power during "peak" days when electricity demand is high. This unit is located outside the power plant building and is less fuel efficient but has the advantage of being able to start up without external power. This is referred to as blackstart capability and is used to help the grid recover from major blackouts.

Emissions

Table II-23 provides the 2009 GHG emissions reported by Encina Power Plant in compliance with ARB's GHG Mandatory Reporting Regulation. Encina Power Plant contributes four percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation.

Table II-23: Encina 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.52

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-24.

Table II-24: Encina 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Total Organic Gases (TOG)	52.4
Reactive Organic Gases (ROG)	26.2
Carbon Monoxide (CO)	176.2
Oxides of Nitrogen (NO_x)	54.6
Oxides of Sulfur (SO_x)	2.9
Particulate Matter (PM)	47.6

Table II-25 lists the top prioritized TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-25: Encina 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/yr)
Diesel engine exhaust, particulate matter (Diesel PM)	20
Formaldehyde	719
Benzene	20
Naphthalene	6
p-Dichlorobenzene	11
Acetaldehyde	1
Toluene	33
Hexane	17,132

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-26 provides information on the nine energy efficiency improvement projects identified in Encina's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

The Encina power plant reported that it has identified seven implemented projects as Completed/Ongoing. These Completed/Ongoing projects, completed in the 1990 to 2009 time frame, are estimated to reduce GHG emissions by 41,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.03 and 0.01 tpd, respectively. The Completed/Ongoing projects are estimated to cost approximately $15 million in one-time costs, with an additional $75,000 in annual costs. Encina has estimated that these projects will save approximately $0.3 million annually.

The Encina power plant also identified one project as Scheduled and one project as Under Investigation. The data for these projects could not be aggregated in such a way as to protect the confidential nature of the data. However these projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report.

Table II-26: Encina Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Electrical Equipment / Steam Equipment	Electric motors - other (variable frequency drives) / Air compressors / Steam turbine	3	-	12,295,000	30,000	272,500	0	0
	Boiler	Boiler for power generation	4	41,000	3,000,000	45,000	-	0.03	0.01
Scheduled	Power Generation Unit	Power generation unit	1	CBI	CBI	CBI	CBI	CBI	CBI
Under Investigation	Other Equipment	Other - fluorescent fixtures	1	CBI	CBI	CBI	CBI	CBI	CBI
Total for all Completed/Ongoing projects			7	41,000	15,295,000	75,000	273,000	0.03	0.01

CBI – Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.7 Kern River Cogeneration Company

General Facility Information

Kern River Cogeneration Company (KRCC) is a cogeneration facility located in the Kern River oilfield in Kern County, California with a generation capacity of 300 MW. KRCC commenced commercial operation in August 1985. KRCC's plant has four generation units each consisting of a 75 MW natural gas combustion turbine manufactured by General Electric which are equipped with Dry Low NOx (DLN) combustors and unfired heat recovery steam generators (HRSGs). KRCC sells generated electricity to a public regulated utility in California, and steam to an oil production company located in the Kern River oilfield for use in enhanced oil recovery. The primary emission sources are the combustion turbines. KRCC's facility is located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SVAPCD).

Emissions

Table II-27 provides the 2009 GHG emissions reported by KRCC in compliance with ARB's GHG Mandatory Reporting Regulation. KRCC contributes seven percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation.

Table II-27: KRCC 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.8

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-28.

Table II-28: KRCC 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	0.01
Carbon monoxide (CO)	242.2
Oxides of Nitrogen (NO_x)	91.9
Oxides of Sulfur (SO_x)	2.8
Particulate Matter (PM)	35.7

Table II-29 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-29: KRCC 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Benzene	493
Acetaldehyde	171
Formaldehyde	78
Naphthalene	9
Benz[a]anthracene	<1
Chrysene	<1
Acrolein	94
Toluene	1,861
Xylenes (mixed)	1,876

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-30 provides information on the three energy efficiency improvement projects identified in KRCC's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

KRCC reported that it identified one project as Completed/Ongoing, and two other projects as Under Investigation on Table II-4. No specific cost or GHG benefit data are provided for the Completed or Under Investigation projects individually. These data could not be aggregated in such a way as to protect the confidential nature of the data. Additionally, the projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report. The three projects are estimated to reduce GHG emissions by 510 metric tons annually. In addition, these projects are estimated to reduce NOx by approximately 0.5 tpd, and have no anticipated PM impact. The Completed and Under Investigation projects cost approximately $27 million in one-time costs, with an additional $800,000 in annual operating costs. KRCC has estimated that these projects will save approximately $30,000 annually.

