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Cost of Reducing Aromatics and Sulfur Levels in Motor Vehicle Fuels

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ABSTRACT

Aromatics in gasoline and diesel along with sulfur in diesel are significant contributors to automotive emissions. In this study linear programming (LP) models were developed for five refineries representative of the California refining industry and validated against historic operation. Process options to reduce gasoline and diesel contaminants were selected and represented in the LP models. The models were then used to estimate the costs of separately reducing aromatics levels in automotive gasoline, aromatics in diesel and sulfur in diesel for 1991 and 1995 based on CEC forecasts of refinery crude slate, product demands and prices. The model cost impacts were scaled up to obtain the overall cost impact in California.

Estimates were made of the impact on total aromatics and benzene in gasoline and of sulfur, aromatics and cetane levels in diesel. Finally, estimates were made of the impact of improving automotive fuel quality on refinery emissions, automotive emissions and automotive performance.

It was concluded that gasoline and diesel contaminant levels could only be reduced marginally in existing refineries but could be reduced substantially with the addition of process capacity. The cost to reduce diesel sulfur level to .05% was estimated at 6.3¢/gallon and 0.3 billion $ investment. The cost to reduce diesel aromatics level to 10% was 27.6¢/gallon and 1.4 billion $ investment. The cost to reduce gasoline aromatics levels by 18% was 7.0¢/gallon and 1.4 billion $ investment.

Reductions in contaminant levels could be achieved through purchase of high quality feedstocks from outside California, but it is uncertain if these feedstocks would be available.

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- Eugene Motte, Unocal;
- Jim Edwards, Mobil Research;
- Brian Wood, UOP Inc.;
- Dale Rodman, California Energy Commission; and
- Dr. Frederick Bowditch, Motor Vehicle manufacturers association.

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DISCLAIMER

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I. INTRODUCTION

A. OVERVIEW

The California Air Resources Board (ARB)[1] retained Arthur D. Little, Inc., to conduct a study that was allied with its program to reduce emissions from vehicular sources. ARB is developing the following three component approach to reducing emissions:

- Promulgating increasingly stringent regulations for new vehicles;
- Including diesel-powered vehicles in its smog-check program; and
- Improving the quality of motor fuel.

Arthur D. Little, Inc., was retained to analyze the third approach, i.e., reducing emissions from vehicular sources by improving the quality of motor fuel. In undertaking the study effort, we adopted an approach using a series of refinery models to estimate the cost of improving the quality of motor fuel (1) by reducing aromatics levels in gasoline and diesel fuel, and (2) by reducing the content of sulfur in diesel fuel. Such reductions will improve the quality of the air in California through:

- The reduction of the aromatics contained in evaporative emissions; and
- The reduction of aromatics, polycyclic aromatic hydrocarbons (PAH), nitrated polycyclic aromatics (NPAH), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates in automotive emissions.

B. INDUSTRY BACKGROUND

Automotive gasoline and diesel fuel contain high levels of aromatics. Aromatics are a high-octane gasoline component which can range from 18% to 45% of gasoline with the average in California about 33%. Although some of these aromatics, such as benzene, have been identified as carcinogenic, gasoline aromatics levels have been rising with increased octane requirements, because of the phaseout of tetra-ethyl lead (TEL). Such processes as catalytic reforming have been designed to increase rather than decrease aromatics levels to improve gasoline octane. Further, there has been little incentive to install processes that will extract light aromatics (benzene, toluene and xylenes) on the West Coast, since petrochemical processing is concentrated on the Gulf Coast. Unless controls are introduced, gasoline aromatics levels are expected to increase because of the

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[1] A list of acronyms is included at the end of this report.

elimination of lead from gasoline and the increased demand for high-octane, unleaded premium gasoline.

Diesel fuel aromatics levels can range from 17% to 43% with the average in California at about 31%. Diesel aromatics levels have been gradually rising, because of the increased conversion of heavy oils to light products through catalytic cracking. Unless controls are introduced, diesel aromatics levels are expected to continue to increase because of increased levels of conversion processing. However, in the case of diesel fuel, aromatics are not desirable. In fact, increased aromatics levels have lowered diesel cetane numbers (a measure of diesel automotive performance). Although many cracked diesel components are hydrotreated to reduce sulfur levels, generally the severity of hydrotreating is not sufficient to significantly reduce aromatics content by saturation.

Diesel sulfur contents can range from 0.05 to 0.98 wt% (exceeding ASTM specification of 0.5 wt%); they average about 0.3 wt% in California. Increased crude oil sulfur levels, declining conversion feed quality and increased conversion levels, have been partially offset by increased diesel hydrotreating to remove sulfur. Thus diesel sulfur content will likely remain near current levels without some form of regulation. Diesel sulfur levels are currently limited to 0.05 wt% in the Los Angeles Basin. Diesel sulfur levels can be reduced (at some cost to refiners) through additions to hydroprocessing capacity.

C. PROJECT OBJECTIVES

The objectives of our research project efforts were to:

- Develop linear programming (LP) models of California refineries;
- Use these models to estimate the cost of reducing various types of aromatics levels in automotive gasoline and diesel fuel, and sulfur levels in diesel fuel;
- Provide the ARB with cost equations that will enable the Board to update or extend the results of this analysis;
- Scale up the individual refinery costs to obtain the overall cost impact to California; and
- Determine the impact of improving automotive fuel quality on refinery emissions, automotive emissions, and automotive performance.

D. SUMMARY OF RESULTS

1. Costs of Reducing Diesel Sulfur and Aromatics

It is technically feasible to reduce diesel sulfur to 0.05 wt% using currently available commercial processes at an average cost in

California of 6 ¢/gallon. Diesel aromatics level can be reduced to 10% using a combination of currently available commercial processes and developing process technology at an average cost of 28 ¢/gallon.

Major refinery changes will be required for new processing capacity, and all components of refinery costs will increase.

Cost impact in individual refinery groups will vary significantly because of the differences in size, existing process configuration, and current diesel quality. Costs for sulfur reduction to 0.05 wt% will vary from 2 to 35 ¢/gallon and costs to reduce aromatics to 10% will vary from 13 to 126 ¢/gallon.

Both sulfur and aromatics reduction costs will increase if new hydrogen plant capacity is required to support all new hydrogen processing investment.

Diesel sulfur and aromatics reduction costs are sensitive to initial sulfur and aromatics level, refinery configuration, and refinery size. Costs for reduction of aromatics levels to 10% are sensitive to methanol price. Availability of low-sulfur/low-aromatics diesel blendstocks would dramatically reduce costs, but it is uncertain that these blendstocks will be available. Costs will likely increase in the future because of increased refinery utilization, diesel demand, and energy price.

Diesel cetane index will be improved as a result of reductions of diesel sulfur and aromatics level.

2. Costs of Reducing Gasoline Aromatics

Gasoline aromatics content can be reduced in 1991 by an average of 18% of base levels while maintaining base octane with process investment at an average cost of 7 ¢/gallon.

Aromatics reduction will vary from 5% to 21% by refinery type and costs will vary from 6 to 16 ¢/gallon. Major refinery changes will be required for new processing capacity and all components of refinery cost will increase.

Refiners will not be able to make gasoline demand grade split and octane without substantial investment in 1995. As a result of increased octane requirements in 1995, gasoline aromatics content can only be reduced by an average of 15% with new process investment and average costs increased to 9 ¢/gallon.

Gasoline aromatics reduction costs are sensitive primarily to refinery octane constraints which are a function of gasoline octane requirements and refinery configuration. Gasoline aromatics content can be reduced by 50% in 1995 at an average cost of 17 ¢/gallon with unlimited purchase of high octane, low aromatics blendstocks, but it is uncertain if these blendstocks will be available. Costs for gasoline aromatics reduction will likely increase in the future because of increased octane requirements and energy price.

Gasoline benzene content will be reduced along with total aromatics content but at a somewhat different rate depending upon refinery configuration.

E. BASIS OF ANALYSIS

In this study, we focussed on the refining cost of reducing diesel and gasoline contaminant levels in California. We developed these costs using an LP modelling technique to measure the difference in refining costs relative to producing current quality diesel and gasoline. While the absolute levels of cost for each case are of interest, the increase in costs to reduce diesel and aromatics levels are of critical importance.

We selected the November 1987 California Energy Commission "Fuels Report" as the basis for this study since it was a published survey that had been reviewed by the industry and contained complete and consistent energy and price forecasts. Other published energy forecasts did not give the required regional product demand necessary for our analysis. While we fully recognize the uncertainty in future energy and demand forecasts, it is not necessary to directly analyze a wide range of scenarios in order to obtain a reasonable estimate of the increase in refining costs to reduce diesel and gasoline contaminant levels, since the unit cost to reduce contaminant levels is mainly a function of initial and final product quality rather than the absolute level of demand.

The major impact of the price forecast on the overall cost of reducing diesel and gasoline contaminant levels is on refinery feedstock costs which can be directly related to marginal energy cost. We have provided feedstock cost equations in this study to adjust our results for differences in marginal energy cost.

We selected Alaskan North Slope (ANS) crude as the marginal crude for this analysis. Although not all refineries in California process ANS crude, ANS is clearly the marginal, price-setting crude on the U.S. West Coast. There is a surplus of ANS crude on the West Coast and it makes up any swing in overall California oil demand, with the surplus moving to the U.S. Gulf Coast.

We maintained all primary product demands at base levels in this analysis such that loss in volume caused by aromatics removal, sulfur removal, changes in process severity, etc., would have to be replaced either through increased crude oil processed or purchase of outside feedstocks. Allowing other prime product volumes to vary would allow refiners to dispose of unwanted sulfur and aromatics in alternate products such as military diesel and No. 2 fuel, that have limited demand in California.

The results presented in this summary are based on the total cost of contaminant reduction to each level. The marginal costs to reduce contaminants at each level are discussed in the main body of the report.

F. STUDY QUALIFICATIONS AND LIMITATIONS

1. Qualifications

The technique used for this study, linear programming analysis, is one that is widely used by the petroleum industry to optimize refinery operations and to assist in capital investment decisions. When used to represent, in a single model, a number of different refineries, some over-optimization of capacity utilization and blending inevitably occurs. LP modelling of individual refineries is not a feasible approach for studies of this type because of the enormous work effort involved and the inavailability of the detailed data required on each refinery. By concentrating its analysis on small groups of refineries with similar characteristics, ADL believes that a reasonable assessment of the likely costs of reducing sulfur and aromatics contents has been made. However, these results must be interpreted as providing an indication of the broad level of costs, rather than as giving an exact prediction of the costs that will actually be incurred.

2. Limitations

In our analysis we did not include other product quality restrictions under consideration by the U.S. EPA and the ARB, such as:

- Reduction of summer gasoline volatility by up to 2.5 RVP; and

- Reduction of the gasoline olefins content.

In addition, we did not consider the effects of seasonality on automotive fuel demand, gasoline vapor pressure, and refinery butane balance.

Although we analyzed the impact of three levels of diesel segregation, incremental refinery storage or product supply costs associated with different segregation levels were not considered.

While we analyzed the impact on refinery emissions from improving automotive fuel quality, we did not examine the cost or availability of environmental permits or emission offsets required for refinery modifications.

Offsite requirements, including environmental facilities, were based on standard factors and did not reflect on a refinery-specific analysis.

We did not consider the impact of decreasing the specific gravity of diesel and gasoline fuels on automotive fuel consumption, or demand on refineries. Nor did we consider the impact on demand of increases in diesel and gasoline price caused by quality regulation.

Rather than develop an independent forecast, we used the latest CEC forecast, published in the November 1987 "Fuels Report", as the supply/demand and price basis for our analysis. We were not required to evaluate a range of supply/demand scenarios in this analysis.

Finally, the level of accuracy of costs for this study is limited by the level of accuracy of process investment costs which are estimated at ±25-30% for commercial process technology and ±40-50% for developing process technology.

II. FINDINGS AND CONCLUSIONS

The major findings and conclusions of our study are summarized below:

A. DIESEL AND GASOLINE QUALITY WITHOUT ADDITIONAL REGULATIONS

- Current diesel content is about 0.3% sulfur and 31% aromatics, and there will be little change in quality through 1995.
- Current gasoline content is about 33% aromatics and 1.85% benzene.
- Gasoline aromatics levels are expected to remain about constant to 1991, but benzene levels are expected to increase to about 2.0%.
- By 1995 because of isomerization, MTBE, and etherol process additions to meet higher octane requirements, gasoline aromatics levels are expected to decline to about 32% and benzene levels to 1.9%.

B. OPTIONS FOR REDUCING DIESEL SULFUR AND AROMATICS

- Standard hydrotreating can reduce sulfur levels by 85% to 95%, but would have little impact on aromatics.
- Conventional hydro-refining can reduce sulfur levels by up to 95% and aromatics by 15% to 30%.
- Two-stage hydro-processing can reduce diesel aromatics levels by up to 70%.
- Mobil's MOGD process can produce low-sulfur, low-aromatics diesel.
- Both two-stage hydro-processing and Mobil's MOGD process can be commercially available by early to the mid-1990s.

C. OPTIONS FOR REDUCING GASOLINE AROMATICS

- Octanes lost through aromatics reduction must be replaced.
- Isomerization, MTBE, etherol, and BTX extraction are attractive options.

D. LEVEL OF ACCURACY OF CAPITAL COSTS

- The level of accuracy of capital costs for conventional commercial processes is about ±25-30%.

- The level of accuracy of capital costs for developing processes, such as two-stage hydroprocessing and the MOGD process, is about ±40-50%.

F. DIESEL SULFUR AND AROMATICS REDUCTION

- Little new capacity is justified in 1991, based on current quality restrictions.
- Lowest attainable diesel sulfur level without investment is 0.19% for high-sulfur diesel and 0.14% for total California diesel.
- Diesel aromatics can be reduced by only 5 to 14% of base levels without investment.
- Diesel sulfur levels can be reduced to 0.05% sulfur with investment.
- Controlling diesel sulfur at 0.05% reduces diesel aromatic levels by only 1.3%.
- Costs to reduce diesel sulfur to 0.05% are about 6¢/gallon and investment requirements are about $0.3 billion.
- Diesel aromatics can be reduced to 10% with new process capacity.
- Most diesel will meet 0.05% sulfur if reduced to 10% aromatics.
- Costs to reduce diesel aromatics increase from about 4¢/gallon for 20% aromatics to 8¢/gallon for 15% aromatics and 28¢/gallon for 10% aromatics. Investment requirements are $0.4, $0.9 and $1.5 billion, respectively.
- Costs are significantly higher for small, simple topping and hydroskimming refineries.
- Use of low-sulfur/low-aromatics diesel blendstocks dramatically reduces costs, but it is uncertain whether these blendstocks will be available at diesel prices.
- Control of only segregated diesel will reduce control costs but increase levels of overall sulfur and aromatics;
- If new hydrogen plant capacity is required to support all new hydroprocessing units, costs of diesel sulfur and aromatics reduction will increase about 10 to 20%.
- An increase in methanol prices to 70¢/gallon eliminates the MOGD process route for aromatics levels of 20 and 15%. For aromatics levels of 10%, the MOGD process is still utilized and costs increase proportionately with the price of methanol.

- Control costs will increase in the future, because of increased refinery utilization, diesel demand, and energy price.

E. GASOLINE AROMATICS REDUCTION

- California gasoline aromatics can be reduced by only about 1% of base levels while maintaining base case octanes without process investment.

- Gasoline aromatics can be reduced by 5% to 20% of base levels while maintaining base case octane with process investment.

- Maximum California aromatics reduction with process investment is 18.1% of base level aromatics, or from 31.5% to 25.8%.

- Costs to reduce gasoline aromatics to 25.8% are about 7¢/gallon and investment requirements are about $1.4 billion.

- Costs per gallon are significantly higher for small, simple hydroskimming refineries.

- Costs of gasoline aromatics reduction will decrease dramatically with the use of purchased high-octane/low-aromatics blendstocks, but availability of these blendstocks at gasoline blending value is uncertain.

- With increase in the price of methanol to 70¢/gallon, MTBE capacity is largely replaced by isomerization at a slight increase in cost.

- Refiners will not be able to make gasoline demand, grade split, and octane without substantial investment in 1995.

- Costs for gasoline aromatics reduction cases were higher in 1995 versus 1991, because of increased gasoline octane, increased gasoline demand, and increased energy (crude oil) costs.

- Aromatics levels could be reduced by only 15% in 1995 versus 18% in 1991 because of increased gasoline octane requirements.

- Aromatics levels can be reduced by 25 to 70% with unlimited purchase of high-octane, low-aromatics blendstocks.

- Costs will continue to increase and the level of aromatics reduction will decrease beyond 1995 because of increased gasoline octane requirements, refinery utilization, gasoline demand and energy price.

E. IMPACT ON REFINERY EMISSIONS

- Refinery emissions will decline for diesel sulfur reduction because of decreased FCC utilization and increased FCC feed desulfurization.

- Refinery emissions will increase for diesel aromatics reduction because of increased downstream processing.

- All refinery emissions will increase, except for SO_x, for gasoline aromatics reduction because of increased downstream processing. SO_x emissions will decrease because of decreased FCC utilization.

F. IMPACT OF FUEL QUALITY ON AUTOMOTIVE PERFORMANCE AND EMISSIONS

- Lower diesel fuel sulfur levels, lower aromatics content, and higher cetane number will improve automotive performance.

- Higher cetane will more than offset lower diesel heating value and result in increased fuel efficiency in new lower compression ratio engines.

- Projected changes in gasoline quality will have little impact on automotive performance.

- Reduction of diesel sulfur will lead to a proportional decrease in SO_x exhaust emissions and a reduction in particulate emissions.

- Reduction of diesel aromatics content will directly reduce evaporative emissions and will reduce exhaust emissions as a result of improved combustion efficiency.

G. RECOMMENDATIONS FOR FUTURE STUDIES

- Analysis of the refining cost of reducing diesel aromatics levels to 20% and 15% along with diesel sulfur levels to 0.05%.

- Analysis of the cost of reducing the content of benzene in gasoline.

H. IMPLICATIONS FOR ARB REGULATORY PROGRAM

This study provides an analysis of the refining costs necessary to improve motor vehicle fuel quality to various levels. The ARB is independently investigating the impact of fuel quality on emissions from vehicular sources. The results of these two studies can be combined to determine the cost of reducing vehicular emissions through refining improvements in motor vehicle fuel quality.

III. METHODOLOGY AND STUDY RESULTS AND RECOMMENDATIONS FOR FUTURE STUDIES

A. METHODOLOGY

1. Development of Refinery Cost Model

In 1986, there were 30 operating refineries in California, each with a slightly different configuration. These variations led to the use of different options to achieve more restrictive product qualities. To analyze these differences and the costs associated with them, we divided the 30 operating California refineries into 6 groups.

We obtained information about the operation of California refineries through a confidential refinery survey.

Based on the survey information, we selected the following refineries for modeling in each refinery group:

Group	Description	Refinery/Location
I	Topping	Not modeled*
II	Hydroskimming	Kern Oil-Bakersfield
III	Conversion	Unocal - Los Angeles
IV	Deep Conversion - w/o hydrocracking	Shell - Wilmington
V	Deep Conversion - LA Basin	ARCO - Carson
VI	Deep Conversion - Northern CA	Exxon - Benicia

In addition to the refinery survey data, we obtained additional information about 1986 refinery operation from other sources . The California Energy Commission provided valuable statistics on refinery input and output for the refinery groups selected for 1986. Reports and studies from state and federal agencies provided information that proved particularly useful in identifying current diesel sulfur and aromatics content and gasoline aromatics content.

LP models were developed for each selected refinery, based on refinery survey information. Each model was calibrated by comparing results against actual refinery operating data for 1986. We then scaled up the data obtained from the refinery surveys and LP modeling work for the entire state. We compared scaled up model results with the volumes of refinery input and output obtained from the surveys and

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* Since topping refineries generally do not produce gasoline and produce only a small volume of diesel, we chose not to model this refinery type. We estimated the costs for this refinery type outside the LP model.

with the CEC data. We scaled up the diesel and gasoline qualities from the survey and LP model results on a product volume basis. We compared the overall diesel and gasoline qualities to published surveys by the NPRA (National Petroleum Refiner's Association) and CARB, respectively, and we found the scaled-up results we had obtained to be reasonable when compared to these published sources.

2. Basis of Study

The required periods of analysis for this study were 1991 and 1995. We selected the November 1987 California Energy Commissions "Fuels Report" as the basis for refinery input and refined product output. We chose this report as a baseline, because it was a published survey that had been reviewed by the industry, and it contained complete and consistent energy and price forecasts.

We based the price of Alaskan North Slope (ANS) crude (marginal crude oil) and feedstocks (i.e., natural gas, butane, and methanol) used by the LP model on the CEC forecast, and we valued gasoline and diesel feedstacks as blending components.

The only refined products that we valued in this study were LPG, petroleum coke, and BTX. We price these products because their level of production was not limited. We ran all other prime products, crude oils other than ANS, and feedstocks, such as vacuum gas oil, as fixed volumes in the LP model. Prices were therefore not required for these materials.

3. Selection of Process Technology

a. Options for Reducing Diesel Sulfur and Aromatics

Options for reducing diesel sulfur and aromatics fall into three general categories:

- Existing process equipment
- Additions to process capacity; and
- Non-process options.

Short-term options with existing capacity include changes in kerosene/diesel cutpoint, full utilization of existing hydroprocessing capacity, increases in hydroprocessing severity, and upgrading of hydroprocessing catalyst.

Possible additions to process capacity include:

- Low-severity distillate hydrotreating;
- Moderate-severity distillate hydrorefining;
- Noble metal catalyst distillate hydro-dearomatization;

- High-severity hydrorefining/mild hydrocracking;
- Hydrogen production;
- Aromatics extraction;
- Mobil methanol-to-olefins (MTO) process to produce mixed light olefins; and
- Mobil olefins to gasoline and distillate (MOGD) process to convert refinery or MTO olefins to low-aromatics, high-cetane distillate.

Non-process options include segregation of No. 2 fuel and diesel products (so that only diesel stocks have to be improved) and purchase of low-aromatics/low-sulfur blendstocks from outside California.

The diesel hydro-dearomatization process currently is not commercially available, but it has operated successfully on kerosene feed in a number of commercial units. Similarly, there are no current commercial Mobil synthetic diesel process units, but the process is similar to the commercially available Mobil methanol-to-gasoline (MTG) process and has been tested in a semi-commercial size unit. However, in our opinion both processes could be made commercially available by the early to mid-1990s if reduction of diesel aromatics is mandated on a state or national level.

b. Options for Reducing Gasoline Aromatics

Whereas the reduction of diesel sulfur and aromatics will improve the diesel cetane number, reduction of gasoline aromatics reduces gasoline octane. A major assumption in this study was that gasoline octanes would have to be maintained at projected base case levels, and any octanes lost through aromatics reduction would have to be replaced. In addition, gasoline volatility may be reduced by EPA legislation in the near future. Thus, process options to reduce gasoline aromatics cannot be considered without also considering their impact on gasoline octane and volatility.

Options to reduce gasoline aromatics fall into three general categories:

- Existing process equipment;
- New or modified process equipment; and
- Blending.

Options to reduce gasoline aromatics with existing processing equipment include modification of product cut points, reduced severity on catalytic reforming, reduced cat cracking severity, full utilization of aromatics extraction capacity, and increased utilization of light-naphtha isomerization, alkylation, and catalytic polymerization (cat poly) capacity.

New conventional process options considered to reduce gasoline aromatics include:

- Reformer modifications and new continuous reforming;
- BTX extraction from reformate and light FCC gasoline;
- Alkylation, catalytic polymerization, and dimerization;
- Isomerization;
- MTBE production; and
- Etherol production.

Many of these conventional technologies do not directly remove aromatics, but they can decrease gasoline pool aromatics content through the blending of low-aromatics content streams, and they will replace octanes lost because of declines in reformer severity and aromatics extraction.

All of the above process options were available in our LP model analysis at standard process costs. The use of catalytic polymerization and dimersol was limited to prevent increase of gasoline olefins content.

4. Cost of Reducing Diesel Sulfur, Diesel Aromatics and Gasoline Aromatics

a. Approach

We applied common methodology to estimate the refinery costs to reduce aromatics levels in diesel fuel, reduce aromatics levels in gasoline, and reduce sulfur levels in diesel fuel. We analyzed each case separately, however, to determine the refining cost of reducing each contaminant level in each motor vehicle fuel. In each case, we maintained all primary product volumes such that losses in product volume caused by aromatics removal, sulfur removal, changes in processing severity, etc., were compensated either through increased crude oil processed or purchase of outside feedstocks.

We analyzed cases both with and without allowing the purchase of outside feedstocks. Outside feedstocks that we considered included:

- Oxygenates (MTBE and ethanol);
- Gasoline blendstocks (alkylate and isomerate); and
- Distillate blendstocks (low-sulfur distillate).

To estimate the net feedstock cost impact, we developed prices for each of these feedstocks and for BTX product that were consistent with the underlying crude oil and product price forecasts. Net feedstock cost was the sum of crude oil and outside feedstock costs less credits for aromatics removed.

The only change we permitted in crude oil slate was in the volume of the marginal ANS crude oil processed. We fixed all other crude oil inputs to levels determined in the base case analysis.

For each case, we estimated the change in net feedstock costs, variable costs, fixed costs and capital costs (new investment cases only) to reduce contaminant levels relative to the base case for the modeled refinery. The cost components provided equations that the ARB can use to update or extend the results of this analysis.

b. Diesel Sulfur and Aromatics Reduction

For the diesel analysis, we modeled low sulfur, high sulfur and military diesel separately as appropriate in each selected refinery. We included an additional "uncontrolled" distillate category in each refinery selected for our analysis of diesel and other distillate segregation sensitivity.

We analyzed cases for the reduction of diesel sulfur and aromatics both with and without new process investment. In the sulfur reduction analysis, total California costs include those costs for reducing high-sulfur diesel and exclude refineries at or below each prescribed sulfur level. The average diesel sulfur level attained and costs per gallon are expressed in terms of total California diesel produced, including current production of low sulfur diesel. In the aromatics reduction analysis, we reduced aromatics levels of both high-sulfur and low-sulfur diesel.

c. Gasoline Aromatics Reduction

For the gasoline analysis, we modeled each grade of gasoline separately based on the estimated grade split for each selected refinery, and we controlled aromatics levels on the overall gasoline pool.

We analyzed cases for reduction of gasoline aromatics both with and without new process investment. The average gasoline aromatics reduction and costs per gallon are expressed in terms of total California gasoline produced.

B. STUDY RESULTS

1. Costs of Reducing Diesel Sulfur and Aromatics

a. Diesel Sulfur and Aromatics Reduction without New Process Investment

In the first series of cases analyzed, we progressively reduced high-sulfur diesel levels from the base case to 0.25%, 0.20% and the maximum extent possible without new process investment.

High-sulfur diesel could be reduced to 0.25% sulfur in all refinery groups without investment. Costs averaged 1.3 ¢/gallon for 178 MB/D of high sulfur diesel and 0.8 ¢/gallon of total California diesel. Including the effect of current low-sulfur diesel, the average sulfur level dropped from 0.27% in the base case to 0.17%.

The maximum sulfur reduction attainable in high-sulfur diesel without process investment varied from 0.21% in Groups III and VI to 0.20% in Group V and 0.10% in Groups I and II. This resulted in an average attainable sulfur level of 0.19% for high-sulfur diesel and 0.14% for total California diesel. Total diesel aromatics levels decreased slightly from 30.7% in the base case to 29.2%, because of the increased utilization of existing hydrotreating and hydrorefining capacity to reduce sulfur levels. Cetane number increased slightly from 43.7 to 44.4, along with the decrease in aromatics content.

Cost of maximum sulfur reduction without investment varied from 3.3 ¢/gallon in Group V to 18.4 ¢/gallon in Group I and averaged 7.7 ¢/gallon of high-sulfur diesel, or 5.0 ¢/gallon of total California diesel. Costs were by far the highest in small topping refineries which have few options to reduce diesel sulfur without investment.

In the next series of cases, we successively decreased both high and low-sulfur diesel aromatics levels by a nominal 5%, 10% and to the maximum extent possible from base case aromatics levels without new process investment. Since existing California hydroprocessing capacity was designed for diesel sulfur removal only and has limited capability to reduce diesel aromatics levels, it was possible to reduce aromatics by only a nominal amount in all refinery groups without investment. Maximum aromatics reduction without investment varied from 5% in Group VI to 14% in Groups I and II and averaged 8.7% of base aromatics levels, or an absolute reduction from 30.7 to 27.9%. Cost for maximum aromatics reduction averaged 14.3 ¢/gallon, but was 60 ¢/gallon in Groups I and II, which have little capability to reduce diesel aromatics without investment. Diesel sulfur level was reduced to 0.20% and cetane increased to 44.4 with 8.7% aromatics reduction.

b. Diesel Sulfur and Aromatics Reduction with New Process Investment

We analyzed the following seven cases to determine refinery process requirements and costs for reducing diesel sulfur and aromatics:

- Reduction of diesel sulfur level to 0.15 wt%;
- Reduction of diesel sulfur level to 0.05 wt%;
- Reduction of diesel aromatics level to 20 vol%;
- Reduction of diesel aromatics level to 15 vol%;
- Reduction of diesel aromatics level to 10 vol%;
- Reduction of both diesel sulfur level to 0.05 wt% and aromatics level to 10 vol%; and
- Reduction of diesel sulfur level to 0.05 wt% and aromatics level to 10 vol%, allowing purchase of low-sulfur, low-aromatics diesel blendstocks.

The 1991 costs of reducing diesel sulfur level with new process investment are shown in Figure I. Costs are shown separately for small, simple Group I and II refineries; for larger, more complex Group III-VI refineries; and for total California.

Costs for reduction of diesel sulfur to 0.15 wt% averaged 1.9 ¢/gallon for California. Costs were 1.0 ¢/gallon for Group III-VI refineries, but were 7.8 ¢/gallon for Group I and II refineries, because of higher initial sulfur levels and little existing hydroprocessing capacity. Total investment requirements were $96 million for 34 MB/D of new hydroprocessing capacity.

All refineries modeled were able to reduce diesel sulfur levels to 0.05% with new process investment. Costs averaged 6.3 ¢/gallon of total California diesel, but varied from 1.9 ¢/gallon for Group III-VI refineries to 34.7 ¢/gallon for Group I and II refineries. Process investment requirements were $266 million for 112 MB/D of hydroprocessing investment. Total aromatics levels were reduced slightly from 30.7% in the base case to 29.4% in the maximum sulfur reduction case, because of partial aromatics saturation in hydroprocessing units. Cetane levels also increased from 43.7 in the base case to 44.9.

The costs for reducing diesel aromatics level with new process investment are shown on Figure II. Costs for reduction of diesel aromatics to 20% averaged 3.8 ¢/gallon for California. Costs were 5.2 ¢/gallon for Group I and II refineries and 3.6 ¢/gallon for Groups III-VI refineries. Costs for reducing aromatics to 20% for Group I and II refineries were <u>lower</u> than costs for reducing sulfur to 0.05 wt%, because of the high initial sulfur levels in these refineries. Costs for reducing aromatics to 20% for Group III-VI refineries were <u>higher</u> than costs for reducing sulfur to 0.05 wt% because of the higher severity hydroprocessing required to achieve aromatics reduction. Total investment requirements for reduction to 20% aromatics were $410 million for 162 MB/D of new hydroprocessing investment.

