4.3.1.3 Operating Costs

Changes in throughput and operating conditions on existing facilities plus variable costs on new facilities show a small increase with more restrictive vapor pressure. These costs include purchase of chemicals and make-up catalyst less the value of elemental sulfur from sulfur recovery operations. Lead alkyls (for octane improvement) purchase is constant because gasoline volume was constant for each period studied. Table 4-18 summarizes changes in variable operating costs.

TABLE 4-18

CHANGES IN VARIABLE OPERATING COSTS
(M$/D Above Base Case)

	Max RVP for 1985			Max RVP for 1990		
	8	7	6	8	7	6
Catalyst & Chemicals	1.4	3.4	6.2	2.1	4.6	7.7
Recovered Sulfur	-0.4	-1.5	-2.5	-0.6	-1.2	-2.3
Net Charge	1.0	1.9	3.7	1.5	3.4	5.4

4.3.1.4 Total Refining Costs

Combining the components of refining costs discussed in the previous subsections produces an estimate of the total cost impact associated with reduced gasoline vapor pressure. These are presented in Table 4-19 in two forms. One is the annual refining cost, assuming 6.4 months as the summer period. The other is the cost per barrel of total motor gasoline. This latter basis shows clearly that the larger portion of unleaded premium in 1990 causes volatility control to be more expensive on a unit cost basis as well as on an annual basis.

TABLE 4-19

CHANGES IN TOTAL REFINING COSTS

	Max RVP for 1985			Max RVP for 1990		
	8	7	6	8	7	6
Total Cost,						
MM$/Yr.	65.1	141.2	253.2	70.4	149.2	260.1
$/BBL	0.45	0.97	1.75	0.51	1.08	1.88

4.3.1.5 Cost of Utilizing Rejected Hydrocarbons

Alternate dispositions for light hydrocarbons which must be removed from gasoline blending include use as burner fuel, as feedstocks for processing to make gasoline boiling-range material, and as liquified petroleum gas (the butane portion) in competition with similar material from the natural gas processing industry. Rejected light hydrocarbons could also be stored from summer to winter to the extent that they could be used in winter gasoline blending.

In this study, it was assumed that rejected light hydrocarbon would compete with other fuels in the industrial energy market. As such, the cost of downgrading light hydrocarbons from gasoline blending to use as industrial fuel is reflected in the net raw material costs presented earlier in subsection 4.3.1.1. It has been further assumed that any higher transportation cost (per unit of supplied energy) for the rejected hydrocarbons compared to heavy fuel oil would be offset by handling and clean-burning credits. Thus, the only cost which might accrue would be associated with investments for pressurized transport and storage facilities.

The reader is reminded that this assumed use as industrial energy is a 'last resort' use. As support for the validity of this disposition as a last resort, some facts and estimated costs are presented in the following paragraphs.

Based on 1977 statistics, an average of about 3200 billion Btu/day were fired in steam-electric power facilities in California. The quantity of rejected light hydrocarbons in the 6 RVP case represents approximately 200 billion Btu/day during the summer period. This represents a little over six percent of the total fuel fired. Of the total energy for steam-electric power, approximately two-thirds was supplied by fuel oil, thus, rejected light hydrocarbons could be used to replace only residual fuel energy.

The capital cost for modifications needed to burn light hydrocarbons is estimated to be five dollars per annual-barrel burned[1]. Such expenditures could be offset by permitting increased use of higher-sulfur fuel oil relative to very low-sulfur fuel oil while keeping total SO_2 emissions constant.

For example, if the price spread between 0.25 weight-percent-sulfur fuel oil and that with 0.5 weight-percent-sulfur were $2.50[2], it can be shown that the zero-sulfur credit for light hydrocarbons would amount to $.40 per million Btu or to $1.60 per barrel of butane. This results in a payout period of three and one half years for the five-dollar-per-annual-barrel investment estimated for facilities needed to utilize rejected light hydrocarbons.

---

[1]Based on $50/Bbl of spherical storage, 10 days storage capacity for light hydrocarbons for a burning season of 200 days, plus 100 percent for other facilities and modifications such as flare systems, unloading facilities and burner modifications (if any).

[2]This is based on the marginal production costs for these fuels for the 1990 6-RVP cases.

Rough engineering evaluations of other potential uses of the rejected light hydrocarbons show somewhat poor pay-out conditions. It is, therefore, concluded that fuel value for these hydrocarbons is a reasonable assessment and that other uses would only be competitive under special circumstances of high value of products and/or enhanced process technology.

Applying the investment estimate of five dollars per barrel to the volume of rejected light hydrocarbons produces the estimated capital requirements shown in Table 4-20.

TABLE 4-20

CAPITAL ESTIMATES FOR REJECTED HYDROCARBONS
(Above Base Case)

	Max RVP for 1985			Max RVP for 1990		
	8	7	6	8	7	6
Rejected Volume, MBPD, or	13.3	25.7	60.1	12.9	27.5	50.9
MBPY	2.6	5.0	11.7	2.5	5.4	9.9
Requ'd Capital, MM$	12.9	25.0	58.4	12.6	26.8	49.6

It should be emphasized that these capital estimates and potential values of rejected hydrocarbons are predicated on energy supply-demand balances for the State of California.

If, for example, a scheme to utilize this material outside of the state or in a disposition other than energy supply were put into place, these estimates could be in error. Sensitivity of results to the fuel value of these hydrocarbons is discussed in subsection 4.3.2. Furthermore, the lower the allowable vapor pressure, the worse the discrepancy because the marginal cost of producing gasoline increases with lowering of vapor pressures.

4.3.2 Sensitivity Analyses

Two sets of LP model runs were made to measure impact variations with changes in two study parameters. One parameter is the assumed ratio of gasoline demand to distillate-fuel demand. The other is the distribution of gasoline grades within the forecast of total gasoline demand. An analysis of the effect of changing sulfur content of unleaded gasoline was also performed because early LP results were inadvertently prepared with gasoline sulfur content limited to 1500 ppm. Subsequent runs were made with unleaded grades limited to 400 ppm. A fourth sensitivity analysis was performed on the disposition of low-boiling hydrocarbons rejected from gasoline blending by lower RVP limits. Each of these sensitivity analysis is discussed in the following subsections.

4.3.2.1 Gasoline-to-Distillate Ratio

Uncertainty surrounding the extent to which diesel-powered vehicles will continue to penetrate new-car sales produces uncertainty about the ratio of demand forecasts. The diesel fuel demand imposed in this study is a significant reduction from forecasts being made two-to-three years ago. There is, however, considerable opinion that diesel-powered vehicles could increase or decrease in popularity.

While sensitivity to a change in gasoline-to-distillate ratio was measured by increasing diesel fuel demand and reducing gasoline demand, the effect is essentially the same (with direction reversed) as would have been measured for an increase in this ratio. To account for the greater thermodynamic efficiency of the diesel engine and the greater volumetric energy content of diesel fuel, an exchange rate of 1.25 volumes of gasoline per volume of diesel fuel was used.

Refining impacts the change in gasoline-to-distillate ratio are presented in Table 4-21. Also shown, for comparison, are the impacts for the normal case and the gasoline octane and sulfur cases. As shown, increasing diesel demand by 20,000 BPD and decreasing gasoline demand by 25,000 BPD has a small effect on measured impacts. The shift in composition of vehicular fuels changes the gasoline-to-distillate ratio from 1.23 to 1.16. The gasoline demand has been reduced by 3.5 percent of the normal case demand, the No. 2 portion of distillate fuels[1] has been increased by 5.5 percent.

---

[1]Distillate fuel demand for 1990 was forecast to include 37,000 BPD of naphtha jet, 173,000 BPD of kerosene jet and 365,000 BPD of No. 2 diesel and fuel oils.

TABLE 4-21

SENSITIVITY ANALYSES RESULTS
(For 1990 @ 6 RVP)

	Normal	+Diesel(1)	-Octane(2)	+Sulfur(3)
Gasoline-to-Distillate Ratio	1.23	1.16	1.23	1.23
Pool (Clear) Octane, (R+M)/2	89.4	89.4	89.1	89.4
Unleaded Gasoline Sulfur Content, ppm	400	400	400	1500
Cost Impacts: $/BBL				
Raw Material Costs (Net)	1.047	1.009	1.050	0.924
Operating Costs	0.008	0.011	0.005	0.027
Capital Related Costs	0.827	0.833	0.807	0.717
Total Cost Increase	1.882	1.853	1.862	1.668
Change in Cost Increase, %	-	-1.5	-1.1	-11.4
Investment Increase, MM$	372	375	363	358
Change in Investment, %	-	0.8	-2.4	-3.8
Raw Material Increase:				
ANS Crude, MBPD	33	31	33	27
Adjusted ANS Crude, MBPD	22	20	22	-
Energy Requirement Increase:				
MMM Btu per Day	36	36	33	54

(1) Diesel demand increased by 5.5 percent or 20,000 BPD: motor gasoline decreased by 3.5 percent or 25,000 BPD.
(2) Unleaded premium decreased from 27.6 percent of gasoline pool to 20.7 percent: unleaded regular volume increased to maintain constant total.
(3) Unleaded gasoline sulfur content increased from 400 ppm to 1500 ppm or 375 percent.

4.3.2.2 Gasoline Octane

Uncertainty concerning the growth in demand for premium unleaded gasoline, within a fixed overall demand for total gasoline, reflects itself in uncertainty concerning the pool octane requirement. To measure the influence of pool octane on the impacts of restricting vapor pressure, a pair of cases were run with premium and regular unleaded gasoline demands shifted by 49,000 BPD (by 25 percent of the base demand for unleaded premium).

As shown in Table 4-21, the shift in gasoline grade mix, while amounting to a significant volume change, does not change the pool octane greatly. Thus, the changes in vapor pressure impacts are small.

4.3.2.3 Gasoline Sulfur

Although not intended as one of the variable parameters of this study, sulfur content of gasoline had to be adjusted because early results were obtained from runs employing a 1500-ppm limit instead of the current maximum of 300 ppm on unleaded gasolines. All subsequent cases were run with a limit of 400 ppm[1]. The effect of changing this limit is included in these results.

---

[1]Due to an input error, the attempt to correct the gasoline sulfur constraint caused all useful runs to contain 400 rather than 300 as the maximum.

From the results shown in Table 4-21, it is obvious that the relaxed sulfur-content limit makes it easier to lower vapor pressure. The cost change amounts to $0.019 per barrel per 100 ppm. Using this effect to adjust the normal cost to a 300-ppm basis, the apparent cost would be approximately $0.02 per barrel higher or $1.90 per barrel. Since this is only a one-percent change for the 6-RVP extreme, re-running of LP cases at 300 ppm was judged unnecessary.

4.3.3 Refinery Simulator Results

The industry aggregate model was used to determine the minimum cost to overall refining operations of adjusting to reduced maximumm RVP specifications on summer motor gasoline while satisfying fixed demands of all major refinery products. In that scenario the refiner's response to the specification change is to expand capacities, alter operations, run more crude etc., to maintain fixed production rates.

An alternative response, and one that could be considered by each individual refinery, is to take a route of minimum investment and operational change to meet the specification change. His production rates would vary. The cost of the specification change to that refiner choosing this course of action would be (1) a loss in revenue due to decreased production of gasoline and (2) some operating cost debits associated with additional processing required to separate light hydrocarbons from gasoline components. Obviously, if one or more refiners were to take this approach, other refiners would need to assume the lost share of his market. In order to meet forecasted demands, some refiners would be required to increase production if others reduced theirs.

To estimate cost changes, refinery netbacks for products are required when production rates are allowed to vary. Incremental product costs taken from the aggregate model (fixed production) base case (9 RVP, 1990) were used as product netbacks in a series of minimum action studies using several refinery simulation models.

While it is not claimed that the incremental cost of products, as determined by the composite model of this study, will become future market prices, we believe that the changes in these costs from case to case are indicative of changes in market prices which could occur. Furthermore, differentials between incremental costs reflect real world differences. Consequently, these incremental costs can be used to gain some insight into the changes in profitability for individual refineries.

In these minimum action cases, the only production rates affected by a change in gasoline RVP specification are (1) unleaded gasoline, (2) leaded gasoline, (3) LPG[1] and (4) industrial fuels. Furthermore, the absolute level of these prices will not affect the results because the total refinery charge was not changed from case-to-case nor did the conversion processes (one that show volumetric loss or gain) change operations from case-to-case. The netback values used are presented below.

---

[1]In the minimum action case, surplus butanes were sold at LPG prices rather than as industrial fuels. The resulting costs of reducing the maximum allowed RVP are slightly higher than would have been determined had the butane been priced as industrial fuel.

PRODUCT	REFINERY NETBACK, $/Bbl
Regular, leaded gasoline	31.11
Unleaded gasoline	33.63
LPG (Butanes)	21.0 ($5.22/MMBtu)
Pentanes to Fuel	22.7 ($5.29/MMBtu)[1]

Several alternative refinery configurations and crude charge qualities were considered. Effort was made when specifying individual refinery situations to not represent any specific existing refinery in California. The objective was to specify refinery situations that span those found in operation.

Eight situations were selected:

1) A single moderately large complex refinery running the same proportions of four crude types as used in the LP model.