Table II-30: KRCC Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed	Combustion Gas Turbines	Stationary gas turbine - electricity generation	1	CBI	CBI	CBI	CBI	CBI	CBI
Under Investigation	Combustion gas Turbines	Stationary gas turbine - electricity generation	2	CBI	CBI	CBI	CBI	CBI	CBI
Total			3	510	26,880,000	800,000	30,000	0.5	0

CBI - Confidential Business Information pursuant to CCR §95610

Table II-31 below lists one project identified by the energy audit and the reason that the project was not implemented.

Table II-31: KRCC Energy Efficiency Improvement Option Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Project Not Being Implemented
Not Being Implemented	Combustion Gas Turbines	Stationary gas turbine - electricity generation	1	Not cost effective

II.8 Los Angeles Department of Water and Power (LADWP) – Haynes Generation Station

General Facility Information

Haynes Generation Station (HnGS) is located in Long Beach, California within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). It is owned, operated and maintained by LADWP. As of December 2011, HnGS consists of seven power generation units (Units 1, 2, 5, 6, 8, 9, and 10). HnGS Units 1 and 2 are natural gas fired boiler units that operate on a regenerative, reheat steam cycle with a turbine nameplate rating of 230 MW each. HnGS Units 5 and 6 are natural gas-fired, supercritical boiler units that also operate on a regenerative, reheat steam cycle with a turbine nameplate rating of 330 MW each. HnGS Units 5 and 6 are in the process of being repowered with six high efficiency 100 MW combustion gas turbines. HnGS Units 8, 9 and 10 are natural gas fired combined cycle units, consisting of two combustion turbines with a turbine nameplate rating of 180 MW each and equipped with heat recovery steam generators (HRSG) to provide steam to one steam turbine with a turbine nameplate rating of 330 MW and a generator nameplate rating of 265 MW. This facility has a once-through cooling system and thus is subject to the statewide Once-Through Cooling Water Policy (OTC Policy) adopted by California State Water Resources Control Board. The cooling system's intake is from Alamitos Bay in Long Beach, with the outfall to the lower San Gabriel River that enters the Pacific Ocean. Units 1 and 2 are scheduled to be repowered by 2029. However, none of the projects identified for this facility are associated with this repower.

Natural gas is used as the fuel for this facility. The boilers and gas turbines are the primary emission source in this facility.

Emissions

Table II-32 provides the 2009 GHG emissions reported by LADWP – HnGS in compliance with ARB's GHG Mandatory Reporting Regulation. LADWP – HnGS is the largest GHG emitter of the 14 electricity generation facilities subject to the EEA Regulation and contributes 15 percent of the total GHG emissions in this sector.

Table II-32: LADWP – HnGS 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	1.91

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-33.

Table II-33: LADWP – HnGS: 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	45.9
Carbon monoxide (CO)	133.6
Oxides of Nitrogen (NO_x)	109.0
Oxides of Sulfur (SO_x)	7.4
Particulate Matter (PM)	55.6

Table II-34 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-34: LADWP – HnGS: 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Formaldehyde	15,113
Benzene	278
1,3-Butadiene	10
Asbestos	<1
Nickel	<1
Lead	<1

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-35 provides information on the 14 energy efficiency improvement projects identified in LADWP - HnGS's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

LADWP - HnGS reported that it has identified 13 projects as Completed/Ongoing. These projects, completed in the 1998 to 2010 time frame, are estimated to reduce GHG emissions by 126,600 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.015 and 0.02 tpd, respectively. The Completed/Ongoing projects are estimated to cost approximately $41 million in one-time costs, with an additional $55,000 in annual costs. LADWP - HnGS has estimated that these projects will save approximately $12.6 million annually.