Figure I
1991 Costs of Reducing Diesel Sulfur

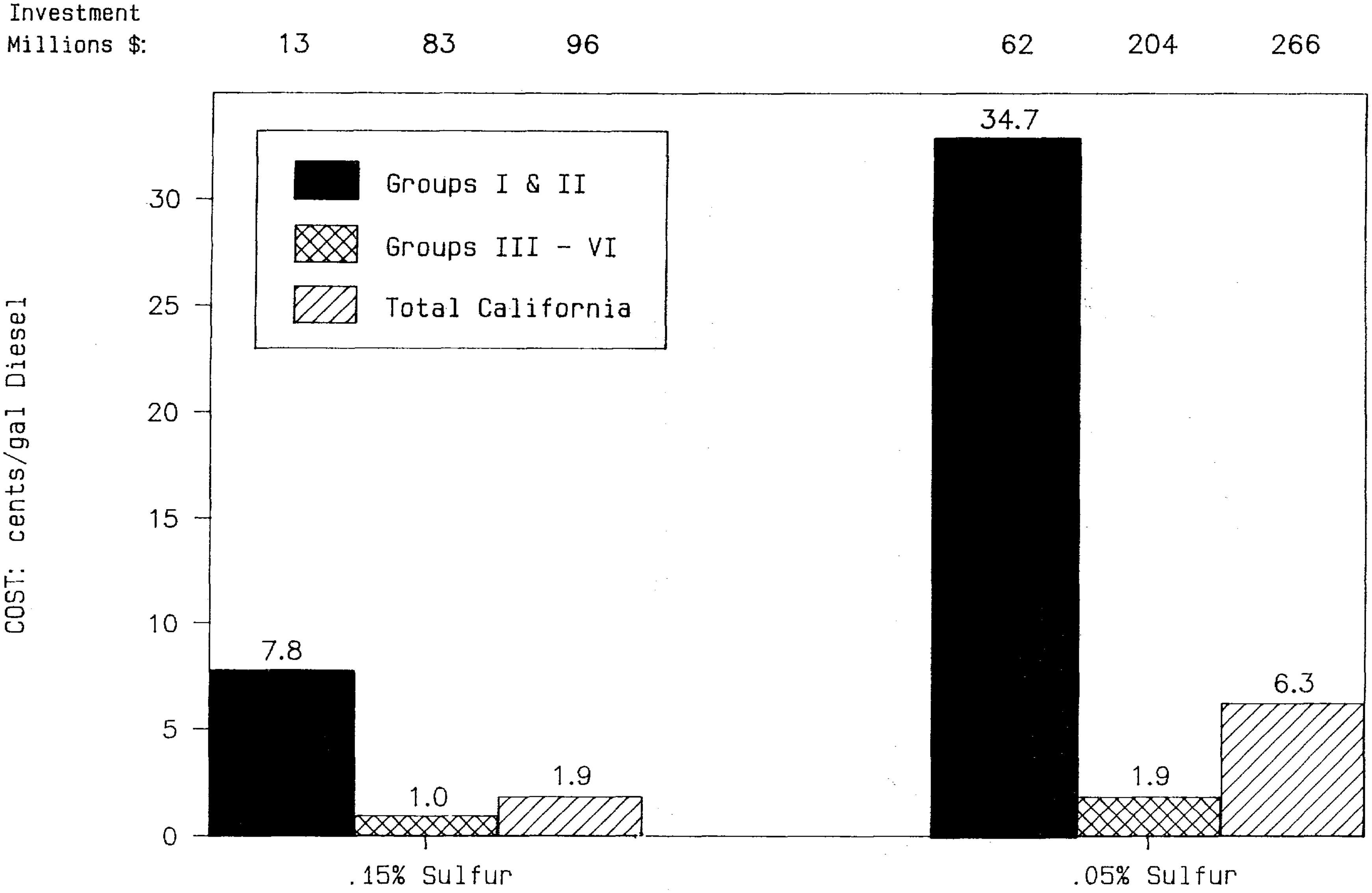
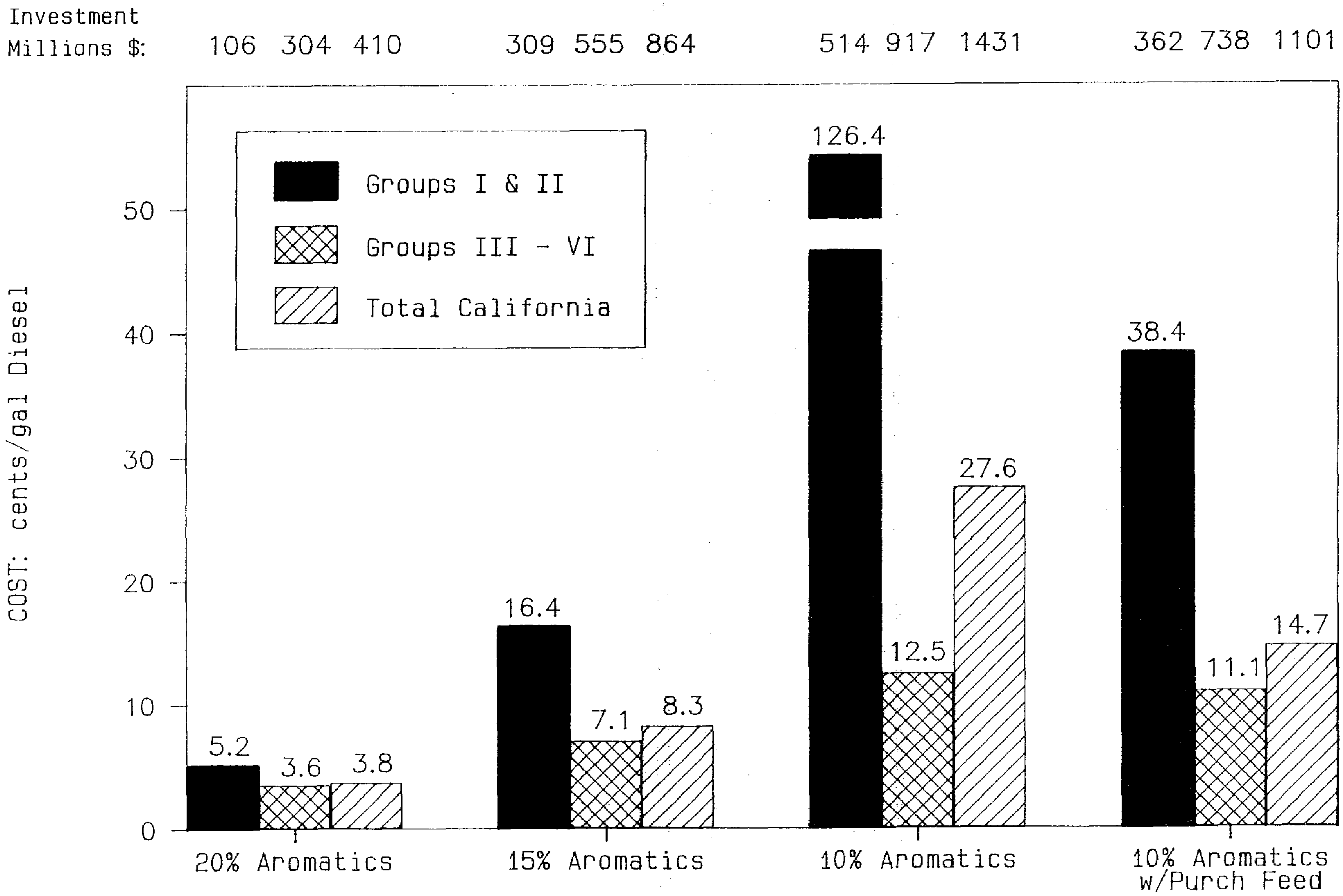


Figure II
1991 Costs of Reducing Diesel Aromatics



Costs to reduce diesel aromatics to 15% increased to 8.3 ¢/gallon. Costs were 16.5 ¢/gallon for Group I and II refineries and 7.1 ¢/gallon for Group III-VI refineries. Investment costs were $864 million for 330 MB/D hydroprocessing and 17 MB/D of Mobil synthetic diesel. Sulfur levels were reduced to an average of 0.05 wt% and the cetane level increased to 49.9.

Costs to reduce diesel aromatics to 10% increased to 27.6 ¢/gallon. Costs were 126.4 ¢/gallon for Group I and II refineries and 12.5 ¢/gallon for Group III-VI refineries. Investment costs increased to $1.4 billion for 380 MB/D of hydroprocessing, 105 MM SCF/D hydrogen production and 55 MB/D of Mobil synthetic diesel processing. Diesel sulfur was reduced to an average of 0.03% and cetane increased to 50.9.

Diesel sulfur levels were below 0.05% in the 10% aromatics case except for Group VI which was at 0.07%. We analyzed an additional case with Group VI at both 10% aromatics and 0.05% sulfur which increased total California costs slightly. Results for this case are shown in the main body of the report.

The availability of low-sulfur/low-aromatics diesel blendstocks at projected 1991 diesel price had a dramatic impact on the cost of reducing diesel sulfur and aromatics levels. Costs decreased by nearly 50% to an average of 14.7 ¢/gallon. Costs in Groups I and II decreased even more dramatically -- from 126.5 ¢/gallon to 38.4 ¢/gallon. Costs for Groups III-VI dropped to 11.1 ¢/gallon and investment costs dropped by $350 million to $1.1 billion.

Although the cost of aromatics reduction in diesel was significantly lower with purchased low-aromatics/low-sulfur feedstock, the analysis is based on the assumption that these feedstocks would be available at the price of diesel. It is uncertain if these feedstocks would be available -- particularly if a reduction of diesel aromatics is mandated in other U.S. regions.

c. Impact of Diesel Segregation

In the base diesel analysis performed in this study, we assumed zero percent segregation; that is, all diesel was required to meet the same restrictive quality requirements. Two sensitivities were analyzed controlling only a portion of the diesel fuel based on the 1986 NPRA survey level of diesel segregation and based on a 50% diesel segregation.

Total California costs for 0.05% sulfur diesel were reduced by 1.0 ¢/gallon in the NPRA segregation case and 5.1 ¢/gallon in the 50% segregation case. However, since a lower volume of diesel was controlled, average California diesel sulfur levels were reduced only to 0.12% in the NPRA segregation case and 0.17% in the 50% segregation case versus 0.05% when all diesel was controlled.

Similarly, total California costs for 10% aromatics and 0.05% sulfur diesel were reduced by 6.1 ¢/gallon in the NPRA segregation case and 13.3 ¢/gallon in the 50% segregation case. The average California diesel aromatics level was reduced only to 21% in the NPRA segregation case and to 20% in the 50% segregation case versus 10% when all diesel was controlled.

d. Impact of Hydrogen Plant Capacity on Diesel Costs

The LP solutions derived during this study generally indicated little need for new hydrogen plant capacity, except in Group I and II refineries. While we feel that an assumption that new hydrogen plant capacity is required to support every new hydroprocessing project is too conservative, our results may be too optimistic. We have therefore estimated hydrogen plant costs to support new hydroprocessing capacity selected in our analysis as shown on Figure III. The hydrogen plant costs shown are in addition to hydrogen plant requirements based on the LP model study results.

Additional hydrogen plant requirements to reduce diesel sulfur levels to 0.05 wt% would increase investment costs $78 million, or 0.5 ¢/gallon of diesel. Additional hydrogen plant requirements to reduce diesel aromatics increase by 137 million to $209 million, and unit costs would increase by 1.1 to 1.5 ¢/gallon of diesel.

e. Impact of Methanol Prices on Diesel Costs

Mobil's MOGD process was selected in some refinery groups for reduction of diesel aromatics. With an increase in methanol price to 70 ¢/gallon, the MOGD process was replaced in the 15% aromatics case by new hydroprocessing capacity at an 85% increase in costs. For aromatics levels of 10%, the MOGD process was still fully utilized and costs doubled. The cost increase was nearly proportional to the increase in the price of methanol.

f. 1995 Diesel Analysis

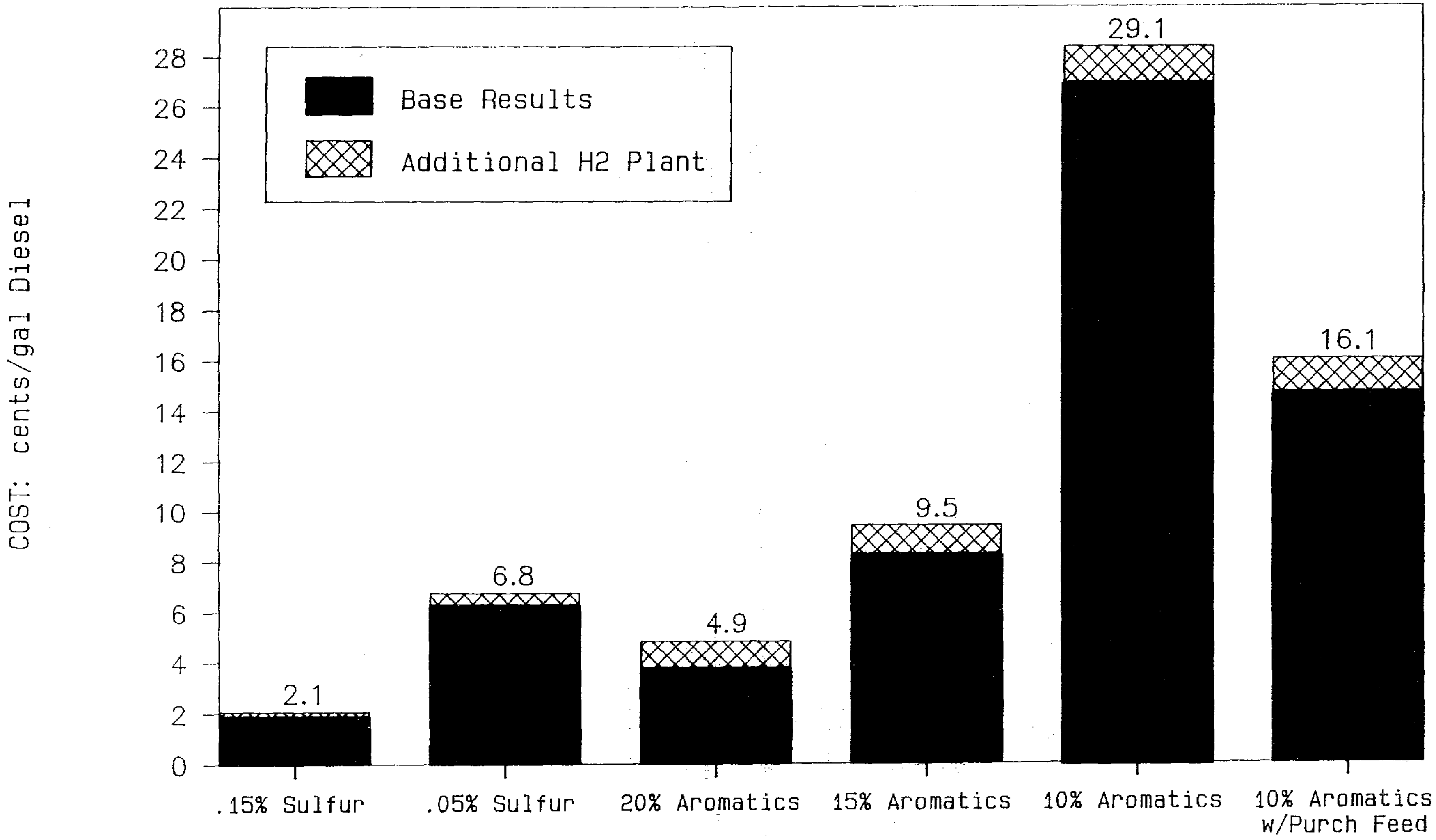
We also examined cost impacts from reducing diesel sulfur and aromatics in 1995 versus 1991. Costs were higher in 1995 because of increased refinery utilization, diesel demand, and increased energy (crude oil) costs.

Total costs to reach 0.05% sulfur increased from 6.3 ¢/gallon in 1991 to 7.7 ¢/gallon in 1995. Investment costs (in constant 1987 dollars) increased from $266 million to $291 million, and total annual costs increased from $280 million to $363 million.

Total costs to reach 20% aromatics increased from 3.8 ¢/gallon in 1991 to 4.0 ¢/gallon in 1995. Investment costs were nearly constant at about $410 million and total annual costs increased from $170 million to $190 million.

Figure III
Impact of Hydrogen Plant Capacity on Diesel Costs

	Base	96	266	410	864	1431	1101
Investment	H2	35	78	137	175	209	198
Millions $:	Total	131	344	547	1039	1640	1299



Costs to reach 15% aromatics versus 20% aromatics in 1995 more than doubled to 8.6 ¢/gallon at an annual cost of $405 million. Investment requirements were $850 million.

As in 1991, costs increased significantly to reach 10% aromatics. Total costs were 33.5 ¢/gallon or $1.6 billion per year, and investment requirements were $1.6 billion.

We expect costs of diesel sulfur and aromatics reduction to continue to increase beyond 1995, because of increased refinery utilization, diesel demand, and energy costs.

2. Cost of Reducing Gasoline Aromatics

a. Gasoline Aromatics Reduction without New Process Investment

Aromatics levels were first reduced from the base case level in selected refineries to the maximum extent possible without new process investment. In all aromatics reduction cases, gasoline octanes were maintained at base case 1991 levels.

California gasoline aromatics can be reduced only 1.0 to 4.7%[2] without new process investment because of octane constraints. Total costs averaged 3.1 ¢/gallon of gasoline, but were 62 ¢/gallon in Group II hydroskimming refineries. Benzene levels decreased,[3] along with the aromatics level, from 1.97% in the base case to 1.89%.

b. Gasoline Aromatics Reduction with New Process Investment

We developed refinery costs and process requirements to reduce gasoline aromatics content for the following five cases:

- 5% aromatics reduction in 1991;
- Maximum (18%) aromatics reduction in 1991;
- 18% aromatics reduction in 1991 with purchased feedstocks;
- Maximum (15%) aromatics reduction in 1995; and
- Maximum % aromatics reduction in 1995 with purchased feedstocks.

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[2] Note: In all gasoline aromatics reduction cases, results are expressed as a % reduction from the base case level rather than the absolute reduction in pool level.

[3] The accuracy of benzene levels is estimated at 0.1%. Results are reported to a level of 0.01% to show the difference between cases.

All refinery groups were able to reduce gasoline aromatics by a nominal 5% from base case levels in 1991 with new process investment. Benzene levels were reduced from 1.80% to 1.75%. Total costs averaged 0.7 ¢/gallon of gasoline. However, costs were much higher for simple Group II hydroskimming refineries at 15.7 ¢/gallon. Investment requirements were $129 million for 103 MB/D of isomerization, MTBE, and etherol capacity.

Reduction of gasoline aromatics is severely limited by refinery octane constraints. Reduction of aromatics in Group II was limited to about 5%. Groups III and IV were limited to a nominal 15% aromatics reduction. It was possible to reduce aromatics levels in the most complex Group V and VI refineries by about 20% of base case levels.

The costs for maximum reduction of gasoline aromatics with new process investment are shown on Figure IV.

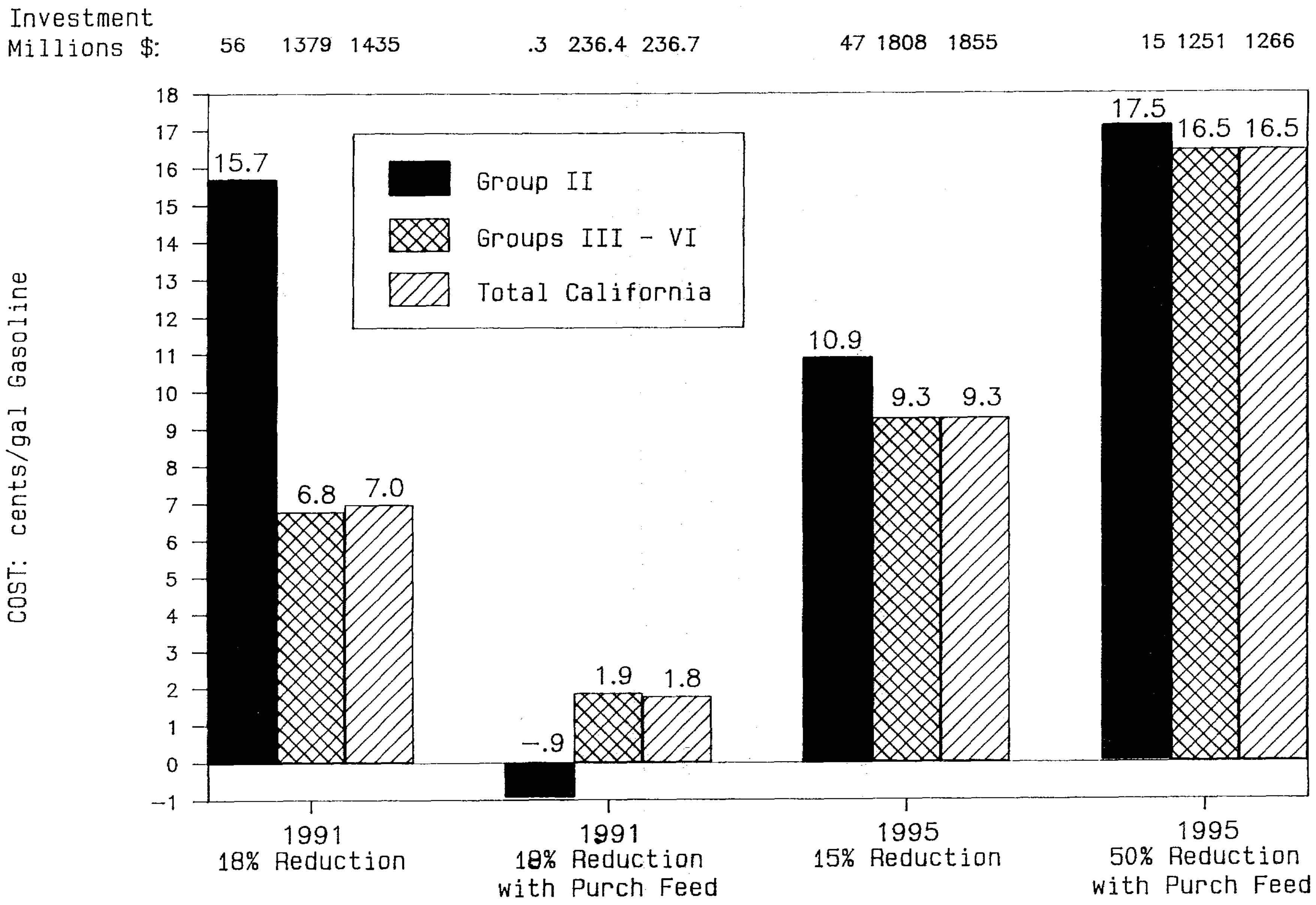
The maximum gasoline aromatics reduction possible in California in 1991, with new process investment, was 18.1% for reduction to an absolute level of 25.8%. Benzene levels were reduced to 1.54%. Total costs for maximum aromatics reduction averaged 7.0 ¢/gallon, but were 15.7 ¢/gallon in Group II refineries. Investment requirements were $1.4 billion for about 756 MB/D of isomerization, MTBE, etherol, BTX extraction, and hydrogen plant capacity. BTX sales volumes were 28 MB/D for an aromatics reduction in gasoline of 47 MB/D.

The maximum aromatics reduction case with investment was repeated allowing purchase of MTBE, ethanol, isomerate and alkylate at gasoline blending value. A total of 31 MB/D MTBE and 2 MB/D alkylate were purchased and had a dramatic impact on refining costs. Average costs dropped to 1.8 ¢/gallon. Investment requirements dropped to $237 million for 120 MB/D of isomerization, MTBE, etherol and BTX extraction capacity. Costs for reduction of aromatics in Group II were lower than the base case because of the availability of low-aromatics feedstocks.

Although costs of aromatics reduction were considerably lower with purchased low-aromatics feedstocks, we based our analysis on the assumption that these blendstocks would be available at projected gasoline blending value. It is uncertain if low-aromatics blendstocks will be available at blending value--particularly if reduction of gasoline aromatics is mandated in other U.S. regions.

Refineries will not be able to make 1995 gasoline demand, grade split and octanes without substantial investment. Gasoline demand is forecast to increase by 7.0 MB/D, or 0.8%, between 1991 and 1995. More significantly, because of increased unleaded premium and unleaded intermediate demand, gasoline pool octane is forecast to increase from 88.3 to 89.0 (R+M)/2. With this significant increase in octane requirements, $236 million worth of new process investment was justified in the base case without any reduction in gasoline aromatics.

Figure IV
Costs of Reducing Gasoline Aromatics



The maximum aromatics reduction possible in 1995 averaged 14.7% to an absolute level of 27.5% aromatics. Benzene level was reduced to an average of 1.61%.

Aromatics reduction was lower and absolute aromatics levels were higher in 1995 because of higher pool octane requirements than in 1991. Average costs for 14.7% aromatics reduction in 1995 were 9.3 ¢/gallon versus 7.0 ¢/gallon for 18.1% reduction in 1991. Thus, costs were higher in 1995 for less reduction because of higher octane requirements.

Investment requirements in 1995 were $1.9 billion for maximum gasoline aromatics reduction versus $1.4 billion in 1991. More than 1,150 MB/D of new processing was required, including isomerization, MTBE, etherol, BTX extraction and hydrogen plant capacity. BTX sales volumes were 30 MB/D for an aromatics reduction in gasoline of 40 MB/D.

The maximum gasoline aromatics reduction in 1995 with purchased feedstocks available averaged 50% to an absolute level of 16.1%. Benzene level was reduced to an average of 1.61%. Costs averaged 16.5 ¢/gallon and were similar in all refinery groups. Investment requirements were $1.3 billion for 700 MB/D isomerization, MTBE, BTX extraction, and hydrogen plant capacity. Purchased blendstock requirements included 109 MB/D alkylate, 62 MB/D MTBE, and 8 MB/D ethanol.

The maximum gasoline aromatics reduction possible in 1995 by refinery group, both with and without purchased feedstocks, is shown in Figure V.

Maximum aromatics reduction without purchased feedstock varied from 5% in Group II to 17% in Groups V and VI and averaged 14.7% Maximum aromatics reduction with purchased feedstocks varied from 24% in Group IV to 67% in Group II and averaged 50.3%.

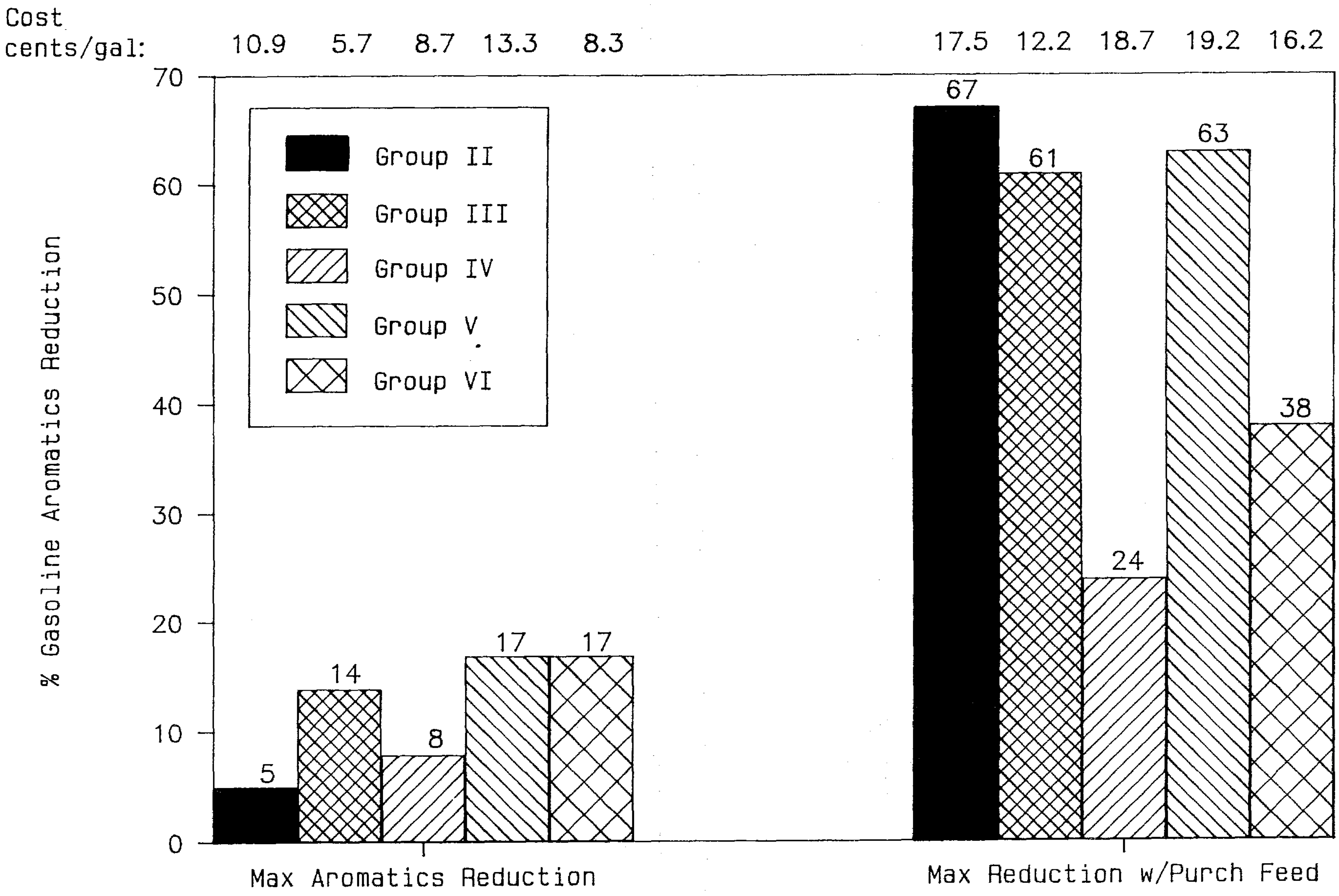
While gasoline aromatics can be reduced significantly with purchased feedstocks, it is uncertain if the level of feedstocks necessary would be available in the future.

We would expect costs to continue to increase and the level of gasoline aromatics reduction possible to decrease beyond 1995 because of increasing pool octane requirements, refinery utilization, gasoline demands, and energy costs.

c. Impact of Methanol Prices on Gasoline Costs

We selected the MTBE and etherol processes in most cases to reduce gasoline aromatics. With an increase in methanol price to 70 ¢/gallon, about 15 to 25% of this process capacity would be replaced by isomerization and alkylation. Costs for gasoline aromatics reduction increased by about 5%.

Figure V
1995 Maximum Gasoline Aromatics Reduction by Group



3. Impact of Fuel Quality on Refinery Emissions

The reduction of sulfur and aromatics in diesel and aromatics in gasoline will have an impact on refinery emissions, because of increased crude runs, fuel consumption, downstream processing requirements, and sulfur recovery. Refinery capacity utilization and fuel consumption results from the LP model were applied to standard AP-42 industry factors to calculate the following refinery emissions for each case:

- Nitrogen oxides (NO_x);
- Sulfur oxides (SO_x);
- Carbon monoxide (CO);
- Volatile organic compounds (VOC); and
- Particulates.