2) Two medium-sized hydroskimming refineries, each with a different crude type.

3) Five cracking refiners, each with a different crude type.

---

[1]The Btu value for pentanes is an incremental value from the LP results and is essentially a check on the fuel value of LPG which was derived as a ratio to projected crude cost comparable to that of recent market quotations.

A more complete description of each situation is presented in the following.

NAME	DESCRIPTION
Composite	A refinery with the same ratios of major process unit capacities as those of the aggregate LP model and charging the same crude mix as that model.
H2SKIM, Large Reformer	A hydroskimming refinery, charging light, low sulfur California crude (such as Elk Hills) with adequate reforming capacity to make all gasoline as unleaded gasoline.
CCU- Low Sulfur	A refinery with adequate catalytic cracking and reforming capacity to utilize all the available feed from a light, low sulfur California crude. All C_4 olefins are alkylated.
CCU Mixed Crude	Same as above but the crude charge is the same as that of the Composite refinery.
H2 SKIM Small Reformer	Same as the earlier H2SKIM model except the gasoline reformer has less capacity.
CCU-Wilm, Small Alky	A refinery with sufficient catalytic cracking and reforming capacity to handle all available charge but not all C_4 olefins produced by the CCU can be alkylated. The crude charge was medium sulfur, medium weight (for California) - such as Wilmington crude.

TABLE 4-23

ADDED COST - MINIMUM ACTION CASES
($/Bbl of Gasoline Production at
Stated Vapor Pressure)

Model	Maximum Allowed Vapor Pressure		
	8 RVP	7 RVP	6 RVP
Composite	0.272	0.684	1.462
CCU - Mixed Crude	0.297	0.605	0.993
CCU - Low Sul. Crude	0.374	0.657	1.218
CCU - Wilm. Crude	0.298	0.603	1.138
CCU - Wilm., Sml. Alky.	0.301	0.612	1.151
CCU - ANS Crude	0.303	0.599	0.929
H2SKIM, Lrg. Reform	0.267	0.675	1.792
H2SKIM, Sml. Reform	0.176	0.659	1.253

Almost all of the cost increase is a consequence of lost gasoline production and shift in gasoline octane quality. (The gasoline volume loss is matched by an equal volume increase of butane and pentane sales). The production loss of gasoline and the shift in production between the two grades of gasoline is given in Table 4-24 and presented in bar chart form in Figure 4-5. Two things are obvious. First, the production loss becomes progressively more severe for each step in RVP reduction. Second, for modest decreases in RVP there is a net quality loss as shown by a decrease in the unleaded/leaded production ratio, but this loss is reduced or reversed in going from a 7 RVP limit to 6 RVP. (In the case of the hydroskimmer with a small reformer, this reversal occurs in going from 8 to 7 RVP).

This behavior is simply a consequence of the fact that the first component removed from gasoline in order to lower vapor pressure is butane, and butane has a high octane rating. Consequently, the octane rating of the pool is lowered as the butane is removed. Once all the butane that can be practically removed has been removed, it becomes necessary to remove pentanes. Since pentanes are generally lower in octane rating than the remainder of the pool, reducing vapor pressure by removing pentanes improves the octane rating of the remaining pool.

It is more economical to reduce gasoline RVP by removing butanes than by removing pentanes, even though butane has a better octane rating, because much less butane has to be removed to achieve a given vapor pressure reduction. This is also the explanation for the rapid loss in gasoline production as the allowable vapor pressure is reduced to the point that additional reductions cannot be made by removing butane.

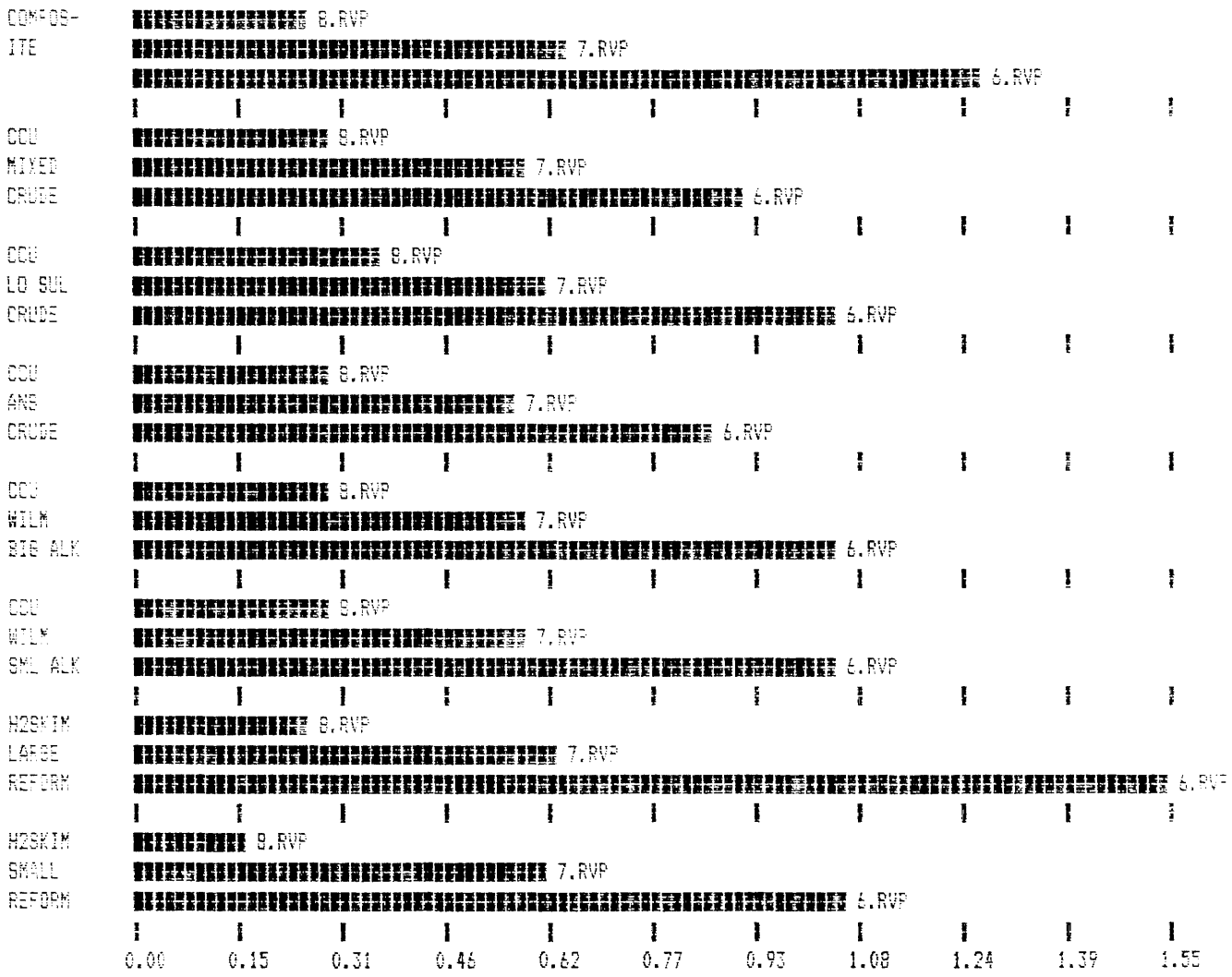

Figure 4-3. Added Cost, $/BBL 9 RVP Gasoline
(By RVP Within Model Type)

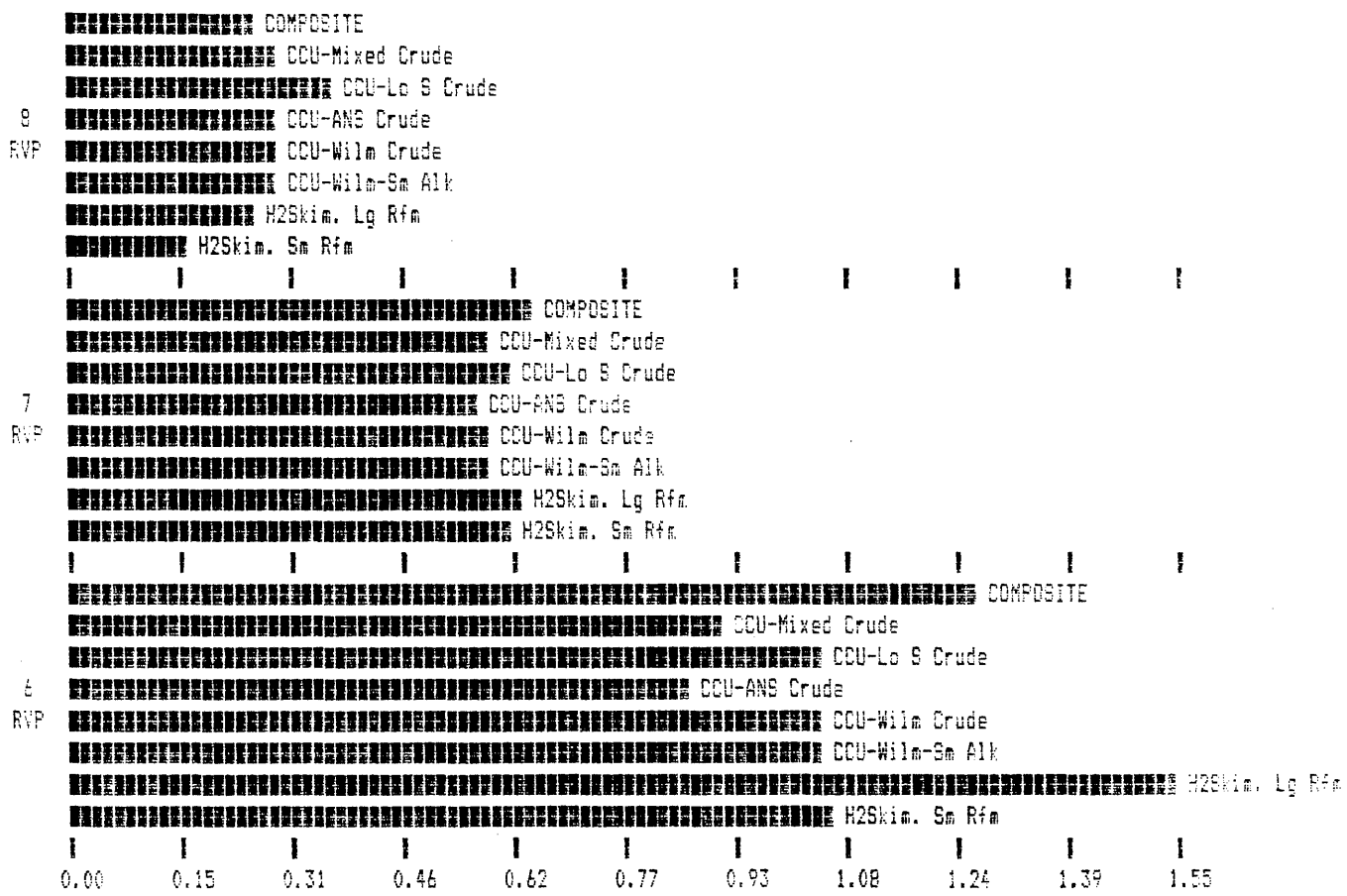

Figure 4-4. Added Costs, $/BBL 9 RVP Gasoline Produced (By Model Within RVP Class)

TABLE 4-24

GASOLINE PRODUCTION - MINIMUM ACTION CASES

(Relative to 9 RVP Production)

	MAXIMUM RVP								
	8 RVP			7 RVP			6 RVP		
MODEL	TOTAL	UNLEADED	LEADED	TOTAL	UNLEADED	LEADED	TOTAL	UNLEADED	LEADED
Composite	.985	.945	1.099	.949	.920	1.027	.865	.973	.561
CCU - Mixed Crude	.983	.946	1.230	.966	.894	1.453	.918	.948	.709
CCU - Low Sul. Crude	.983	.944	1.141	.951	.953	1.016	.867	1.078	.000
CCU - Wilm. Crude	.983	.952	1.969	.966	.906	2.905	.919	.891	1.833
CCU - Wilm., Sml. Alky.	.983	.945	1.244	.966	.893	1.479	.918	.878	1.199
CCU - ANS Crude	.983	.934	1.103	.965	.870	1.201	.940	.853	1.156
H2SKIM, Large Reformer	.978	.978	-	.946	.946	-	.863	.863	-
H2SKIM, Small Reformer	1.000	.883	1.149	.933	1.003	.847	.851	1.188	.434