The LADWP – HnGS also identified one project as Scheduled. The data for this project could not be aggregated in such a way as to protect confidential business information.

Table II-35: LADWP – HnGS Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Type	Equipment Sub-type	Number of projects	Estimated GHG Reduction (metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Other Equipment Types	Feedwater heater / condenser	7	9,803	7,475,000	55,000	834,000	0.001	0.002
	Boiler / Steam Equipment	Boiler/ Boiler for power generation / Steam turbine	6	116,770	33,552,000	0	11,795,000	0.014	0.020
Scheduled	Boiler	Boiler for power generation	1	CBI	CBI	CBI	CBI	CBI	CBI
	Total for all Completed / Ongoing projects		13	126,573	41,027,000	55,000	12,629,000	0.015	0.022

CBI- Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.9 Los Angeles Department of Water and Power (LADWP) - Scattergood Generation Station

General Information

The Scattergood Generation Station (SGS) is located in Playa Del Rey, California within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). It is owned, operated and maintained by LADWP. As of December 2011, SGS consists of three boiler units, SGS Units 1, 2, and 3. Units 1 and 2 are regenerative, reheat system steam cycle boiler units with turbine nameplate ratings of 156 MW each and operate on natural gas or a blend of natural gas and digester gas from the nearby Hyperion Wastewater Treatment Plant. Unit 3 is a natural gas-fired supercritical boiler that operates on a regenerative reheat steam cycle with a turbine nameplate rating of 460 MW. The primary GHG emission sources at the site are the three boilers. This facility has a once-through cooling system and thus is subject to the statewide Once-Through Cooling Water Policy (OTC Policy) adopted by California State Water Resources Control Board. The cooling system's submerged offshore intake and outfall are from and to the Pacific Ocean. Unit 1 and Unit 2 are scheduled to be repowered by 2024, and Unit 3 is scheduled to be repowered by 2015. These repowers are not represented in the projects identified for this facility.

Emissions

Table II-36 provides the 2009 GHG emissions reported by LADWP – SGS in compliance with ARB's GHG Mandatory Reporting Regulation. LADWP – SGS contributes 6 percent of the total GHG emissions emitted from the 14 electricity generation facilities subject to the EEA Regulation.

Table II-36: LADWP - SGS 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.69

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-37.

Table II-37: LADWP - SGS 2009 Criteria Pollutant Emissions

Criteria Pollutant (CP)	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	33.0
Carbon Monoxide (CO)	608.2
Oxides of Nitrogen (NO_x)	58.5
Oxides of Sulfur (SO_x)	38.5
Particulate Matter (PM)	40.6

Table II-38 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-38: LADWP - SGS 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants (TAC)*	2009 Annual Emissions (lbs/year)
Asbestos	<1
Benzene	21
Perchloroethylene	92
Formaldehyde	45
Methylene Chloride	121
1,3 Butadiene	<1
Hexane	<1
PAH	5

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-39 provides information on the 19 energy efficiency improvement projects identified in LADWP – SGS's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

LADWP - SGS reported that it has identified 14 projects as Completed/Ongoing. These projects, completed in the 2004 to 2010 time frame, are estimated to reduce GHG emissions by 27,600 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.0037 and 0.0026 tpd, respectively. The Completed/Ongoing projects are estimated to cost approximately $13 million in one-time costs, with an additional $39,000 in annual costs. LADWP - SGS has estimated that these projects will save approximately $2.4 million annually.

LADWP – SGS also identified five projects as Scheduled. The Scheduled projects are estimated to further reduce GHG emissions by an estimated 147,000 metric tons annually and NOx and PM by 0.0085 tpd and 0.019 tpd respectively.