Actual California refinery emissions will be lower than our calculation using AP-42 factors; however, we are primarily concerned with the differences in emissions caused by contaminant reduction in diesel and gasoline rather than absolute emissions levels.

Total California refinery emissions will decline in diesel sulfur reduction cases. This will occur because of reduction in FCC utilization and increased FCC feed desulfurization (for refineries with FCC feed hydrotreating units).

For diesel aromatics reduction, refinery emissions will increase for all cases. This is attributed to increases in crude runs and downstream process utilization needed to maintain diesel production as volume is lost because of aromatics reduction. With purchased feedstocks available, emissions will decline because of reduced refinery operations.

Emission impact will be reduced with NPRA or 50% diesel segregation because of a lower volume of diesel controlled.

For the maximum gasoline aromatics reduction case, all emissions increased except SO_x because of major process additions required to reduce aromatics levels. SO_x decreased because of decreased FCC utilization as high-aromatics FCC gasoline was replaced by other blendstocks. With purchased feedstocks available, emissions will decline across the board because of reduced refinery operations.

4. Impact of Fuel Quality on Automotive Performance and Emissions

The major impacts on diesel fuel quality as a result of sulfur and aromatics reduction will be as follows:

- Decrease in specific gravity (and heating value);
- Decrease in sulfur level;
- Increase in cetane number;
- Decrease in total aromatics; and
- Decrease in polycyclic aromatic hydrocarbons (PAH).

The major impacts on gasoline quality as a result of aromatics reduction will be as follows:

- Decrease in specific gravity (and heating value);
- Pool octane unchanged at 88.3 (R+M)/2;
- Vapor pressure unchanged at 9.8 psi;
- Benzene levels reduced along with total aromatics level; and
- C_7+ aromatics reduced along with total aromatics level.

Lower diesel fuel sulfur levels, lower aromatics content, and a higher cetane number will improve automotive performance. Reduction of diesel sulfur will reduce engine wear and particulate emissions. Fuel economy may be reduced slightly because of lower heating value fuel in existing diesel engines. However, the higher cetane level will more than offset lower diesel heating value and result in increased fuel efficiency in new lower compression ratio engines.

Changes in gasoline quality will have little impact on automotive performance. As a basis for our analysis, we maintained the major gasoline qualities affecting automotive performance--octane, volatility, and distillation--at base case levels. Because of the decrease in gasoline specific gravity, there would be a theoretical 2% decrease in fuel efficiency attributed to lower heating value.

Sulfur is the single most significant contributor to diesel engine particulate emissions. In addition, sulfur compounds can interfere with oxidizing catalysts in particulate trap-oxidizers making them less effective. Lower sulfur diesel fuel is essentially required to achieve heavy-duty diesel engine particulate standards in 1991 and 1995 with practical emission control devices (exclusive of particulate traps). Reduction of diesel sulfur will lead to a proportional decrease in the SO_x exhaust emission rate and a reduction in particulate emissions.

Reduction of diesel aromatics content will directly reduce evaporative emissions and will reduce exhaust emissions as a result of improved combustion efficiency. Reduction of diesel aromatics content will reduce particulate emissions, especially under cold-start and light-load conditions.

The emission rate of individual compounds (e.g., benzene) and combustion products (e.g., sulfur dioxide) is directly proportional to the concentration in the gasoline and fuel consumption rate. Prediction of emission rates for complex mixtures of compounds is much less reliable, but emission rates would tend to increase with increased concentration of contaminants.

Reduction of gasoline benzene and aromatics content will reduce both evaporative and exhaust emissions. Polycyclic aromatic hydrocarbons (PAH) and their nitro-derivatives will also be reduced because of the reduction of PAH compounds in the fuel.

As a result of this analysis we recommend that the ARB initiate the following studies:

C. RECOMMENDATIONS FOR FUTURE STUDIES

1. Analysis of the Refining Cost of Reducing Diesel Aromatics Levels to 20% and 15% Along with Diesel Sulfur Levels to 0.05%.

In our study, we separately analyzed the cost of reducing sulfur to .05% and aromatics to 20, 15 and 10%. In addition, we analyzed the impact of reducing diesel aromatics levels to 10%, along with diesel sulfur to 0.05%.

It is likely that costs would increase significantly to control both aromatics levels to 20% and sulfur to 0.05%. In addition, control of diesel aromatics levels to 20% and sulfur level to 0.05% is a strategy that is currently under consideration by the U.S. EPA. An analysis by the ARB with the objective of reaching the same aromatics and sulfur levels would give a direct point of comparison with the EPA results.

Although neither the U.S. EPA has not examined the costs to control diesel to both 15% aromatics and 0.05% sulfur, this case should be analyzed by the ARB if it is to be considered as a control strategy.

2. Analysis of the Cost of Reducing the Content of Benzene in Gasoline

In our study, we analyzed the refining cost impact of reducing total aromatics in gasoline and reported the impact on the benzene content of gasoline. Although benzene generally decreased along with aromatics, the rate of decrease was different.

The results of this analysis would have been significantly different if benzene rather than total gasoline aromatics had been controlled. Since benzene makes up a much smaller portion of the gasoline pool (1.85% versus 33% total aromatics), reduction of only the benzene content would have a much less dramatic effect on refinery octanes and refinery costs. Previous studies have indicated that benzene levels can be reduced by considerably more than total aromatics content.(1,2)

If the ARB is considering a control strategy to reduce benzene levels, we recommend an analysis of the cost impact on refiners to reduce gasoline benzene content.

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(1) Arthur D. Little, Inc., "Cost of Benzene Reduction in the Petroleum Refining Industry", Report to U.S. EPA, April 1978.

(2) Arthur D. Little, Inc., "Impact on German Refiners of Removing Lead Additive Compounds and Controlling Benzene Content of Gasoline", Report to Umweltbundesamt, November 1983.

IV. REFINERY COST MODEL DEVELOPMENT

A. Refinery Representation in LP Model

1. Linear Programming (LP) Technique

The simulation of refinery processing in this study has been made using the Linear Programming (LP) technique. LP is a mathematical technique which enables a large number of inter-relationships to be studied using computer technology to speed up the process of problem solving. It is a technique which is highly suitable for the study of continuous process operations such as oil refining. It is widely used by refiners to:

- Plan refinery process capacity modifications/additions; and
- Plan refinery operations over various time frames.

In particular, LP modelling can be used to monitor changes in refining operations as various parameters, such as diesel aromatics and sulfur level, are changed. It can study changes in:

- Direct fuel used for process heat (most refining processes use heat to achieve their objectives);
- Indirect fuel for steam raising;
- Other energy requirements (e.g., electricity);
- Variable operating costs;
- Existing process capacity utilization; and
- New process capacity requirements.

The LP technique derives an "optimum" solution to each individual problem by either maximizing or minimizing any pre-determined parameter. It could therefore minimize energy, maximize revenue, minimize costs and so on. For the purposes of this study, we have used cost minimization to derive "optimum" solutions. We believe that the cost minimization approach will produce results which are consistent with the day-to-day objectives of refiners.

A generalized description of petroleum refining and the Arthur D. Little LP model is shown in Appendix A.

2. Categorization of Industry by Refinery Group

One major problem facing a study of this nature is the need to strike a balance between complexity and simplicity. On the one hand, simulation of each refinery would require an enormous work effort and conversely a single model simulation of the total refining industry would grossly underestimate the complexities of the refining situation.

In 1986, there were thirty refineries operating in California. In addition, there were ten refineries which were idle or shut down during this period. The refineries which were shut down were primarily small in size with simple configurations.

Refineries of varying configurations will use different options to achieve the more restrictive product qualities studied in this analysis. In order to analyze these differences, and the cost associated with them, the California refining industry was divided into several groups. These groups differentiate between gasoline and diesel yield and quality characteristics. The six groups ultimately selected are summarized below:

I. Topping: simple distillation; often includes asphalt manufacturing.

II. Hydroskimming: distillation plus reforming.

III. Conversion: includes FCC and/or hydrocracking. Excludes coking.

IV. Deep Conversion - without hydrocracking: vacuum gas oil conversion limited to FCC. Includes coking.

V. LA Basin Deep Conversion - with hydrocracking: includes coking. All refineries contain hydrocracking and some also have FCC units.

VI. Northern CA Deep Conversion - with hydrocracking: identical to Group V except all refineries located in Northern California.

Groups I and II which represent the simplest refinery configuration have between separated for this analysis because

- The hydroskimming refinery has hydrogen production from reforming which will help in diesel sulfur removal.

- Group II refineries can produce finished gasoline in-house. A Group I refinery would require outside blend stocks.

The Group III refineries are complex but they do not have coking capability to upgrade heavy residual fuel. Conversion refineries generally produce residual fuel oil from heavy resid and light cycle oil from the FCC unit as cutter.

The Group IV refineries were separated from Groups V and VI since the Group IV refineries do not have hydrocracking. This distinction was made since hydrocracker products are considerably different from those produced in a fluid catalytic cracker. The hydrocracking process, which operates in a hydrogen-rich atmosphere, produces products that are desulfurized and relatively saturated as compared to fluid catalytic cracked products.

Since our Group IV contains only two refineries, results of our analysis for Group IV were combined with Group III to maintain confidentiality of data.

The Los Angeles Basin and Northern California refineries from Groups V and VI were put into two separate categories due to differences in the diesel fuel quality used in those regions. Large refineries in the South Coast Air Management District (SCAMD) and Ventura Co. must produce diesel at 0.05 wt.% sulfur which is sold in this region. The sulfur specification of diesel sold in Northern California is 0.50 wt% sulfur. Since the quality of diesel sold in the LA Basin is already 0.05 wt% sulfur, Group V refineries will likely require less process additions than Group VI refineries for sulfur control.

A list of the thirty California refineries operating in 1986 is shown by group on Table IV.1. A characterization of all 1986 California refinery capacity is shown in Appendix B.

B. California Refinery Survey

Information about the operation of California refineries was obtained through a refinery survey. Two questionnaires were prepared and are shown in Appendix C. The first and more detailed questionnaire was prepared for potential candidates for refinery modeling. The second, less-detailed questionnaire, was prepared to allow scale-up of data for the remaining refineries.

The refinery questionnaire was developed by Arthur D. Little, Inc., but was sent to each refiner under ARB letterhead. The information was requested under provisions of the Public Records Act with provision for maintaining confidentiality of trade secrets and other proprietary information.

Both surveys requested details of 1986 refinery input and prime product output. The sulfur and aromatics quality of the diesel fuels and the aromatic and benzene content of the gasolines were critical for our study. A summary of gasoline and diesel blending components with appropriate qualities was also requested from all refineries.

The detailed refinery survey requested information about capacity yield, operating parameters, product qualities and feedstocks to all process units necessary for a refinery model. The operating parameters of interest include hydrogen consumption/production, operating pressure and severity including sulfur reduction. The less detailed questionnaire requested this information about processes used in the production of gasoline and diesel fuel.

The detailed refinery survey required information on fixed and variable operating costs which were used in the calibration of the model.

TABLE IV.1

1986 CALIFORNIA REFINERY GROUPS

Group I: Topping

Conoco	-	Santa Maria
Edington	-	Long Beach
Witco Chemical	-	Oildale
MacMillon	-	Signal Hill
Oxnard	-	Oxnard
San Joaquin	-	Bakersfield
Huntway	-	Benicia
Huntway	-	Wilmington
Gibson	-	Bakersfield

Group I Operating: 9(1)

Group II: Hydroskimming

Beacon	-	Hanford
Kern Oil	-	Bakersfield
Newhall	-	Newhall
Paramount	-	Paramount
Sunland	-	Bakersfield

Group II Operating 5(2)

Group III: Conversion

Chevron	-	Richmond
Fletcher	-	Carson
Golden West	-	Santa Fe Spr.
Pacific RFG	-	Hercules
Texaco	-	Bakersfield
Unocal	-	Los Angeles

Group III Operating 6

Group IV: Deep Conversion - Without Hydrocracking

Shell	-	Wilmington
Union Pacific	-	Wilmington

Group IV Operating: 2

Group V: Deep Conversion - LA Basin

Arco	-	Carson
Chevron	-	El Segundo
Mobil	-	Torrance
Texaco	-	Wilmington

Group V Operating: 4(3)

Group VI: Deep Conversion - Northern California

Exxon	-	Benicia
Shell	-	Martinez
Tosco	-	Martinez
Unocal	-	Rodeo and Santa Maria

Group VI Operating: 4

Total Refineries Operating: 30

(1) 7 refineries shut down
(2) 2 refineries shut down
(3) 1 refinery shut down

Both refinery groups were requested to provide details about planned changes in crude and product slate, feedstocks and process modifications and additions.

Following a review of the completed questionnaires, a final selection was made about the refineries to be modeled. The selection was based on appropriate size and configuration of the refinery and completeness of survey data.

The following refineries were modeled in this study:

Group	Description	Refinery/Location
I	Topping	Not modeled *
II	Hydroskimming	Kern Oil Bakersfield
III	Conversion	Unocal - Los Angeles
IV	Deep Conversion - w/o hydrocracking	Shell - Wilmington
V	Deep Conversion - LA Basin	ARCO - Carson
VI	Deep Conversion - Northern CA	Exxon - Benicia

* Since topping refineries generally do not produce gasoline and only produce a small volume of diesel, no model was used for this refinery type. The costs for this refinery type were estimated outside the LP model.

In order to maintain confidentiality of proprietary data received thru these questionnaires no data or results will be provided for groups of less than four refineries in this study.

C. 1986 Basis

Prior to analyzing the impact of reduced aromatics and sulfur levels in motor vehicle fuels, ADL reviewd actual 1986 operating data. The most important elements of data included feedstock input, product yield, diesel sulfur and aromatics levels and gasoline grade split, octane and aromatics content.

The most important source of data on refinery operation and product quality was provided by the refinery survey which was described in the previous section. The California Energy Commission (CEC) also provided valuable 1986 statistics on refinery input and output for five of the six refinery groups selected by Arthur D. Little. (The CEC combined groups III and IV to protect the confidentiality of the two refineries in Group IV). The CEC's 1986 and 1987 Biennial Fuels Reports and 1986 Quarterly Oil Reports were also reviewed in this study.

Additional information was obtained from the following sources. This information was particularly useful in identifying current diesel sulfur and aromatics content and gasoline aromatics content.

- Motor Vehicle Manufacturers' Association (MVMA) Survey of 1986 California Diesel Fuel and Gasoline Quality;
- 1986 Coordinating Research Council Study of Vehicle Emissions influenced by benzene content of gasoline;
- CARB Benzene Control Plan, 1986;
- CARB Diesel Fuel Specification Survey, 1984;
- National Petroleum Council U.S. Refining Survey, 1986;
- National Petroleum Refiners Association (NPRA) 1986 Survey of Industry Capability to Meet Low Sulfur Diesel Fuels, (Results were provided by the NPRA for the refinery groups identified by ADL);
- U.S. EPA report on Diesel Fuel Quality Effects on Emissions, Durability and Performance, 1985; and
- U.S. EPA Draft Report on Economic Impact of Restriction of Sulfur and Aromatics Content of Diesel Fuel, 1987.
- California Department of Transportation 1987 Fuel Forecast - December 1987
- 1987 National Petroleum Council (NPC) outlook
- 1987 Department of Energy Long Range Energy Projection

The Arthur D. Little proprietary LP model contains representations of standard refinery processes, yields and operating costs for several crude oils typically available in California. Refinery stream qualities including aromatics by type (i.e. benzene, mono-, poly- and total aromatics) and sulfur content were estimated for each crude oil. Qualities were obtained directly from crude oil assays or where not directly available from correlations derived from crude oil assays and technical literature. Correlations were necessary to develop some aromatics data and most polycyclic aromatic hydro-carbon data, since information on many crude oil streams and some process streams was not directly available. The model also contains typical product blending options and product specifications. A generalized description of this model is included in Appendix A.

The generalized LP model was modified to represent the selected refinery from each group identified in the previous section. The modifications were made based on data provided via the refinery survey. Since the survey data was confidential we cannot provide detailed descriptions of individual refineries modeled in this report. However, a general description of major refinery types with generalized flow diagrams is included in Appendix A.

D. Validation of Models

Each of the selected refineries were calibrated versus actual 1986 refinery operation. The models were formulated to match actual refinery configuration, capacity, processing flexibility, input and product output based on the information provided in the refinery survey. The refining companies were given the opportunity to comment on ADL's 1986 calibration results before they were finalized.

The refinery models were calibrated in four areas.

- Material Balance: matched volume of crude oil and other feedstock input and volume of prime product output. The volumes of LPG and petroleum coke were not controlled in this analysis. The average gravity and sulfur of the crude oil selected by the model matched actual operation. Crude oils typically used in California were used in this modelling study;
- Process Unit Utilization: process utilization, severity (i.e. FCC and hydrocracker severity) and feedstock selection was matched against actual operation;
- Prime Product Qualities: met or exceeded the qualities shown on Table IV.2. Tighter specifications used by some modelled refineries were included in the calibration. Data on diesel aromatics content from the refiner survey was very limited; and
- Operating Costs: fixed, variable and total cash costs were compared with actual operation. Actual unit costs for electricity and manpower (i.e. ¢/Kwh and $/person/year) provided by refiners was used in the model.

Arthur D. Little sent the results of the calibration runs to the appropriate refinery representatives for their review. Comments received from the refiners were considered and incorporated in the final model calibrations.

E. Scale-up of 1986 Results

The data obtained from the refinery surveys and LP modelling work was scaled up for the overall state and compared to published sources. The overall California material balance (volume of material input and output) based on our refinery survey is compared to CEC statistics on Table IV.3. The data from Groups III-VI were quite similar between those two sources. However, there were several refineries from Groups I and II which did not respond to our survey. The CEC volumes were therefore larger than the survey data for these two groups. The CEC data was chosen as the basis for Groups I and II in order not to underestimate total gasoline and diesel volume.

The material balance on prime products is within 0.3% for the entire state. The biggest difference between the ADL survey data and the CEC data is in the "other products" category. This difference is due to some refiners reporting unfinished product in the "other products" category, while other refiners call it "unfinished feedstock". To correct this problem, the difference between the CEC and refinery submissions in the "other products" category has been applied to "other feedstocks" in the CEC category. This correction substantially improved the overall material balance.

TABLE IV-2
CALIFORNIA PRODUCT SPECIFICATIONS

SPECIFICATION	UNITS	MINIMUM/ MAXIMUM	LPG	UNLEADED REGULAR	UNLEADED PREMIUM	LEADED REGULAR	LEADED PREMIUM	NAPHTHA JET	KEROSENE JET	LOW-SULFUR DIESEL	HIGH-SULFUR[3] DIESEL	LOW-SULFUR FUEL OIL	HIGH SULFUR FUEL OIL
Road Octane*	(R+M)/2	Minimum	--	87.0	92/91	88.0	92	-	-	-	-	-	-
RVP*	psia	Minimum	-	-	-	-	-	2.0	-	-	-	-	-
		Maximum	225	9.8	9.8	9.8	9.8	3.0	-	-	-	-	-
TEL*	Gm/Gal	Maximum	-	0	0	0.1(4)	0.1(4)	-	-	-	-	-	-
Butane*	Vol %	Maximum	10	-	-	-	-	-	-	-	-	-	-
ASD Distillation % off at:													
150*	°F	Minimum	-	12	12	12	12	-	-	-	-	-	-
		Maximum	-	33	33	33	33	-	-	-	-	-	-
160	°F	Minimum	-	15	15	15	15	-	-	-	-	-	-
		Maximum	-	35	35	35	35	-	-	-	-	-	-
210*	°F	Minimum	-	39	39	39	39	-	-	-	-	-	-
		Maximum	-	57	57	57	57	-	-	-	-	-	-
230	°F	Minimum	-	49	49	49	49	-	-	-	-	-	-
330	°F	Minimum	-	84	84	84	84	-	-	-	-	-	-
		Maximum	-	95	95	95	95	-	-	-	-	-	-
400	°F	Minimum	-	-	-	-	-	60	10	-	-	-	-
Smoke pt*	mm	Minimum	-	-	-	-	-	-	20	-	-	-	-
Specific Gravity*		Minimum	-	-	-	-	-	0.751	0.775	0.816	0.816	-	-
		Maximum	-	-	-	-	-	0.802	0.840	0.876	0.876	0.997	0.997
Sulfur*	wt %	Maximum	-	0.03	0.03	0.15	0.15	0.40	0.30	0.05	0.50	0.25[1] (0.5)[2]	3.0
Cetane Index*		Minimum	-	-	-	-	-	-	-	40	40	-	-
Luminometer No		Minimum	-	-	-	-	-	44	40	-	-	-	-
Pour Point*	°F	Maximum	-	-	-	-	-	-	-	0	0	125	-
Olefins	Vol %	Maximum	5	15[5]	15[5]	15[5]	15[5]	-	-	-	-	-	-
Aromatics	Vol %	Maximum	-	-	-	-	-	25	20	-	-	-	-
Viscosity at 122 °F	Furol	Minimum	-	-	-	-	-	-	-	-	-	45	45
		Maximum	-	-	-	-	-	-	-	-	-	300	300
Viscosity at 122 °F	Centistokes	Minimum	-	-	-	-	-	-	-	-	-	-	-
		Maximum	-	-	-	-	-	-	-	3.5	3.5	-	-
Viscosity Index at 122 °F*	Refutas	Minimum	-	-	-	-	-	-	-	-	-	20.21	20.21
		Maximum	-	-	-	-	-	-	-	16.46	16.46	38.125	38.125
Flash Index		Maximum	-	-	-	-	-	-	705	378	378	208	208

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* Specifications modelled (1) Southern, CA (2) Northern, CA (3) Also No. 2 Fuel oil (4) Zero lead beyond 1990 (5) Max. Bromine No. 30

TABLE IV.3

1986
California Material Balance[1]
MB/D

	CEC	Refinery Submissions	Delta
Output:			
Mogas	877.6	887.7	(10.1)
Kerosene	196.3	211.4	(15.1)
Distillate	301.2	287.3	13.9
Residual Fuel	254.9	247.5	7.4
S.T. Prime Products	1630.0	1633.9	(3.9)
Other Products	413.4	479.9	(66.5)[2]
Total Output	2043.4	2113.8	(70.4)
Input:			
Crude	1808.7	1813.0	(4.3)
Others	113.5[2]	234.0	(54.0)
Difference from "other products"	66.5[2]		
Total	1988.7	2047.0	(58.3)
Output less Input	54.7	66.8	

[1] Groups 1 and 2 assumed equal to CEC data

[2] Net out difference in "other products" from "other feedstocks"

- in some cases one refinery reports "other products" which are picked up by a second refiner as "other feedstocks".

The quality of 1986 diesel fuel obtained from our refinery survey, the results of the calibration model runs and the 1986 National Petroleum Refiners Association (NPRA) Survey[1] are compared on Table IV.4. The diesel product qualities by group shown on this table (except NPRA) were scaled-up from individual refinery results on a diesel volume basis. The qualities provided from the refinery surveys were used for all refineries in this category. The results from the LP model were used for the modeled refinery in each group. The product qualities for the other refineries were derived from the refinery surveys. The quality differences between the three sources of data is quite small for the overall state indicating a good 1986 LP model calibration. The difference between the highest and lowest sulfur for the state is .04% (0.36% vs. 0.32%) and 2.0% on the aromatics content (32.8% vs. 30.8%). The largest difference on an individual group basis between the three sources is for Group 1's sulfur content. The refinery survey and LP model results indicated a 1.35wt% content, whereas NPRA indicated a 0.79wt% content.

Estimates of 1986 gasoline aromatics and benzene content calculated by ADL is compared on Table IV.5 with results obtained by the ARB. The ARB conducted a refinery survey in April and May 1985 to determine aromatic and benzene contents of gasoline in 1984 and 1990 (Technical Support Document to Proposed Benzene Control Plan - CARB - 5/20/86).

The 1986 modeled aromatics level was calculated on an individual refinery basis and then scaled-up on a gasoline volume basis. The aromatics content for the modeled refineries was obtained from the LP model results. The aromatics content for the other refineries was derived from the refinery surveys. The benzene content of gasoline was obtained from the LP model results. The ratio of benzene to aromatics obtained from the modeled refinery was used as a surrogate for all other refineries in a given group. The gasoline quality from Group II was used as the gasoline quality for Group I. Since Group I refineries must obtain blendstocks from other refineries to produce gasoline, we felt Group II was a reasonable surrogate for these topping refineries.

The ADL aromatics results for 1986 fall betweeen the 1984 and 1990 values as was anticipated. The ADL benzene content of 1.84 vol.% is .05% higher than CARB's 1985 forecast of 1990 results. Overall, however, the aromatics and benzene content calculated by ADL seem reasonable compared to the ARB's results.

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[1] U.S. Refining Industry Capability to Manufacture Ultra Low Sulfur Diesel Fuels - NPRA Survey 1986

TABLE IV-4

1986 Diesel Quality

	VOL. (1)	REFINERY SURVEY			LP MODEL (2)			NPRA	
	MB/D	SULFUR Wt%	AROM Vol%	CETANE Index	SULFUR Wt%	AROM Vol%	CETANE Index	SULFUR Wt%	AROM Vol%
GROUP 1: TOPPING	19.2	1.35	22.2	39	1.35	22.2	39	0.79	22.5
GROUP 2: HYDROSKIMMING	16.5	0.4	30	41.3	0.39	30	43.4	0.33	29.5
GR. 3 & 4: CONV. AND D.CONV	110.8	0.2	33.5	43	0.2	32.3	43.6	0.19	30.1
GROUP 5: D.CONVERSION - LA	86.7	0.38	36.4	44.4	0.38	33.8	44.4	0.46	35.9
GROUP 6: D.CONVERSION - N. CA	54.1	0.26	30	43.8	0.23	26.3	43.8	0.29	29.8
TOTAL:	287.3	0.36	32.8	43.2	0.35	30.8	43.6	0.32	31.6

(1) Includes 23.5 MB/D of military and other off-road diesel. In Group V there is 20.2 MB/D of this material which has a sulfur content of 0.64 wt%, 39.9% aromatics and 43.5 cetane.

(2) LP model results for modeled refineries and survey results for other refineries.

TABLE IV-5

Estimates of Gasoline Aromatics and Benzene Content

		1986 MODELED RESULTS		1984 CARB RESULTS		1990 REFINERS FORECAST	
	MB/D	AROM Vol%	BENZ Vol%	AROM Vol%	BENZ Vol%	AROM Vol%	BENZ Vol%
GROUP 1: TOPPING	1.9	35.3	2.50				
GROUP 2: HYDROSKIMMING	13.0	43.3	3.06				
GR. 3 & 4: CONV. AND D. CONV.	330.0	33.2	1.58				
GROUP 5: D. CONVERSION - LA	282.4	32.3	1.94				
GROUP 6: D. CONVERSION - N.CA	253.5	35.6	2.00				
TOTAL:	880.8	33.8	1.84	33	1.37	34.7	1.79

V. 1991 AND 1995 STUDY BASIS

In order to analyze the impact of changing product qualities on California refineries, a basis was established for 1991 and 1995. The basis includes assumptions on refinery input, refined product output, refinery configuration, and crude product and feedstock prices. All of these assumptions were necessary to define the LP model analysis. The refinery product demand was the most important for the scale-up of modeled refinery results to get overall California impact.

A. Refinery Input

A summary of California refinery input is given on Table V.1 for 1986, 1991 and 1995. The inputs can be generalized into two categories: crude oil and other feedstocks. The 1986 data was obtained from the refinery surveys and from CEC data (Groups I and II).

Other feedstock inputs were assumed to remain constant into the future for the overall state. Within the LP model analysis for the five selected refineries, the other feedstock input was held constant unless specific information was provided by the refiner to the contrary. Other feedstock qualities in the LP model were also kept consistent with 1986 quality unless data was provided otherwise.

The total volume of crude oil was adjusted from 1986 based on the change in overall refinery product demand (see section V.B for further discussion). Between 1986 and 1991 the crude demand was reduced 0.6% and between 1986 and 1995 it was increased by 2.2%.

The adjustment of crude availability by type was based on CEC and ADL forecast. The assumed changes for 1991 and 1995 are given below:

	1991	1995
	% change over 1986	% change over 1986
ANS	(25.2)	(27.6)
OCS	80.0	80.0
Other California	6.1	4.7
Foreign	23.8	105.9

The crude slate shown on Table V-1 shows only one volume for California crude, but in the LP model analysis, ANS, OCS and other California crudes were modeled separately. The crude slate for each modeled refinery was escalated from the 1986 level based on the above information. This was done unless specific information was obtained from a refinery about future operation.

The average crude quality for the modeled refineries is shown below for 1986, 1991 and 1995. The average crude slate qualities were almost identical for all three years. The sulfur content increased slightly

TABLE V.1

1986, 1991 and 1995 California Refinery Input

1986 CALIFORNIA REFINERY INPUT

	ALASKAN MB/D	CALIF MB/D	FOREIGN MB/D	TOTAL CRUDE MB/D	MOGAS STOCKS MB/D	DIST STOCKS MB/D	OTHER STOCKS MB/D	TOTAL INPUT MB/D
GROUP 1: TOPPING	9.5	66.7	0	76.2	0	0	0	76.2
GROUP 2: HYDROSKIMMING	17.3	59.6	1.3	78.2	2.6	0.2	0.7	81.7
GR. 3 & 4: CONV./D. CONV.	265	320	45.9	630.9	56.6	7.6	108.4	803.5
GROUP 5: DEEP CONVERSION - LA	242.9	296.1	43.8	582.8	4.1	0.6	14.6	602.1
GROUP 6: DEEP CONVERSION - N. CA	174	262.2	8.7	444.9	4	1.6	32.2	482.7
CALIFORNIA TOTAL	708.7	1004.6	99.7	1813	67.3	10	155.9	2046.2

1991 CALIFORNIA REFINERY INPUT

	ALASKAN MB/D	CALIF MB/D	FOREIGN MB/D	TOTAL CRUDE MB/D	MOGAS STOCKS MB/D	DIST STOCKS MB/D	OTHER STOCKS MB/D	TOTAL INPUT MB/D
GROUP 1: TOPPING	7.1	68.6	0.0	75.7	0.0	0.0	0.0	75.7
GROUP 2: HYDROSKIMMING	12.9	63.2	1.6	77.7	2.6	0.2	0.7	81.2
GR. 3 & 4: CONV./D. CONV.	198.2	372.1	56.8	627.1	56.6	7.6	108.4	799.7
GROUP 5: DEEP CONVERSION - LA	181.7	343.4	54.2	579.3	4.1	0.6	14.6	598.6
GROUP 6: DEEP CONVERSION - N. CA	130.2	301.3	10.8	442.2	4.0	1.6	32.2	480.0
CALIFORNIA TOTAL	530.1	1148.6	123.4	1802.1	67.3	10.0	155.9	2035.3

1995 CALIFORNIA REFINERY INPUT

	ALASKAN MB/D	CALIF MB/D	FOREIGN MB/D	TOTAL CRUDE MB/D	MOGAS STOCKS MB/D	DIST STOCKS MB/D	OTHER STOCKS MB/D	TOTAL INPUT MB/D
GROUP 1: TOPPING	6.9	71.0	0.0	77.9	0.0	0.0	0.0	77.9
GROUP 2: HYDROSKIMMING	12.5	64.7	2.7	79.9	2.6	0.2	0.7	83.4
GR. 3 & 4: CONV./D. CONV.	191.9	358.4	94.5	644.8	56.6	7.6	108.4	817.4
GROUP 5: DEEP CONVERSION - LA	175.9	329.6	90.2	595.6	4.1	0.6	14.6	614.9
GROUP 6: DEEP CONVERSION - N. CA	126.0	310.8	17.9	454.7	4.0	1.6	32.2	492.5
CALIFORNIA TOTAL	513.1	1134.5	205.3	1852.9	67.3	10.0	155.9	2086.1

from 1986 to 1991/1995. The crude gravity returned to the 1986 level in 1995 after decreasing slightly in 1991.