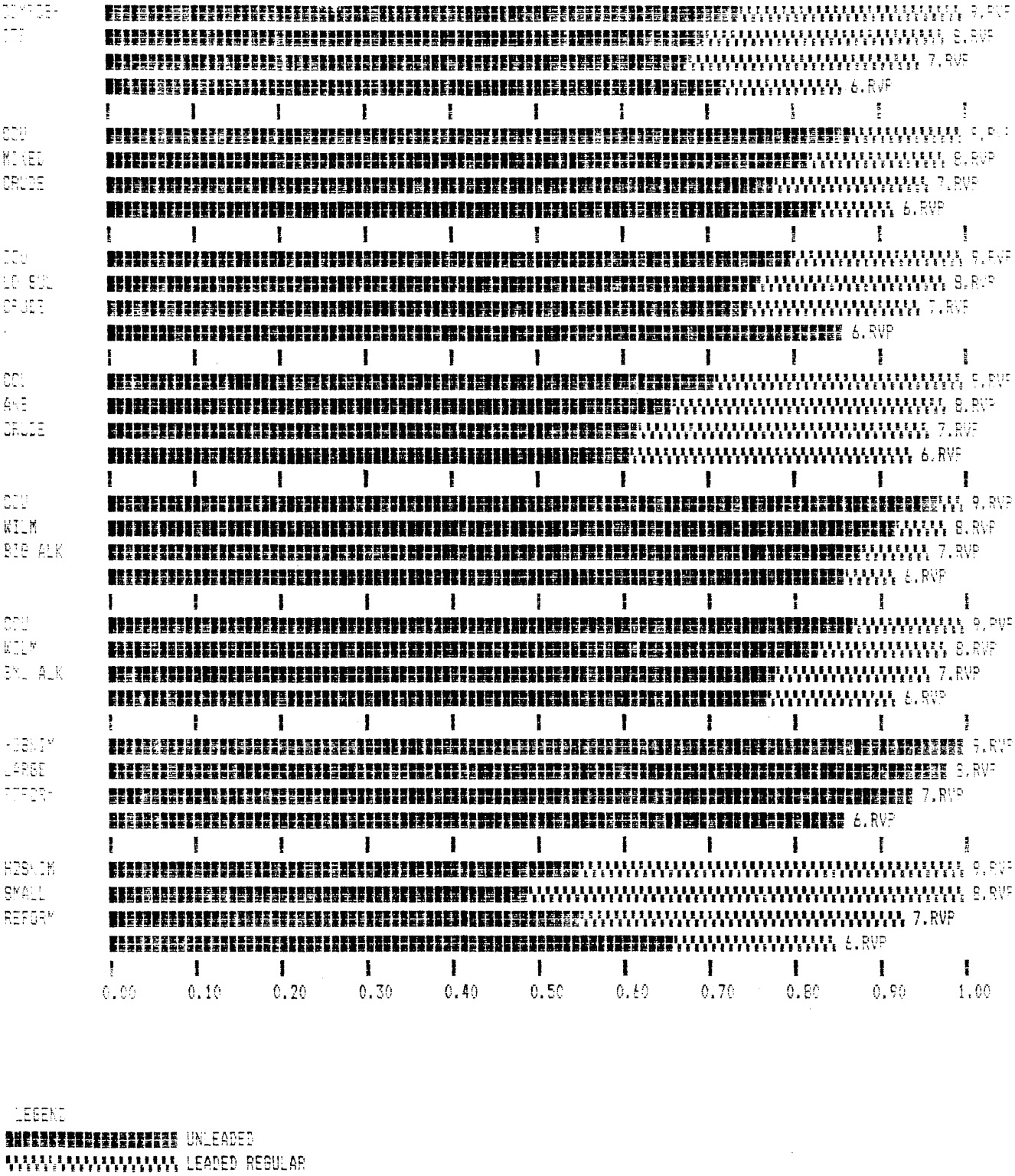

Figure 4-5. Relative Gasoline Production

Results of the fixed refinery simulation or minimum action cases can be summarized as follows:

1) All situations show a progressive reduction in total gasoline output as the RVP specification limits are reduced. The reductions are quite consistent for all the cases studied.

   (a) at 8 RVP, production is down 1 to 2 percent.

   (b) at 7 RVP, production is down 3 to 6 percent.

   (c) at 6 RVP, production is down 8 to 15 percent.

2) For modest decreases in RVP, the production of unleaded gasolines suffers much more than does leaded regular gasoline. For more severe RVP reductions this trend may be reversed in certain refining situations. When it is reversed, the loss in total gasoline production is accelerated.

REFERENCES

(1) Bureau of Mines, U.S. Department of Interior
RI 7291 1970

(2) Bureau of Mines, U.S. Department of Interior
RI 7707 1972

(3) The Effect of Fuel Volatility Variations on Evaporative and Exhaust Emissions, Exxon Research and Engineering, May 1979, API #4310

(4) Mathematical Expressions Relating Evaporative Emissions from Motor Vehicles without Evaporative Loss Control Devices to Gasoline Volatility, W. F. Biller, Michael Manoff, Jyotin Sachdev and W. C. Zegel, Scott Research Laboratories and David Wade, Exxon Research and Engineering, August 1972, SAE Technical Paper #720700

(5) Unpublished data provided by Mobil Oil

(6) Procedures and Basis for Estimating On-Road Motor Vehicle Emissions, State of California Air Resources Board-Technical Services Division (January 1980)

(7) Supplement 2 (June 1981) to (6) above

(8) Supplement 3 (November 1982) to (6) above

(9) Letter to Mr. Garret E. Pack, Mittelhauser Corp., from Mr. Edward E. Yotter, Manager, ARB Motor Vehicle Emissions and Projections Section

(10) Compilation of Air Pollution Emission Factors Including Supplements 1-12, Report #AP-42, U.S. Environmental Protection Agency

(11) Rules and Regulations, Bay Area Air Quality Management District

(12) Rules and Regulations, Southcoast Air Quality Management District

(13) Cold Weather Driveability Performance of 1975-1981 Model Cars; A. M. Horowitz and M. S. Stawnychy, Mobil R&D, SAE Technical Paper #821203, 1982

(14) Unpublished data made available by Chevron Research.

basin in California. Process categories include broad areas of hydrocarbon emissions such as tanks, tank cars and trucks, marine vessels, vehicle refueling and off-road motor vehicles. Activity categories give additional breakdown of emissions within the process categories and include such activities as petroleum refining, bulk plants, and service stations. For the purpose of the work performed here, emissions for on-road motor vehicles were extracted from the emissions inventory since that type of emissions is considered earlier in subsections 4.1.1 and 4.1.2.

Since the object of this work was to estimate emissions in 1985 and 1990, the existing inventory had to be translated from 1983 and 1987 to the years of interest. Fortunately, hydrocarbon emissions in 1983 and 1987 were nearly constant once emissions from on-road motor vehicles were extracted. Emissions from non-vehicular sources were projected to be 113 tons/day in 1983 and 115 tons/day in 1987 for the entire state. The 1983 inventory was then assumed to be applicable to 1985 and the 1987 inventory was assumed to be applicable to 1990.

4.1.3.2 Liquid Storage

Two types of storage are used for storing relatively large volumes of gasoline - floating-roof tanks and fixed cone-roof tanks equipped with vapor recovery facilities. Gasoline is also stored in drum-type storage containers in service stations and small storage facilities. Hydrocarbon emissions occur through breathing and working.

This study assumes that floating-roof storage is used for large volume storage requirements such as petroleum refinery product storage. Cone-roof storage tanks are assumed to be used in other storage applications.

AP-42[10] gives correlations for predicting emissions from both types of storage. The effect of vapor pressure in these correlations, usually expressed as true vapor-pressure, was analyzed in order to determine adjustment factors for lower volatility gasoline products. In floating-roof tanks, the effect of vapor pressure on breathing losses is related by the following expression:

$$\frac{\left(\frac{p}{14.7}\right)}{\left[1 + \left(1 - \frac{p}{14.7}\right) 0.5\right]^2}$$

Where p is the true vapor pressure, in psi, at a given temperature corresponding to a given Reid vapor pressure. In all work performed, the temperature was assumed to be 70°F. Using this expression, adjustment factors for breathing losses from floating-roof tanks were determined as follows:

RVP	Adjustment Factor
9	1.0
8	0.842
7	0.735
6	0.593

In addition to breathing losses, floating-roof tanks also experience working losses. However, these are small by comparison and for purposes of adjusting the emissions inventory, the above factors were used.

APPENDIX A

REFINERY DEMAND FORECASTS

APPENDIX A

REFINERY DEMAND FORECASTS

Projections of refined product requirements for this study have been prepared by reviewing forecasts employed in four recent studies.1 Each study required California refined products forecast, as such, or as part of a larger western area. Growth rates for each major product class from each of these sources are summarized in Table A-1.

All sources show declines in demands for gasoline and residual fuels over the forecast periods involved. In all of these, California accounts for the vast majority of each demand. The forecasts from the Heavy Crude Oil study sponsored by the California Energy Commission and the Natural Gas Study are both newer by approximately one year than those of the other studies and reflect optimistic estimates of the penetration of diesel-powered vehicles into the automobile population. The shorter forecast period and the use of Census Bureau Regions 8 and 9 (roughly equal to PADDs IV and V) prevents more direct comparison of the growth rates from the Natural Gas Study.

---

[1]"Refining and Downstream Impacts of Modifying Diesel Fuel Qualities," Vols. I and II. (Bonner & Moore Associates, Inc.: Houston, Tx., September, 1982) (publication pending);

"Heavy Crude Oil Refining in California and the Residual Oil Surplus," (Booz, Allen & Hamilton Inc.: Menlo Park, California, June, 1981);

"Impacts of Alcohol Fuels on the U.S. Refining Industry," (Bonner & Moore Assoc., Inc.: Houston, Texas, September, 1982);

"Gas and Oil Markets in the United States to 1990 and Beyond: A Confidential Report on Regional Interfuel Competition," (Jensen Assoc., Inc.: Boston, Massachusetts with Bonner & Moore Assoc., Inc.: Houston, Texas, April, 1982).

TABLE A-1

COMPARISON OF PRODUCT DEMAND GROWTH RATES

	API Diesel Study	Alcohol Fuel Study	Hvy. Crude Study	Nat. Gas Study
Forecast Period	1978-1995	1978-2000	1978-2000	1980-1990
Region	PADD V	PADD V	Calif.	CBR8/9
Reginery Demand Growth, Percent Per Year				
Gasoline	-2.0	-1.7	-1.4	-0.9
Jet Fuel	2.9	2.6	0.9	2.4
Dist. Fuel	2.8	2.8	3.1	2.4
Resid. Fuel	-2.9	-2.7	-1.5	-2.5
Lubes, Waxes, Asphalts	-0.7	-0.7	-0.4	1.4

To compare the absolute volumes of these forecasts, it is necessary to adjust each one involving more than California to approximate forecasted volumes for California alone. For the Natural Gas Study, a first adjustment was made to approximate PADD V requirements by subtracting projections for PADD IV (from the Alcohol Fuels Study) from those for Census Bureau Regions 8 and 9. PADD V forecasts were then reduced to California estimates by applying factors for each major product class as follows:

Product Class	California Demand As a Fraction of PADD V Demand
Gasoline	0.80
Jet Fuel	0.78
Dist. Fuel	0.77
Resid Fuel	0.90
LWA	0.82
Petrochemical Naphthas	0.50

These were derived from California refinery outputs and PADD V outputs for 1978. Comparison of the projected California refinery demands is shown graphically in Figure A-1. Also shown are recent refinery output estimates for California. These latter were derived by applying the factors shown earlier to DOE annual petroleum statistics for PADD V.

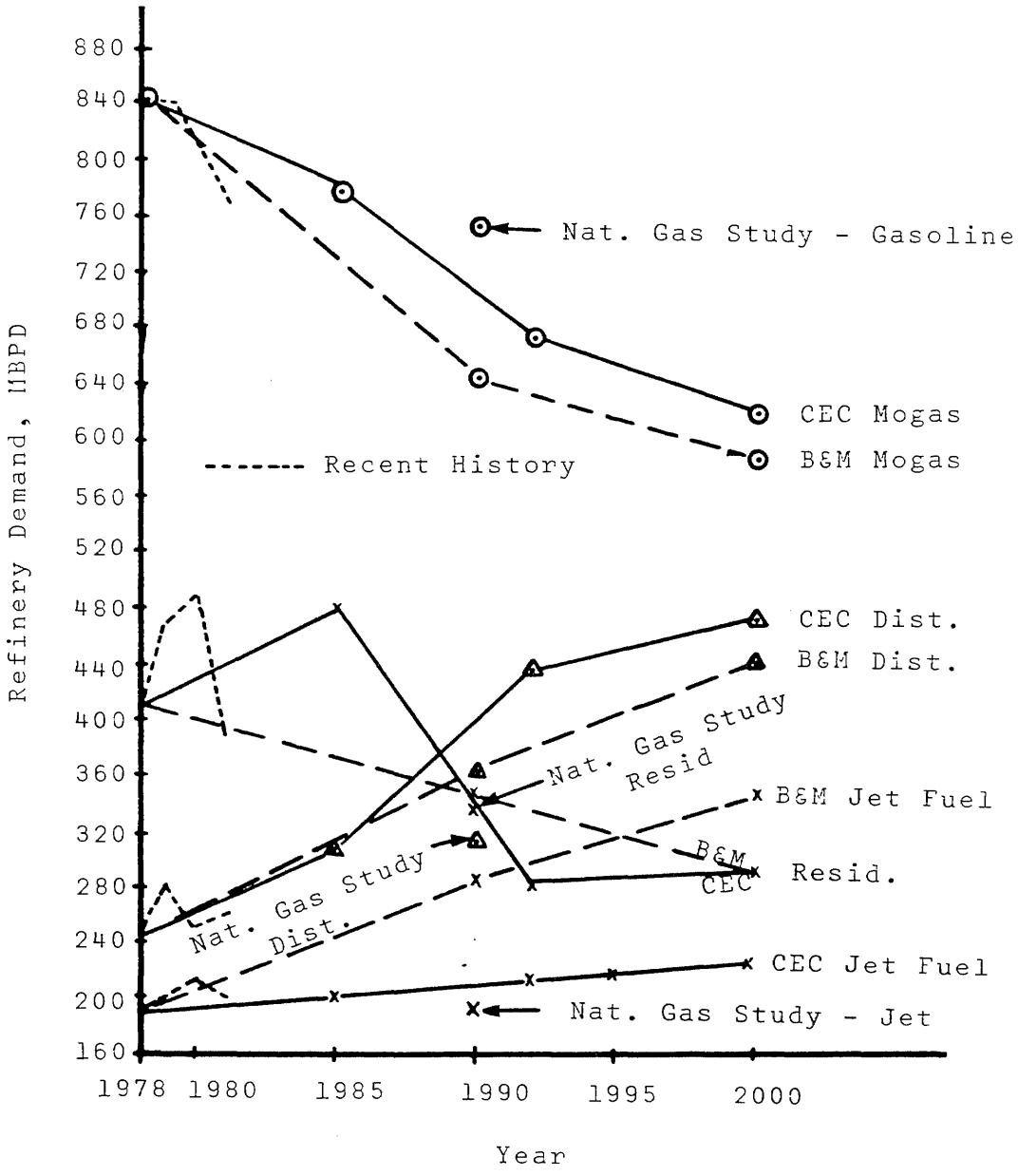

Figure A-1. Refinery Demands Comparison

From this information, the following items have been used to prepare product demand forecasts for this study.