Table II-39: LADWP - SGS Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Other Equipment	Feedwater heater / Condenser / Turbine-generator	11	20,993	10,956,000	39,000	1,835,000	0.0027	0.0022
	Boiler	Boiler for power generation	3	6,607	2,321,000	0	551,000	0.0010	0.0004
Scheduled	Other Equipment / Boiler	Turbine-generator / Boiler for power generation	5	146,954	22,060,000	944,000	847,000	0.0085	0.0192
Total for all projects			19	174,554	35,337,000	983,000	3,233,000	0.012	0.022

Table II-40 below lists one project identified by the energy audit that was not implemented and the reason for not implementing it.

Table II-40: LADWP - SGS Energy Efficiency Improvement Option Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Project Not Being Implemented
Not Being Implemented	Boiler	Boiler for power generation	1	Equipment still operating properly and in serviceable condition

II.10 Los Angeles Department of Water and Power (LADWP) - Valley Generation Station

General Information

Valley Generation Station (VGS) is located in Sun Valley, California within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). It is owned, operated, and maintained by LADWP. As of December 2011, VGS consists of one simple cycle gas turbine and a combined cycle generation unit consisting of two gas turbines and one steam turbine. The combined cycle generation unit, built in 2004, produced greater than 99 percent of the facility's total GHG emissions in 2009. Therefore, energy efficiency improvement projects are not required to be identified for the VGS facility.

Emissions

Table II-41 provides the 2009 GHG emissions reported by LADWP – VGS in compliance with ARB's GHG Mandatory Reporting Regulation. LADWP – VGS contributes 8 percent of the total GHG emissions emitted from the 14 electricity generation facilities subject to the EEA Regulation.

Table II-41: LADWP - VGS 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	1.0

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-42.

Table II-42: LADWP - VGS 2009 Criteria Air Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	2.2
Carbon monoxide (CO)	1.8
Oxides of Nitrogen (NO_x)	73.0
Oxides of Sulfur (SO_x)	2.2
Particulate Matter (PM)	21.9

Table II-43 lists the top prioritized TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-43: LADWP - VGS 2009 Top Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Formaldehyde	13,005
Benzene	221
1,3-Butadiene	8
Arsenic	<1
Cadmium	<1
Nickel	<1
Lead	<1
Dioxins, total, with individ. isomers also reported {PCDDs}	<1

*Listed in rank order based on toxics cancer potency.

II.11 Midway Sunset Cogeneration

General Information

Located near Fellows (Kern County), Midway Sunset Cogeneration Company (MSCC) is part of the Midway Sunset Oil Field, California's largest oil field. The principal operators of Midway Sunset Cogeneration, as of 2008, were Aera Energy LLC and San Joaquin Energy Company. Several enhanced oil recovery technologies have been employed at the Midway Sunset Oil Field. Thermal methods are used to assist the production of the heavy non-free flowing oil generated at this location. The Midway Sunset field has a large amount of heavy oil reserves requiring steam to facilitate its recovery. Consequently, many of the field operators have built cogeneration plants to both create steam for their operations and produce power to sell to the electric grid. These power plants burn natural gas, and convert the energy into both electricity and steam which is used to flood the heavy oil reservoirs. One of the largest of these cogeneration plants is Midway Sunset Cogeneration, a 225-megawatt facility on the western boundary of the field. The plant began operation in 1989. The primary emission sources at the facility are the combustion turbine generators that generate steam for the enhanced recovery operation in the oilfield and generate electricity that is sold to California's electric grid.

Emissions

Table II-44 provides the 2009 GHG emissions reported by MSCC in compliance with ARB's GHG Mandatory Reporting Regulation. MSCC contributes 10 percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation.

Table II-44: MSCC 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	1.21

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-45.

Table II-45: MSCC 2009 Criteria Pollutant Emissions

Criteria Pollutant (CP)	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	0.01
Carbon Monoxide (CO)	63.2
Oxides of Nitrogen (NO_x)	146.6
Oxides of Sulfur (SO_x)	0.03
Particulate Matter (PM)	57

Table II-46 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-46: MSCC 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Formaldehyde	2,051
Benzene	247
Acetaldehyde	807
Ethyl Benzene	288
Naphthalene	18
PAHs	4
Acrolein	196
Toluene	1,584
Hexane	38,185
Propylene	22,959

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-47 provides information on the energy efficiency improvement projects identified in MSCC's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

MSCC has identified one project as Ongoing and one project as Completed. No specific cost or GHG benefit data are provided for the two projects in order to protect the confidential nature of the data. However the projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report.