	1986	1991	1995
Sulfur, wt%	1.09	1.10	1.10
Gravity, °API	25.7	25.3	25.7

Average California crude quality over the 1986 to 1995 period is similar to the quality of ANS crude (26.3 ° API and 1.01%S).

B. Product Demands

Refined product demand for this analysis was based on the CEC's forecast given in the 1987 "Biennial Fuels Report". This forecast was chosen over published DOE and NPC forecasts since it included a regional breakdown of product demand. This forecast was used in lieu of other state agency forecasts because it also included an energy (crude and natural gas) and product price forecast. Since the major thrust of ADL's research project was to determine the impact on refining costs rather than on a detailed supply/demand balance, ADL chose not to develop an independent forecast. The CEC forecast was chosen because it was a published survey which had been reviewed by the industry and contained a complete and consistent energy and price forecast. The refined product forecast for this analysis is based on the following changes in prime product demand on refining.

	1991 % change over 1986	1995 % change over 1986
Motor Gasoline	(7.0)	(6.3)
Aviation Fuel	16.4	22.3
Diesel Fuel	8.3	14.9
Residual Fuel	(0.4)	2.7
Other Products	(3.7)	1.1
Total	(0.6)	2.2

These changes were applied to the 1986 production levels obtained from the refinery surveys. These changes were applied to Groups I and II. One of the Group III-VI modeled refineries supplied its own demand forecast which was used in this study. The other refineries in Groups III-VI were adjusted so that the overall state totals were escalated by the above CEC forecast percentages. A summary of California refinery output is given on Table V.2 for 1986, 1991 and 1995.

The demand forecast developed by CEC and used in this study shows a decrease in gasoline demand for 1991 and 1995 relative to 1986. ADL is aware of, and has reviewed the California Department of Transportation (CalTrans) - December, 1987 motor fuels forecast which predicts an increase in motor gasoline demand. However, our analysis required that

TABLE V.2

1986, 1991 and 1995 California Refinery Output

1986 CALIFORNIA REFINERY OUTPUT

	MOGAS	KERO/JET	DIST	RESID	OTHER	TOTAL OUTPUT
	MB/D	MB/D	MB/D	MB/D	MB/D	MB/D
GROUP 1: TOPPING	1.9	4	19.2	13.4	36.9	75.4
GROUP 2: HYDROSKIMMING	19.9	6.6	16.5	15.5	20.6	79.1
GR. 3 & 4: CONV. & D. CONV.	330	87.3	110.8	134.8	152.1	815
GROUP 5: D. CONVERSION (LA)	282.4	66.6	86.7	35.2	149	619.9
GROUP 6: D. CONVERSION (N. CA)	253.5	33.1	54.1	48.6	121.3	510.6
CALIFORNIA TOTAL	887.7	197.6	287.3	247.5	479.9	2100

1991 CALIFORNIA REFINERY OUTPUT

	MOGAS	KERO/JET	DIST	RESID	OTHER	TOTAL OUTPUT
	MB/D	MB/D	MB/D	MB/D	MB/D	MB/D
GROUP 1: TOPPING	1.8	4.7	20.8	13.3	35.5	76.1
GROUP 2: HYDROSKIMMING	18.5	7.7	17.9	15.4	19.8	79.3
GR. 3 & 4: CONV. & D. CONV.	315.6	102.6	123.7	132.1	149.1	823.1
GROUP 5: D. CONVERSION (LA)	258.4	77.1	91.8	35.8	133	596.1
GROUP 6: D. CONVERSION (N. CA)	230.6	38.4	57.6	50.8	121.3	498.7
CALIFORNIA TOTAL	824.9	230.5	311.8	247.4	458.7	2073.3

1995 CALIFORNIA REFINERY OUTPUT

	MOGAS	KERO/JET	DIST	RESID	OTHER	TOTAL OUTPUT
	MB/D	MB/D	MB/D	MB/D	MB/D	MB/D
GROUP 1: TOPPING	1.8	4.9	22.1	13.8	36.5	79.1
GROUP 2: HYDROSKIMMING	18.6	8.1	19	15.9	20.4	82
GR. 3 & 4: CONV. & D. CONV.	320.1	107.7	131.1	135.5	158.5	852.9
GROUP 5: D. CONVERSION (LA)	260.6	81.5	96.9	36.9	143.9	619.8
GROUP 6: D. CONVERSION (N. CA)	232.5	40.2	61.6	52.4	106	492.7
CALIFORNIA TOTAL	833.6	242.4	330.7	254.5	465.3	2126.5

we use a forecast which provided details on the energy price assumptions as well as product volumes. The CalTrans report only provided a price forecast on gasoline.

While the CEC forecast was used for total gasoline demand, ADL independently forecast gasoline grade mix. The average grade mix and octane demand for the modeled refineries is given below:

	Octane R+M/2	1986 %	1991 %	1995 %
Leaded	88/91	30	--	
Unleaded Reg.	87	40	65	55
Unleaded Prem.	91/92	15	20	35
Unleaded Mid.	89	15	15	10
Pool Octane		87.5	88.3	89.0

The grade split shown for 1986 is based on average survey results for the modeled refineries. The grade split shown for 1991 is the average for the modeled refiners. The actual 1991 pool octane varied for modeled refiners from 87.7 to 89.0. A range of pool octanes was used in 1991 to account for varied refinery octane capabilities available without investment. The grade mix shown for 1995 was used for all modeled refineries because octane investments were allowed in the base case.

This study measures the changes in gasoline quality and cost rather than the absolute level. The increased pool octane requirement has a greater impact on aromatics content and costs than does gasoline volume alone.

The CEC forecast shows an increase diesel demand in both 1991 and 1995 relative to 1986. The base quality specifications for this diesel is unchanged from 1986 levels in the future base cases.

C. Basic Economic Parameters

1. Crude, Product and Feedstock Prices

Crude oil and feedstock prices used in the LP model analysis were based on the CEC forecast. A summary of refinery model input/out price assumptions prices used is given on Table V.3. The marginal crude in this study was ANS. The ANS crude was input to the LP model at a price while the other crude input volumes were fixed. The price on ANS crude set the cost of energy for the refinery model. Feedstocks such as natural gas, butanes and methanol were also available as needed by the model at a price.

The only refinery products valued in this study were LPG, petroleum coke and BTX. These products required prices since their level of production was not limited. Prices for other prime products were not necessary since their level of production was fixed in the LP model analysis.
The price of MTBE, alkylate, isomerate and ethanol which were available as feedstocks to the LP model were valued as unleaded gasoline

TABLE V.3

INPUT/OUTPUT PRICE ASSUMPTIONS
$/Bbl (1987$)

	1991	1995	Basis
ANS Crude	24.90	26.78	CEC, ADL
Natural Gas(1)	34.56	37.75	CEC
Normal Butane	24.12	25.63	CEC-No. 2 Diesel Parity
ISO Butane	26.22	27.73	ADL - NC_4 + $0.05/gal isomerization cost
Methanol	12.52	16.46	ADL, CEC
LPG	18.60	20.03	CEC - No. 6 Fuel oil parity
MTBE	49.59	53.72	ADL(2)
Ethanol	51.33	55.73	ADL(2)
Isomerate	32.29	33.85	ADL(2)
Alkylate	42.14	44.95	ADL(2)
Low Aromatic Gas Oil	32.76	34.86	CEC No. 2 Diesel Price
BTX	42.92	45.53	ADL(3)

1 Fuel oil equivalent barrels (FOEB)

2 ADL calculated gasoline blending value based on CEC forecast unleaded regular gasoline, nC_4 and implied octane cost. The implied octane cost was $0.58/octane - Bbl in 1991 and $0.67/octane - BBL in 1995 based on CEC forecast price differential between unleaded regular and unleaded premium and an octane spread of 5 numbers. Unleaded Regular Gasoline price was $36.54/B in 1991 and $39.30/B in 1995.

3 Same as (2) except transportation cost to US Gulf Coast excluded.

	Transportation Cost $/Bbl
1991	3.36
1995	4.20

blendstocks. The BTX was valued as a gasoline blendstock with the transportation cost to the U.S. Gulf Coast netted off. The basis for these blendstock calculations was the CEC forecast of unleaded regular gasoline price and the implied octane cost given by the delta between wholesale unleaded regular and unleaded premium prices. A 5 number octane spread between the two unleaded grades was assumed.

Methanol was used as a feedstock to MTBE, Etherol and Mobil Methanol to Olefins processes. The 1991 price is equivalent to 30 cpg and the 1995 price is 39 cpg. To check the sensitivity of methanol price, two 1991 cases were run with methanol at 35 cpg with no change in methanol purchases.

D. Configuration

The 1991 and 1995 configurations were based on the 1986 refinery survey data and any additions which the modeled refineries indicated. There were few changes to the modeled refinery configurations. With the exception of a new 70 MB/D FCC feed pretreater which was streamed by one refinery in 1987, all other additions involved gasoline production. The additions include a new 2.2 MB/D Dimersol unit, 3.5 MB/D of new MTBE capacity and 4 MB/D of increased alkylation capacity.

2. Other Basic Economic Parameters

Other basic economic parameters are shown on Table V.4 in 1987$. Variable and fixed unit costs are based on local California refinery costs. Catalyst and chemicals cost factors are unit specific. Process unit consumption factors for existing refinery processes have been developed by ADL from process licensor and in-house data over an extended period and are proprietory. Process unit consumption factors for new process options are provided in Appendix D.

California new process investments are based on USGC costs with a location factor of 1.05. A capital change factor of 25% of process plus offsites investment has been included in this analysis to provide an approximate 15% discounted cash flow return on investment.

Associated costs for offsites and environmental facilities have been included in our offsites factor. Offsites requirements to support new process investment are highly site specific and can vary from 10% to 100% of inside battery limits (ISBL) process investment. For this reason, we have used a rule of thumb factor for offsites requirements of 50% of (ISBL) process investment for all cases. A specific estimate of best available control technology (BACT) environmental costs is beyond the scope of our analysis.

Process Investment costs are process unit specific. Process unit costs and scale factors are included in Appendix D for all new process options considered.

TABLE V.4

OTHER BASIC ECONOMIC PARAMETERS: 1987$

		1991	1995
Variable Costs:			
Electricity (¢/Kwh)		10	10
Catalyst and Chem	$	(1)	(1)
Cooling Water	$/mGal	.05	.05
Makeup Water	$/mGal	.74	.74
Fixed Costs:			
Manpower:	$/Shift position/dzy	688	688
Maintenance:	% Investment	3.25	3.25
Tax Ins and Other:	% Investment	2.0	2.0
Process Investment			
California vs. USCG		1.05	1.05
Capital Charge Factor:	%	25(2)	25(2)
Offsites, Utilities and Environmental:	% Process	50	50
Process Investment:	$	(1)	(1)

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(1) Process Unit Specific

(2) Approximately equivalent to 15% discounted cash flow return after taxes.

VI. PROCESS OPTIONS FOR REDUCING DIESEL SULFUR, DIESEL AROMATICS AND GASOLINE AROMATICS

A. Process Options for Reducing Diesel Sulfur and Aromatics

1. Process Options Considered

Possible options for reducing aromatics and sulfur in diesel fuels include: short term options with existing capacity, options with new process capacity and non-process options.

Short term options with existing capacity include:

- Changes in kerosene/diesel cutpoint;
- Full utilization of existing hydroprocessing capacity;
- Increases in hydroprocessing severity; and
- Upgrading hydroprocessing catalyst.

Options with new processing capacity will take more time to implement and will be more costly, but can provide further reductions in diesel sulfur and aromatics content.

Possible process options include:

- Low severity distillate hydrotreating;
- Moderate severity distillate hydrorefining;
- Noble metal catalyst distillate hydro-dearomatization;
- High severity hydrorefining/mild hydrocracking;
- Hydrogen plant;
- Aromatics extraction;
- Mobil methanol to olefins (MTO) process to produce mixed light olefins; and
- Mobil olefins to gasoline and distillate (MOGD) process to convert refinery or MTO olefins to low aromatics, high cetane distillate.

High severity hydroprocessing and extraction of diesel aromatics were dropped from consideration in our initial technology review. High severity hydroprocessing using conventional catalyst is the process route selected for aromatics reduction in the current study by the

U.S. EPA.[1] Units would operate in the range of 1,500-2,000 psig and could remove over 99% of feed sulfur, reduce aromatics 40 to 70% and increase cetane index 10 to 25 numbers. In order to achieve this level of sulfur and aromatics reduction using conventional catalyst, however, we would expect about 25% conversion of distillates to lighter products with this process. The process is not currently commercially available on distillate feedstock. Since this process results in significant conversion of distillate to lighter products it was dropped in favor of the two stage hydroprocessing route discussed below.

Distillate aromatics extraction was dropped from consideration due to limited markets for disposal of high aromatic content distillate boiling range material (similar to pyrolysis distillate).

Non-process options include segregation of No. 2 fuel and diesel products (so that only diesel stocks need to be improved) and purchase of low aromatics/low sulfur blendstocks from outside California. Refining ability to segregate No. 2 fuel and diesel products will be limited by product supply restrictions (more significant in the U.S. Gulf Coast than California due to use of common carrier pipelines). The availability of low aromatics/low sulfur blendstocks in California from other US regions will be severely limited if the US EPA mandates reduction of diesel sulfur and aromatics on a national basis.

2. Process Options Selected

New process options selected for reduction of diesel sulfur and aromatics are shown on Figure VI along with existing process options. Also shown on Figure VI are relative sulfur and aromatics content of existing and new process distillate blend streams.

Existing diesel blends are composed of the following components:

	% Sulphur	% Aromatics
Straight Run Distillate	0.07 - 1.2	12-28
Hydrotreated Straight Run Distillate	0.02 - 0.3	11-26
Cracked Distillate	0.1 - 5.8	30-80
Hydrotreated Cracked Distillate	0.02 - 1.5	24-64
Hydrorefined Distillate	.02 - 0.3	10-56
Hydrocracked Distillate	0.02	25

Although hydrotreated, hydrorefined and hydrocracked distillate are at low sulfur levels, all three streams contain significant levels of aromatics and additional processing will be required to reach low diesel aromatics levels.

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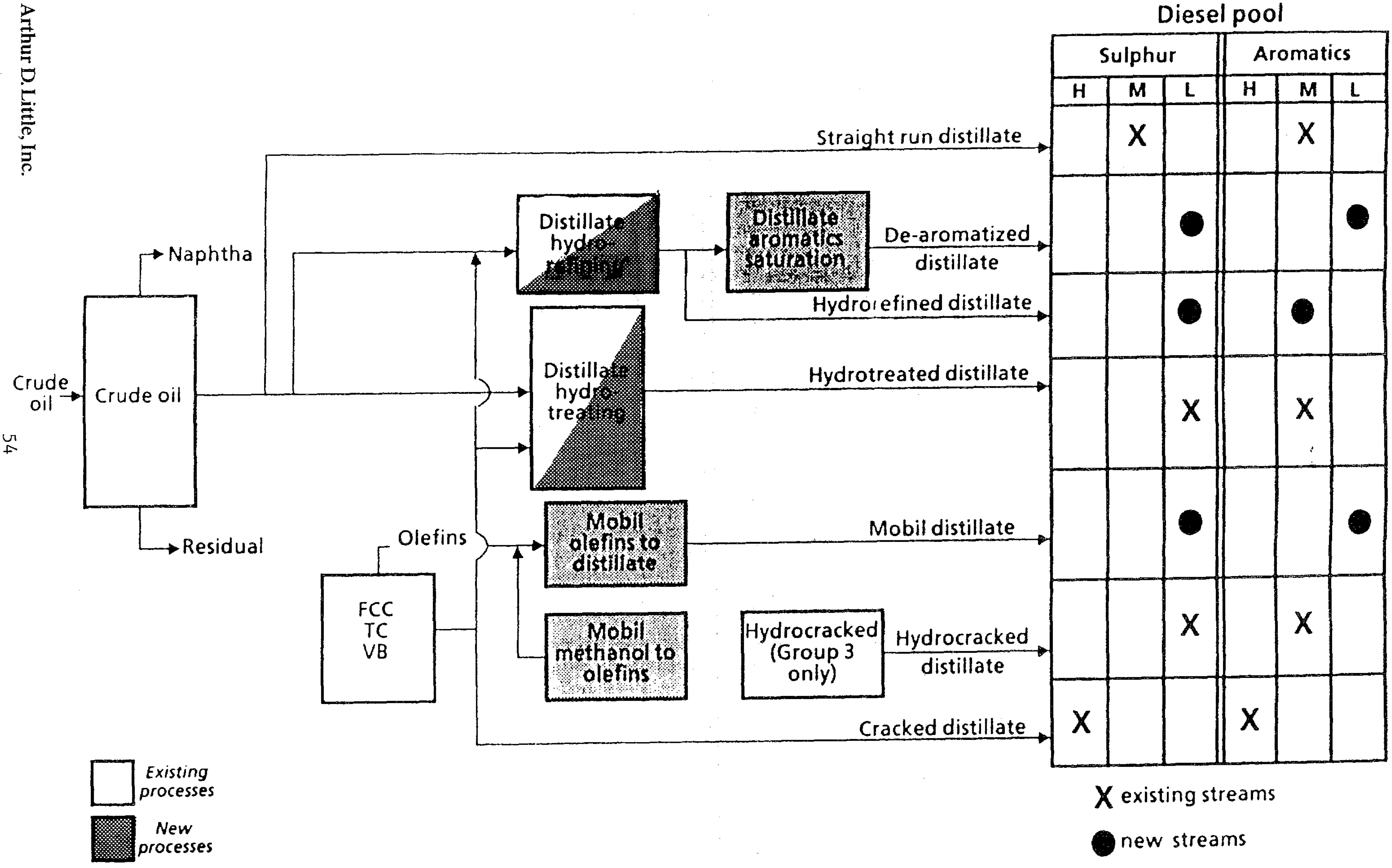
[1] A study on "Restriction of Sulfur and Aromatics Content of HIghway Diesel Fuel" Draft Report for U.S. Environmental Protection Agency by Bonner & Moore Management Science, June 24, 1987.

FIGURE VI

PROCESS OPTIONS FOR REDUCING DIESEL SULPHUR AND AROMATICS



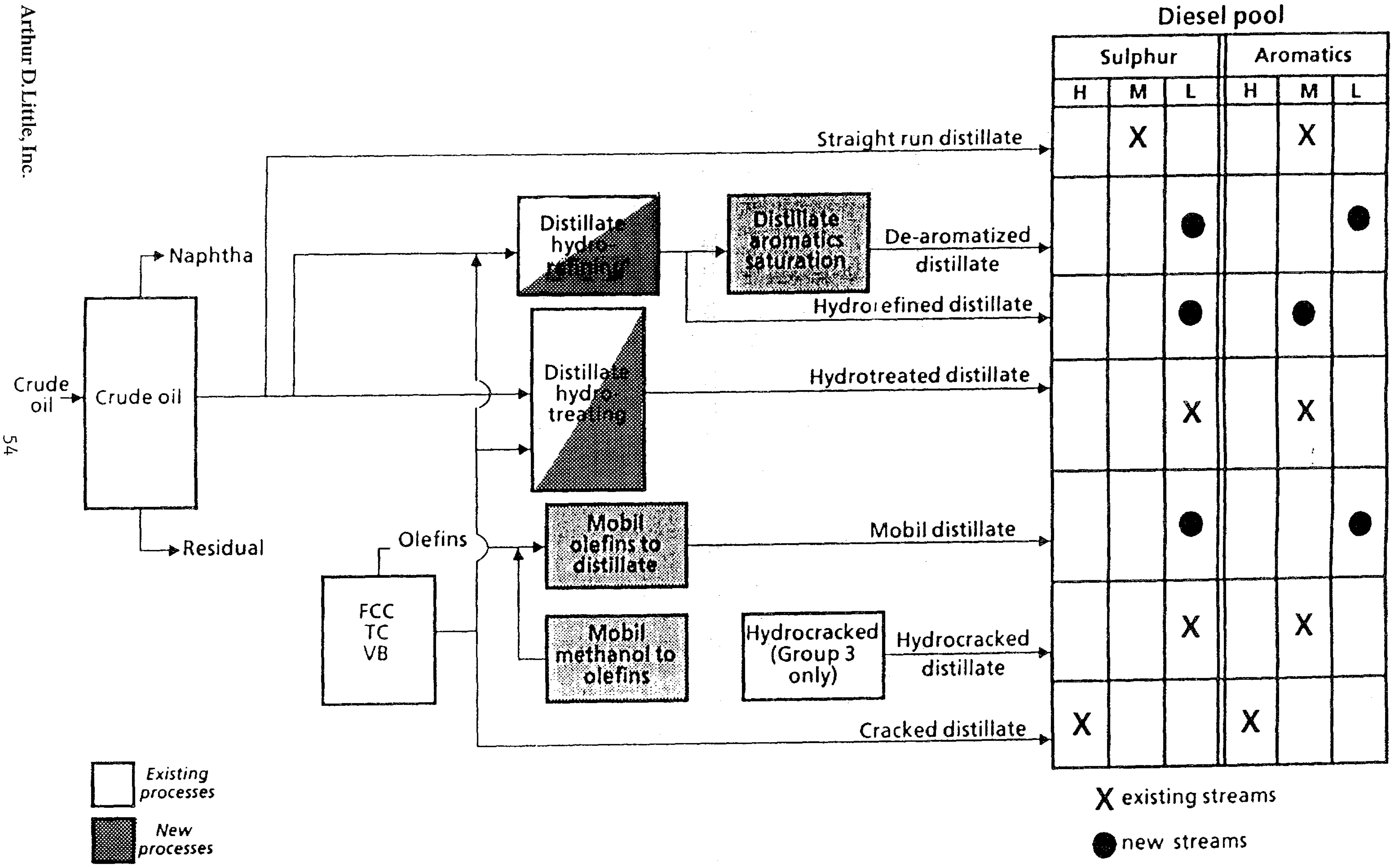
Diesel pool	Sulphur			Aromatics		
	H	M	L	H	M	L
Straight run distillate		X			X	
De-aromatized distillate			●			●
Hydrorefined distillate			●		●	
Hydrotreated distillate			X		X	
Mobil distillate			●			●
Hydrocracked distillate			X		X	
Cracked distillate	X			X		

X existing streams

● new streams

FIGURE VI

PROCESS OPTIONS FOR REDUCING DIESEL SULPHUR AND AROMATICS



	Sulphur			Aromatics		
	H	M	L	H	M	L
Straight run distillate		X			X	
De-aromatized distillate			●			●
Hydrorefined distillate			●		●	
Hydrotreated distillate			X		X	
Mobil distillate			●			●
Hydrocracked distillate			X		X	
Cracked distillate	X			X		

The first process option likely to be selected for reduction of diesel sulfur level is full utilization of existing distillate hydrotreating and hydrorefining capacity. Standard distillate hydrotreaters are low pressure (about 650 psig), and can remove about 85% to 95% of feed sulfur although aromatics reduction is limited to 5% to 20%. Distillate hydrotreating is a well known commercial process and new capacity is estimated to cost about 18 million $ for inside battery limits (ISBL) investment for a 30 MB/D unit. Accuracy of cost estimates for established commercial processes is estimated at ±25-30%.

New Distillate Hydrorefining can further reduce distillate sulfur level and marginally improve aromatics. Distillate hydrorefiners are moderately high pressure, moderately high severity with high levels of sulfur removal and moderate reduction in aromatics levels. Units operate in the range of 900-1500 psig, remove over 95% sulfur and reduce nitrogen levels to about 1 ppm. Aromatics can be reduced up to 20 to 30% and cetane index improvement by 2 to 7 numbers. Distillate hydrorefining is fully commercialized and estimated to cost about 32 million $ ISBL for a new 30 MB/D unit.

The major process we have selected for reduction of diesel aromatics reduction is distillate hydro-dearomatization. This is a two stage process designed to decrease sulfur levels, reduce aromatics levels and improve cetane index. The first stage is a distillate hydrorefiner (described above) to reduce nitrogen and sulfur content to very low levels. The second stage can accept low nitrogen/low sulfur feed from existing or new distillate hydrorefiners and operates at a moderate pressure of about 1,000 psig with a noble metal catalyst. The process requires very low sulfur/low nitrogen feed due to the noble metal catalyst but can be designed for aromatics removal of over 70% and cetane index improvement of 10 to 25 numbers with little conversion of distillate to lighter products. This process is <u>not currently commercially available on distillate feed</u>, but has operated successfully on kerosene feed in a number of commercial units. Pilot plant studies by process licensors on distillate boiling range feed indicate that the process could be commercialized to reduce aromatics levels in diesel. Process licensor estimates for the two stage process are about 53 million $ ISBL for 30 MB/D of capacity.[2] The level of accuracy for this developing process is estimated at ± 40 to 50%.

The new Mobil Methanol to Olefins to Distillate (MOGD) Process produces low sulfur, low aromatics distillate. This is a two stage

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[2] Costs are based on the UOP AH Unibon process extrapolated from commercial processing of straight run distillates. To provide definitive estimates of processing Light Cat Cycle Oil (LCO), UOP would need to conduct a pilot plant program followed by some engineering design and estimating work.

process for converting methanol to olefins and olefins to distillate. The second stage can operate independently on refinery produced olefins or from olefins produced in the first stage. Although there are no current commercial units, the MOGD process is similar to commercially available Mobil Methanol to Gasoline (MTG) process and has been tested in a semi-commercial size unit. Process licensor-estimates for the two stage process are about 68.5 million $ ISBL for 20 MB/D of olefins capacity (7.7 MB/D distillate, 3.5 MB/D jet fuel and 1.8 MB/D gasoline product). The level of accuracy of costs for this developing process is estimated at ± 40-50%. The economics of the MOGD process will be highly dependent on future price differentials between conventional hydrocarbons and methanol.

In our opinion both the distillate hydro-dearomatization and Mobil MOGD processes could be commercially available by the early to mid-1990s if reduction of diesel aromatics levels is mandated on a state or national level. Detailed process cost, feedstock and product quality information is provided for each selected process option in Appendix D.

B. Process Options for Reduction of Gasoline Aromatics

Lead phasedown removed an important source of octane from the gasoline pool which caused refiners to add new reforming capacity, increase reformer severity and move to FCC octane promoting catalysts. These processing changes increased gasoline volatility and aromatics content which now may be limited by environmental legislation. Reduction of gasoline volatility will further reduce pool octane capability and could cause gasoline aromatics levels to increase in order to replace lost gasoline octane. Thus, process options to reduce gasoline aromatics cannot be considered without also considering their impact on gasoline octane and volatility. A listing of major refinery process options and their impact on gasoline octane, volatility and aromatics is shown on Table VI.1.

New continuous catalytic reforming would increase aromatics. However, continuous reforming would both improve gasoline yield and reduce butane yield at the same octane -- offsetting some of the increase in volatility accompanying increased severity of operation. Use of FCC octane promoting catalyst is also accompanied by increased production of aromatics, olefins and butanes which will increase volatility unless there is sufficient alkylation or condensation capacity available to absorb incremental production. Taking a heart cut from FCC gasoline for hydrotreating and catalytic reforming will increase octane but will also result in increased production of aromatics and ultimate gasoline volatility. All of the condensation processes -- aklylation, cat poly and dimersol -- will increase pool octane, reduce gasoline volatility and decrease pool aromatics. Extraction and reblending of BTX with sale of light raffinate can reduce gasoline volatility through the elimination of a high RVP, low octane component but will increase aromatics. If BTX is sold, octane will be reduced but aromatics content and volatility will improve. Isomerization processes increase octane substantially but also increase gasoline

TABLE VI.1

PROCESS IMPACT ON OCTANE RVP AND AROMATICS

	STATUS	OCTANE	RVP	AROMATICS
Reforming	C	+	-	-
FCC Octane Promoting Catalyst	C	+	-	-
FCC Heart Cut/Reforming	C	+	-	-
Alkylation, Cat. Poly, Dimersol	C	+	+	+
Isomerization	C	+	-	+
MTBE	C	+	+	+
Etherol	NC	+	+	+
Cyclar	D	+	+	-
BTX Extraction	C	-	+	+
Lt. FCC H.T./Extraction*	C	-(+)	+	+

Status: C-Commercial; NC-New Commercial; D-Developing

Impact: + positive; - negative

volatility. Both MTBE and the new BP Etherol process provide a high octane, low volatility, low aromatics product through the reaction of methanol and iso-olefins. The developing UOP/BP Cyclar process can convert LPG and butane into benzene. If butane is the feedstock for this process, the result is a significant increase in octane and decrease in volatility, but an increase in aromatics level. Extraction of BTX from light FCC gasoline will result in a decrease in volatility and aromatics but a loss of octane. Accompanied by a change in octane promoting catalyst it may be possible to get an increase in octane while improving volatility and aromatics via this route.

U.S. refiners have been adding capacity to increase octanes to meet lead phasedown. Actual capacity additions since 1985 and announced capacity additions through 1989 are shown in Table VI.2. As discussed above, some of these capacity additions to improve octanes will also improve volatility but others will improve octane at the expense of increased gasoline volatility and increased aromatics levels. There have been major conversions of high pressure to low pressure reforming, conversion of stacked reactor reformers to continuous regeneration operation, and additions to alkylation, cat poly and dimerization capacity. Isomerization capacity will have <u>tripled</u> over the 1985-1991 period in order to meet lead phasedown. Certainly refinery process selection would have been different if refiners had designed to increase octane, decrease volatility and decrease aromatics at the same time!

2. Process Options Selected for Reduction of Gasoline Aromatics

Options to reduce gasoline aromatics include options with existing process equipment, options with new or modified process equipment, and blending options.

Options to reduce gasoline aromatics with existing processing include modification of product cut points, reduced severity of catalytic reforming, reduced cat cracking severity, full utilization of aromatics extraction capacity, and increased utilization of light napththa isomerization, alkylation and catalytic polymerization (cat poly) capacity.

Two of the general options with existing equipment will have little application in California:

- There is no existing BTX extraction in California; and
- Utilization of cat poly capacity will be limited due to gasoline bromine number restrictions.

New conventional process options considered to reduce gasoline aromatics include:

- Reformer modifications and new continuous reforming capacity to improve reformer yields;

TABLE VI.2

1985-1986 REFINERY PROCESS ADDITIONS TO MEET LEAD PHASEDOWN

Process	1/1/85	1/1/89(1)	Change
High Pressure Reforming	702	411	(291)
Low Pressure Reforming	2,523*	2,814	291
Continuous Reforming	446*	601	155
Alkylation	913	959	46
Cat Poly	74	47	(27)
Dimersol	12	18	6
Once Through Isomerization	106	318	212
Recycle Isomerization	15	53	38

* Estimated split between low pressure and continuous reforming.