1) Gasoline demand should decline uniformly to the 2000 estimate by CEC, but should be increased by 25,000 barrels per day to reflect our belief that diesel-powered vehicle penetration will be slower than previously estimated.

2) Distillate fuel forecast should follow that shown by the Bonner & Moore projection. This is lower in 2000 than the CEC forecast which corrects for the slower diesel-powered vehicle penetration assumed for this study.

3) Jet fuel should follow the CEC forecast.

4) Residual fuel should follow the Bonner & Moore projection.

5) Petrochemical naphtha, lubes, waxes and asphalt demands should follow the Bonner & Moore projections (not shown in Figure A-1), except that the petrochemicals growth rate is cut in half.

The resulting refined product demands (refinery output) are shown in Table A-2. No projections for LPG and for petroleum coke are shown because these two products will be modeled as by-products rather than fixed demands. Grade distributions for gasolines and residual fuels were derived from those of previous studies.2,3

---

[2]"Impacts of Alcohol Fuels on the U.S.Refining Industry," (Bonner & Moore Assoc., Inc.: Houston, Texas, September, 1982).
[3]"Heavy Crude Oil Refining in California and the Residual Oil Surplus," (Booz, Allen & Hamilton Inc.: Menlo Park, California, June, 1981).

TABLE A-2

REFINED PRODUCT DEMANDS
(MBPD)

	1978[1]	1985	1990
Gasoline			
Leaded Regular	342.4	205	121
Leaded Premium	221.1	0	0
Unleaded Regular	278.0	385	393
Unleaded Premium	0.0	155	196
Subtotal	841.5	745	710
Naphtha Jet Fuel	33.5	36	37
Kero. Jet Fuel[2]	154.5	164	173
Subtotal	188.0	200	210
Distillate Fuels	242.2	310	365
Residual Fuels			
0.25	140.0	151	111
0.5	68.4	86	71
2.0	112.9	35	30
Bunkers	87.0	103	138
Subtotal	408.3	375	350
Petro. Naphtha	17.4	20	22
LWA	78.0	76	75

[1]"1985 California Oil Scenario Study" (Bonner & Moore Assoc., Inc.: Houston, Texas, March, 1980).

[2]Estimated as 0.822 of total.

APPENDIX B

CRUDE SUPPLY FORECAST

APPENDIX B

CRUDE SUPPLY FORECAST

Estimates of future crude availabilities in California have been based on review and revision of projections from two recent studies.1 Comparison of the Bonner & Moore projections for Californian and Alaskan production indicates that:

1) Both are lower than other estimates,

2) Both studies show enough Alaskan North Slope production to exceed estimated requirements, and

3) Neither projection recognizes the potential from recent tests on Santa Maria Basin offshore wells.2

Further analysis of these two projections shows that the decline rate for basic production used in the Bonner & Moore forecast is valid over the previous decade. We, therefore, assume that basic production will continue to decline at this same rate. CEC's estimates for Elk Hills production, based on discussions with DOE and thus deemed more reliable, are higher than those from the Bonner & Moore study. The impact of steam drive and other enhanced recovery measures assumed in the prior Bonner & Moore study appears low compared to the CEC Heavy Crude Oil Study projections.

Based upon this analysis of these two recent projections, the availability estimates shown in Table B-1 were prepared. Adjustments to the CEC projections include:

---

[1]"Impacts of Alcohol Fuels on the U.S. Refining Industry," (Bonner & Moore Assoc., Inc.: Houston, Texas, September, 1982);
"Heavy Crude Oil Refining in California and the Residual Oil Surplus," (Booz, Allen & Hamilton Inc.: Menlo Park, California, June, 1981).

[2]Oil and Gas Journal, Oct. 4, 1982, p. 29.

1) A decline in Elk Hills productin from 200 MBPD in 1980 to 135 MBPD in 2000,

2) Addition of 150 MBPD of new offshore production from the Santa Maria Basin by 1990,

3) Reduction of 1990 foreign imports by dropping all Arabian Gulf crudes, and

4) Balancing estimated total crude requirements with Alaskan North Slope crude.

The projection of an additional 150 MBPD of heavy offshore crude is the main distinction of this forecast from other recent projections. Because the increased offshore crude presumably will back out Alaskan North Slope crude, its effect on this study is increased processing to convert residual material to lighter products than would be required for the North Slope crude. This higher conversion would produce additional light hydrocarbons which would likely be used as refinery fuel. This, in turn, would reduce the value of butanes and pentanes backed out of gasoline to meet tighter summer vapor pressure limits thus making it more expensive to meet these limits.

TABLE B-1

CRUDE SUPPLY PROJECTIONS
(MBPD)

California Crudes	1978	1985	1990
>20°F API			
Elk Hills	120	184	172
Dos Cuadros	34	76	62
Ventura	58	50	39
H. Beach	89	75	66
Coalinga	105	115	109
Subtotal	406	500	448
<20°F API			
Wilmington	136	77	66
Kern River	224	330	343
San Ardo	80	88	69
Santa Ynez	0	40	66
+ Santa Maria Basin	0	0	150
Subtotal	440	535	691
California Total	846	1,035	1,139
Alaskan			
Cook Inlet	80	50	40
ANS (to balance est. total)	470	299	333
Foreign	424	387	268
Est. Total Crude	1,820	1,771	1,780

APPENDIX C

ECONOMIC ASSUMPTIONS

Current opinions on the future crude oil world markets are mixed. We project a real increase in crude oil cost, primarily on the assumption that economic recovery will mean increased demand for petroleum products. One recent study shows a 38-percent increase by 1990. Other investigators predict both increased and decreased real cost of world crude oil. Because the refining cost impacts of this study will include both fuel and capital costs, results would vary with changes in crude cost, but not in direct proportion to such changes. Since, however, fuel costs will be proportional to crude cost, the main effect of varying crude cost would be to shift the balance (chosen during optimization) between capital and raw material costs. Such shifts would have a negligible impact on overall costs, provided crude costs were not changed dramatically.

No one knows, of course, what will happen to crude costs. No one knows, for certain, whether increases or decreases are more likely, although it seems unlikely that crude cost will increase without significant economic recovery.

In view, then, of these uncertainties, it was agreed that a constant crude cost was a good basis, if for no other reason than making comparisons of economic results easier. Cost of other raw materials, excluding natural gas, are also to be held constant, as are prices for by-products.

Natural gas cost, for fuel or for methane feed to hydrogen manufacture, can be expected to increase as a result of price decontrol. A recent study[1] predicts West Coast natural gas price to reach $5.48 per million BTUs by 1985. This is essentially an energy cost equivalent to the current cost of Alaskan North Slope crude landed in Los Angeles, namely, $29.80 per barrel.

Economic factors, prices and costs to be used in this study are summarized in Table C-1.

---

[1] "Gas and Oil Markets in the United States to 1990 and Beyond: A Confidential Report on Regional Interfuel Competition", (Jensen Assoc., Inc.: Boston, Massachusetts with Bonner & Moore Assoc., Inc.: Houston, Texas, April, 1982).

TABLE C-1

SUMMARY OF STUDY ECONOMIC ASSUMPTIONS
(Constant 1982 Dollars)

RAW MATERIAL COSTS, $/BBL	
Alaskan North Slope Crude	$ 29.80
Iso-Butane	32.90
Normal Butane	30.10
Methane (Nat. Gas)	12.37
FUEL COST (NATURAL GAS), $/MM BTU	5.48
BY-PRODUCT PRICES, $/BBL	
LPG, $/BBL	$ 21.00
Petroleum Coke, $/FOEB	4.23
Sulfur, $/S-Ton	54.42
TEL COST, $/42-gm OF METALLIC LEAD	0.286
COST OF CAPITAL, PERCENT PER ANNUM	15
ECONOMIC AND DEPRECIATION LIFE, YEARS	13
INCOME TAX RATE, PERCENT*	51
FIRST YEAR INVESTMENT TAX CREDIT, PERCENT	10
CAPITAL RECOVERY FACTOR, Dollars Per Year Per Dollar Invested**	0.250
MAINTENANCE, INSURANCE, LOCAL TAXES, OVERHEAD Percent of Investment Per Year	6

---

*Effective rate with 46% F.I.T. and 9.6% state income tax rates.

**Assumes double-declining-balance depreciation.

APPENDIX D

SUMMARY OF INTERVIEWS WITH REFINERS

APPENDIX D

SUMMARY OF INTERVIEWS WITH REFINERS

D.1 INTRODUCTION

In order to better understand the various problems that will face refiners if the maximum allowable RVP is reduced on summer gasoline for California, several interviews were held (by telephone) with members of the technical staffs of six California refiners. Except for a few lead-in questions, the interview technique was unstructured. Three large, integrated refiners and three independent refiners were interviewed.

This appendix presents our conclusions from these interviews and is not meant to represent a summary of the opinions expressed or data presented by the refiners.

It must be pointed out that our objective in these interviews was to understand the problems associated with lowering the vapor pressure on gasoline, excluding the side effects of reducing octane number, gasoline volume, etc.

The need for the interviews arose from the fact that a linear programming model of the California refinery industry is the major tool to be used in evaluating the impact on the California refinery industry of the RVP reduction. Although linear programming models have been commonly used for years for refinery operations planning purposes, as well as general industry simulations, extreme caution must be exercised when using such models in studies where the effect of new product specifications, well outside the range of previous experience, is being evaluated. Past successes of a linear programming model are not necessarily proof of the suitability of the model for a new study. Consequently, for this study it was imperative to obtain as full an understanding as possible of where new or previously unimportant processing limitations will arise when gasoline vapor pressure is reduced. It is to be expected that previous linear programming experience will not have represented these limitations.

Results of these interviews are presented under four major headings:

1) Debutanization of major gasoline components,

2) Disposal of surplus light hydrocarbons,

3) Superfractionation versus the disposal of butane/pentane mixtures, and

4) Other concerns expressed by the refiners.

D.2 DEBUTANIZATION OF MAJOR GASOLINE COMPONENTS

Although major gasoline components are usually described as "debutanized", there is a significant amount of C_4s remaining in these streams. Most of the refiners interviewed did not have detailed analyses of the C_4 and C_5 contents of these streams but were able to provide typical RVP data for current summer operations and to express an opinion about possible additional reductions in RVP with present equipment.

There are five generic classes of streams that are important in this regard: (1) light straight-run naphtha, (2) light cracked (both catalytic and thermal) naphtha, (3) light naphtha from hydrocracking, (4) alkylate and (5) reformate. Each is discussed in the following subsections.

D.2.1 Light Straight-Run Naphtha (LSR)

This stream is produced from the crude distillation unit and primarily consists of C_5 and C6 hydrocarbons. Its butane content and vapor pressure are both dependent on crude type and fractionation capability. Typical RVP values range from 7 to 12 pounds with 10 to 11 quite common. Butane contents for the upper range of RVP values probably run four to six percent, although very few of the refiners interviewed had any detailed analyses available and the values given were "educated guesses". Back calculation of the "perfectly debutanized" light straight-run naphtha RVP values would lead to an estimate of 8 to 9 RVP for the remaining portion. This figure appears quite low for the remaining material. It can be expected to be almost entirely a mixture of C_5 and C6 hydrocarbons with similar proportions. Three things could explain this back-calculated low RVP: (1) butane content was over-estimated, (b) the $C_5/C6$ ratio is much lower than would be expected, or (c) there are significant volumes of C_7 hydrocarbons in the stream. We believe over-estimating the butane content accounts for most of the discrepancy.

At any rate, it appears that further debutanization of this stream for vapor pressure reduction is a poor choice for gasoline vapor pressure reduction:

1) For many refiners (especially those processing heavy crudes), the C_4 and lighter fraction goes to the refinery fuel system.