Table II-47: MSCC Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-Type	Number of Projects	Estimated GHG Reduction (metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Ongoing	Power Generation Units	Power Generation Units	1	CBI	CBI	CBI	CBI	CBI	CBI
Completed	Combustion Gas Turbines	Gas Turbine - Other	1	CBI	CBI	CBI	CBI	CBI	CBI

CBI-Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.12 Mt. Poso Cogeneration

General Information

The Mt. Poso power plant was built in 1989 and designed to burn coal, petroleum coke and tire derived fuel to generate steam and electricity. In 2011, the facility was retrofitted by new owners, a partnership of Macpherson Energy Corporation and DTE Energy Services, to use woody biomass as fuel. Woody biomass is a combination of sawmill waste wood, wood from forest thinning, and orchard waste such as prunings, as well as urban wood. However, the 2009 emissions information provided in this report was reported during the time when it was burning coal as well as biomass. The air toxics data (2008 inventory) is representative of coal combustion. According to the Macpherson Energy Corporation, as of February 2012, the Mt. Poso cogeneration plant uses only woody biomass (with natural gas for startup) fuel and produces 44 MW of Renewable Portfolio Standard-eligible electricity.

The steam produced by the Mt. Poso plant is used in the adjacent oil field for oilfield operations. In return the plant uses water from the oilfield operations for producing steam and cooling. Any excess water is used for nearby cattle grazing or reinjected into the oilfield.

Emissions

Table II-48 provides the 2009 GHG emissions reported by Mt. Poso Cogeneration in compliance with ARB's GHG Mandatory Reporting Regulation. Based on the 2009 data, Mt. Poso Cogeneration contributes four percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation. Note that the Mt. Poso GHG emissions from biomass fuel are exempt from compliance with the ARB Cap and Trade Regulation per CCR section 95852.2. While only 12 percent of the Mt. Poso 2009 GHG emissions were from biomass, the 2011 facility retrofit resulted in an increase in the percentage of the facility's emissions which are from biomass fuel to 95 percent in 2012.

Table II-48: Mt. Poso 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.52

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-49.

Table II-49: Mt. Poso 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Total Organic Gases (TOG)	<1
Reactive Organic Gases (ROG)	<1
Carbon Monoxide (CO)	73.3
Oxides of Nitrogen (NO_x)	179.0
Oxides of Sulfur (SO_x)	49.1
Particulate Matter (PM)	20.7

Table II-50 lists the top ten TACs ranked according to an estimated combined mass TAC emissions and cancer potency factor, as described in Section 1.2. The TAC inventory for this facility is currently being updated by the San Joaquin Valley APCD. Consequently, current information is not available but will be provided via an errata sheet once the emissions inventory has gone through the AB2588 review process.

Table II-50: Mt. Poso Top Ten Toxic Air Contaminant Emissions

Toxic Air Contaminants*	Annual Emissions (lbs/year)**
Arsenic	
Chromium, hexavalent (& compounds)	
Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	
Dioxins, total, w/o individ. Isomers reported	Current information not available
Cadmium	
Nickel	
Naphthalene	
Lead	
Beryllium	
Benzo[b]fluoranthene	

*Listed in rank order based on toxics cancer potency.

**Current information not available but will be provided via errata sheet once through AB2588 review process.

Mercury was reported as a TAC for this facility. Mercury is a toxic substance with both acute and chronic toxicity factors; however, no cancer potency factor has been developed. Since the top 10 TACs are prioritized based on cancer potency factors, mercury was not included. Total mercury emissions for this facility is 11 pounds per year.

Energy Efficiency Improvement Options

Table II-51 provides information on the energy efficiency improvement projects identified in Mt. Poso's EEA Report. The project is identified by timing (whether it is Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and

Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

Mt. Poso reported that it has implemented and identified one project as Completed/Ongoing. No specific cost or GHG benefit data are provided for the Completed project as to protect the confidential nature of the data. However this project was included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report.