(1) 1/1/88 <u>Oil & Gas Journal</u> capacities plus announced additions.

- Extraction to remove BTX from reformate for sale;
- Alkylation to convert olefins and isobutane to high octane, low aromatics alkylate;
- Catalytic polymerization and dimerization to convert olefins to polymer gasoline;
- Isomerization to upgrade octane of light straight run and natural gasoline without increasing aromatics;
- MTBE to produce a high octane, low aromatics gasoline blend component from C_4 olefins and methanol;
- Etherol to produce a high octane low aromatics blend component from mixed FCC olefins and methanol;
- Separation of light FCC gasoline followed by mild hydrotreating and extraction of BTX for sale.[3]

While many of these conventional techologies do not directly remove aromatics, they can decrease pool aromatics content through the blending of low aromatics content streams and will replace octanes lost due to declines in reformer severity and aromatics extraction.

Increased catalytic reforming severity accompanied light reformate extraction and sale of aromatics can maintain octane without increasing overall pool aromatics content. Similarly, loss of octane due to extraction of BTX from light FCC gasoline can be offset by the use of FCC octane promoting catalysts with no increase in pool aromatics content.

All of the above process options were available in our LP model analysis although the use of catalytic polymerization and dimersol was limited to prevent increase of gasoline olefins content. Standard costs have been used in our LP model for all of these conventional refinery processes.[3] The level of accuracy of cost estimates for these conventional refinery processes is estimated at ± 25-30%.

In addition to processing options, it is possible to reduce gasoline aromatics levels by displacement of high aromatics blendstocks and purchase of low aromatics/high octane blendstocks.

As discussed above, BTX was extracted for sale in order to reduce gasoline aromatics. Octane lost due to displacement of BTX was replaced with other process options.

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[3] Although not common practice, separation, mild hydrotreating and BTX extraction of lt. FCC gasoline is a combination of conventional refinery process steps.

Purchased blend components available to our LP model in our sensitivity analysis included:

- MTBE;
- Ethanol;
- Isomerate; and
- Alkylate.

Methanol blends were not considered to be a viable general blending option but may also be used by some refiners. It is uncertain if low aromatics blendstocks will be available at gasoline blending value -- particularly if reduction of gasoline aromatics is mandated in other U.S. regions. In addition, many forecasters are projecting shortages of methanol and isobutylene in the 1990's which could limit MTBE availability.

VII. STUDY METHODOLOGY

A. Common Methodology

The first step in both the gasoline and diesel analysis was to develop a base case without new investment for the 1991 and 1995 analysis. The selected refinery LP model for each group was run to meet projected gasoline, diesel and other product demand using projected crude slate and other refinery feedstocks. Refinery capacity and process limitations were as in 1986 or as provided by modeled refineries for future periods including announced additions to capacity.

Target product qualities were as provided by modeled refineries or based on ASTM and California specifications as shown on Table IV.2. Base case gasoline and diesel quality was estimated for each selected refinery and compared to 1986 model results. The ratio of future quality to 1986 quality in the modeled refinery was applied to 1986 quality for other refineries in each group to get projected future gasoline and diesel quality.

The only feedstocks and products that were permitted to vary in the LP model were:

- Marginal crude oil processed (Alaskan North Slope),[1]
- Purchased butanes,
- Natural gas,
- LPG,
- Methanol,
- MTBE, alkylate, isomerate gasoline blendstocks*,
- Distillate blendstocks*, and
- BTX product*.

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[1] Alaskan North Slope (ANS) crude was selected as the marginal crude for this analysis. Although not all refineries in California run ANS crude, ANS is clearly the marginal, price setting crude and makes up any swing in overall California crude runs with the balance moving to the U.S. Gulf Coast.

* Fixed in the base case.

All other crude, feedstocks and products were fixed in all cases at base case levels and not priced in the LP model.

All primary product demands were maintained at base levels in this analysis such that loss in volume due to aromatics removal, sulfur removal, changes in process severity, etc. must be replaced either through increased crude oil processed or purchase of outside feedstocks. Allowing other prime product volumes to vary would allow refiners to dispose of unwanted sulfur and aromatics in alternate products such as military diesel and No.2 fuel that have limited demand in California.

The LP model was run to estimate changes in total refinery costs in each case including:

- Net feedstock costs.
- Variable operating costs.
- Fixed operating costs.
- Capital investment related costs.

Net feedstock costs include:

- Marginal (ANS) crude oil;
- Butanes, natural gas, methanol, gasoline blendstocks and distillate blendstocks;
- Excess or deficit LPG versus the base case; less
- Petroleum coke and BTX products.

Variable operating costs account for all costs (exclusive of refinery fuel) that vary directly with process thruput and include:

- Catalyst and chemicals,
- Electricity,
- Cooling water,
- Make up water, and
- TEL additive (zero beyond 1990 with unleaded gasoline)

Refinery fuel use and other energy changes are accounted for internally in the LP model and expressed in terms of crude oil costs.

Fixed operating costs account for all costs to maintain and man an existing or new process unit. Although termed "fixed" these costs vary with startup or shutdown of process units. Fixed costs include:

- Maintenance costs,
- Manpower costs, and
- Property tax, insurance and miscellaneous fixed costs.

Capital investment related costs include financial costs to cover depreciation, income tax and return on investment. Capital costs are included at a rate of 25 percent of capital investment which is approximately equivalent to 15% discounted cash flow rate of return after income tax.

As discussed in section IV.A above, the LP model objective function is to minimize costs to meet any imposed constraints (such as reduced diesel and gasoline contaminant level). The model simultaneously analyzes the tradeoffs between different cost paths such as increased feedstock utilization versus increased new process investment to reach the optimal (minimum cost) solution.

Energy requirements were estimated for each case based on standard conversion factors on a crude oil equivalent basis for marginal feedstocks and products plus electricity.

Since our analysis is based on <u>differences</u> in cost versus the base case, no costs or energy requirements are shown in our results for the base case.

A common methodology was applied to estimate the refinery costs to reduce aromatics levels in diesel fuel, reduce aromatics levels in gasoline, and reduce sulfur levels in diesel fuel. Each case was analyzed separately, however, to determine the refining cost of reducing each contaminant level in each motor vehicle fuel. In each case all primary product volumes were maintained such that loss in product volume due to aromatics removal, sulfur removal, changes in processing severity, etc. was replaced either through increased crude oil processed or purchase of outside feedstocks.

Cases were analyzed both with and without allowing purchase of outside feedstocks. Outside feedstocks that were considered include:

- Oxygenates (MTBE and ethanol),
- Gasoline blendstocks (alkylate and isomerate), and
- Distillate blendstocks (low sulfur distillate).

In order to estimate the net feedstock cost impact, prices were developed for each of these feedstocks and for BTX product consistent with the underlying crude oil and product price forecast. Net feedstock cost was the sum of crude oil and outside feedstock costs less credits for aromatics removed.

The only change permitted in crude oil slate was in the volume of the marginal crude oil processed (Alaskan North Slope). All other crude oil inputs were fixed to levels determined in the base case analysis. Whereas crude slates may be modified by individual refineries, California as a whole is surplus in crude production (including availability of Alaskan crude) and is unlikely to import major quantities of crude from overseas or the Gulf coast to displace local production.

For each case we estimated the change in net feedstock costs, variable costs, fixed costs and capital costs (new investment cases only) to reduce contaminant levels relative to the base case for the modeled refinery.

Net feedstock cost, variable cost, fixed cost and capital costs were scaled for other refineries in the group to get total group and California costs as follows:

- Feedstock and variable costs were scaled linearly based on gasoline or diesel volume.[2]
- Fixed costs (which vary with startup of new process capacity) were scaled exponentially based on gasoline or diesel volume (e = 0.65).
- New process capacity requirements were scaled linearly based on gasoline or diesel volume.

Capital costs were scaled based on the selected process capacity and individual process unit scale exponents.

The cost basis for all new process options is provided in Appendix D.

B. Diesel Sulfur and Aromatics Reduction

For the diesel analysis, low sulfur, high sulfur and military diesel were modeled separately as appropriate in each selected refinery. An additional "uncontrolled" distillate category was included in each selected refinery for our analysis of diesel and other distillate segregation sensitivity.

Although initial diesel quality targets were identical to the 1986 calibration, in some cases due to increased process utilization flexibility diesel quality improved marginally in the future versus 1986. This future base case diesel quality was used as the basis for our analysis of the cost of reducing diesel aromatics and sulfur levels.[3]

Both high and low sulfur diesel were produced in some refineries and within different refineries in the same group. Sulfur reduction costs were based on reducing sulfur levels of only high sulfur (above .05%)

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[2] Feedstock and variable costs are primarily a function of the volume of gasoline or diesel processed and contaminant level reduced. Fixed costs are also a function of volume processed and process unit capacity required must be scaled for process size.

[3] Due to differences in measurement, techniques, sampling frequency, accuracy of survey data, variations in crude assay quality, and variations in refinery operation, sulfur and aromatics levels will vary somewhat from our future base cases. Although the absolute sulfur and (particularly) aromatics levels may be somewhat different, the analysis of costs changes for reductions of sulfur and aromatics levels from the selected base case to each target level remains valid.

diesel regardless of the refinery or group. These costs were expressed both in terms of cents/gallon high sulfur diesel and cents/gallon total diesel produced.

Diesel qualities were scaled differently in the sulfur and aromatics reduction cases.

For the sulfur reduction cases, diesel sulfur, cetane and aromatics were estimated for each refinery based on the ratio of future quality to 1986 quality in the modeled refinery times the 1986 quality in each individual refinery.

For the diesel aromatics reduction cases, aromatics were reduced to target levels in all refineries. It was assumed that at the same aromatics level diesel cetane in each refinery would be equal to the modeled refinery. Diesel sulfur levels were scaled based on the modeled refinery or a similar refinery at the same final aromatics level.

Net feedstock costs, variable costs and fixed operating costs were scaled as discussed in A above to get overall group and California impact.

Initial diesel aromatics levels varied widely between refineries within the same group. Unit capacity requirements were scaled based on the ratio of hydro-dearomatization plus MOGD diesel yield to total diesel production adjusted for differences in % aromatics removal between refineries to reach target aromatics levels.

Since the two stage hydro-dearomatization process route and the MOGD process can produce low aromatics level products, the total of the diesel yield from these processes was limited to the total diesel production in the scale up.

1. Diesel Sulfur and Aromatics Reduction Cases Without Investment

High sulfur diesel levels were progressively reduced from the base case to 0.25%, 0.20% and the maximum extent possible without new process investment. Cost impacts were included only for refineries producing high sulfur diesel in the base case. Groups III, IV, V and VI had refineries producing both low and high sulfur diesel.

Costs were expressed both in terms of high sulfur diesel controlled and total diesel produced for California.

Diesel aromatics were reduced without new investment in nominal increments of 5% reduction from base case levels until the maximum aromatics reduction level was reached in each group. Aromatics levels were reduced for both low and high sulfur diesel.

Net feedstock costs, variable costs and fixed costs were scaled up as discussed above to get overall group and California impact.

2. Diesel Sulfur and Aromatics Reduction Cases With Investment

A separate base case was developed for each selected refinery with the following new process options available:

- Naphtha hydrotreating
- Distillate hydrotreating
- Distillate hydrorefining
- Distillate hydro-dearomatization
- Hydrogen plant
- Mobil methanol to olefins (MTO)
- Mobil olefins to gasoline and distillate (MOGD)

o Due to constraints on diesel sulfur levels, small volumes of naphtha and distillate hydrotreating were selected in the base case. Base case investment costs were not included in the cost of reducing diesel sulfur and aromatics level and the effect of these process additions on base case diesel quality was insignificant.

Sulfur levels were successively reduced to .15% and .05% in high sulfur diesel utilizing the new process options outlined above. Costs and qualities were scaled up as discussed above and expressed both in terms of diesel controlled and total diesel produced in California.

Aromatics levels were reduced to levels of 20%, 15% and 10% for both high and low sulfur diesel using new process options. An additional case was analyzed both reducing sulfur to .05% and aromatics to 10%. Costs and qualities were scaled up as discussed above.

The 10% aromatics case at 0.05% sulfur was repeated allowing purchase of low sulfur/low aromatics (South Louisiana) Gas Oil. Low sulfur/low aromatics gas oil feedstock may be available from other U.S. regions or imports in 1991. Cost of low sulfur/low aromatics feedstock was based on CEC 1991 diesel price.

3. Impact of Diesel Segregation

The base diesel analysis done in this study assumed zero percent segregation. That is, all diesel was required to meet the same restrictive quality requirements.

In order to assess the impact of diesel segregation, two sensitivity analyses were conducted. These sensitivities were used to determine the cost of controlling only a portion of the diesel fuel to restricted specifications. The two sensitivities analyzed were as follows:

o NPRA survey diesel segregation, and

o 50% diesel segregation.

The level of segregation for the first case was derived from the NPRA's published diesel sulfur and aromatics reduction survey and is shown below:

Group	% Controlled	% Uncontrolled
I	100	0
II	100	0
III	75	25
IV	25	75
V	21	79
VI	50	50

The NPRA's questionnaire requested a split between disel fuel and common product. The portion reported as diesel is shown as controlled product and was required to meet quality restrictions in this sensitivity case. The industry's response to NPRA's survey was assumed to represent the maximum current level of segregation of diesel product.

In California, the split between on-road diesel and other distillate is approximately 50% for each. A second sensitivity case was therefore analyzed assuming 50% controlled product and 50% uncontrolled product in each group.

The 50% segregation case is actually less restrictive than the NPRA segregation for Groups I, II and III. The two segregation cases are identical for Group VI and the 50% segregation case is more restrictive for Groups IV and V.

The sensitivity cases described above considered reduction in sulfur content and aromatic content independently. In the sulfur analysis, the controlled material was reduced to a 0.05 wt% sulfur level. The uncontrolled material was limited to a maximum of the base case sulfur level.

The aromatics sensitivity was analyzed at the 10% aromatics level. The uncontrolled volume was limited to a maximum of the base case aromatics level.

New process investment was allowed in both the sulfur and aromatics diesel segregation sensitivity cases.

The diesel product qualities and costs were scaled up by group using a similar methodology as described earlier but the costs were scaled on only the controlled volumes. The uncontrolled volumes were assumed to remain at existing quality, and therefore incurred no additional cost versus the base case.

C. Gasoline Aromatics Reduction

In all gasoline aromatics reduction cases, gasoline octane and vapor pressure was maintained at base case levels. Thus, any loss in gasoline octane thru aromatics reduction was replaced thru processing changes, new process additions or (in the sensitivity analysis) purchased high octane, low aromatics blendstocks.

1. Maximum Gasoline Aromatics Reduction Without Investment

Aromatics levels were progressively reduced from base case level in selected refineries to the maximum extent possible without new process investment[4] or additional purchased blendstocks. Aromatics levels were reduced in increments of 1% until the maximum level of reduction was achieved in each modeled refinery. Percent reduction for each group was based on the modeled refinery and overall California reduction was based on the volume weighted average of group results. Net feedstock costs, variable costs and fixed costs were scaled as discussed in (A) above to get overall group and California impact.

2. Maximum Gasoline Aromatics Reduction With Investment

A separate gasoline base case was run for each selected refinery with new process investment options available. Due to future constraints on octane, the refinery models selected several process options (particularly isomerization, MTBE and etherol) which reduced gasoline aromatics and benzene content from the base case without investment.

Since these process options were justified based on octane requirements rather than aromatics reduction, the base case investment costs were not included in the cost of reducing gasoline aromatics levels. Changes in aromatics level, benzene level and costs were all measured against this base case for all aromatics reduction cases where new process investments were allowed.

Model runs were next made for each selected refinery reducing base case aromatics with investment by a nominal 5, 10, 15, 20 and maximum percent. Percent aromatics reduction for each selected refinery and net feedstock, variable and fixed costs were scaled up identically to the non-investment case. New process requirements were scaled up linearly (at the same % aromatics reduction) based on gasoline volume for refineries within each group. Investment and capital costs were scaled exponentially based on individual process unit scale exponents.

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[4] Note: In all gasoline cases in this study, results are expressed as a % reduction from the base case level rather than the absolute % reduction in pool level.

The maximum aromatics reduction with investment case was repeated allowing purchase of the following low aromatics, high octane gasoline blendstocks:

- MTBE,
- Ethanol,
- Isomerate, and
- Alkylate.

These blendstocks may be available locally or from other refinery regions at a price based on gasoline blending values using 1991 CEC gasoline and butane price forecasts.

VIII. 1991 COST OF REDUCING DIESEL SULFUR AND AROMATICS

The results of our analysis for the 1991 cost of California reducing diesel sulfur and aromatics are shown on Tables VIII.1 thru 4 as follows:

VIII.1	1986 AND 1991 Base Case Diesel Quality
VIII.2	1991 California Cost of Sulfur and Aromatics Reduction Without Investment
VIII.3	1991 California Cost of Sulfur and Aromatics Reduction With Investment
VIII.4	1991 California Diesel Segregation Sensitivity Results

A. 1991 Base Case

1. 1991 Versus 1986 Diesel Production and Quality

A summary of diesel volume, sulfur, aromatics and cetane content by refinery group is shown on Table VIII.1 for 1986 and 1991. Both investment and non-investment cases are shown for 1991.

The 1986 data is based on our survey results and ADL's LP model analysis. The 1991 qualities are based on the 1991 LP model results scaled up to get results for each refinery group. To maintain confidentiality, Group III and IV data have been combined for all results.

Based on CEC forecasts the volume of automotive diesel will increase 10.6% from 263.8 MB/D in 1986 to 291.7 MB/D in 1991. As discussed in establishing the 1991 and 1995 study basis, since a specific forecast was provided by one Group III/IV refiner, diesel demand by group varies somewhat from overall California growth.

The difference in quality between 1986 and the 1991 - non-investment case are relatively small. Overall sulfur decreased from 0.33% to 0.27% wt%, aromatics content decreased from 30.9% to 30.7% and cetane increased from 43.6 to 43.7.

The small changes in diesel quality resulted from several offsetting effects:

- o Crude runs decreased slightly due to reduced gasoline demand;
- o Quality of crude remained fairly constant;
- o The level of FCC and hydrocracking utilization increased to meet increased diesel demands

TABLE VIII.1

1986 AND 1991 BASE CASE DIESEL QUALITY

		1986				1991								
							WITHOUT INVESTMENT				WITH INVESTMENT			
GROUP		MB/D	SULF WT %	AROM VOL %	CETANE	MB/D	SULF WT %	AROM VOL %	CETANE	POLY AROM VOL %	SULF WT %	AROM VOL %	CETANE	POLY AROM VOL %
1	TOPPING	19	1.36	22.0	39.0	20.8	0.98	22.4	39.6	6.7	0.98	22.4	39.6	6.7
2	HYDROSKIMMING	15.1	0.40	30.0	43.5	17.9	0.32	29.2	43.1	8.7	0.32	29.2	43.1	8.7
3 & 4	CONV & D. CONV. (FCC)	109.3	0.20	32.3	43.6	123.7	0.19	32.5	41.4	7.3	0.18	32.5	41.4	7.4
5	D. CONVERSION - LA	66.5	0.31	35.3	44.6	71.6	0.27	34.1	48.3	10.3	0.27	34.1	48.3	10.3
6	D. CONVERSION - N. CA	53.9	0.23	26.3	43.9	57.7	0.18	26.0	44.6	7.1	0.18	26.0	44.7	7.1
	TOTAL	263.8	0.33	30.9	43.6	291.7	0.27	30.7	43.7	8.0	0.27	30.7	43.7	8.1

(1) EXCLUDES 20.2 MB/D MILITARY DIESEL FROM GROUP 5.

TABLE VIII.2

1991 CALIFORNIA COST OF SULFUR AND AROMATICS REDUCTION - WITHOUT INVESTMENT

1991 Diesel Aromatics & Sulfur Results - Summary Diesel without Investment

		DIESEL					REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION [1]	PROD 000 B/D [2]	SULFUR WT% [2]	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
Base Case without Investment	0.0	291.7	0.27	43.7	8.1	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
.25 Sulfur	-	291.7	0.17	44.6	7.3	29.9	65.6	10.7	22.8	0.0	99.1	0.8	0.0	2.76
.20 Sulfur	-	291.7	0.15	44.7	7.0	29.2	441.6	13.4	33.7	0.0	488.7	4.0	0.0	16.77
Max Sulfur Reduction	-	291.7	0.14	44.4	6.9	29.2	552.7	17.5	41.5	0.0	611.7	5.0	0.0	19.91
5% Aromatics Reduction	6.0	291.7	0.22	44.4	6.5	28.7	611.1	35.2	69.7	0.0	716.1	5.8	0.0	20.80
10% Aromatics Reduction	12.0	121.4	0.28	44.0	5.0	25.3	601.8	48.2	73.6	0.0	723.7	14.2	0.0	25.76
Max Aromatics Reduction	8.7	291.7	0.20	44.4	6.0	27.9	1,563.5	64.0	123.6	0.0	1,751.1	14.3	0.0	60.30

	PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
DESCRIPTION	NAPHT HDT	DIST HDT	DIST HR	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
Base Case without Investment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
.25 Sulfur	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
.20 Sulfur	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Max Sulfur Reduction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5% Aromatics Reduction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10% Aromatics Reduction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Max Aromatics Reduction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

1) % Reduction from Base Case Aromatics Level.
2) Includes Refineries Currently at .05 Sulfur.

TABLE VIII.3

1991 CALIFORNIA COST OF SULFUR AND AROMATICS REDUCTION - WITH INVESTMENT

		DIESEL					REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION [1]	PROD 000 B/D [2]	SULFUR WT% [2]	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
Base Case with Investment	0.0	291.7	0.27	43.7	8.1	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
.15 Sulfur	-	291.7	0.11	42.5	7.2	29.6	112.7	14.4	31.6	68.7	227.3	1.9	96.2	4.62
.05 Sulfur	-	291.7	0.05	44.9	6.8	29.4	493.6	23.9	58.7	189.8	766.0	6.3	265.7	19.8
20% Aromatics	25.4	291.7	0.14	49.1	3.8	20.0	84.8	29.1	59.8	293.0	466.6	3.8	410.2	2.29
15% Aromatics	51.6	291.7	0.07	49.9	1.6	14.0	195.1	76.0	131.2	617.2	1,019.4	8.3	864.0	5.20
10% Aromatics	65.1	291.7	0.03	50.9	0.3	10.0	1,885.4	176.7	297.9	1,022.2	3,382.2	27.6	1,431.1	71.79
10% Aromatics at .05 Sulfur	65.1	291.7	0.03	50.9	0.3	10.0	1,876.1	194.8	314.2	1,037.9	3,423.1	27.9	1,453.1	102.53
10% Aromatics with Purch Feedstock	65.1	291.7	0.03	51.4	0.7	10.0	810.4	90.9	113.1	786.3	1,800.7	14.7	1,100.8	35.40

	PROCESS ADDITIONS : 000 B/D							
DESCRIPTION	NAPHT HDT	DIST HDT	DIST HR	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	PURCHASED STOCKS SO LA GAS OIL 000 B/D
Base Case with Investment	1.8	0.0	0.0	0.7	0.0	0.0	0.0	0.0
.15 Sulfur	0.0	7.1	27.2	0.0	0.0	0.0	0.0	0.0
.05 Sulfur	0.0	33.9	78.5	0.0	0.0	0.0	0.0	0.0
20% Aromatics	3.5	0.0	51.5	105.7	0.0	1.8	1.8	0.0
15% Aromatics	5.2	0.0	109.7	179.0	36.3	16.5	16.5	0.0
10% Aromatics	8.5	0.0	153.5	217.6	105.0	55.1	55.1	0.0
10% Aromatics at .05 Sulfur	8.5	0.0	150.7	214.8	105.0	59.3	59.3	0.0
10% Aromatics with Purch Feedstock	4.0	0.0	129.6	207.9	49.6	29.7	29.7	48.1

1) % Reduction from Base Case Aromatics Level.
2) Includes Refineries Currently at .05 Sulfur.

TABLE VIII.4

1991 CALIFORNIA DIESEL SEGREGATION SENSITIVITY RESULTS

		DIESEL					REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION[1]	PROD[2] 000 B/D	SULFUR[2] WT%	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
NPRA Segregation: .05 Sulfur	-	291.7	0.12	43.3	8.1	30.5	471.0	13.2	44.1	124.6	652.8	5.3	174.4	18.03
NPRA Segregation: 10% Aromatics	30.7	291.7	0.13	49.2	4.0	21.1	1,636.5	90.6	227.4	722.5	2,676.9	21.8	1,011.5	61.72
50% Segregation: .05 Sulfur	-	291.7	0.17	43.4	8.1	30.5	13.0	12.5	28.7	92.5	146.7	1.2	129.5	(0.06)
50% Segregation: 10% Aromatics	35.2	291.7	0.18	48.7	4.2	20.3	919.6	75.9	171.5	619.9	1,786.9	14.6	867.9	34.37

	PROCESS ADDITIONS : 000 B/D							
DESCRIPTION	NAPHT HDT	DIST HDT	DIST HR	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	PURCHASED STOCKS SO LA GAS OIL 000 B/D
NPRA Segregation: .05 Sulfur	0.0	27.2	42.9	0.0	0.0	0.0	0.0	0.0
NPRA Segregation: 10% Aromatics	15.4	0.0	89.3	122.1	105.0	33.4	33.4	0.0
50% Segregation: .05 Sulfur	0.0	0.0	39.2	0.0	0.0	0.0	0.0	0.0
50% Segregation: 10% Aromatics	10.0	0.0	85.8	112.5	36.3	15.9	15.9	0.0

1) % Reduction from Base Case Aromatics Level.
2) Includes Refineries Currently at .05 Sulfur.

- Increased FCC utilization increases aromatics content whereas increased hydrocracking utilization decreases both sulfur and aromatics content.
- Existing hydrorefining capacity, which lowers sulfur and saturates some aromatics compounds was more effectively utilized in 1991.

On an overall state level, there was no difference in quality between the investment and the non-investment base cases. This resulted since little new capacity was justified in the investment base case.

The aromatic content in Groups III/IV fell slightly in the investment case due to the addition of a small amount of hydroprocessing capacity justified by sulfur constraints. The aromatics decrease in Groups III/IV was so small it affected total California aromatics level by less than .1%.

The cetane in Group VI increased slightly with the addition of a small amount of heavy naphtha hydrotreating. The hydrotreating capacity is not severe enough to saturate aromatics, but did improve cetane slightly.

2. <u>1991 Base Case Results Without Investment</u>

Results for 1991 California cost of diesel sulfur and aromatics reduction without investment are shown on Table VIII.2. Results by refinery group including volumes of high sulfur and total diesel are shown in Appendix E for each case analyzed.

Diesel production and quality for the base case are the same as shown on Table VIII.1. No cost impact is shown for the base case since this is the case against which all non-investment diesel contaminant reduction cases are measured.

B. <u>Maximum Diesel Sulfur Reduction Without Investment</u>

Cases were analyzed reducing high sulfur diesel to .25%, .20% and to the maximum extent possible without new process investment.

Total California costs are for reducing high sulfur diesel and exclude refineries at or below each prescribed sulfur level. Average diesel sulfur level attained and costs per gallon are expressed in terms of total California diesel produced including diesel below each prescribed level.

The cost of reducing high sulfur diesel to 0.25% sulfur varied from 0.2 to 7.0 ¢/gallon by refinery group. Costs were highest in Group I - topping refineries which have few existing process options to reduce sulfur and the highest initial diesel sulfur level of 0.98 wt%. High sulfur diesel production requiring sulfur reduction was 178 MB/D of the total 292 MB/D California diesel production. Costs averaged 1.3 ¢/gallon of high sulfur diesel or 0.8 ¢/gallon of total California diesel.

Average California diesel sulfur dropped to 0.17% including the impact of low sulfur diesel. As a result of increased hydroprocessing utilization and re-blending to reduce diesel sulfur level, aromatics dropped slightly from 30.7% to 29.9% and cetane increased slightly from 43.7 to 44.6.

The cost of reducing high sulfur diesel to 0.20% sulfur varied from 1.1 ¢/gallon for Group II to 8.1 ¢/gallon for Group I. Costs were again highest in Group I topping refineries. High sulfur diesel production requiring sulfur reduction to 0.20% increased to 190 MB/D from 178 MB/D in the 0.25% sulfur case.

Average cost increased to 6.1 ¢/gallon of high sulfur diesel or 4.0 ¢/gallon of total California diesel. Average California diesel sulfur dropped to 0.15% including the impact of low sulfur diesel. Aromatics dropped further to 29.2% and cetane increased to 44.7.

Results for the 1991 maximum California diesel sulfur reduction case without investment are shown by group on Table VIII.5.

The maximum sulfur reduction attainable in high sulfur diesel without process investment varied from .21% in Groups III and VI to 0.20% in Group V and 0.10% in Groups I and II. This resulted in an average attainable sulfur level of 0.19% for high sulfur diesel and 0.14% for total California diesel. Total diesel aromatics levels decreased slightly from 30.7% in the base case to 29.2% due to increased utilization of existing hydrotreating and hydrorefining capacity to reduce sulfur levels. Cetane number increased slightly from 43.7 to 44.4 along with the decrease in aromatics content.

Cost of maximum sulfur reduction varied from 3.3 ¢/gallon in Group V to 18.4 ¢/gallon in Group I and averaged 7.7 ¢/gallon of high sulfur diesel or 5.0 ¢/gallon of total California diesel. Costs were again by far the highest in small topping refineries which have few options to reduce diesel sulfur without investment and the highest initial sulfur level. Net feedstock costs represented 90% of the cost increase versus the base case, but variable and fixed operating costs also increased.

C. Maximum Diesel Aromatics Reduction Without Investment

Existing California hydroprocessing capacity in California was designed for diesel sulfur removal only and has limited capability to reduce diesel aromatics levels. In our analysis both high and low sulfur diesel aromatics levels were successively decreased by a nominal 5%, 10% and to the maximum extent possible of base case aromatics levels without process investment. Results of this analysis for California are shown on Table VIII.2. Results for each group are included in Appendix E.

TABLE VIII.5

1991 COST OF MAXIMUM SULFUR REDUCTION - WITHOUT INVESTMENT

			DIESEL					REFINERY COST CHANGES							
GROUP	DESCRIPTION	% SULFUR	PROD 000 B/D	SULFUR WT%	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
I	Topping	0.10	20.8	0.10	38.6	5.1	20.7	142.3	5.2	13.1	0.0	160.6	18.4	0.0	5.85
II	Hydroskimming	0.10	17.9	0.10	42.0	6.7	27.0	35.6	1.3	4.6	0.0	41.6	5.5	0.0	0.07
III + IV	Conv + D. Conv	0.21	73.5	0.21	44.3	7.7	28.3	259.2	2.8	12.6	0.0	274.5	8.9	0.0	9.62
V	D. Conversion - LA	0.20	41.0	0.20	49.8	8.0	31.1	42.8	7.4	6.9	0.0	57.0	3.3	0.0	1.61
VI	D. Conversion - N. Cal	0.21	36.7	0.21	45.9	7.0	28.3	72.8	0.8	4.3	0.0	77.9	5.1	0.0	2.76
TOTAL HIGH SULFUR		0.19	189.9	0.19	45.0	7.3	28.0	552.7	17.5	41.5	0.0	611.7	7.7	0.0	19.91
TOTAL CALIFORNIA		0.14	291.7	0.14	44.4	6.9	29.2	552.7	17.5	41.5	0.0	611.7	5.0	0.0	19.91

		PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
GROUP	DESCRIPTION	NAPHTHA HDT	DIST HDT	DIST HR7	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
I	Topping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
III + IV	Conv + D. Conv	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V	D. Conversion - LA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VI	D. Conversion - N. Cal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CALIFORNIA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: Volume & Cents/Gallon are based on High Sulfur Diesel volume only for Groups II, V, and VI.