2) A very limited number of trays are available to achieve the C_4/C_5 separation in the crude unit; thus, significant quantities of C_5s would accompany complete C_4 removal. This could produce problems in the refinery gas system by significantly raising the dew point of the gas going to burners and/or compressors with adverse impacts on safety and burner operation.

3) Except for refiners mainly processing light crudes, this stream is a relatively small part of the total gasoline pool.

Some refiners take the C_4 and lighter stream to light ends recovery facilities where the LPG components are recovered. Many of these plants are not equipped to make a C_4/C_5 separation and excessive C_5s in the feed stream would present problems for the marketability of the butane stream.

D.2.2 Light Cracked Naphthas

The typical vapor pressures of 8 to 13 pounds on these streams are quite similar to the LSR RVP, but the similarity ends there:

1) The cracked C_4 and lighter fractions are almost universally processed through special light ends recovery plants to select feeds for alkylation and/or polymerization plants.

2) The end point of cracked naphtha is higher than it is for LSR, so the similar vapor pressures imply higher butane contents for cracked naphtha than for LSR.

3) Increasing C_4 removal without additional fractionation implies more C_5 hydrocarbons going to the alkylation plant. This loads the alkylation plant, degrades alkylate quality somewhat and increases acid consumption. Since the cracked C_4 stream is normally produced as a liquid stream from the cracked naphtha debutanizer, the inclusion of C_5s in it is less troublesome from a safety standpoint than it is from other operations where the C_4s are part of a gas stream.

The C_4 content of the light cracked stream was estimated to be from 3 to 6 volume percent, indicating that from 2 to 4 pounds of the reported vapor pressure on cracked naphthas could be eliminated by perfect removal of the remaining butanes.

We believe that light cracked naphthas are probably the best candidate for the first step of extreme vapor pressure control because:

1) At least some of the C_4s and C_5s removed can be alkylated to make low vapor pressure, high-octane gasoline components, and

2) It is a major gasoline component for complex refineries.

D.2.3 Reformates

These gasoline components are the least troublesome from the standpoint of making low RVP gasoline. Reported RVPs ranged from 3 to 7 pounds, with a C_4 content of 2 to 3 percent. Further reduction of RVP of these would have to be done by taking proportionately significant quantities of C_5s into the refinery fuel system or light ends recovery units.

D.2.4 Alkylates

Alkylate represents another stream that promises very little in the way of gasoline vapor pressure reduction by further debutanization. Reported values for RVP range from 5 to 7 pounds with C_4 contents of 3 to 5 volume percent. The remainder of the RVP is explained by C_5 hydrocarbons that are in the alkylate as a consequence of being a part of the C_4 feed stream to the alkylation plant. Additional C_4 removal would be done only at the expense of including more C_5 hydrocarbons in the C_4 stream from the alkylate fractionator, and this would jeopardize the marketability of these C_4s and/or restrict their use in plant fuel systems.

D.2.5 Light Hydrocrackates

These streams are produced from hydrocrackers and are separated from the remainder of the naphtha produced from the hydrocracker because the light hydrocrackate is not a good reforming feed. In many respects, it is similar to light straight-run naphtha. RVPs were reported to range from 8 to 15 pounds with 3 to 6 volume percent C_4 hydrocarbons. Most of the RVP derives from the C_5 portion which is rich in isopentane. The relatively high isopentane content of this stream complicates the problem of producing marketable C_4s by further debutanization since isopentane is harder to separate from the normal butane than is normal pentane.

D.3 DISPOSAL OF SURPLUS LIGHT HYDROCARBONS

A key item in the overall economic impact of lowering RVP specifications is the disposition of the C_4 hydrocarbons that must be removed from the gasoline pool. Unfortunately, a linear programming model of the refinery industry represents only part of the picture regarding alternate end uses of butanes.

One alternative is burning the butane as plant fuel. There was almost universal agreement that only a small fraction of the C_4s being displaced from gasoline could be disposed of in this way. The reasons are as follows:

1) Steps that have been taken to reduce energy consumption in the refinery have already resulted in backing out almost all refinery discretionary fuel.[1]

2) Refinery fuel systems can take very little additional C_4 or C_5 hydrocarbons without safety problems due to condensation in the fuel system or (at least) burner modifications.

Most refiners describe themselves as sellers of C_4 hydrocarbons during the summer months, although some indicate they are purchasing mixed butanes as an isobutane source (for alkylation) at the same time and might not be a seller if they were purchasing straight isobutane.

Some refiners have the ability to seasonably store normal butane and do so even though the operation incurs significant costs, as well as working capital requirements. Net purchases of C_4s during winter operations seem universal, even with seasonal storage. Consequently, additional seasonal storage, whether operated by the refiner or a separate company, is one potential use for at least part of the rejected summer C_4s.

---

[1]Fuels that are being purchased or which could be sold by the refinery as finished products using present facilities.

Another alternative is for the refiner to make room for C_4s and C_5s as refinery fuel by "cleaning up" the refinery gas streams to a quality suitable for natural gas pipelines and arranging to sell this dry, quality-controlled gas to gas pipeline companies.

Another disposition - not discussed with the refiners - is the dehydrogentation of C_4s to make olefins for alkylation feed. Rough, preliminary estimates indicate that this route would not be the economic choice unless C_4 values are even further below fuel cost than we are postulating.

It is important to point out that all these "novel" ways of utilizing C_4 hydrocarbons may require more lead time to put facilities in place, to make contractual arrangements, etc., than it would take for the refiners to remove light ends from gasoline.

Of course, some of the normal C_4s could be isomerized in new isomerization facilities to back out the purchased isobutane. Whether this is done will be entirely a matter of the difference between the cost, to the refiner, of isobutane and the value (or price he can receive) for normal butanes. It is beyond the scope of this study to predict what might happen to the isobutane price as a consequence of the amount of surplus C_4 the refineries would have to eliminate from gasoline, but there certainly would be some effect. We have chosen to represent purchasing isobutane at constant cost (relative to crude cost) rather than including any new isomerization as an alternative.

D.4 SUPERFRACTIONATION VS. $C_{4/C5}$ DISPOSAL

Disregarding the cost of separation, it is more economical to reduce the RVP of gasoline by removing normal butane than by removing isopentane, even though the butane has slightly better octane ratings. Separating C_{4s} from C_{5s} and heavier has generally been considered to be a relatively simple task, but this view was based on the ability to leave significant amounts of normal butane in the C_5 and heavier product. Meeting extreme RVP specifications, such as 6 pounds, requires essentially complete debutanization of all components going into the motor gasoline pool if the C_{5s} are left in.

Making a clean separation between the C_{4s} and C5s requires both more capital and more energy for the fractionation than would be required if some pentanes are removed with the butanes. Any individual refiner's decision will depend on which streams he has to work with, how light ends are currently processed, his marginal cost for gasoline volume and octane quality, and whether including C_{5s} will affect the value of the butane stream.

The budget constraints for this project will not permit including all the options within the LP model. We have chosen to model the superfractionation possibility such that:

1) It represents relatively little disturbance or interaction with the remaining, time-proven LP model structure, and

2) The total cost implications are not completely out of line with the alternatives of mixed $C_{4/C5}$ dispositions in California.

D.5 OTHER CONCERNS EXPRESSED BY THE REFINERS

A number of other concerns were expressed by the refiners that are outside the scope of this study or that do not involve possible alteration of the LP model. Among those that are outside the scope of the study are the following:

1) The cost of lowering RVP is not independent of other possible regulatory changes dealing with gasoline or other refined products. Particular concern was expressed over further restrictions in the usage of lead in gasoline and the sulfur content of fuels.

2) Results of LP modeling work depends to a great extent on forecasts of: (a) product demands, (b) raw material costs, (c) construction cost indexes, and (d) cost and time requirements to obtain permits for new facilities. These variables are not being considered in the study.

A general and very broad concern was simply whether an aggregate or composite model of the refining industry could express properly the extra costs incurred as a consequence of the fact that each refinery is different. As an example, the industry as a whole may have spare catalytic cracking capacity, whereas some given refiner may not. If RVP reductions caused a need for more cracking capacity, the model would show its being available to all the industry, whereas it is not available to the refiner at capacity in the base case.

This is a valid and common criticism of any model for an industrial segment. The counter-arguments are as follows:

1) While the aggregate model does not represent uncommon limitations present at individual refineries, neither does it show the flexibility offered in having a larger number of processing units and segregated feed streams. Thus, better matching of a

feedstock characteristic to process unit design and operating conditions is possible in the industry as compared to the options presented in the model.

2) The ability to use surplus capacity at one refinery to process surplus feed available at another refinery exists through the mechanism of the purchase/sale of unfinished oils. The purchase/sales dollars remain within the industry, except for the cost of transportation. Thus, ignoring the local limitations is more a matter of ignoring the variation in the impact among refiners than ignoring the cost impact on the industry.

3) In actual fact, the disparity between refineries--so far as the cost impact is concerned--is to a considerable extent reflected by changes in market share for petroleum products. Even if it were possible to model this, which we doubt, we believe it to be improper for any public study to put forth a prediction of which individual refineries will lose and which will gain market share as a consequence of possible regulatory changes. It should remain the individual refiner's job to argue his case, decide how aggressively he should apply his resources to keeping or expanding his market share, etc.

Other expressed concerns will be addressed in the study but do not have a significant impact on the model. These are:

1) Operability of automobiles using the lower vapor pressure fuels.

2) Effect on emissions of use of lower vapor pressure gasoline.

3) Emissions changes from refining operations.

The first of the above questions will have to be addressed in the model, at least partially. In the ASTM recommendation for gasoline fuels (ASTM D-439), there is a recommended maximum temperature for 10 percent distilled as a function of season and location. This maximum temperature is normally a non-limiting specification at conventional vapor pressures--that is, the temperature for the 10-percent-distilled point would be below the maximum allowed even in the absence of such a specification. This may not be true for summer gasoline in Northern California if low RVP regulations are imposed.

APPENDIX E

PRODUCT SPECIFICATIONS

APPENDIX E

PRODUCT SPECIFICATIONS

With the exception of gasoline vapor pressure, all quality restrictions on finished properties have been defined to agree with appropriate ASTM standards or data from surveys of actual products qualities. Gasoline quality specifications have been adjusted to recognize California summer limits as defined by ASTM D-439 and octane quality indicated by recent survey data.[1] These survey data show that marketed fuels, on average, are currently below the maximum allowed distillation temperatures. On occasion, however, refiners do have problems meeting the volatility restrictions and the current 9 lb. RVP limit.

Octane specifications, in particular, are considered confidential by most branded marketers. Required posting represents a minimum average octane (R+M)/2,[2] but does not define minima for either Research or Motor ratings. Typically, these are imposed to assure a predetermined vehicle percentage satisfaction or other marketing policies. As shown in Figures E-1 and E-2, survey sample data cannot be used to identify the Research or Motor minima being imposed. This is because individual marketers are meeting various (R+M)/2 minima and, in doing so, may also be marketing excess quality (referred to as quality giveaway). As indicated by the broken lines of constant (R+M)/2, most of the sampled gasolines have (R+M)/2 values above the values defined by the broken lines. Unleaded premium samples from Northern California show three of the eight samples falling below 91 (R+M)/2 and are, thus, exceptions. Based on these sample ratings, minimum (R+M)/2 levels of 87.5 for unleaded regular, 88.5 for leaded regular and 91.0 for unleaded premium have been selected as industry-wide minima for this study. Motor octane minima were set to

---

[1]Ella Mae Shelton, "Motor Gasoline, Summer 1981". DOE/BETC/PPS-82/1, Bartlesville Energy Technology Center; April, 1982.

[2]Average octane equals 1/2(Research Octane + Motor Octane).

limit the maximum sensitivity (i.e., differences between Research and Motor ratings) of 9, 10 and 12 numbers, respectively. Minimum Research limits, although probably unnecessary, were selected to allow 1.0 to 1.5 numbers variation in Motor ratings at constant (R+M)/2 and to recognize the limits indicated by the sample data shown in Figures E-1 and E-2.

The use of lead alkyl antiknock additive is controlled by governmental regulation. In 1978, historical data[3] indicated that the average lead content was approximately 1.0 gm per gallon of all gasoline. After September 30, 1984, regulations will limit lead content of leaded gasolines to 0.8 gm per gallon.

The 1978 calibration case represents yearly average operations which require imposing an RVP limit of 10.2 psi. Subject cases for 1985 and 1990 represent summer operations and will be limited to the present 9 psi maximum and for cases representing further restrictions to 8, 7 and 6 psi limits. To these latter, a blending tolerance must be applied to prevent production of a fuel that could test above the regulated limit and to allow for the repressuring resulting from blending back hydrocarbons captured via vapor recovery. A tolerance of 0.3 psi has been used in this study but should not be taken as the value used by any specific refiner because actual tolerances depend on the experience and operating policies of each manufacturer.

A summary of quality restrictions for all blended products is shown in Table E-1.

---

[3]"Public Hearing to Consider Amendments to Section 2253 and Adoption of Section 2252 of Title 13, California Administrative Code, Regarding Lead in Gasoline", Air Resources Board of California, September 1982, p. 19 and 26.