Table II-51: Mt. Poso Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed	Steam Equipment	Steam turbine	1	CBI	CBI	CBI	CBI	CBI	CBI

CBI – Confidential Business Information pursuant to CCR §95610

There were no projects identified as not being implemented for this facility.

II.13 Sycamore Cogeneration Company

General Information

Sycamore Cogeneration Company (Sycamore) is a cogeneration facility located in the Kern River oilfield located in Kern County, California with a generation capacity of 300 MW. Sycamore commenced commercial operation in January 1987. Sycamore's plant has four generation units each consisting of a 75 MW natural gas combustion turbine manufactured by General Electric which are equipped with Dry Low NOx (DLN) combustors and unfired heat recovery steam generators (HRSGs). Sycamore sells generated electricity to a public regulated utility in California, and steam to an oil production company located in the Kern River oilfield for use in enhanced oil recovery. The primary emission sources are the combustion turbines. Sycamore's facility is located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SVAPCD).

Emissions

Table II-52 provides the 2009 GHG emissions reported by Sycamore in compliance with ARB's GHG Mandatory Reporting Regulation. Sycamore contributes 11 percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation.

Table II-52: Sycamore 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	1.39

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-53.

Table II-53: Sycamore 2009 Criteria Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	0.01
Carbon Monoxide (CO)	246.9
Oxides of Nitrogen (NO_x)	146.8
Oxides of Sulfur (SO_x)	4.24
Particulate Matter (PM)	29.9

Table II-54 lists the top TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-54: Sycamore 2009 Top Prioritized Toxic Air Contaminant Gas Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Benzene	835
Acetaldehyde	290
Formaldehyde	132
Naphthalene	15
Benz[a]anthracene	<1
Chrysene	<1
Acrolein	160
Toluene	3,150
Xylenes (total)	3,175

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-55 provides information on the three energy efficiency improvement projects identified in Sycamore's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

Sycamore reported that it has identified one project as Completed/Ongoing, and two projects as Under Investigation. No specific cost or GHG benefit data are provided for the listed projects. The data were aggregated as a total for all these projects to protect the confidential nature of the data. Additionally, the projects were included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report. These projects are estimated to reduce GHG emissions by 1,200 metric tons annually and NOx by 0.93 tpd. The Completed/Ongoing and Under Investigation projects are estimated to cost approximately $22 million in one-time costs, with an additional $800,000 in annual operating costs. Sycamore has estimated that these projects would save approximately $55,000 annually.

Table II-55: Sycamore Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed	Combustion Gas Turbines	Stationary gas turbine - electricity generation	1	CBI	CBI	CBI	CBI	CBI	CBI
Under Investigation	Combustion Gas Turbines	Stationary gas turbine - electricity generation	2	CBI	CBI	CBI	CBI	CBI	CBI
Total			3	1,205	22,050,000	800,000	55,000	0.93	0

CBI – Confidential Business Information pursuant to CCR §95610

Table II-56 below lists one project identified by the energy audit and the reason that the project was not implemented. The Equipment Category and Equipment Sub-type are also listed in Table II-56.

Table II-56: Sycamore Energy Efficiency Improvement Options Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Project Not Being Implemented
Not Being Implemented	Combustion Gas Trubines	Stationary gas turbine - electricity generation	1	Not cost effective

II.14 Wheelabrator Shasta

General Information

The Wheelabrator Shasta biomass facility is located on a 77 acre site in Anderson, California. It is a 50MW biomass-to-electricity facility that burns approximately 400,000 bone dry tons (BDT) of biomass annually. Wheelabrator Shasta is a certified Renewable Portfolio Standard-eligible facility. This facility operates three identical Zurn Industries swept-spout stoker steam boilers each rated at 339 MMBTU/hr, and three Elliot steam turbines rated at 19.8 MW that produce the electricity which is then sold to Pacific Gas and Electric (PG&E). The facility boilers were first fired in November 1987 and commenced operation on May 30, 1988. Over 95% of the facility's GHG emissions come from the operation of the three boiler units, and efficiency improvements revolve around routine maintenance and complete replacement of the existing boilers with more efficient designs. The facility is located within the jurisdiction of the Shasta County Air Quality Management District.