Aromatics content, sulfur level, cetane and total costs changed as follows with increased aromatics removal:

Nominal % Aromatics Reduction %	Controlled Diesel 000 B/D	Aromatics %	Sulfur wt %	Cetane No	Total Costs ¢/gal.
Base	291.7	30.7	0.27	43.7	0
5%	291.7	28.7	0.22	44.4	5.8
10%	121.4	25.3	0.28	44.1	14.2
Maximum	291.7	27.9	0.20	44.4	14.3

It was possible to reduce diesel aromatics by a nominal 5% in all refinery groups without investment. Costs averaged 5.8 ¢/gallon but varied from 0.7 ¢/gallon in Group V to 19.5 ¢/gallon in Groups I and II that have little capability to reduce diesel aromatics without investment. Sulfur decreased from 0.27% in the base case to 0.22% as a result of the 5% reduction in aromatics. Cetane also improved from 43.7 to 44.4.

It was possible to reduce diesel aromatics by a nominal 10% without investment only in Groups I, II and part of Group III/IV. Total volume reduced by 10 or more % was only 121 MB/D or about 40% of California production. Costs averaged 14.2 ¢/gallon of controlled diesel but were 19.5 ¢/gallon in Groups I and II versus 11.7 ¢/gallon in Groups III/IV.

Sulfur decreased from 0.39% in the controlled refineries in the base case to 0.28% with 10% aromatics reduction. Cetane also improved from 42.3 to 44.1.

Results for the 1991 Maximum Aromatics Reduction Case by group are shown on Table VIII.6. Maximum aromatics reduction varied by group from 5% in Group VI to 14% in Groups I and II. Maximum California aromatics reduction without investment averaged only 8.7% of base case aromatics. This represents an absolute reduction from 30.7 to 27.9%.

Costs for maximum aromatics reduction without investment varied from 2.6 ¢/gallon in Group V (for 6% reduction) to 60 ¢/gallon in Groups I and II (for 14% reduction) and averaged 14.3 ¢/gallon of total California diesel. Net feedstock changes accounted for 89% of the total cost increase and energy requirements increased 60 MB/D of equivalent crude. The energy requirement exceeds aromatics reduction of 25 MB/D.

Diesel sulfur level was reduced to 0.20% and cetane increased to 44.4 as a result of the 8.7% reduction in aromatics.

TABLE VIII.6

1991 COST OF MAXIMUM AROMATICS REDUCTION - WITHOUT INVESTMENT

			DIESEL					REFINERY COST CHANGES							
GROUP	DESCRIPTION	% AROMATICS REDUCTION	PROD 000 B/D	SULFUR WT%	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
I	Topping	14.0	20.8	0.49	40.6	4.9	19.3	499.5	2.2	25.0	0.0	526.8	60.3	0.0	20.13
II	Hydroskimming	14.0	17.9	0.16	44.1	6.4	25.2	429.9	1.9	20.7	0.0	452.5	60.2	0.0	17.33
III + IV	Conv + D. Conv	10.3	123.7	0.19	42.2	5.2	30.4	336.4	46.7	58.3	0.0	441.4	8.5	0.0	11.42
V	D. Conversion - LA	6.0	71.6	0.20	49.3	7.5	29.5	61.7	10.5	7.3	0.0	79.6	2.6	0.0	2.55
VI	D. Conversion - N. Cal	5.0	57.7	0.15	44.7	6.1	24.8	236.0	2.6	12.3	0.0	250.8	10.4	0.0	8.88
TOTAL CALIFORNIA		8.7	291.7	0.20	44.4	6.0	27.9	1,563.5	64.0	123.6	0.0	1,751.1	14.3	0.0	60.30

		PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
GROUP	DESCRIPTION	NAPHTHA HDT	DIST HDT	DIST HR7	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
I	Topping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
III + IV	Conv + D. Conv	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V	D. Conversion - LA	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VI	D. Conversion - N. Cal	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CALIFORNIA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

D. Diesel Sulfur Reduction With Investment

Results for 1991 cost of diesel sulfur and aromatics reduction with new process investment are shown on Table VIII.3.

Due to constraints on diesel sulfur levels, naphtha and distillate hydrotreating were justified in the base case costing 12 million $. These base case investment costs were not included in the cost of reducing diesel sulfur and aromatics level. The effect of these process additions on base case diesel quality was insignificant.

Sulfur levels were successively reduced to .15% and .05% in high sulfur diesel utilizing the new process options outlined in Section VI above. As in the non-investment case, costs are for reducing high sulfur diesel and exclude refineries at or below each prescribed sulfur level. Average sulfur attained and costs per gallon shown on Table VIII.3 expressed in terms of total diesel produced including diesel below each prescribed level. The results by group including volumes of high sulfur diesel and total diesel are shown in Appendix E for each case.

The costs to reduce high sulfur diesel from base case levels to .15% varied from 0.5 ¢/gallon in Group II to 14.0 ¢/gallon in Group I. Group II (hydroskimming) refineries were able to reach .15% sulfur without new process investment. Substantial investment in new hydrotreating capacity was required in Group I (topping) refineries to reach .15%S.

Costs to reduce high sulfur diesel to 0.15% sulfur averaged 2.9 ¢/gallon of high sulfur diesel and 1.9 ¢/gallon of total California diesel. Investment requirements were 96 million $ for 7 MB/D of distillate hydrotreating and 27 MB/D of distillate hydrorefining. Capital costs accounted for 30% and net feedstock accounted for 50% of total cost.

As a result of reducing high sulfur diesel to 0.15%, total California diesel was reduced to an average of 0.11% sulfur. Total aromatics level was reduced slightly from 30.7% to 29.8%, but cetane decreased slightly due to refinery blend mix changes.

Results for 1991 California diesel sulfur reduction to .05% by group are shown on Table VIII.7.

All refineries modeled were able to reduce diesel sulfur levels to .05% with new process investment. A total of 190 MB/D of the total 292 MB/D California diesel production required further desulfurization at an average cost of 9.6 ¢/gallon or 6.3 ¢/gallon of total California diesel. Costs varied from 2.8 ¢/gallon in Group VI to 50.5 ¢/gallon in Group I. Costs for the small, relatively simple Group I and II refineries were much higher than for other larger, more complex groups.

TABLE VIII.7

1991 COST OF DIESEL SULFUR REDUCTION TO .05 WT% - WITH INVESTMENT

			DIESEL					REFINERY COST CHANGES							
GROUP	DESCRIPTION	% SULFUR	PROD 000 B/D	SULFUR WT%	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
I	Topping	0.05	20.8	0.05	36.7	4.9	20.4	380.0	9.2	25.5	26.4	441.1	50.5	36.9	15.40
II	Hydroskimming	0.05	17.9	0.05	39.9	6.4	26.7	93.8	2.3	9.2	17.8	123.1	16.4	24.9	3.58
III + IV	Conv + D. Conv	0.05	73.5	0.05	47.5	7.6	27.9	4.7	1.7	2.1	78.6	87.0	2.8	110.0	0.22
V	D. Conversion - LA	0.05	41.0	0.05	49.8	7.7	31.6	10.3	9.8	18.0	33.4	71.4	4.1	46.7	0.39
VI	D. Conversion - N. Cal	0.05	36.7	0.05	45.9	6.3	28.3	4.8	1.0	3.9	33.6	43.3	2.8	47.0	0.16
TOTAL HIGH SULFUR		0.05	189.9	0.05	45.8	7.0	27.8	493.6	23.9	58.7	189.8	766.0	9.6	265.7	19.76
TOTAL CALIFORNIA		0.05	291.7	0.05	44.9	6.8	29.4	493.6	23.9	58.7	189.8	766.0	6.3	265.7	19.76

		PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
GROUP	DESCRIPTION	NAPHTHA HDT	DIST HDT	DIST HR7	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
I	Topping	0.0	27.2	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	0.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0
III + IV	Conv + D. Conv	0.0	0.0	38.6	0.0	0.0	0.0	0.0	0.0
V	D. Conversion - LA	0.0	0.0	17.3	0.0	0.0	0.0	0.0	0.0
VI	D. Conversion - N. Cal	0.0	0.0	22.7	0.0	0.0	0.0	0.0	0.0
TOTAL CALIFORNIA		0.0	33.9	78.5	0.0	0.0	0.0	0.0	0.0

Note: Volume & Cents/Gallon are based on High Sulfur Diesel volume only for Groups III, V, and VI.

Process investment requirements were 266 million $ for 27 MB/D of distillate hydrotreating in Group I and 85 MB/D of hydrorefining in other refinery groups. Capital costs accounted for 25% and net feedstock costs accounted for 64% of total costs. Energy requirements were 20 MB/D of equivalent crude.

Total aromatics levels were reduced from 30.7% in the base case to 29.4% in the maximum sulfur reduction case due to partial aromatics saturation in hydroprocessing units. Cetane levels also increased from 43.7 in the base case to 44.9.

E. Diesel Aromatics Reduction With Investment

New process capacity will be required in California for significant levels of aromatics reduction. In our analysis, diesel aromatics levels were successively reduced to 20%, 15% and 10% for both low and high sulfur diesel using process options discussed in Section VI. Results of this analysis for California are shown on Table VIII.3. Results for each group are included in Appendix E.

The costs to reduce diesel aromatics level to 20% varied from 3.3 ¢/gallon in Groups III/IV to 5.3 ¢/gallon in Groups I and II and averaged 3.8 ¢/gallon. Costs were again highest in simple Group I and II refineries. Investment costs were substantial at 410 million $ for 4 MB/D of naphtha hydrotreating, 52 MB/D distillate hydrorefining and 106 MB/D distillate hydro-dearomatization capacity. Capital requirements were the most significant cost component at 293 M$/D or 63% of total costs. Net feedstock costs and operating costs were not as significant as for sulfur reduction and totaled only 174 M$/D or 37% of total costs. Net energy requirements were minimal at 2.3 MB/D equivalent crude due to lower FCCU utilization and decreased utilization of existing hydrotreating capacity.

As a result of aromatics reduction to 20%, diesel sulfur levels were reduced from .27% in the base case to an average of .14%. Cetane improved from 43.7 to 49.1.

Costs to reduce diesel aromatics level to 15% increased to an average of 8.3 ¢/gallon. Costs varied from 5.3 ¢/gallon in Group V to 16.5 ¢/gallon in Groups I and II. Investment costs increased to 864 million $ for 5 MB/D naphtha hydrotreating, 110 MB/D distillate hydrorefining, 179 MB/D distillate hydro-dearomatization, 36 MM SCF/D hydrogen plant and 17 MB/D Mobil synthetic diesel processing. Capital requirements were again the most significant cost component at 617 M$/D or 61% of total costs. Net feedstock and operating costs also increased to 402 M$/D or 49% of total costs. Net energy requirements doubled from the 20% aromatics reduction case to 5 MB/D.

As a result of aromatics reduction to 15%, diesel sulfur levels were reduced to an average of .07% and cetane increased to 49.9.

Costs to reduce diesel aromatics level to 10% increased to an average of 27.6 ¢/gallon. Costs varied from 9.8 ¢/gallon in Groups III/IV to 126.5 ¢/gallon in Groups I and II.

Investment costs increased to 1,431 million $ for 380 MB/D of hydroprocessing, 105 MM SCF/D hydrogen plant and 55 MB/D of Mobil synthetic diesel processing. A total of 218 MB/D of distillate hydro-dearomatization plus 21 MB/D of synthetic diesel was required to reach 10% diesel aromatics. Thus, 82% of total diesel demand would require either severe two-stage hydroprocessing or be synthetically produced to meet this case.

Although capital requirements increased to 1,022 M$/D, they were overshadowed by an increase in net feedstock costs to 1,885 M$/D. Energy requirements increased to 72 MB/D equivalent crude due to increased hydroprocessing and production of synthetic diesel. Energy requirements exceed diesel aromatics reduction of 55 MB/D (19% of diesel production). Total costs to reduce diesel aromatics to 10% were 3.3 million $/D or 1.2 billion $ per year.

As a result of aromatics reduction to 10%, diesel sulfur was reduced to an average of .03% and cetane increased to 50.9.

Although average diesel sulfur levels were below .05% in the 10% aromatics case, Group VI diesel sulfur level was still at .07%. As a result, an additional case was required to reduce Group VI diesel sulfur to .05% sulfur and 10% aromatics. The results of this additional case by group are shown on Table VIII.8. Additional Mobil synthetic diesel capacity was required to reduce diesel sulfur content to .05% which increased Group VI cost from 12.5 to 17.0 ¢/gallon diesel and energy requirements from 4 to 35 MB/D.

Total California costs increased slightly from 27.6 to 27.9 ¢/gallon and investment costs increased to 1453 million $. Energy requirements increased significantly to 103 MB/D due to increased production of synthetic diesel.

The impact of Group VI processing changes to meet .05% had a negligible impact on total California diesel quality.

F. Diesel Aromatics Reduction with Investment and Purchased Feedstock

The 10% aromatics case at 0.05% sulfur was repeated allowing purchase of low sulfur/low aromatics (South Louisiana) Gas Oil which may be available from other U.S. regions or imports in 1991. Cost of low sulfur/low aromatics feedstock was based on CEC 1991 diesel price. The results of this case for California are shown on Table VIII.3. Results by refiner and group are shown in Appendix E.

TABLE VIII.8

1991 COST OF DIESEL AROMATICS REDUCTION TO 10% AND SULFUR REDUCTION TO .05 WT%

			DIESEL					REFINERY COST CHANGES							
GROUP	DESCRIPTION	% AROMATICS REDUCTION	PROD 000 B/D	SULFUR WT%	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
I	Topping	65.0	20.8	0.003	51.2	0.7	10.0	765.3	39.2	104.0	194.7	1,103.2	126.3	272.6	30.37
II	Hydroskimming	65.0	17.9	0.001	51.2	0.7	10.0	658.6	33.7	86.1	172.4	950.8	126.5	241.3	26.13
III + IV	Conv + D. Conv	62.5	123.7	0.049	51.9	0.2	10.0	180.3	31.2	29.6	273.4	514.4	9.9	382.7	6.83
V	D. Conversion - LA	70.7	71.6	0.000	49.6	0.2	10.0	119.3	50.8	62.9	209.0	442.0	14.7	292.6	4.14
VI	D. Conversion - N. Cal	64.0	57.7	0.047	50.0	0.3	10.0	152.8	39.9	31.6	188.5	412.8	17.0	263.9	35.06
TOTAL CALIFORNIA		65.1	291.7	0.031	50.9	0.3	10.0	1,876.1	194.8	314.2	1,037.9	3,423.1	27.9	1,453.1	102.53

		PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
GROUP	DESCRIPTION	NAPHTHA HDT	DIST HDT	DIST HR7	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
I	Topping	0.0	0.0	9.4	8.9	49.3	11.4	11.4	0.0
II	Hydroskimming	0.0	0.0	10.6	10.2	55.8	13.1	13.1	0.0
III + IV	Conv + D. Conv	0.0	0.0	59.3	108.2	0.0	10.5	10.5	0.0
V	D. Conversion - LA	4.3	0.0	37.7	54.2	0.0	12.1	12.1	0.0
VI	D. Conversion - N. Cal	4.2	0.0	33.7	33.3	0.0	12.2	12.2	0.0
TOTAL CALIFORNIA		8.5	0.0	150.7	214.8	105.0	59.3	59.3	0.0

The availability of low sulfur/low aromatics diesel blendstocks at projected 1991 diesel price decreased the cost of reducing diesel sulfur and aromatics levels. Costs decreased by nearly 50% to an average of 14.7 ¢/gallon. Costs in Groups I and II decreased from 126.5 ¢/gallon to 38.5 ¢/gallon.

Investment requirements dropped from 1453 million $ to 1,101 million $. Hydroprocessing requirements dropped by 33 MB/D and synthetic diesel processing dropped by 30 MB/D or 50%.

Although low sulfur gas oil was purchased in every refinery group totaling 48 MB/D, net feedstock costs dropped by over 1 million $/D due to decreased crude runs and decreased production of synthetic diesel. Total net energy consumption declined from 103 MB/D to 35 MB/D of equivalent crude.

Although cost of aromatics reduction in diesel was significantly lower with purchased low aromatics/low sulfur feedstock, the analysis is based on the assumption that these feedstocks would be available at diesel price. It is uncertain if these feedstocks would be available - particularly if reduction of diesel aromatics is mandated in other U.S. regions.

G. Impact of California Diesel Segregation

The base diesel analysis in this study assumed zero percent diesel segregation. That is, all diesel was required to meet the same restrictive quality requirements.

In order to assess the impact of diesel segregation, two sensitivity analyses were conducted. These sensitivities were used to determine the cost of controlling only a portion of the diesel fuel to restricted specifications. The two cases analyzed were as follows:

- NPRA survey level of diesel segregation, and
- 50% diesel segregation.

The results of the 1991 California diesel segregation sensitivity analyses are shown on Table VIII.4.

In the 50% segregation case, 114.9 MB/D of diesel was restricted to 0.05 wt% sulfur. This volume is less than 50% of total California production because the portion of California diesel which is currently produced at .05 wt% sulfur has been excluded (i.e., no additional cost is assumed). The overall diesel sulfur content was 0.17 wt% in this segregation case versus 0.27 wt% in the base case and 0.12 wt% in the NPRA segregation case.

The total cost (000 $/D) for Groups I, II and III were less than the NPRA segregation case because less volume was restricted to 0.05 wt% sulfur. The cost for Group V increased at 50% segregation because more diesel volume was controlled. The cost for Group VI remained constant because the volume controlled was identical.

Cost for sulfur reduction was 3.0 ¢/gallon of controlled diesel and 1.2 ¢/gallon of total diesel. This is a savings of 5.1 ¢/gallon compared to controlling all diesel to a 0.05 wt% sulfur level. However, this lower cost must be weighed against the lower volume of diesel controlled and the higher average California diesel sulfur level of 0.17 wt%.

In the aromatics case at 50% segregation, a total of 145.9 MB/D of diesel was restricted to 10 volume % aromatics. The overall diesel aromatics content was 20.3% in this segregation case. The sulfur level of the controlled diesel was 0.04 wt% and 0.18 wt% for the overall volume.

The total cost of aromatics reduction in the 50% segregation case was 29.2 ¢/gallon of the controlled volume and 14.6 ¢/gallon of total California diesel. The cost of reducing all of the diesel to 10% aromatics and 0.05 wt% sulfur was 27.9 ¢/gallon. This 50% segregation case, therefore, represents a savings of 13.3 cents per total gallon of diesel produced. Again, however, the total California diesel aromatics level has only been reduced to 20.3% versus 10% due to the lower volume controlled.

The controlled volume of diesel fuel forced to meet 0.05% wt% sulfur for the NPRA segregation case was 149.8 MB/D, or 51% of the total diesel volume. Total California diesel sulfur content was 0.12 wt% in this segregation case versus 0.27 wt% in the base case.

The costs for Groups I and II are equivalent to their respective 0.05 wt% sulfur base case and maximum aromatics reduction case since all of their diesel falls in the controlled volume category. The controlled portion of Group V's diesel was also produced at .05% sulfur in the base case.

Cost for sulfur reduction was 10.4 ¢/gallon of controlled diesel and 5.3 ¢/gallon of total diesel. This is a savings of 1 ¢/gallon compared to controlling all diesel to a 0.05 wt% level (however, average California diesel sulfur level is only reduced to .12%).

In the NPRA aromatics segregation case, 170.5 MB/D or 58% of the total diesel production was required to meet 10% aromatics. Total California diesel aromatics were reduced to 21.1%. The sulfur level of the controlled diesel is 0.04 wt% versus 0.13 wt% for the total California diesel.

The total cost for this segregation case is 37.4 ¢/gallon of the controlled volume and 21.8 cents per gallon of the total California diesel. The cost of reducing all the diesel to 10% aromatics and .05% S was 27.9 ¢/gallon of total diesel. Thus, the NPRA segregation case represents a savings of 6.1 cents per total gallon of diesel produced (although total California diesel aromatics levels are only reduced to 21.1 versus 10%) due to the lower volume of diesel controlled.

TABLE VIII.9

1991 Costs of Reducing Diesel Sulfur and Aromatics Levels for Total California: Hydrogen Plant Sensitivity[3]

	SULFUR wt%	AROMATICS vol%	CETANE	TOTAL COST MM$/yr	TOTAL COST cents/gal[1]	INVESTMENT MM$	PROCESS CAPACITY[2] 000 B/D	ENERGY 000 B/D
Base Case w/Investment	0.27	30.7	43.7	-	-	-	-	-
.15% Sulfur	0.11	29.6	42.5	93	2.1	131	52	5
.05% Sulfur	0.05	29.4	44.9	303	6.8	344	167	20
20% Aromatics	0.14	20.0	49.1	219	4.9	547	272	2
15% Aromatics	0.07	14.0	49.9	426	9.5	1,039	525	5
10% Aromatics	0.032	10.0	50.9	1,299	29.1	1,640	769	72
10% Aromatics at .05% S	0.031	10.0	50.9	1,316	28.4	1,660	823	103
10% Aromatics at .05% S with Purchased Feedstock	0.034	10.0	51.4	719	16.1	1,299	634	35

1) Based on Groups I thru IV Diesel Production of 291,700 B/D.

2) Includes Hydrogen Plant Capacity in Millions SCF/D.

3) New Hydrogen Plant Capacity Provided to Support all new Hydroprocessing Investment.

H. Impact of Hydrogen Plant Capacity on Diesel Costs

The LP solutions derived during this study generally indicated little need for new hydrogen plant capacity except in Group I and II refineries. While we feel that an assumption that new hydrogen plant capacity is required to support every new hydroprocessing project is too conservative, our results may be too optimistic. We have therefore estimated hydrogen plant costs to support new hydroprocessing capacity selected in our analysis as shown on Table VIII.9.

The impact of hydrogen plant costs on Group I and II and Group III-VI refineries are shown in Appendix E.

The hydrogen plant cost shown in Table VIII.9 are in addition to hydrogen plant requirements based on the LP model study results.

Additional hydrogen plant requirements to reduce diesel sulfur levels to 0.05 wt% would increase investment costs 78 million $ or 0.5 ¢/gallon of diesel. Additional hydrogen plant requirements to reduce diesel aromatics increase by 137 million to 209 million $ and costs increase by 1.1 to 1.5 ¢/gallon of diesel. Other process requirements and diesel quality are unchanged from the base analysis.

I. Impact of Methanol Prices on Diesel Costs

The Mobil MOGD process was selected in some refinery groups for reduction of diesel aromatics. With an increase in methanol price to 70 ¢/gallon, the MOGD process was replaced in the 15% aromatics case by new hydroprocessing capacity at an 85% increase in costs.

The refinery model was severely constrained by process limitations at the 10% aromatics level and the MOGD process was the only option available to provide a very low aromatics content blendstock. Thus, with methanol prices at 70¢/gallon, for aromatics levels of 10%, the MOGD process was still fully utilized and costs doubled. The cost increase was nearly proportional to the increase in methanol price.

J. Cost Equations

Costs of diesel and gasoline contaminant reduction have been developed in this analysis for the following major components of refinery cost:

- Feedstock costs
- Variable operating costs
- Fixed operating costs
- Capital related costs

Refinery cost equations have been developed in terms of $/barrel of diesel or gasoline for each major component of cost for each case analyzed. These cost equations can be used by the ARB to extend and update results of our analysis.

Cost equations for both 1991 Diesel and Gasoline Analysis are provided in Appendix F.

K. Marginal Refinery Costs

Our analysis focuses primarily on the total cost of reducing diesel and gasoline contaminants from projected 1991 and 1995 levels without regulatory control. These costs are based on the difference in total refinery costs versus the base case with no contaminant reduction.

The marginal cost of removing the last increment of contaminant is generally higher than the average cost of contaminant reduction. The marginal costs of contaminant reduction at each contaminant level are available directly from the LP model results. Typical diesel marginal costs are shown on Table VIII.10. Actual marginal costs are not provided in this report since they are specific to the particular refineries modeled and are therefore confidential. In addition these costs are unique at each level of contaminant reduction and should not be used to extend the results of our analysis.

Marginal results have been provided to the ARB on a confidential basis for all cases analyzed.

TABLE VIII.10

TYPICAL DIESEL MARGINAL COSTS

Case (with Investment)	Sulfur $/B/%	Aromatics $/B/%
.05% Sulfur	25	-----
20% Sulfur	----	0.3
15% Aromatics	----	0.8
10% Aromatics	----	1.5
10% Aromatics and Purchased Feedstocks	----	1.4

IX. 1991 COST OF REDUCING GASOLINE AROMATICS

The results of our analysis for the 1991 cost of California reducing gasoline aromatics are shown on Tables IX.1 thru 3 as follows:

IX.1 1991 and 1986 Base Case Gasoline Quality
IX.2 1991 California Cost of Gasoline Aromatics Reduction Without Investment
IX.3 1991 California Cost of Gasoline Aromatics Reduction With Investment

A. 1991 Base Case

1. 1991 Versus 1986 Gasoline Production and Quality

A summary of gasoline volume, aromatics and benzene content is shown on Table IX.1 for 1986 and 1991. Both investment and non-investment base cases are shown for 1991.

The 1986 data is based on our survey results and ADL's LP model analysis. The 1991 qualities are based on the 1991 LP model results scaled up to get results for each refinery group. To maintain confidentiality, Group III and IV data have been combined for all results.

Based on CEC forecasts, the volume of automotive gasoline will decrease 6.3% from 880.8 MB/D in 1986 to 824.8 MB/D in 1991. As discussed in Section V above, since a specific forecast was provided by one Group III/IV refiner, gasoline demand by group varies somewhat from overall California growth.

California pool octane is forecast to increase from 87.5 to 88.3 between 1986 and 1991. Although pool octane will increase due to the decrease in gasoline production, octane barrels[1] requirement will decrease from 77,070 MOB/D to 72,830 MOB/D.

The decrease in gasoline volume and octane barrel requirements in 1991 resulted in a slight reduction in aromatics from 33.8% to 33.2% for the non-investment case. Benzene levels increased from 1.84% to 1.97%. The level of accuracy of benzene levels is estimated to be ±0.1%. Benzene levels were reported to .01% to show differences between cases.

The decrease in aromatic content between 1986 and 1991 resulted primarily from the announced addition of two MTBE units and a dimersol unit between 1986 and 1991. The increased benzene content resulted from increased reforming severity and utilization of light naphtha in reforming.

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[1] Barrels x octane = octane-barrels

TABLE IX.1

1986 and 1991 BASE CASE GASOLINE QUALITY

		1986			1991				
						WITHOUT INVESTMENT		WITH INVESTMENT	
GROUP		MB/D	AROM	BENZ	MB/D	AROM	BENZ	AROM	BENZ
1	TOPPING	1.9	35.3	2.50	1.8	37.4	2.66	37.4	2.66
2	HYDROSKIMMING	13.0	43.3	3.06	18.5	45.8	3.26	36.1	2.61
3 & 4	CONV. & D. CONV (FCC)	330	33.2	1.58	315.3	31.7	1.81	30.3	1.78
5	D. CONVERSION - LA	282.4	32.3	1.94	258.5	32.0	1.96	29.5	1.69
6	D. CONVERSION - N. CA	253.5	35.6	2.00	230.7	35.6	2.09	34.9	1.89
	TOTAL	880.8	33.8	1.84	824.8	33.2	1.97	31.5	1.80

TABLE IX.2

1991 CALIFORNIA COST OF GASOLINE AROMATICS REDUCTION - WITHOUT INVESTMENT

		MOTOR GASOLINE			REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION[1]	PROD 000 B/D	AROM VOL%	BENZ VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG	INVEST MILLION $	ENERGY 000 B/D
Base Case without Investment	0.0	824.8	33.2	1.97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Max Aromatics Reduction	3.4	824.8	32.1	1.89	927.6	44.5	88.5	0.0	1,060.6	3.1	0.0	31.10

	PROCESS ADDITITIONS: 000 B/D																PURCHASED FEEDSTOCKS: 000 B/D				
DESCRIPTION	NAPHTHA HDT	FCC GASO HDT	H2 PLANT	ALKYL	CAT POLY	DIMERSOL	ONCE THRU ISOM	RECYCLE ISOM	MTBE	ETHEROL	C4 ISOM	REFORM-ATE EXTRACT	FCC GASO EXTRACT	FCC GASO FRAC	REFORM	BTX SALES 000 B/D	MTBE	ETOH	ISOM	ALKYL	TOTAL
Base Case without Investment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Max Aromatics Reduction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[1] % Reduction from Base Case Aromatics Level

TABLE IX.3

1991 CALIFORNIA COST OF GASOLINE AROMATICS REDUCTION - WITH INVESTMENT

DESCRIPTION	% AROMATICS REDUCTION [1]	MOTOR GASOLINE PROD 000 B/D	MOTOR GASOLINE AROM VOL%	MOTOR GASOLINE BENZ VOL%	REFINERY COST CHANGES NET FEEDST 000 $/D	REFINERY COST CHANGES VAR COST 000 $/D	REFINERY COST CHANGES FIXED COST 000 $/D	REFINERY COST CHANGES CAPITAL COST 000 $/D	REFINERY COST CHANGES TOTAL COST 000 $/D	TOTAL COST CPG	INVEST MILLION $	ENERGY 000 B/D
Base Case with Investment	0.0	824.8	31.5	1.80	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
5% Aromatics Reduction	5.1	824.8	29.8	1.75	164.0	4.5	(10.7)	91.9	249.7	0.7	128.6	3.40
10% Aromatics Reduction	10.0	804.5	28.2	1.87	364.7	28.7	39.9	169.7	603.1	1.8	237.6	7.70
15% Aromatics Reduction	14.9	804.5	26.7	1.62	573.0	94.0	261.5	640.5	1,569.0	4.6	896.8	24.60
20% Aromatics Reduction	20.4	489.2	25.5	1.66	299.3	107.6	371.0	557.7	1,335.5	6.5	780.8	19.00
Max Aromatics Reduction	18.1	824.8	25.8	1.54	652.9	182.1	560.8	1,025.1	2,420.9	7.0	1,435.1	37.20
Max Arom Red with Purch Feedstock	18.7	824.8	25.6	1.52	557.7	(32.9)	(66.5)	169.0	627.3	1.8	236.7	(14.00)

PROCESS ADDITITIONS: 000 B/D

PURCHASED FEEDSTOCKS: 000 B/D

DESCRIPTION	NAPHTHA HDT	FCC GASO HDT	H2 PLANT	ALKYL	CAT POLY	DIMERSOL	ONCE THRU ISOM	RECYCLE ISOM	MTBE	ETHEROL	C4 ISOM	REFORM-ATE EXTRACT	FCC GASO EXTRACT	FCC GASO FRAC	REFORM	BTX SALES 000 B/D	MTBE	ETOH	ISOM	ALKYL	TOTAL
Base Case with Investment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5% Aromatics Reduction	4.9	0.0	9.9	0.0	0.0	0.0	9.6	36.2	15.0	6.2	20.3	1.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
10% Aromatics Reduction	4.0	0.0	0.0	0.0	0.0	0.3	0.0	47.8	14.6	6.2	33.1	4.0	3.7	40.1	0.0	1.1	0.0	0.0	0.0	0.0	0.0
15% Aromatics Reduction	4.3	0.0	98.9	0.0	0.0	0.6	0.0	51.9	18.1	13.0	92.5	14.9	77.8	76.7	39.3	14.4	0.0	0.0	0.0	0.0	0.0
20% Aromatics Reduction	5.9	0.0	0.0	3.2	0.0	0.0	0.0	34.0	16.5	7.0	47.3	33.9	98.5	136.4	21.3	17.8	0.0	0.0	0.0	0.0	0.0
Max Aromatics Reduction	5.9	0.0	108.7	3.2	0.0	0.6	0.0	58.4	22.2	13.5	111.3	43.6	150.9	178.0	60.1	28.0	0.0	0.0	0.0	0.0	0.0
Max Arom Red with Purch Feedstock	2.7	0.0	0.0	0.0	0.0	0.3	0.0	49.0	17.1	13.4	8.2	14.5	1.9	13.0	0.0	6.1	30.6	0.0	0.0	2.1	32.7

1) % Reduction from Base Case Aromatics Level

The aromatic and benzene content of Group II increased in the non-investment case since the only source of additional octane is reforming. Group III/IV showed the largest decrease in aromatics content with 1.5% decrease in the non-investment case. This decrease reflects the addition of MTBE capacity between 1986 and 1991 in these groups. Group VI included the addition of a dimersol unit but the result did not change the aromatic content.