Figure E-1. Octane Quality, Summer 1981, Southern California

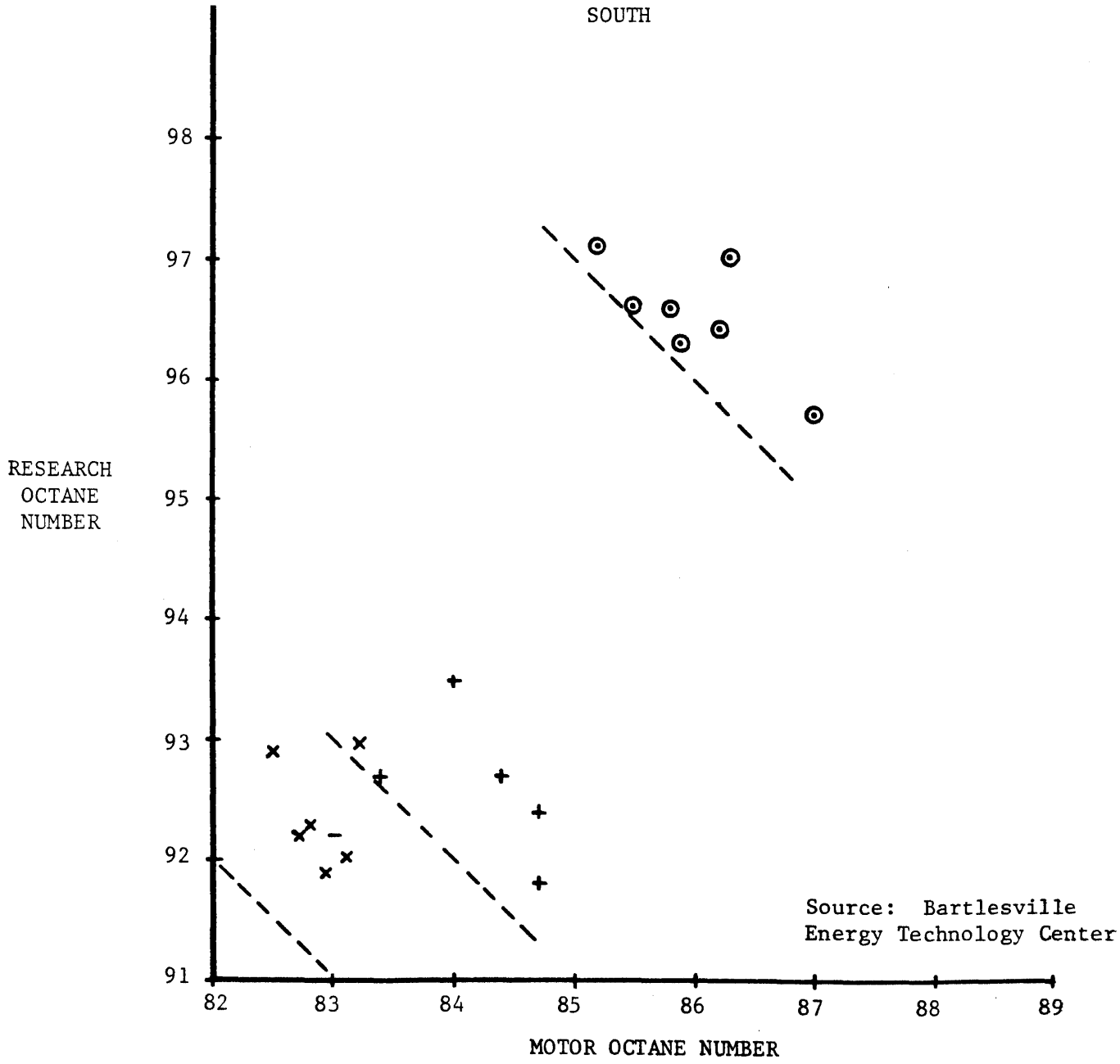

Figure E-2. Octane Quality, Summer 1981, Northern California

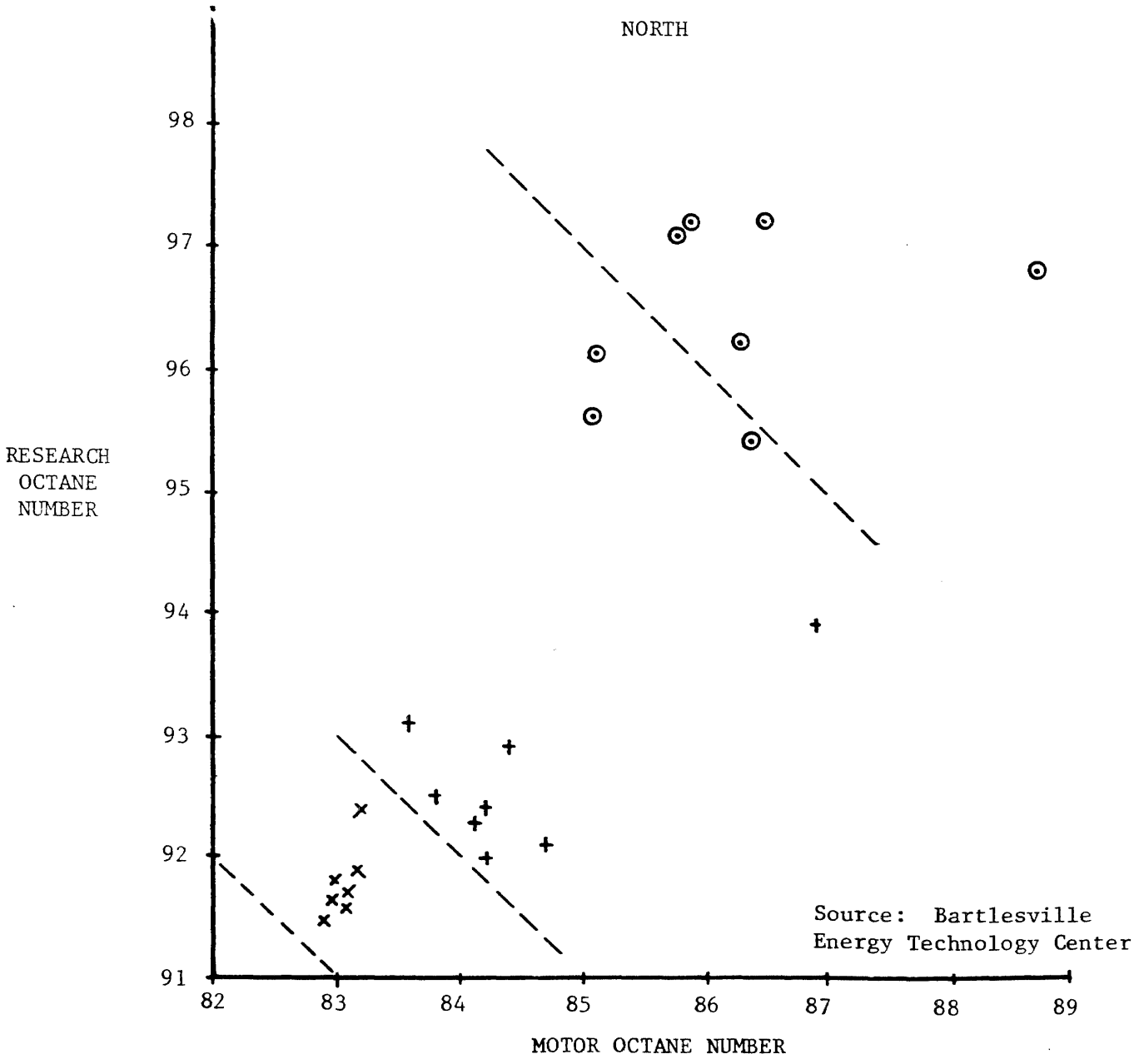

TABLE E-1

PRODUCT SPECIFICATION SUMMARY
(Sheet 1 of 4)

SPECIFICATION SUMMARY FOR LPG

Property	Minimum	Maximum
Percent Olefins		50.00
Percent Butanes		2.50

SPECIFICATION SUMMARY FOR LEADED REGULAR

Property	Minimum	Maximum
Tel, gm/Gal		0.80
(R+M)/2 Octane	88.5	
Research Octane	92.0	
Motor Octane	83.5	
Reid Vapor Pressure		9.00
Pct Off at 160 F	14.00	35.00
Pct Off at 210 F	35.00	57.00
Pct Off at 230 F	44.00	
Pct Off at 330 F	81.00	98.00
Weight Pct Sulfur		0.15

SPECIFICATION SUMMARY FOR UNLEADED REGULAR

Property	Minimum	Maximum
(R+M)/2 Octane	87.50	
Research On Clear	91.00	
Motor On Clear	83.00	
Reid Vapor Pressure		9.00
Pct Off at 160 F	14.00	35.00
Pct Off at 210 F	35.00	57.00
Pct Off at 230 F	44.00	
Pct Off at 330 F	81.00	98.00
Weight Pct Sulfur		0.03

TABLE E-1

PRODUCT SPECIFICATION SUMMARY
(Sheet 2 of 4)

SPECIFICATION SUMMARY FOR UNLEADED PREMIUM

Property	Minimum	Maximum
(R+M)/2 Octane	91.00	
Research On Clear	95.50	
Motor On Clear	85.00	
Reid Vapor Pressure		9.00
Pct Off at 160 F	14.00	35.00
Pct Off at 210 F	35.00	57.00
Pct Off at 230 F	44.00	
Pct Off at 330 F	81.00	98.00
Weight Pct Sulfur		0.03

SPECIFICATION SUMMARY FOR NAPHTHA JET

Property	Minimum	Maximum
Specific Gravity	0.75	0.80
Pct Off at 400 F	60.00	
Percent Aromatics		25.00
Weight Pct Sulfur		0.40
Smoke Pt. Est.	20.00	

SPECIFICATION SUMMARY FOR KERO JET

Property	Minimum	Maximum
Specific Gravity	0.77	0.84
Pct Off at 400 F	10.00	
Percent Aromatics		25.00
Weight Pct Sulfur		0.10
Smoke Pt. Est.	18.00	
Flash, Deg F	100.00	

SPECIFICATION SUMMARY FOR LOW SULFUR FUEL

Property	Minimum	Maximum
Pct Off at 400 F	10.00	

TABLE E-1

PRODUCT SPECIFICATION SUMMARY
(Sheet 3 of 4)

SPECIFICATION SUMMARY FOR LOW S NO.2 FUEL OIL

Property	Minimum	Maximum
Weight Pct Sulfur		0.05
Cetane Blending No	42.00	
Flash, Deg F	125.00	
Pour Point, Deg F		500.00

SPECIFICATION SUMMARY FOR NO.2 FUEL OIL

Property	Minimum	Maximum
Specific Gravity		0.88
Pct Off at 400 F	10.00	
Weight Pct Sulfur		0.30
Cetane Blending No	42.00	
Flash, Deg F	125.00	
Pour Point, Deg F		500.00

SPECIFICATION SUMMARY FOR 0.25%S RESID

Property	Minimum	Maximum
Weight Pct Sulfur		0.25
Flash, Deg F	150.0	
Viscosity, SSF/122		300.00

SPECIFICATION SUMMARY FOR 0.5%S RESID

Property	Minimum	Maximum
Weight Pct Sulfur		0.50
Flash, Deg F	150.00	
Viscosity, SSF/122		300.00

TABLE E-1

PRODUCT SPECIFICATION SUMMARY
(Sheet 4 of 4)

SPECIFICATION SUMMARY FOR 2.0%S RESID

Property	Minimum	Maximum
Specific Gravity		0.997
Weight Pct Sulfur		2.00
Flash, Deg F	150.00	
Viscosity, SSF/122		300.00

SPECIFICATION SUMMARY FOR BUNKERS

Property	Minimum	Maximum
Specific Gravity		0.997
Weight Pct Sulfur		3.00
Flash, Deg F	150.00	
Viscosity, SSF/122		300.00

Petrochemical naphtha and LWA (lubes, waxes and asphalts) are represented as fixed formula blends since their manufacture has little interaction with fuel products production. The main purpose of modeling the production and sale of these specialty products is to account for the volumes of hydrocarbons, of proper boiling range, that are needed to satisfy the projected demands.

Petrochemical naphtha is any blend of virgin or hydrocracked material boiling between approximately 80°F and 400°F. LWA is any blend of vacuum distillation products from California crudes as long as the mix contains 12.5 percent 700-930°F gas oil, 5.5 percent 650-700°F gas oil and 0.07 percent kerosene.

APPENDIX F

MODELING

APPENDIX F

MODELING

REFINERY ENERGY DEMAND MODELING

Energy consumption within the refining industry is always a point of interest in any study dealing with changes in petroleum product demand, product quality specifications or the nature (quality) of crude oils available. Such studies usually depend on an estimate (forecast, projection) of the demand for petroleum products that includes the energy demand for the petroleum refining industry itself. Alternative cases normally hold these demands fixed--as was done in this study. For this study, however, the variation in refining energy use must be recognized by changes in product demands in both simulation results and in final estimates of added refining costs since changes in energy consumption are part of the total cost impact of the alternatives under study.