Typically about two or three times per year, the boilers are shut down for maintenance activities. One outage per year is a longer "annual" outage, while the others are typically shorter in time duration. The shorter outages typically involve activities that can be considered minor maintenance while the annual outage involves major maintenance activities encompassing major equipment repair and replacement.

Emissions

Table II-57 provides the 2009 GHG emissions reported by Wheelabrator Shasta in compliance with ARB's GHG Mandatory Reporting Regulation. Wheelabrator Shasta contributes six percent of the total GHG emissions emitted from electricity generation facilities subject to the EEA Regulation. Note that the Wheelabrator GHG emissions from biomass fuel, which constitute about 98 percent of their emissions, are exempt from compliance with the ARB Cap and Trade Regulation per CCR section 95852.2.

Table II-57: Wheelabrator Shasta 2009 Greenhouse Gas Emissions

Pollutant	2009 Annual Emissions (MMTCO2e)
GHG	0.72

In addition, the facility reported the following emissions of criteria pollutants as shown in Table II-58.

Table II-58: Wheelabrator Shasta 2009 Criteria Air Pollutant Emissions

Criteria Pollutant	2009 Annual Emissions (tpy)
Reactive Organic Gases (ROG)	22.1
Carbon monoxide (CO)	1,920.
Oxides of Nitrogen (NO_x)	448.9
Oxides of Sulfur (SO_x)	16.6
Particulate Matter (PM)	183.0

Table II-59 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-59: Wheelabrator Shasta 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Air Contaminants*	2009 Annual Emissions (lbs/year)
Naphthalene	831
Benzene	696
Formaldehyde	2,069
Acetylaldehyde	481
Chloroform	82
Lead	11
Sodium Hydroxide	20
Manganese	154
Copper	11
Zinc	82

*Listed in rank order based on toxics cancer potency.

Energy Efficiency Improvement Options

Table II-60 provides information on the 24 energy efficiency improvement projects identified in Wheelabrator Shasta's EEA Report. The projects are grouped by timing (whether they are Completed/Ongoing, Scheduled, or Under Investigation), by Equipment Category (including boilers, combustion gas turbines, electrical equipment, etc.) and by equipment sub-type (boiler for power generation, stationary gas turbine, etc.). In compliance with the confidentiality requirements under CCR §95610, specific ways that the projects improve energy efficiency are not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-9 through I-14 in Part I of this report.

The Wheelabrator Shasta reported that it has identified 23 projects as Completed/Ongoing, and one project as Scheduled. No specific cost or GHG benefit data is provided for the project listed as Scheduled. The data could not be aggregated in such a way as to protect the confidential nature of the data. However the project was included in the full list of possible projects in Tables I-9 through I-14 in Part I of this report.

Table II-60 shows that GHG emission reductions of all the Completed/Ongoing projects, either ongoing or completed in the 2010 to 2011 time frame, are estimated to be 19,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.04 and 0.013 tpd, respectively. The Completed/Ongoing projects are estimated to cost approximately $0.9 million in one-time costs, with an additional $26,000 in annual costs. Wheelabrator Shasta has estimated that these projects will save approximately $500,000 annually.

Table II-60: Wheelabrator Shasta Energy Efficiency Improvement Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Electrical Equipment	Electric motors - pumps & fans	12	2,312	584,000	21,000	61,000	0.0049	0.0017
	Electrical Equipment	Electric motors - other (hog motor) / air compressors	8	558	198,000	5,000	15,000	0.0012	0.0004
	Steam Equipment	Steam turbine	3	16,360	72,000	-	432,000	0.034	0.011
Scheduled	Steam Equipment	Steam turbine	1	CBI	CBI	-	CBI	0.0050	0.0017
Total for all Completed/Ongoing projects			23	19,230	855,000	26,000	507,000	0.04	0.013

CBI – Confidential Business Information pursuant to CCR §95610
Numbers may not add due to rounding.

There were no projects identified as not being implemented for this facility.