The 1991 investment base case reflects addition of capacity selected to relieve octane constraints. The capacity selected for the 1991 base case included new MTBE, Isomerization and Etherol capacity. All three of these processes produce gasoline streams high in octane but low in both aromatics and benzene.

As a result of the processes selected to relieve octane constraints, the aromatic content in the 1991 investment base case dropped from 33.8% in 1986 to 31.5%. Groups II-VI all showed a decrease in aromatics due to the above process additions necessary for octane.

Group I gasoline qualities were assumed to be the same in both the investment and non-investment case. This assumption was made since the gasoline product made by Group I refineries is primarily from purchased feedstocks from other refineries. Other than naphtha, Group I refineries do not produce gasoline blending streams.

Overall benzene content decreased slightly in the 1991 investment base case from 1.84% in 1986 to 1.80%. This decrease results from the new process additions which produced low benzene blendstocks and decreased the utilization of light naphtha in catalytic reforming.

2. <u>1991 Base Case Results Without Investment</u>

Results for 1991 California cost of gasoline aromatics reduction without investment are shown on Table IX.2. Results by refinery group (Groups III and IV combined) are shown in Appendix G for each case analyzed.

Gasoline production and quality for the base case are the same as shown on Table IX.1. No cost impact is shown for the base case since this is the case against which all non-investment gasoline aromatics reduction cases are measured.

B. <u>Maximum Gasoline Aromatics Reduction Without Investment</u>

Aromatics levels were progressively reduced from base case level in selected refineries to the maximum extent possible <u>without</u> new process investment. In all aromatics reduction cases, gasoline octanes were maintained at base case 1991 levels.

Results for the 1991 maximum California gasoline aromatics reduction case without investment by group are shown on Table IX.4.

TABLE IX.4

1991 MAXIMUM CALIFORNIA GASOLINE AROMATICS REDUCTION - WITHOUT INVESTMENT

			MOTOR GASOLINE			REFINERY COST CHANGES							
GROUP	DESCRIPTION	% AROMATICS REDUCTION[1]	PROD 000 B/D	AROM VOL%	BENZ VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG	INVEST MILLION $	ENERGY 000 B/D
I	Topping	0.0	1.8	37.4	2.66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	1.0	18.5	45.5	2.51	455.8	1.5	24.0	0.0	481.4	62.0	0.0	18.3
III + IV	Conv + D Conv	4.6	315.3	30.2	1.72	153.3	18.0	21.5	0.0	193.0	1.5	0.0	3.4
V	D Conversion - LA	4.2	258.5	30.6	2.00	235.1	8.2	8.9	0.0	252.3	2.3	0.0	7.8
VI	D Conversion - N. Cal	1.1	230.7	35.2	1.96	83.4	16.7	34.0	0.0	134.1	1.4	0.0	1.6
TOTAL CALIFORNIA		3.4	824.8	32.1	1.89	927.6	44.5	88.5	0.0	1,060.6	3.1	0.0	31.1

		PROCESS ADDITIONS: 000 B/D																PURCHASED FEEDSTOCKS: 000 B/D				
GROUP	DESCRIPTION	NAPHTHA HDT	FCC GASO HDT	H2 PLANT	ALKYL	CAT POLY	DIMERSOL	ONCE THRU ISOM	RECYCLE ISOM	MTBE	ETHEROL	C4 ISOM	REFORM-ATE EXTRACT	FCC GASO EXTRACT	FCC GASO FRAC	REFORM	BTX SALES 000 B/D	MTBE	ETOH	ISOM	ALKYL	TOTAL
I	Topping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
III + IV	Conv + D Conv	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V	D Conversion - LA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VI	D Conversion - N. Cal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CALIFORNIA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

1) % Reduction from Base Case Aromatics Level

California gasoline aromatics can only be reduced slightly while maintaining base case octanes without new process investment. The maximum % reduction from base case aromatics levels without new process investment varied from 1.0% for Group II to 4.6% for Group III and averaged 3.4%[2]. Benzene levels decreased along with aromatics level from 1.97% in the base case to 1.89% or by 4.1% of base case aromatics. Benzene levels varied from 1.72% in Group III/IV to 2.66% in Group I.

Total costs increased 1.06 million $/D in California or 3.1 cents per gallon of gasoline produced. Costs for complex refineries varied from 1.4 ¢/gallon in Group VI to 2.3 ¢/gallon for Group V. Simple hydroskimming Group II refineries are very constrained and have few options to replace gasoline aromatics. Costs for Group II refineries were 62.0 ¢/gallon for only a 1% reduction in gasoline aromatics. Costs increased in all groups due to severe constraints against gasoline octane with reduced aromatics level.

Net feedstock costs increased by .93 million $/D or 87% of total cost increase. Variable and fixed operating costs also increased slightly. Energy requirements increased 31 MB/D equivalent crude for a decrease of only 9 MB/D aromatics in gasoline (1.1% of total gasoline). Energy requirements for Group II refineries of 18.3 MB/D nearly equaled total gasoline production of 18.5 MB/D.

C. Gasoline Aromatics Reduction With New Process Investment

Results for 1991 California cost of gasoline aromatics reduction with investment are shown on Table IX.3. Detailed results by refinery group are shown in Appendix G.

1. 1991 Base Case

A separate base case was run for each selected refinery with the new process investment options available discussed in Section VI above. Due to constraints on octane, the refinery models selected several process options (particularly isomerization, MTBE and etherol) which reduced gasoline aromatics and benzene content from the base case without investment.

Since these process options were justified based on octane requirements rather than aromatics reduction, the base case investment costs were not included in the cost of reducing gasoline aromatics

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[2] Note: In all gasoline aromatics reduction cases, results are expressed as a % reduction from the base case level rather than the absolute reduction in pool level. In this case, a 3.4% reduction in base case aromatics is an absolute reduction in aromatics level from 33.2% in the base case to 32.1% or 1.1% (e.g., 1.1%/33.2% = 3.4% reduction).

levels. Changes in aromatics level, benzene level and costs are measured against this base case for all aromatics reduction cases where new process investments were allowed.

New process options selected in the base case with investment were as follows:

	000 B/D
Naphtha hydrotreating	4.9
Recycle isomerization	30.0
MTBE	12.5
Etherol	10.8
C_4 isomerization	1.2

Total cost of these new investment options was 200 million $.

The impact of the selected process options on base case aromatics and benzene levels was as follows:

	Base Case w/o Investment	Base Case w/Investment
Aromatics Vol. %	33.2	31.5
Benzene Vol. %	1.97	1.80
Process Investment:		
Million $	0	200.0

Since this was the base case from which all gasoline aromatics reduction cases were measured, no base case costs are included in the summary California results.

5, 10, 15, 20 and Maximum % Aromatics Reduction with Investment

Model runs were made for each selected refinery reducing base case aromatics with investment by a nominal 5, 10, 15, 20 and maximum %. BTX displaced thru extraction in each case was credited against feedstock costs. The benzene was priced at gasoline blending value based on 1991 CEC price forecasts less (8 ¢/gallon) transportation cost to the USGC.

Absolute gasoline aromatics and benzene levels decreased and costs increased with the nominal decreases in aromatics content as follows:

Aromatics Reduction	Gasoline*	Aromatics	Benzene	BTX Sales	Cost	Cost	Inv.
	000 B/D	%	%	MB/D	000 $/D	¢/gal.	MM$
Base Case	824.8	31.5	1.80	-	-	-	-
5%	824.8	29.8	1.75	.1	250	0.7	129
10%	804.5	28.2	1.87	1.1	603	1.8	238
15%	804.5	26.7	1.62	14.4	1,569	4.6	897
20%	489.2	25.5	1.66	17.8	1,335	6.5	781
Max.	824.8	25.8	1.54	28.0	2,421	7.0	1,435

* Volume of gasoline controlled.

All refinery groups were able to reduce gasoline aromatics by a nominal 5% from base case levels with new process investment. Aromatics were reduced from 31.5% to 29.8% and benzene levels were reduced from 1.8% to 1.75%. Total costs were 250,000 $/D and averaged 0.7¢/gallon of gasoline. However, costs were much higher for simple hydroskimming Group II refineries at 15.7¢/gallon! Net feedstock requirements accounted for 65% and capital costs for 35% of total costs with variable and fixed operating costs virtually unchanged. Investment requirements were 129 million $ for 5 MB/D naphtha hydrotreating, 46 MB/D isomerization, 15 MB/D MTBE, 20 MB/D C_4 isomerization and 6 MB/D etherol process capacity. Only minimal BTX extraction capacity was required (1 MB/D in Group II) and BTX sales were insignificant at 0.1 MB/D. Net energy requirements were minimal at 3 MB/D.

Reduction of aromatics in Group II was limited to about 5%. Groups III and IV were limited to a nominal 15% aromatics reduction. It was possible to reduce aromatics levels in the most complex Group V and VI refineries by about 20% of base case levels. Results for the 10%, 15% and 20% aromatics reduction cases are based on volume controlled gasoline.

Aromatics could be reduced by 10 or 15% relative to base case levels in 805 MB/D or 97.5% of total California gasoline produced in Group III-VI refineries. Total costs averaged 1.8 ¢/gallon with 238 million $ investment to reduce aromatics by 10% in Groups II-VI refineries. Absolute aromatics levels dropped to 28.2%, but benzene level increased slightly to 1.87%[3]. New process requirements included 48 MB/D isomerization, 15 MB/D MTBE, 6 MB/D etherol and 33 MB/D C_4 isomerization. BTX extraction capacity requirement was 4 MB/D in Group III/IV to remove 1 MB/D BTX for outside sales. Net energy requirements were 8 MB/D.

Costs increased to 4.6 ¢/gallon and investment requirements increased to 897 million $ for 15% aromatics reduction in Group II-VI refineries. Absolute aromatics levels dropped to 26.7% and benzene levels dropped to 1.62%. New process requirements increased to 52 MB/D isomerization, 18 MB/D MTBE, 13 MB/D etherol, 93 MB/D of C_4 isomerization, 39 MB/D reforming and 99 MSCF/D of hydrogen plant. BTX extraction capacity increased to 15 MB/D for reformate and 78 MB/D for light FCC gasoline to remove 14 MB/D BTX for sales. Net energy requirements increased to 25 MB/D.

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[3] Only total aromatics levels were controlled in our analysis. Although benzene level generally followed total aromatics level in some cases benzene levels decreased less than total aromatics or even increased slightly due to selective blending.

Aromatics could only be reduced by 20% in Groups V and VI representing 489 MB/D or 59% of total California gasoline. Total costs for 20% aromatics reduction increased to 6.5 ¢/gallon and investment costs were 781 million $. Absolute aromatics levels dropped to 25.8% and benzene dropped to 1.66% in controlled gasoline. New process requirements were nearly as great as in the 15% reduction case on a smaller volume of controlled gasoline. Process requirements included 34 MB/D isomerization, 17 MB/D MTBE, 7 MB/D etherol, 47 MB/D C_4 isomerization and 21 MB/D reforming. BTX extraction capacity increased to 34 MB/D for reformate and 99 MB/D for light FCC gasoline to remove 18 MB/D of BTX. Net energy requirements were 19 MB/D.

Results of the maximum gasoline aromatics reduction cases in each group were combined to get the maximum gasoline aromatics reduction possible in California. Results of this maximum gasoline aromatics reduction case by group are shown on Table IX.5.

Maximum % aromatics reduction, absolute % aromatics level and % benzene level achieved by group were as follows:

		Gasoline 000B/D	% Aromatics Reduction	Aromatics %	Benzene %
Group I	Topping	1.8	0	37.4	2.66
Group II	Hydroskimming	18.5	5.0	34.3	3.30
Group III/IV	Conversion/D.Conv.	315.3	15.0	25.8	1.24
Group V	D. Conv. - LA	258.5	20.0	23.6	1.82
Group VI	D. Conv. - N. Ca.	230.7	20.8	27.6	1.49
	Total California	824.8	18.1	25.8	1.54

Maximum gasoline aromatics reduction possible in California with new process investment was 18.1% to an absolute level of 25.8%. Benzene levels were reduced by 14.4% from the base case to 1.54%. Total costs for maximum aromatics reduction were 2.4 million $/D and averaged 7.0 ¢/gallon. Costs were highest for simple hydroskimming refineries in Group II at 15.7¢/gallon for only 5% aromatics reduction.

Investment requirements were 1,435 million $ for about 650 MB/D of new process capacity. Capital costs accounted for 42% of total costs followed by feedstock costs (27%), fixed operating costs (23%) and variable operating costs. BTX sales were 28 MB/D for an aromatics reduction in gasoline of 47 MB/D (5.7% of total gasoline). Net energy requirements were 37 MB/D of equivalent crude.

D. Maximum Gasoline Aromatics Reduction With Investment and Purchased Feedstock

The maximum aromatics reduction case with investment case was repeated allowing purchase of the following gasoline blendstocks:

TABLE IX.5

1991 MAXIMUM GASOLINE AROMATICS REDUCTION

			MOTOR GASOLINE			REFINERY COST CHANGES							
GROUP	DESCRIPTION	% AROMATICS REDUCTION[1]	PROD 000 B/D	AROM VOL%	BENZ VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG	INVEST MILLION $	ENERGY 000 B/D
I	Topping	0.0	1.8	37.4	2.66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	5.0	18.5	34.3	3.30	64.2	3.7	13.8	40.1	121.8	15.7	56.1	2.0
III + IV	Conv + D Conv	14.8	315.3	25.8	1.24	289.4	70.9	176.0	427.4	963.6	7.3	598.3	16.2
V	D Conversion - LA	20.0	258.5	23.6	1.82	187.8	48.8	181.0	265.4	683.0	6.3	371.6	10.0
VI	D Conversion - N. Cal	20.8	230.7	27.6	1.49	111.4	58.8	190.0	292.3	652.5	6.7	409.2	9.0
TOTAL CALIFORNIA		18.1	824.8	25.8	1.54	652.9	182.1	560.8	1,025.1	2,420.9	7.0	1,435.1	37.2

		PROCESS ADDITIONS: 000 B/D																PURCHASED FEEDSTOCKS: 000 B/D				
GROUP	DESCRIPTION	NAPHTHA HDT	FCC GASO HDT	H2 PLANT	ALKYL	CAT POLY	DIMERSOL	ONCE THRU ISOM	RECYCLE ISOM	MTBE	ETHEROL	C4 ISOM	REFORM-ATE EXTRACT	FCC GASO EXTRACT	FCC GASO FRAC	REFORM	BTX SALES 000 B/D	MTBE	ETOH	ISOM	ALKYL	TOTAL
I	Topping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
II	Hydroskimming	0.0	0.0	9.9	0.0	0.0	0.0	0.0	3.9	0.0	0.0	5.2	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
III + IV	Conv + D Conv	0.0	0.0	98.8	0.0	0.0	0.6	0.0	20.6	5.7	6.5	58.8	8.7	52.4	41.6	38.8	10.1	0.0	0.0	0.0	0.0	0.0
V	D Conversion - LA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	6.5	7.0	20.9	27.1	50.5	46.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VI	D Conversion - N. Cal	5.9	0.0	0.0	3.2	0.0	0.0	0.0	11.3	10.0	0.0	26.4	6.7	48.0	90.1	21.3	17.8	0.0	0.0	0.0	0.0	0.0
TOTAL CALIFORNIA		5.9	0.0	108.7	3.2	0.0	0.6	0.0	58.4	22.2	13.5	111.3	43.6	150.9	178.0	60.1	28.0	0.0	0.0	0.0	0.0	0.0

1) % Reduction from Base Case Aromatics Level

- MTBE;
- Ethanol;
- Isomerate; and
- Alkylate.

These blendstocks may be available locally or from other refinery regions at a price based on gasoline blending values using 1991 CEC gasoline and butane price forecasts.

Aromatics level targets were identical to the maximum reduction case with investment. However, the group II aromatics levels dropped from the 34.3% target to 25.6% due to the purchase of alkylate blendstock. Total California aromatics level dropped to 25.6%.

Benzene levels increased in Groups III, IV and VI and decreased in Groups II and V relative to the maximum aromatics reduction case without purchased feedstocks. Total California benzene level was virtually unchanged at 1.52% versus 1.54%.

MTBE was purchased in Groups III/IV, V and VI, and alkylate was purchased in Group II. Total California purchased feedstocks were:

	000 B/D
MTBE	30.6
Alkylate	2.1

Refinery energy requirements dropped to 14 MB/D <u>below</u> base case levels including purchase of gasoline blend stocks.[4]

Purchased high octane, low aromatics blendstocks significantly reduce refinery octane constraints. Total costs and investment were reduced significantly with purchased feedstocks for all groups. Total California costs were reduced as follows:

	Total Cost ¢/gallon	Investment million $
Max. aromatics reduction with investment	7.0	1435.1
Max. aromatics reduction with investment and purchased feedstocks	1.8	236.7

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[4] Our study <u>includes</u> the energy content of purchased feedstocks but <u>excludes</u> the energy required to produce these feedstocks (assumed produced outside California).

New process requirements dropped from 650 MB/D to only 120 MB/D with the availability of purchased feedstocks. BTX sales dropped from 28 MB/D to only 4 MB/D.

Although costs of aromatics reduction were considerably lower with purchased low aromatics feedstocks, the analysis is based on the assumption that these blendstocks would be available at gasoline blending value. It is uncertain if low aromatics blendstocks would be available at blending value -- particularly if reduction of gasoline aromatics is mandated in other U.S. regions. In addition, many forecasters are projecting shortages of methanol and isobutylene in the 1990's which could limit MTBE availability.

E. Impact of Methanol Prices on Gasoline Costs

The MTBE and etherol processes were selected in most cases to reduce gasoline aromatics. With an increase in methanol price to 70 ¢/gallon, about 15 to 25% of this process capacity was replaced by isomerization and alkylation. Costs for gasoline aromatics reduction increased by about 5%.

F. Cost Equations

Costs of diesel and gasoline contaminant reduction have been developed in this analysis for the following major components of refinery cost:

- Feedstock costs
- Variable operating costs
- Fixed operating costs
- Capital related costs

Refinery cost equations have been developed in terms of $/barrel of diesel or gasoline for each major component of cost for each case analyzed. These cost equations can be used by the ARB to extend and update results of our analysis.

Cost equation components for both 1991 Diesel and Gasoline Analysis are provided in Appendix F. The equation is the sum of the components.

G. Marginal Refinery Costs

Our analysis focuses primarily on the total cost of reducing diesel and gasoline contaminants from projected 1991 and 1995 levels without regulatory control. These costs are based on the difference in total refinery costs versus the base case with no contaminant reduction.

The marginal cost of removing the last increment of contaminant is generally higher than the average cost of contaminant reduction. The marginal costs of contaminant reduction at each contaminant level are available directly from the LP model results. Typical gasoline marginal costs are shown on Table IX.6. Actual marginal costs are not provided in this report since they are specific to the particular refineries modeled and are therefore confidential. In addition these costs are unique at each level of contaminant reduction and should not be used to extend the results of our analysis.

Cost equations for both 1991 Diesel and Gasoline Analysis are provided in Appendix F.

TABLE IX.6

TYPICAL GASOLINE MARGINAL COSTS

Case (with Investment)	Aromatics $/B/%
5% Reduction	0.3
18.1% Reduction	15
18.7% Reduction with Purchased Feedstock	0.5

X. 1995 COST OF REDUCING DIESEL SULFUR, DIESEL AROMATICS AND GASOLINE SULFUR LEVELS

A. 1995 Versus 1991 Base Case

Refiners will not be able to make 1995 gasoline demand, grade split and octanes without substantial investment. Thus, for 1995 there is no applicable analysis for the cost to reduce diesel sulfur, diesel aromatics and gasoline aromatics without investment.

The 1991 and 1995 study basis was discussed in Section V. The key base case factors affecting our analysis and a summary of 1995 versus 1991 base case results are shown on Table X.1.

Crude price is forecast to increase from 24.90 $/B to 26.78 $/B or by 7.6%. Diesel demands are forecast to increase by 17.4 MB/D between 1991 and 1995 or by 6.0%. Due to higher energy costs, and higher diesel demand, 2.1 MB/D hydroprocessing investment costing 12 million $ was justified in 1995. As a result of this investment, base case sulfur levels are projected to decline slightly in 1995 from .27 to .23 wt%. Diesel aromatics increased slightly from 30.7 to 31.0 vol%, but due to selective blending to produce automotive diesel, base case cetane increased slightly from 43.7 to 44.3.

Gasoline demand is forecast to increase by 7.0 MB/D or 0.8% between 1991 and 1995. More significantly, due to increased unleaded premium and unleaded intermediate demand, gasoline pool octane is forecast to increase from 88.3 to 89.0 R+M/2. With this significant increase in octane requirements, new process investment justified in the base case without gasoline aromatics reduction increased substantially from 200 million $ in 1991 to 236 million $ in 1995. New gasoline related processes increased from 59 MB/D in 1991 to 71 MB/D in 1995.

The increase in reformer and FCC process severity required to meet 1995 gasoline and octane demands more than offset additions to processes producing high octane/low aromatics blendstocks and resulted in a small increase in gasoline aromatics from 31.5% in 1991 to 32.3% in 1995. Benzene levels increased along with aromatics content from 1.80% in 1991 to 1.88% in 1995.

Although absolute 1995 diesel sulfur, diesel aromatics and gasoline aromatics levels may vary somewhat from our base case, the analysis of cost changes for reduction of diesel and gasoline contaminant levels remains valid.

The results of our 1995 analysis for diesel sulfur aromatics reduction are shown on Table X.2 and the results for our 1995 analysis of gasoline aromatics levels are shown on Table X.3. Detailed results by Group are provided in Appendix H for the 1995 Diesel Analysis and Appendix I for the 1995 Gasoline Analysis. Cost equations are provided in Appendix J to allow the ARB to extend the results of the 1995 analysis.

TABLE X.1
1995 VERSUS 1991 BASE CASE

	1991	1995	▲	▲ %
Crude Price: $/B	24.90	26.78	1.88	7.6
Diesel Cases				
Diesel Production: MB/D	291.7	309.1	17.4	6.0
Base Diesel Sulfur: wt%	.27	.23	(.04)	-
Base Diesel Aromatics: vol%	30.7	31.0	0.3	-
Diesel Cetane	43.7	44.3	0.6	-
Diesel Base Case Investment:MM$	12	12	0	0
- Naphtha HDT: MB/D	1.8	-	(1.8)	-
- Hydro-dearomitization: MB/D	0.6	-	(0.6)	-
- Distillate HDT: MB/D	-	2.1	(0.3)	-
Total Diesel Processes: MB/D	2.4	2.1	2.1	-
Gasoline Cases				
Gasoline Production: MB/D	824.8	831.8	7.0	0.8
Gasoline Pool Octane: (R+M)/2	88.3	89.0	0.7	-
Gasoline Aromatics: vol%	31.5	32.3	0.8	-
Gasoline Benzene: vol%	1.80	1.88	0.08	-
Gasoline Base Case Investment: MM$	200	236	36	18.0
- Naphtha HDT	4.9	-	(4.9)	-
- Isomerization: MB/D	30.0	38.4	8.4	
- MTBE: MB/D	12.5	13.7	2.2	-
- Etherol: MB/D	10.8	16.7	5.9	-
- C_4Isom: MB/D	1.2	2.4	1.2	-
Total Gasoline Processes: MB/D	59.4	71.2	11.8	-

TABLE X.2

1995 CALIFORNIA COST OF REDUCING DIESEL SULFUR AND AROMATICS

		DIESEL					REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION [1]	PROD 000 B/D [2]	SULFUR WT% [2]	CETANE NO	POLY AROM VOL%	TOTAL AROM VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
Base Case with Investment	0.0	309.1	0.23	44.3	7.6	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
.05 Sulfur	-	309.1	0.05	44.5	6.4	29.6	693.5	30.6	61.1	208.2	993.4	7.7	291.4	21.95
20% Aromatics	34.1	309.1	0.14	48.7	3.7	20.0	113.6	46.7	63.9	296.2	520.4	4.0	414.7	3.87
15% Aromatics	52.5	309.1	0.07	49.5	1.7	15.0	259.4	105.4	139.3	606.6	1,110.8	8.6	849.2	7.42
10% Aromatics	67.2	309.1	0.030	50.8	0.3	10.0	2,596.9	243.7	370.7	1,142.9	4,354.3	33.5	1,600.1	87.21

	PROCESS ADDITIONS : 000 B/D							PURCHASED STOCKS
DESCRIPTION	NAPHT HDT	DIST HDT	DIST HR	AROM HDA	H2 PLANT	MOBIL OLEFINS	MOBIL MOGD	SO LA GAS OIL 000 B/D
Base Case with Investment	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0
.05 Sulfur	1.5	30.9	97.4	0.0	0.0	0.0	0.0	0.0
20% Aromatics	3.1	0.0	61.1	110.8	0.0	0.8	0.8	0.0
15% Aromatics	9.7	0.0	106.6	173.6	35.3	15.6	15.6	0.0
10% Aromatics	5.3	0.0	163.3	225.5	137.0	72.4	72.4	0.0

1) % Aromatics Reduction from Base Case Aromatics Level

TABLE X.3

1995 CALIFORNIA COST OF REDUCING GASOLINE AROMATICS

		MOTOR GASOLINE			REFINERY COST CHANGES							
DESCRIPTION	% AROMATICS REDUCTION[1]	PROD 000 B/D	AROM VOL%	BENZ VOL%	NET FEEDST 000 $/D	VAR COST 000 $/D	FIXED COST 000 $/D	CAPITAL COST 000 $/D	TOTAL COST 000 $/D	TOTAL COST CPG **	INVEST MILLION $	ENERGY 000 B/D
Base Case with Investment	0.0	831.8	32.3	1.88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Max Aromatics Reduction	14.7	831.8	27.5	1.61	1,028.1	222.7	688.0	1,324.9	3,263.7	9.3	1,854.9	47.39
Max Aromatics Reduction w/Purch Fee	50.3	831.8	16.1	0.81	4,663.4	1.8	190.2	905.0	5,760.4	16.5	1,266.1	5.71

	PROCESS ADDITIONS : 000 B/D																PURCHASED FEEDSTOCK: 000 B/D				
DESCRIPTION	NAPHTHA HDT	FCC GASO HDT	H2 PLANT	ALKYL	CAT POLY	DIMERSOL	ONCE THRU ISOM	RECYCLE ISOM	MTBE	ETHEROL	C4 ISOM	REFORM-ATE EXTRACT	FCC GASO EXTRACT	FCC GASO FRAC	REFORM	BTX SALES 000 B/D	MTBE	ETOH	ISOM	ALKYL	TOTAL
Base Case with Investment	0.0	0.0	0.0	0.0	0.0	0.0	6.2	32.2	13.7	16.7	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Max Aromatics Reduction	7.1	2.6	483.3	3.3	0.0	0.4	0.0	62.1	23.4	11.8	124.2	66.9	130.7	181.6	67.6	29.6	0.0	0.0	0.0	0.0	0.0
Max Aromatics Reduction w/Purch Fee	2.9	11.9	217.5	0.0	0.0	0.0	0.0	49.1	2.7	0.0	13.9	130.1	127.8	146.9	0.0	46.3	61.6	7.5	0.0	108.6	158.1

1) % Reduction from Base Case Aromatics Level

Process options selected in the diesel and gasoline base case were justified based on projected diesel sulfur and gasoline octane constraints rather than on contaminant reduction. These base case investment costs were not included in the cost of contaminant reduction. Changes in contaminant level and costs are measured against this base case for all contaminant reduction cases where new investments are allowed.

B. 1995 Costs of Reducing Diesel Sulfur and Aromatics

The 1995 impact of reducing diesel contaminant levels was analyzed for the following four cases for each refinery group:

- o Reduction to .05% sulfur;
- o Reduction to 20% aromatics;
- o Reduction to 15% aromatics; and
- o Reduction to 10% aromatics.

As a result of increased diesel demand, higher FCC utilization and higher energy costs, costs were higher for diesel contaminant reduction in 1995 than in 1991 for all cases. Total costs to reduce all California diesel sulfur to .05% increased from 6.3 ¢/gallon in 1991 to 7.7 ¢/gallon in 1995. High sulfur diesel requiring reduction to .05% increased from 190 to 202 MB/D. Investment requirements also increased from 265 to 291 million $. Process investments included 31 MB/D of diesel hydrotreating, 97 MB/D of diesel hydrorefining and 15 MB/D of hydro-dearomatization. As in 1991, costs were much higher in less complex Group I and II refineries. Group I costs increased from 50 ¢/gallon in 1991 to 62 ¢/gallon in 1995. Group II costs increased from 16 ¢/gallon in 1991 to 20 ¢/gallon in 1995.

As a result of hydroprocessing required to reduce diesel sulfur levels to .05%, diesel aromatics levels declined 1.4% to 29.6% and cetane increased 0.2 numbers to 44.5 from 1995 base case levels.

Total costs to reduce diesel aromatics to 20% increased from 3.8 ¢/gallon in 1991 to 4.0 ¢/gallon in 1995. Costs varied from 3.3 ¢/gallon in Groups III/IV to 5.5 ¢/gallon in Groups I and II. Investment requirements increased slightly from 410 million $ in 1991 to 415 million $ in 1995 for 176 MB/D of hydroprocessing investment. Diesel sulfur was identical to 1991 at 0.14% but cetane was slightly lower at 48.7 in 1995 versus 49.1 in 1991.