Additional complications seem to appear when it is realized that the marginal fuel for the refinery is often natural gas, not a refinery product. Many refiners also purchase electricity from the utility companies; thus, variations in electrical power usage among study alternatives imply variations in energy consumption by the utilities supplying electricity to refineries.

To get around these problems, the following assumptions have been made regarding the significance of the base case petroleum product forecast and the overall energy balance for the region under study:

1) The base case forecast for refined products includes refining energy demand and all fuel for utility energy forms supplied to the refining industry.

2) The marginal energy source for all industrial energy, including utilities, is derived from petroleum products.

3) The cost and energy impacts calculated for an alternative under study will include cost of energy impacts for the utilities supplying energy to the refining industry as well as those impacts that relate solely to the refining industry.

Even though the refinery's marginal energy sources may be natural gas, purchased electricity, and possibly steam, these assumptions lead to the conclusion that for regional refining studies the effective marginal energy source for the refinery must be modeled as refinery products. If a refinery uses more natural gas, some interruptible user will get less and substitute refined fuel to compensate for the loss in gas availability.

Energy-use accounting is accomplished as follows:

1) A mix of refinery fuel products is defined to serve as the marginal industrial energy source. In this study, marginal energy was defined as the forecast ratio of low-sulfur and medium-sulfur fuel oil.

2) The base case is run using "raw" Btu as the refining industry energy source. Refinery steam and electrical power are generated internally and reflect operating as well as capital costs. The raw Btu cost will be an estimate of the cost of energy from the marginal industrial energy fuel mix.

3) A portion of the base case new energy use is then interpreted as having come from the petroleum product mix defined in (1) above. Notice that this does not necessarily imply that these fuels were burned within the refinery. It allows for a potential refined product demand change caused by changes in refinery energy usage.

4) The refinery raw Btu input, to be allowed in subsequent cases, is restricted to the amount utilized in the base case, 2) above, less the Btu equivalent of the fuels determined in step 3).

5) The external product demand is reduced to account for having moved the fuels determined in step 3) to an internal and variable demand.

6) Refinery energy is then allowed to come from raw energy, now fixed, plus the mix of products defined in step 1).

7) Depending on the magnitude of the discrepancy between the cost of energy used in step 1) and the cost of energy as industry-marginal fuel, a value that can be derived from the step 2) result, the base case may be rerun.

A rerun of the base case must provide a modest improvement in accuracy of the estimated cost of energy and energy impacts for an alternative case.

All subject cases would be run with fixed raw energy input and correspondingly the reduced, non-marginal, product demands.

VAPOR PRESSURE CONTROL MODELING

Three grades of gasoline are represented in the industry-wide LP model employed in this study. Each is constrained to satisfy property specifications as defined in Appendix E, Table E-1. Component blending values for each of the constrained properties are based on properties of conventionally prepared stocks. Distillation and vapor pressure characteristics, therefore, reflect use of existing distillation and stabilization facilities. Design of these processes, for the most part, is based on gasoline blending which includes the intentional addition of normal (or mixed normal and iso) butane to reach the maximum allowed vapor pressure. Thus, there was no reason to design or operate stabilization facilities to remove all butanes, with or without precise separation between butanes and pentanes.

For current summer gasoline manufacture, some intentional blending of butane is used. With lower limits on maximum vapor pressure, intentional blending of butane must be reduced or eliminated. Should even lower vapor pressures be imposed, additional processing of gasoline stocks would be required to remove butanes left in stocks by present operations. Disposition of these butanes would determine whether pentanes, if allowed, could be tolerated and to what extent. Such requirements will vary with each refiner's situation. Since it appears that achieving a 6-psi RVP limit would require removal of some pentanes along with all butanes, this extreme could affect the design and operation of any new fractionation facilities. In all cases, the new facilities would operate only during the summer gasoline season, thus implying either seasonal use of the rejected light hydrocarbons or seasonal storage facilities to smooth their availability.

The modeling approach of this study, because the model represents an industry-wide composite, ignores any alternative disposition of rejected butane and pentane fractions other than to industrial energy. It also employs generic properties for gasoline blend stocks. One such property, added for this study, is the estimated content of removable butanes and pentanes for each stock, based on current operations with current facilities. If ceasing to blend intentional butane will not meet the imposed vapor pressure limit, the model can remove some or all of the "removable" butanes by employing a new fractionation facility for which it must also pay appropriate capital and operating costs. Should removal of all "removable" butane be inadequate, certain prime pentane-containing streams can be processed to remove some of their pentanes. These streams are light straight-run naphtha, light hydrocrackate and catalytically (or thermally) cracked stocks. Appropriate capital and operating costs are incurred, should pentane removal be required.

Since the quantity of energy represented by butanes and pentanes removed from gasoline is one of the results derived from the study, the capital required to utilize these hydrocarbons as a boiler fuel or as a petrochemical feedstock cannot be included in the model (they are not proportional to the quantity of rejected hydrocarbons). Further, the choice of disposition could vary among refiners depending on each situation and, in particular, on matters other than process economics in general.

As a consequence, it was necessary to make post-model-results determinations of the capital requirements. This involved assuming that all rejected hydrocarbons would be used in burners or as feedstock to petrochemical processing. The latter could be as pyrolysis feed or to dehydrogenation and subsequent olefin utilization, such as methyl tertiary butyl ether (MTBE) production. Obviously, estimating the market potential for products from these kinds of processes is beyond the scope of this study.

APPENDIX G

VEHICLE EMISSIONS, PERFORMANCE, AND SAFETY

APPENDIX G

VEHICLE EMISSIONS, PERFORMANCE, AND SAFETY

G.1 DEFINITION OF TERMS

It is assumed that the reader of this report is familiar with technical terms in general use relative to motor fuels and related technology. Therefore, we herein define only those terms of less general use but to which reference is made in this report.

G.1.1 Front End Volatility Index (FEVI)

An expression in which Reid Vapor Pressure value and the value for percent evaporated at 160°F are combined to provide a low-boiling volatility characteristic for gasoline--often expressed as gasoline "front-end volatility".

G.1.2 Modified Reid Vapor Pressure

A vapor pressure characteristic whose value is determined experimentally following the procedure for Reid Vapor Pressure determination except that the measurement is made with the gasoline sample held at a temperature of 130°F instead of the 100°F called for in the Reid determination.

G.1.3 Driveability Demerits

Values to rate driveability of a vehicle, assigned to performance deficiencies or malfunctions that occur during testing. In "weighted element" rating, differing values may be assigned to each of the recognized driving problems or deficiencies, e.g., engine stall--the values, one relative to another, being indicative of the seriousness of the malfunction. The sum of the weighted elements, TWD, provides a single measure of the overall performance deficiency observed in a rated driveability test.

G.2 VEHICLE PERFORMANCE - UNPUBLISHED DATA

Chevron Research rated driveability of eight 1973-76 model cars operated on 6.5 and on 8.5 RVP fuels. Results, including fuel economy were:

	Test Temp.	8.5 RVP Fuel (11.8 FEVI)	6.5 RVP Fuel (8.3 FEVI)
Fuel Economy, miles per gallon	75°F	12.4	12.6
	55	12.1	12.1
Fuel Economy, miles per 100,000 Btu	75	11.0	10.9
	55	10.7	10.5
Driveability Demerits	75	8.1	18.11
	55	9.6	33.8
Stalls per 100 Starts	75	6.3	31.3
	55	12.5	50.0

In another series of tests (1976) with five cars tested for driveability at temperatures between 45 and 75°F, Chevron reported:

For 12.7 FEVI fuel an average of 86 TWD[1]
For 8.4 FEVI fuel an average of 145 TWD[1]

G.3 VEHICLE EMISSIONS - UNPUBLISHED DATA

Reference is made in the report to unpublished data by Mobil (December 1982) wherein reduction of RVP within the approximate range of 6 to 9 RVP had no measurable effect on evaporative emissions from three 1978/79 cars. Those data are given in Table G-1 and shown in Figure G-1. Additional data were provided by Mobil (March '83) from tests with 6, 8, 9 and 12 RVP fuels used in two 1983 vehicles.[2] Results from tests with the 1983 vehicles are provided in Table G-2. Also provided in that table, for comparison, are the calculated emissions both as measured in the tests and as would be predicted from the fuel-data/emissions relationships from reference 6 of Section 4 and as used in calculations to obtain evaporative loss adjustment factors reported in Section 4.1.1.

It will be noted that the RVP effect actually measured is markedly less than that which would be predicted from experience with the mid-70's vehicles.

---

[1]Values as read from graphed data.
[2]These 1983 data were received at a late date which precluded their use in the initial preparation of data for this study.

TABLE G-1

EVAPORATIVE EMISSIONS

Vehicle	Evaporative Emissions, grams					
	Fuel 1	Fuel 2	Fuel 3	Fuel 4	Fuel 5	Fuel 6
Fuel RVP	5.7	6.4	9.1	8.9	11.6	13
% @ 158°F	11	19.4	22.6	28	29.6	34.5
1978 Chevrolet Impala						
Diurnal	0.49	0.67	1.19	1.20	9.07	18.68
Hot Soak	0.84	1.28	0.86	1.05	1.08	1.01
Total	1.32	1.96	2.05	2.24	10.15	19.68
1979 Ford Fairmont						
Diurnal	0.43	--	0.26	0.35	0.75	3.24
Hot Soak	1.05	--	0.91	3.87	4.67	6.25
Total	1.48	--	1.16	4.22	5.41	9.52
1979 Mercury Marquis[1]						
Diurnal	1.06	1.31	0.70	0.93	--	0.63
Hot Soak	1.88	3.04	2.23	2.57	--	1.75
Total	2.94	4.35	2.93	3.51	--	2.38

NOTE: All results are the average of two or more tests.

---

[1]Two carbon canisters

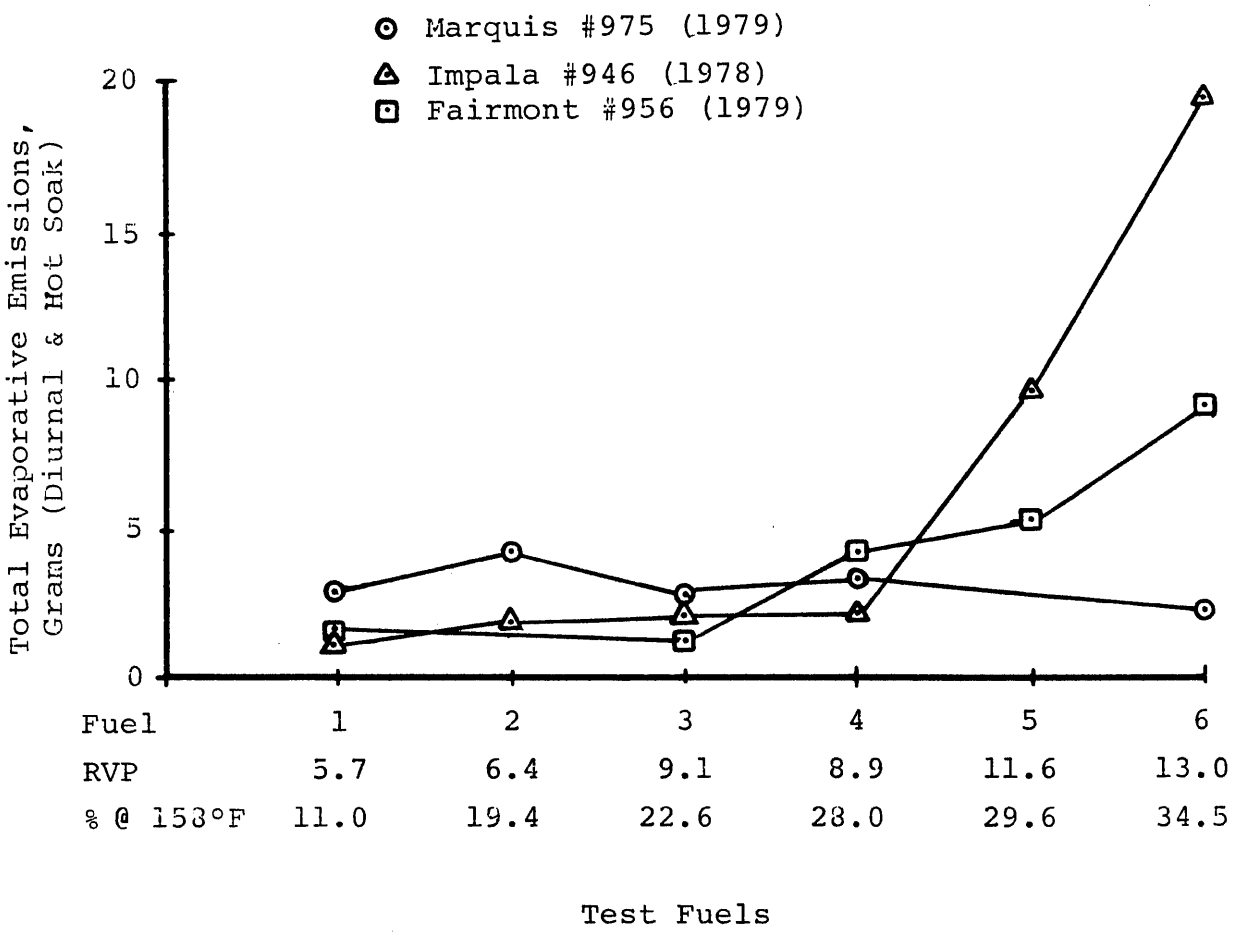

FIGURE G-1. Total Evaporative Emissions

TABLE G-2

EVAPORATIVE EMISSIONS SUMMARY

(Two 1983 Vehicles)

	Test Fuel Nominal RVP (--) % Evap @ 158°F			
	6 (12.2)	8 (17.3)	9 (21.3)	12 (25.2)
1983 Dodge Aries				
Diurnal, gm.	0.38	0.42	0.76	2.07
Hot Soak, gm.	0.94	0.86	0.92	1.02
Total, gm.	1.32	1.28	1.68	3.09
Equiv. gm/mile[1]	0.137	0.128	0.145	
Calc. gm/mile[2]	0.134	0.309	0.485	
1983 Buick Regal				
Diurnal, gm.	0.48	0.55	0.64	1.06
Hot Soak, gm.	0.89	0.88	0.92	0.91
Total, gm.	1.37	1.43	1.56	1.97
Equiv. gm/mile	0.133	0.134	0.142	
Calc. gm/mile[2]	0.134	0.309	0.485	

NOTE: Results of 9 lb. fuel are average of triplicate tests. All others are average of duplicate tests.

---

[1]Calculated after the procedure used for API 4310:

$$\text{gm/mi} = \frac{\text{Diurnal loss} + 4.7\ (\text{Hot Soak loss})}{35}$$

[2]Calculated from fuel data using the relationships form ref. 6, i.e., the relationships used in calculations to obtain the evaporative emissions factors for 1985/90 fuels.

G.4 EXPLOSIVITY OF FUEL TANK VAPORS

With conventional gasolines used in California under virtually all conditions that might be encountered, the equilibrium hydrocarbon vapors and air mixture in fuel tank vapor space are at concentrations well above the rich flammability limit. However, at some lower level of RVP, a hazard is introduced wherein fuel tank vapor space may become explosive at some temperature below normal summer ambient. Such reduced temperatures may be encountered only infrequently and only in geographical areas of limited extent, yet the possible consequences of infrequent and isolated events could, nonetheless, be grave. It is therefore prudent to determine those conditions under which fuel tank vapors might be explosive.

Calculations were therefore made to determine hydrocarbon concentration in the vapor/air mixture above gasoline at reduced RVP levels. Calculations spanned those temperatures at which vapor/air ratios were shown to pass from the overly-rich into the flammable range. Calculations were made following estimating procedures derived from information in NACA Technical Note No. 3276 published in 1956. Briefly these procedures involved:

1) Calculating the true vapor pressure of the gasoline at varied temperature using RVP and estimated 10% slope data for the gasoline at each RVP level studied.

2) Estimating the average heat of combustion and molecular weight of hydrocarbon in the vapor at each condition.

3) Using emperical relationships described in NACA TN 3276 to determine hydrocarbon concentrations and flammability limits associated with the vapor states as found in 1) and 2).

Data are provided in Table G-3 for those combinations of RVP and temperature that may be of interest in connection with gasoline volatility reduction in California.

TABLE G-3

FLAMMABILITY CHARACTERISTICS OF GASOLINE

RVP	Temp.	Fuel Vap. Press., psia	HC Conc., Vol. Pct.	Rich Flammability Limit, Vol. Pct.
5.7	20	1.01	6.92	8.67
	25	1.15	7.87	8.65
	30	1.31	8.93	8.63
	35	1.48	10.1	8.61
6.2	20	1.12	7.66	8.76
	25	1.27	8.7	8.74
	30	1.44	9.86	8.72
	35	1.63	11.13	8.7
6.7	20	1.23	8.41	8.85
	25	1.4	9.55	8.83
	30	1.58	10.8	8.81
	35	1.79	12.18	8.79
7.2	20	1.34	9.18	8.94
	25	1.52	10.4	8.92
	30	1.72	11.75	8.9
	35	1.94	13.24	8.88
7.7	20	1.46	9.95	9.02
	25	1.65	11.26	9.0
	30	1.86	12.71	8.98
	35	2.1	14.3	8.96

NOTE: Values calculated for 10% slope = 1.5°F per 1% evaporated and for fuel tank vapor space to liquid volume ratio = 40.

APPENDIX H

VEHICLE EMISSIONS DETAIL

APPENDIX H

VEHICLE EMISSIONS DETAIL

Predicted vehicle emissions for 1985 and 1990 were supplied by ARB in the form of computer-prepared reports. Tables H-1 and H-2 are re-typed versions of these reports. Retyping was done to improve readability. Addition performed by word processing software was used to provide proofing and has resulted in discrepancies in the last digits of some totals because the computer-prepared reports presented rounded entries and totals.

TABLE H-1

PREDICTED CALIFORNIA VEHICLE EMISSIONS

Year: 1985
Emission Unit: Short Ton
Based on EMFAC6C Emission Factors

Run Date: March 13, 1982
Time Interval: 24 Hour(s)
Altitude: <3500 Feet
Temperature: 75 F

	LIGHT DUTY PASSENGERS			LIGHT DUTY TRUCKS			MEDIUM DUTY TRUCKS			HEAVY DUTY TRUCKS		MOTOR-CYCLES	TOTAL ALL VEHICLES
	CAT	NON-CAT	TOTAL	CAT	NON-CAT	TOTAL	CAT	NON-CAT	TOTAL	GASOLINE	DIESEL		
Number of In Use Vehicles	11228618	1773485	13002103	1847171	734479	2581650	495257	306128	801385	403757	209583	865824	17864302
Daily VMT in Thousand Miles	317532	24378	341910	58379	10386	68765	15899	4746	20645	12945	26372	4509	475146
Number of Daily Trips	43236048	3319399	46555447	8007886	1424534	9432470	2181698	651307	2833005	3652528	0	523400	62996850
HYDROCARBON EMISSIONS													
Running Exhaust	150.53	89.14	239.67	28.18	39.20	67.37	7.80	21.63	29.43	52.79	59.02	8.68	456.97
Cold Start Exhaust	201.66	18.07	219.73	38.59	9.11	47.70	10.81	4.30	15.11	0.00	0.00	1.54	284.08
Hot Start Exhaust	89.95	9.23	99.18	17.50	5.88	23.37	4.59	2.17	6.76	0.00	0.00	0.77	130.09
Total Exhaust	442.14	116.44	558.58	84.27	54.19	138.44	23.20	28.10	51.30	52.79	59.02	10.99	871.14
Fuel Tank Evap	35.95	29.78	65.73	4.91	14.16	19.07	0.75	7.29	8.04	5.04	0.00	6.39	104.28
Hot Soak Evap	79.14	35.40	114.54	12.20	16.54	28.74	1.70	5.60	7.31	12.53	0.00	2.13	165.24
Crankcase	0.00	0.90	0.00	0.86	0.86	0.86	0.00	0.25	0.25	0.34	0.00	0.03	2.37
Total HC Emissions	557.23	182.52	738.85	102.24	85.75	187.11	25.65	41.24	66.90	70.70	59.02	19.54	1143.03
CARBON MONOXIDE EMISSIONS													
Running Exhaust	2130.24	880.81	3011.04	411.80	387.09	798.89	115.21	226.81	342.02	1585.19	186.64	48.34	5972.11
Cold Start Exhaust	3101.57	245.05	3346.62	607.81	118.03	725.84	171.12	55.75	226.88	0.00	0.00	11.60	4310.93
Hot Start Exhaust	291.15	37.02	328.17	58.32	19.55	77.87	15.53	6.69	22.22	0.00	0.00	1.46	429.73
Total CO Emissions	5522.96	1162.88	6685.83	1077.93	524.67	1602.60	301.86	289.25	591.12	1585.19	186.64	61.40	10712.77
OXIDES OF NITROGEN EMISSIONS													
Running Exhaust	486.17	83.77	569.94	113.17	36.63	149.80	32.39	25.61	57.99	119.51	559.34	3.30	1459.89
Cold Start Exhaust	49.84	4.92	54.76	10.97	2.10	13.07	3.13	1.44	4.57	0.00	0.00	0.20	72.60
Hot Start Exhaust	13.40	11.84	25.24	3.17	4.39	7.55	0.89	3.45	4.35	0.00	0.00	0.47	37.61
Total NOX Emissions	549.41	100.53	649.94	127.31	43.12	170.42	36.41	30.50	66.91	119.51	559.34	3.97	1570.10
Particulates	88.22	14.63	102.85	16.21	5.65	21.86	4.42	2.85	7.27	14.06	57.43	0.35	203.82
Lead	0.69	3.11	3.79	0.19	1.29	1.48	0.08	0.82	0.90	4.12	0.0	0.16	10.46
Oxides - Sulfur	23.71	4.17	27.87	5.67	1.67	7.34	2.42	1.08	3.50	6.72	93.31	0.20	138.96
Fuel Consumed in 1000 Gallons	13644.60	1569.20	15213.80	3236.59	666.79	3903.39	1435.10	424.10	1859.20	2294.36	4832.76	93.62	28197.09

Bonner & Moore Management Science

TABLE H-2

PREDICTED CALIFORNIA VEHICLE EMISSIONS

Year: 1990
Emission Unit: Short Ton
Based on EMFAC6C Emission Factors

Run Date: March 13, 1982
Time Interval: 24 Hour(s)
Altitude: <3500 Feet
Temperature: 75 F

	LIGHT DUTY PASSENGERS			LIGHT DUTY TRUCKS			MEDIUM DUTY TRUCKS			HEAVY DUTY TRUCKS		MOTOR-CYCLES	TOTAL ALL VEHICLES
	CAT	NON-CAT	TOTAL	CAT	NON-CAT	TOTAL	CAT	NON-CAT	TOTAL	GASOLINE	DIESEL		
Number of In Use Vehicles	13910590	480664	14391254	2599011	395241	2994252	761436	166575	928011	468385	269060	998232	20042194
Daily VMT in Thousand Miles	373421	5302	378723	75072	4683	79755	21857	2043	23900	15013	33845	5196	536432
Number of Daily Trips	50841344	721885	51563229	10296549	642235	10938784	3000070	280487	3280557	4237289	0	603149	70623008
HYDROCARBON EMISSIONS													
Running Exhaust	170.89	18.97	189.86	35.05	15.71	50.76	10.59	9.46	20.05	49.81	67.05	8.24	385.77
Cold Start Exhaust	227.72	4.09	231.82	47.43	4.12	51.55	14.34	1.90	16.25	0.00	0.00	1.50	301.11
Hot Start Exhaust	102.24	2.16	104.40	21.77	2.78	24.54	6.23	0.97	7.20	0.00	0.00	0.76	136.90
Total Exhaust	500.85	25.22	526.08	104.25	22.61	126.85	31.16	12.33	43.50	49.81	67.05	10.50	823.78
Fuel Tank Evap	23.31	8.50	31.80	4.64	7.31	11.95	1.00	3.87	4.87	3.28	0.00	3.77	55.68
Hot Soak Evap	44.21	8.12	52.33	9.61	7.51	17.12	2.08	2.43	4.51	8.59	0.00	0.96	83.51
Crankcase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total HC Emissions	568.37	41.84	610.21	118.50	37.43	155.92	34.24	18.63	52.88	61.68	67.05	15.23	962.97
CARBON MONOXIDE EMISSIONS													
Running Exhaust	2228.67	197.49	2426.16	472.89	165.14	638.03	140.56	99.39	239.96	1118.34	236.44	52.22	4711.15
Cold Start Exhaust	3228.39	56.14	3284.53	693.11	55.64	748.75	206.48	24.67	231.15	0.00	0.00	12.83	4277.25
Hot Start Exhaust	304.93	7.58	312.51	66.99	8.67	75.66	18.96	2.91	21.87	0.00	0.00	1.59	411.64
Total CO Emissions	5761.99	261.21	6023.20	1232.99	229.45	1462.44	366.00	126.97	492.98	1118.34	236.44	66.64	9400.04
OXIDES OF NITROGEN EMISSIONS													
Running Exhaust	418.24	19.17	437.42	119.59	17.43	137.02	38.67	11.17	49.83	116.65	588.59	3.87	1333.39
Cold Start Exhaust	42.84	1.12	43.96	11.81	1.03	12.84	3.88	0.63	4.51	0.00	0.00	0.24	61.54
Hot Start Exhaust	11.53	2.70	14.23	3.34	2.15	5.49	1.07	1.50	2.57	0.00	0.00	0.55	22.84
Total NOX Emissions	472.61	22.99	495.61	134.74	20.61	155.35	43.62	13.30	56.91	116.65	588.59	4.66	1417.77
Particulates	103.75	3.18	106.93	20.85	2.56	23.41	6.07	1.23	7.30	11.58	73.70	0.37	223.29
Lead	0.80	0.81	1.61	0.24	0.70	0.94	0.12	0.42	0.54	5.71	0.00	0.23	9.02
Oxides - Sulfur	23.82	0.90	24.72	7.29	0.75	8.04	3.33	0.47	3.79	7.80	119.76	0.23	164.34
Fuel Consumed in 1000 Gallons	13783.11	339.80	14122.91	4156.43	298.82	4455.25	1972.76	182.78	2155.54	2658.15	6202.21	106.27	29700.32