As in 1991, total costs more than doubled (to 8.6 ¢/gallon) to reach 15% diesel aromatics vs 20% aromatics. Costs varied from 5 ¢/gallon in Groups III/IV to 16 ¢/gallon in Groups I and II. Process requirements included 290 MB/D hydroprocessing, 35 MMSCF/D hydrogen plant and 16 MB/D Mobil methanol to olefins and MOGD processes. Process investment requirements declined slightly from 864 million $ in 1991 to 849 million $ in 1995. Lower capital costs were more than offset by increases in net feedstock, variable and fixed operating cost.

Sulfur was identical to 1991 at .07 wt% for 15% aromatics reduction and cetane was slightly lower than 1991 at 49.5.

As in 1991, costs increased by nearly a factor of 10 (to 33.5 ¢/gallon) to reach 10% aromatics vs. 20% aromatics. Costs varied from 12 ¢/gallon in Groups III/IV to about 140 ¢/gallon in Groups I and II.

Investment costs increased from 1.4 billion $ in 1991 to 1.6 billion $ in 1995 for 394 MB/D hydroprocessing, 72 MMSCF/D hydrogen plant and 72 MB/D Mobil methanol to olefins and MOGD processes. Feedstocks accounted for 60% and capital costs accounted for 26% of total costs. With aromatics reduced to 10% average California diesel sulfur was .03% as in 1991. However, no further investment was required in 1995 for all groups to meet a maximum of .05% sulfur. Cetane was nearly identical to 1991 at 50.9.

Other than higher costs in 1995 for each case, results were very similar for reduction of sulfur and aromatics levels in diesel in both years.

C. 1995 Cost of Reducing Gasoline Aromatics

Parametric model runs were made for each selected refinery to determine the maximum aromatics reduction possible in gasoline in 1995 both with and without purchases of high octane, low aromatics feedstocks. The maximum aromatics reduction possible in 1995 without purchased feedstocks averaged 14.7% versus 18.4% in 1991. Absolute gasoline aromatics levels obtained were 27.5% in 1995 versus 25.8% in 1991. Similarly, benzene level was reduced to 1.61% in 1991 versus 1.54% in 1991.

Aromatics reduction was lower and absolute aromatics levels were higher in 1995 due to higher pool octane requirements than in 1991. Aromatics reduction was limited to 5% in Group II, 12% in Groups III/IV and about 17% in more complex Groups V and VI. Total costs for 14.7% aromatics reduction in 1995 were 9.3¢/gallon versus 7.0¢/gallon for 18.1% reduction in 1991. Thus costs were higher in 1995 for less reduction due to higher octane requirements.

Investment requirements in 1995 were 1.9 Billion $ for maximum gasoline aromatics reduction versus 1.4 Billion $ in 1991. Over 680 MB/D of new process capacity was required including isomerization, MTBE, etherol and BTX extraction. In addition 483 MMSCF/D hydrogen plant capacity was required. Investment costs accounted for 41%, feedstock costs for 31% and operating costs for 28% of total costs. Total annual costs were 3,264 million $/D or 1.2 Billion $/year.

BTX sales were 30 MB/D for an aromatics reduction in gasoline of 122 MB/D (14.7% of total gasoline). Net energy requirements were 47 MB/D of equivalent crude.

The maximum gasoline aromatics reduction in 1995 with purchased feedstocks available averaged 50% to an absolute level of 16.1%. Benzene level was reduced to an average of 1.61%. Maximum aromatics reduction with purchased feedstocks increased in all refinery groups and varied from 24% in Group IV to 67% in Group II.

The availability of purchased high octane, low aromatics feedstocks at gasoline blending value reduced octane constraints and would lower the cost of gasoline aromatics reduction in all refinery groups at the <u>same</u> level of aromatics reduction. However, since purchased feedstocks were utilized to achieve greater reduction in gasoline aromatics content, costs increased relative to the investment only case. Costs averaged 16.5 ¢/gallon and were similar in all refinery groups. Investment requirements were 1.3 billion $ for 700MB/D isomerization, MTBE, BTX extraction and hydrogen plant capacity. Purchased blendstock requirements included 109 MB/D alkylate, 62 MB/D MTBE and 8 MB/D ethanol.

Marginal costs of gasoline aromatics reduction would be reduced with the availability of purchased blendstocks at the same aromatics level. Marginal costs at the maximum reduction aromatics level would be similar with and without purchased feedstocks.

While gasoline aromatics can be reduced significantly with purchased feedstocks, it is uncertain if the level of feedstocks necessary would be available in the future.

We would expect costs to continue to increase and the level of gasoline aromatics reduction possible to decrease beyond 1995 due to increasing pool octane requirements.

XI. IMPACT OF IMPROVED AUTOMOTIVE FUEL QUALITY ON REFINERY EMISSIONS

A. Methodology

Emission estimates were made using information on refinery capacity utilization obtained from the LP-model. For process heaters and boilers (fuel consumers) the emissions were calculated by using AP-42 factors according to the type of fuel burned. AP-42 emissions factors are based on standard factors and do not account for controls applied to California refineries, especially in the Los Angeles Basin. Use of AP-42 factors will likely overstate absolute level of California refinery emissions. Since differences in emissions between cases rather than absolute levels are important for this analysis, we suggest our emissions results be adjusted by the ratio of actual emissions inventory to emissions calculated using AP-42 factors in the base case.

In this assessment, four of the five representative refineries employ all gas (refinery plus natural) firing. One of the refineries uses some fuel oil and this was accounted for the emissions inventory. Total fuel usage was determined by the LP-model for each case that was analyzed.

AP-42 factors were also used to estimate FCCU regenerator emissions, except for SO_2. Sulfur oxide emissions were calculated on the bases of sulfur content of the FCCU feed, which was determined by LP-model sulfur balance. The SO_2 emissions from the regenerator stack depends on the type of control technology employed. For these, feed sulfur is 100% converted to SO_2 emissions. Three of the representative refineries use FCCU feed HDS to control sulfur emissions. The other two employ H_2S promoting catalyst in the FCCU. In this case, 70% of the feed sulfur is assumed to be converted to H_2S and 30% to stack emissions.

Sulfur oxide emissions from the sulfur reduction unit were estimated based upon 99.75% recovery. The LP-model determines sulfur production based upon 95% recovery. The LP-derived sulfur production was adjusted to the higher recovery bases, and the SO_2 emissions determined by difference.

B. Impact of Diesel Sulfur and Aromatics Reduction

The total estimated impact on California air emissions for diesel fuel quality improvement is presented in Tables XI.1 and XI.2, assuming no new investments and with investments, respectively. Detailed emissions results for all gasoline and diesel cases are shown in Appendix K for 1991 and Appendix L for 1995. The top of Table XI.1 shows the change in the emission inventory that occurs as a result of changes in refinery operations to obtain the desired diesel fuel quality. At the bottom of the table are the total emission levels for the various study cases.

TABLE XI.1

1991 DIESEL SULFUR AND AROMATICS REFINERY EMISSIONS ANALYSIS - WITHOUT INVESTMENT

Increase (Decrease) vs Base case DESCRIPTION	Diesel Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case without Investment	291.7	0.0	0.0	0.0	0.0	0.0
.25 wt% Sulfur	291.7	(19,377.7)	(35,046.5)	(1,983.3)	(84.2)	(2,849.2)
.20 wt% Sulfur	291.7	(16,900.8)	(22,698.1)	(1,727.6)	(73.4)	(2,007.7)
Max Sulfur Reduction	291.7	(16,833.3)	(20,036.4)	(1,708.4)	(72.6)	(2,006.3)
5% Aromatics Reduction	291.7	6,431.9	36,925.2	1,166.2	49.6	628.7
Max Aromatics Reduction	291.7	6,630.2	37,538.6	1,222.9	52.0	632.9

CASE EMISSIONS DESCRIPTION	Diesel Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case without Investment	291.7	246,974.3	383,920.5	34,691.6	1,474.4	38,783.2
.25 wt% Sulfur	291.7	220,271.9	373,491.3	29,024.2	1,233.6	33,104.9
.20 wt% Sulfur	291.7	222,748.8	385,839.7	29,279.9	1,244.4	33,946.4
Max Sulfur Reduction	291.7	222,816.3	388,501.4	29,299.1	1,245.3	33,947.9
5% Aromatics Reduction	291.7	253,406.2	420,845.7	35,857.8	1,524.0	39,411.9
Max Aromatics Reduction	291.7	253,905.2	422,389.6	36,000.4	1,530.0	39,422.6

TABLE XI.2

1991 DIESEL SULFUR AND AROMATICS REFINERY EMISSIONS ANALYSIS - WITH INVESTMENT

Increase (Decrease) vs Base case DESCRIPTION	Diesel Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case with Investment	291.7	0.0	0.0	0.0	0.0	0.0
.15 wt% Sulfur	291.7	(17,886.6)	(29,661.2)	(1,787.9)	(76.0)	(2,409.5)
.05 wt% Sulfur	291.7	(18,638.9)	(10,712.3)	(1,722.0)	(73.2)	(2,872.0)
20% Aromatics	291.7	3,319.3	33,607.6	789.2	33.5	57.7
15% Aromatics	291.7	7,489.8	39,531.4	1,916.2	81.4	(421.4)
10% Aromatics	291.7	13,833.8	5,371.7	3,488.8	148.2	(621.9)
10% Aromatics at .05 Sulfur	291.7	12,813.9	24,490.4	3,358.4	142.6	(654.6)
10% Aromatics Purch Feedstock	291.7	3,964.7	29,992.2	1,585.1	67.3	(1,217.2)

CASE EMISSIONS DESCRIPTION	Diesel Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case with Investment	291.7	247,169.2	356,689.3	34,735.8	1,476.4	38,657.5
.15 wt% Sulfur	291.7	218,782.9	357,397.7	28,362.8	1,205.4	33,424.3
.05 wt% Sulfur	291.7	221,223.2	367,357.9	29,332.5	1,246.7	32,942.9
20% Aromatics	291.7	250,488.5	390,296.9	35,525.0	1,509.9	38,715.2
15% Aromatics	291.7	254,659.0	396,220.7	36,652.0	1,557.7	38,236.1
10% Aromatics	291.7	261,003.0	362,060.9	38,224.6	1,624.5	38,035.7
10% Aromaticsc at .05 Sulfur	291.7	259,983.1	381,179.6	38,094.2	1,619.0	38,003.0
10% Aromatics with Purch Feedstock	291.7	251,133.9	386,681.5	36,320.9	1,543.7	37,440.3

Sulfur oxide emissions are quite sensitive to FCCU feed sulfur level and feedrate. The SO_2 emissions decrease with sulfur reduction in diesel fuel due to deeper desulfurization of the FCCU feed. For refineries with FCC HDS units, every ton of sulfur removed from the feed reduces SO_2 emissions by almost two tons. The factor is less than the theoretical two because the SO_2 emissions from the sulfur plant increase slightly.

Other emissions also decline in the sulfur reduction cases due to a reduction in FCC feedrate. This occurs because deeper desulfurization also improves feed quality and hence product yield. Therefore, less feed is required for a given product volume. However, after the optional sulfur removal is achieved, the heat requirement of the HDS unit increases the plant fuel consumption which offsets the SO_2 reduction achieved from the FCCU stack.

For the aromatics reduction refinery emissions increase for all cases. This is due to increases in process capacity to maintain diesel production as volume is lost due to aromatics removal.

Similar trends are seen in the case of removal of the constraints on new investments as seen in Table XI.2. At the 10% aromatics level, the emissions change quite significantly due to major process additions required to reach this low diesel aromatics level. SOx emissions decrease due to lower FCC feedrate. At 10% aromatics and .05% sulfur, SOx emissions decreased relative to the 10% aromatics case due to increased FCC feed hydrotreating in Group VI. Emissions impact is reduced with purchased feedstocks available due to reduced refinery process operations.

Emission impact will be reduced with NPRA or 50% diesel segregation due to a lower volume of diesel controlled.

C. Impact of Gasoline Aromatics Reduction

The impact of gasoline aromatics reduction with investment on California emissions is presented in Table XI.3 using the same format as the diesel analysis. For the maximum aromatics reduction case, all emissions increased except SOx due to major process additions required to reduce aromatics levels. SOx decreased due to decreased FCC utilization as high aromatics FCC gasoline was replaced by other blendstocks. In the case of purchased feedstocks emissions decline across the board due to reduced refinery process operations.

D. Impact on Hazardous Wastes

The utilization of the FCCU will have an effect on solid waste generation, in terms of both spent catalyst and contact water (from stripping steam). Increases in contact water will add load to the waste water treatment plant resulting in possibly more air flotation float or waste biological solids. The increase in amount of water

TABLE XI.3

1991 GASOLINE AROMATICS REFINERY EMISSIONS ANALYSIS - GASOLINE WITH INVESTMENT

Increase (Decrease) vs Base case DESCRIPTION	Gasoline Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case with Investment	823.0	0.0	0.0	0.0	0.0	0.0
5% Aromatics Reduction	823.0	(633.2)	13,708.9	(79.5)	(3.4)	0.0
Max Aromatics Reduction	823.0	22,063.2	(25,049.5)	4,285.2	182.1	0.0
Max Aromatics Reduction with Purch Feedstock	823.0	(5,302.2)	(19,950.5)	(1,297.0)	(55.1)	0.0

CASE EMISSIONS DESCRIPTION	Diesel Prod 000 B/D	REFINERY EMISSIONS: #/D NOx	SOx	CO	VOC	Particulates
Base Case with Investment	823.0	149,542.2	181,370.5	25,634.9	1,089.5	26,872.7
5% Aromatics Reduction	823.0	148,909.0	195,079.3	25,555.3	1,086.1	26,669.9
Max Aromatics Reduction	823.0	171,605.4	156,321.0	29,920.1	1,271.6	28,414.0
Max Aromatics Reduction with Purch Feedstock	823.0	144,240.0	161,420.0	24,337.9	1,034.4	26,078.5

treatment wastes is very dependent on the type of treatment available at each refinery. The addition of MTBE capacity will also increase the amount of contact water produced. HF alkylation sludge production will also be affected by utilization of HF alkylation capacity.

XII. IMPACT OF IMPROVED FUEL QUALITY ON AUTOMOTIVE PERFORMANCE AND EMISSIONS

A. Changes in Automotive Fuel Quality

Typical changes in both gasoline and diesel fuel quality as a result of contaminant reduction are shown on Table XII.1. Typical gasoline and diesel blends are provided in Appendix M.

For diesel sulfur reduction without process investment, high sulfur full range gas oil (36%) is largely replaced by hydrotreated heavy gas oil and hydrocracker jet to reduce sulfur level. When new investments are allowed, all diesel blend components are hydroprocessed in low severity hydrotreaters (15%), moderate severity hydrorefining (70%) or high severity hydrocracking (15% hydrocracker jet) to produce diesel product at .05 wt% sulfur.

For diesel aromatics reduction to 20% practically all diesel blend components are hydroprocessed. Typical blend composition is approximately 45% hydrotreated diesel, 27% hydro-dearomatized diesel, 14% hydrocracker jet and 14% full range unhydrotreated (low aromatics level) heavy gas oil. For diesel aromatics reduction to 10%, typical blend composition is 2% hydrotreated diesel, 62% hydrode-aromatized diesel, 9% synthetic Mobil diesel, 15% hydrocracker jet and 12% unhydrotreated (low aromatics) heavy gas oil.

When purchased low sulfur, low aromatics blendstocks are permitted blends to produce 10% aromatics diesel change significantly. Purchased blendstocks make up 27% of typical diesel product and synthetic Mobil diesel and hydrocracker jet are largely replaced. The remaining diesel blend components are largely de-aromatized (61%) or hydrotreated (9%), with small volumes (3%) of unhydrotreated (low aromatics) gas oil produced from crude.

As shown on Table XII.1, the major impacts on diesel fuel quality are as follows:

- Decrease in specific gravity (and heating value);
- Decrease in sulfur level (except for low sulfur diesel which is already at .05 wt% S);
- Increase in cetane number; and
- Decrease in total aromatics.

In the high sulfur diesel reduction cases, while total aromatics decrease slightly, single ring aromatics <u>increase</u> slightly due to the partial saturation of polycyclic aromatics to single ring aromatics.

TABLE XII-1

TYPICAL CHANGES IN AUTOMOTIVE FUEL QUALITY

	Base High Sulfur	Base Low Sulfur	New Diesel Quality					
			.15% S	.05% S	25% Arom Red	50% Arom Red	Max Arom Red	.05%S + Max % Arom Red
Diesel								
Spgr.	.859	.851	.856	.855	.854	.844	.839	.842
Sulfur: wt. %	.30	.05	.15	.05	.16	.12	.07	.05
Cetane No.	45.8	49.9	47.0	47.2	47.6	49.5	50.3	50.0
Mono Arom: %	20.1	22.2	20.8	21.1	16.6	16.8	9.6	9.7
Poly Arom: %	7.6	5.6	6.8	6.1	4.4	1.7	0.4	.3
Total Arom: %	27.7	27.8	27.6	27.2	20.6	13.5	10.0	10.0

	Base Case	New Gasoline Quality			
		5% Arom Red	10% Arom Red	15% Arom Red	22% Arom Red
Spgr.	.743	.742	.742	.737	.727
Sulfur: wt. %	.03	.03	.03	.03	.03
(R+M)/2	88.3	88.3	88.3	88.3	88.3
RVP: psi	9.8	9.8	9.8	9.8	9.8
Benzene: %	1.6	1.4	1.3	1.1	0.9
$C7^+$ Arom: %	28.5	27.2	25.8	24.5	22.6
Total Arom: %	30.1	28.6	27.1	25.6	23.5

In the aromatics reduction cases both types of aromatics are reduced, but the polycyclic aromatics are reduced more than single ring aromatics.

Polyclyclic aromatic hydrocarbons are a primary contributor to emissions of carcenogenic nitrated polycyclic aromatic hydrocarbons from diesel exhaust. Thus, the preferential saturation of polyclyclic aromatic hydrocarbons in diesel sulfur and aromatics reduction processes will have a favorable impact on engine emissions.

We have no information on the level of nitrated polycyclic aromatics in diesel fuel, but as discussed in Section C below, some will be produced in the combustion process.

Changes also occur in gasoline blend composition when reducing aromatics. These changes are not as great as in diesel blends since less aromatics reduction in gasoline can be achieved while maintaining gasoline octane. For 18% reduction in gasoline aromatics, high aromatics content FCC gasoline blendstocks are reduced about 10% and replaced by increased levels of low aromatics content alkylate, isomerate and MTBE.

When permitted, purchased high octane, low aromatics content blendstocks account for about 4% of the gasoline blend for the 18% aromatics reduction case and 19% of the blend for the 50% aromatics reduction case.

Also shown on Table XII-1 are the following major impacts on gasoline quality due to aromatics reduction:

- Decrease in specific gravity (and heating value);
- Pool octane unchanged at 88.3 (R+M)/2;
- Vapor pressure unchanged at 9.8 psi;
- Benzene levels reduced along with total aromatics level; and
- C_7^+ aromatics reduced along with total aromatics level.

Two major assumptions in our analysis were that gasoline octane and vapor pressure would be maintained at base case levels. New processes were added in the refinery (such as MTBE, alkylation and isomerization) to replace the octane lost thru aromatics reduction. We have specifically not analyzed the impact of reduced gasoline volatility or decreased gasoline bromine number in this study.

In the particular case shown on Table XII.1, benzene levels decreased more than total aromatics (benzene decreased 44% with 22% aromatics reduction). In other cases analyzed, benzene levels decreased the same or less than total aromatics level. Our study analyzed the refinery impact of reducing total aromatics levels and only reported the effect on benzene level.

C_7^+ aromatics decreased slightly less than total aromatics in the case presented in Table 1 (21% vs. 22%), but this effect was reversed in other cases analyzed. We did not specifically estimate the impact on toluene and xylene levels, but they should approximate 4-5 times benzene level.

We have no information on polycyclic aromatics levels in gasoline, but as discussed in Section C below, some polycyclic aromatics and nitrated polycyclic compounds will be produced in the combustion process.

B. Impact of Improved Fuel Quality on Automotive Performance

1. Changes in Diesel Fuel Quality

Lower diesel fuel sulfur levels, lower aromatics content and higher cetane number will improve automotive performance.

Sulfur in diesel fuel is a major source of wear in piston rings and cylinder liners in diesel engines through a combination of corrosion and deposit formation(1). In addition, sulfur compounds in cylinder blow-by gases can combine with lubricating oil to form acidic compounds. These acidic compounds can cause rapid corrosion and wear of lubricated auto parts. Reductions in diesel fuel sulfur levels will enhance engine durability and extend engine lube oil useful life extending lube oil change intervals.

As discussed further in Section C below, sulfur is the single most significant contributor to diesel engine particulate emissions(2,3). In addition, sulfur compounds can interfere with oxidizing catalysts in particulate trap-oxidizers making them less effective(1). Lower sulfur diesel fuel is essentially required to achieve heavy duty diesel engine particulate standards in 1991 and 1994 with practical emission control devices (exclusive of particulate traps).

As discussed further in Section C below, diesel aromatics content is a contributor to diesel particulate emissions. In addition, aromatics have an important impact on diesel engine performance thru two competing mechanisms.

- Aromatics have a higher heating value than non-aromatic compounds in the same boiling range.
- Cetane number is closely correlated to aromatics content and decreases with increased aromatics content.

Since fuel economy (i.e., miles per gallon) is measured on a volumetric basis, a heavier, higher heating value fuel will increase fuel economy in existing diesel engines. Engine thermal efficiency or brake-specific fuel consumption is related to the mass of fuel burned, not volume of fuel. Thus, an engine with a given thermal efficiency will yield greater or lesser fuel economy (mpg) proportional to the heating value of the fuel (Btu/Lb). Based on the reduction from .859 to .839 specific gravity with reduction to 10% aromatics level, fuel economy theoretically could decrease by about 3.5% in existing engines.

Another significant impact on diesel automotive performance is the projected increase from 45.8 to 50.3 cetane numbers or fuel ignition quality, with aromatics reduction to 10%. Recent work by Cummins (Phatak and Nakamara, 1983) indicated that fuel economy could be improved by 10-15% with a <u>reduction</u> in engine compression from 18:1 to 14:1(1). With current diesel fuel cetane, low compression engines would experience severe cold start problems and may not start at all at low temperatures. Based on the higher cetane fuel from our analysis, diesel engine manufacturers could reduce compression ratio and capture potential increases in fuel efficiency. It is likely that with new, lower compression ratio design engines that this improved efficiency would offset losses due to decreased heating value.

2. <u>Changes in Gasoline Fuel Quality</u>

Gasoline engine performance is highly dependent upon gasoline octane, vapor pressure, distillation range and, to a lesser extent, heating value. Studies have linked gasoline octane and automotive efficiency thru a Car Efficiency Parameter (CEP). CEP measures the increase in automotive efficiency in miles per gallon as a function of gasoline octane. If engine compression levels are increased to accommodate increased gasoline octane a CEP of about 1.0 is typical, e.g., an increase of about 1% in automotive efficiency for each increase of one octane number in gasoline. However, in California it would not be practical to design an automotive fleet to accommodate any increase (or decrease) in gasoline octane, since California gasoline must satisfy the general U.S. fleet. For this reason, no change was permitted in our analysis in gasoline octane, vapor pressure or distillation specifications, and there would be no significant impact on automotive performance or fuel economy.

As a result of decreased aromatics content, gasoline specific gravity would decrease from about .743 to .727. This reduction in specific gravity would be accompanied by a decrease in gasoline heating value. Theoretically this would decrease automotive fuel economy about 2% on a miles per gallon basis.

C. Impact of Fuel Quality Changes on Automotive Emissions

1. Pollutants of Interest

Both on a federal and local basis, regulations have been instituted or proposed since 1973(4) to limit the emission rate of selected pollutants from automotive vehicles. The goal of these regulations is, of course, to reduce the concentration of primary and secondary (reaction products) air pollutants to meet the mandate of the Clean Air Act to limit negative environmental and human health effects. The regulated pollutants include hydrocarbons, carbon monoxide, nitrogen oxides (NO plus NO_2), sulfur (in fuel), lead (in fuel) and particulates. It is also clear that other pollutants (e.g., benzene, aldehydes, and polycyclic aromatic hydrocarbons) are of potential concern. However, sufficient documentation of their presence, level, and hazard does not exist on which to base a regulatory standard.

2. Fuel Quality/Emission Impact

Both chemical and physical characteristics of fuels influence the emission rate of regulated and unregulated pollutants. It is quite clear that the combustion emission process in automobiles is a system of complex reactions(5) including primary oxidation but also pyrolytic degradation, synthetic reformations, catalysis, and volatilization. Simply on the basis of mass conservation, evaporation and inefficiency of combustion, most pollutants present in fuel will exist to some small extent in the exhaust, gas tank or engine compartment of automotive vehicles. In nearly all cases, the emission rate of individual compounds, e.g., benzene, is directly proportional to the concentration in the fuel with a significant, positive correlation. Where the potential combustion products of fuel components are unique or limited, e.g., sulfur, the emission rate is also directly proportional to the concentration in the fuel and the fuel consumption rate. In the cases where the pollutant of interest is a complex mixture of compounds (e.g., hydrocarbons, particulates), combustion efficiency and reaction mechanisms dramatically confound the prediction of emission rate due to variations in fuel quality characteristics, e.g., cetane number, and engine configuration. It is only on the basis of frequently contradictory experimental data that the impact of fuel variation can be predicted. On the basis of these observations, only a qualitative assessment of the impact of changes in gasoline and diesel fuel quality identified in this report is provided in the following sections.

2.1 Gasoline

The reduction of aromatic hydrocarbons in gasoline will clearly lead to a reduction of emission of these components, due to evaporative (engine and fuel tank) emissions, proportional to the reduction in mole fraction in the fuel. In the case of exhaust emissions, aromatics will be reduced similarly since the compounds added to the fuel, e.g., MTBE, to replace the octane value lost through aromatics reduction have little potential as aromatic precursors. Benzene emissions(6) will be reduced on both the basis of a reduction of benzene in the fuel and a reduction of total aromatics. This latter phenomenon observed by Seizinger et al.(6) is likely due to the reduction of benzene precursors, i.e., $C7^+$ aromatic hydrocarbons. The emission of polycyclic aromatic hydrocarbons (PAH) and their nitro-derivatives will also be reduced due to their reduction in the fuel and a reduction of precursors, i.e., PAHs. This latter conclusion assumes that the change in hydrocarbon components does not dramatically affect maximum combustion chamber temperature and the production of NO_x which participates in the formation of nitro-PAH.

Any potential impact on the emission rate of total hydrocarbons as a result of the reduction in aromatics will result mainly from a shift in ignitability (octane value/combustion efficiency) and boiling point distribution of the fuel. Any reduction in volatility will lead to a reduction in evaporative total hydrocarbon emissions. A reduction in octane rating will likely lead to an increase in exhaust hydrocarbon emission due to poorer combustion. The true impact will obviously be affected by the choice of the replacements for aromatics/octane enhancers.

The impact of the reduction in aromatics on particulates is difficult to assess due to the complexity of their formation and the lack of significant data due to the relatively low levels of particulate emission from gasoline-fueled cars. It is likely that if a reduction in aromatic content leads to poorer ignition quality there will be a significant increase in particulate emission. This is, however, not likely in this case due to octane enhancement of gasoline with other compounds, e.g., MBTE. The reduction of aromatics may alternatively reduce particulates slightly due to the ability of aromatics to decompose to acetylene and lead to polymerization and carbon soot formation. All of these particulates are generally in the PM_{10} range.

2.2 Diesel (Middle Distillate) Fuel

As indicated previously, the reduction of sulfur content in fuel including diesel fuel will lead to a proportional decrease in the SO_x (SO_2 and sulfate) exhaust emission rate(7). Since sulfate contributes to primary particulate emission and SO_2 forms secondary particulates through atmospheric reactions, this change will lead to a reduction of atmospheric particulates, especially in the submicron size range. Since SO_2 may be competitively oxidized on a trap oxidizer, a reduction of sulfur content may increase the efficiency of this control device and thus also lead to a secondary reduction in exhaust hydrocarbons(8).

The reduction of aromatic hydrocarbons in diesel fuel has both primary and secondary effects on the emission rate of hydrocarbons. As aromatic hydrocarbons (including benzene) are reduced, the level of these compounds released to the atmosphere through evaporation or combustion are lowered proportionately. This applies to single- or multi-ring aromatics as well as derivatives, e.g., NO_2-PAH. The reduction in aromatics improves ignition quality (higher cetane number) and reduces the density of the fuel. Both of these phenomena reduce total hydrocarbon exhaust emission as a result of improved combustion efficiency (modified ignition delay) and smaller fuel mass since fuel is metered into the engine volumetrically.

The reduction of aromatics in fuel also influences the emission of particulates through several mechanisms. First, the increase in ignition quality resulting from lower aromatic content leads to some reduction in particulates especially under cold starts and light load operation. The potential decrease in fueling rate due to lower fuel density moves the engine further from the smoke limit and thus may improve exhaust quality through less soot formation. The magnitude of the influence of aromatic content on particulate emissions has been evaluated quite extensively in the literature(7,9). However, it is quite clear that many of the results show inconsistencies associated with (1) confounding factors, e.g., sulfur content, (2) differences in test procedures, e.g., FTP versus transient cycle, and (3) differences in engine technology. On average the particulate emission rate does decrease to some extent as the aromatic content of fuel is lowered.

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XIII. ADL VS. NPRA SURVEY RESULTS

The results of our California diesel analysis are compared to the results of the 1986 NPRA Survey on Table XIII.1. Details of the NPRA Survey results for California are provided in Appendix N.

The NPRA provided ADL with a breakdown of their survey results for the same groups of refineries as in our analysis[1]. Costs for the two studies are compared on Table XIII.1 for Groups I and II and Groups III-VI on a total diesel production basis. ADL costs for sulfur reduction to 15% are slightly lower and costs for sulfur reduction to .05% are higher than NPRA Survey results. Both studies show considerably higher costs for sulfur reduction in simple Group I and II refineries.

None of the ADL and NPRA aromatics reduction studies were done on the same basis. However, if the results of our analyses for .05% sulfur and 20% aromatics are added as a first approximation for controlling both sulfur and aromatics to these levels we get 10.1 ¢/gallon versus 8.1 ¢/gallon based on the NPRA Survey.

Our costs for 15% and 10% diesel aromatics diesel exceed the NPRA results for reduction of diesel to .05% S and 20% aromatics.

Both studies show considerably higher costs for aromatics reduction in simple Group I and II refineries.

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[1] One Group VI refinery was included in the NPRA Group IV to maintain confidentiality of data on a minimum 3 refinery basis.

TABLE XIII.1

COSTS OF DIESEL SULFUR AND AROMATICS REDUCTION

	Groups I and II		Groups III-VI		Total California	
	ADL ¢/Gallon	NPRA[1] ¢/Gallon	ADL ¢/Gallon	NPRA[1] ¢/Gallon	ADL ¢/Gallon	NPRA[1] ¢/Gallon
Sulfur Reduction to 0.15%	7.8	16.6	1.0	1.7	1.9	2.6
Sulfur Reduction to 0.05%	34.7	20.7	1.9	2.3	6.3	3.3
Aromatics Reduction to 20%	5.2	----	3.6	---	3.8	---
Sulfur Reduction to 0.05% with Aromatic Reduction to 20%	---	28.2	---	7.1	---	8.1
Aromatics Reduction to 15%	16.4	---	7.1	---	8.3	---
Aromatics Reduction to 10%	126.4	---	12.5	---	27.6	---

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[1] "US Refining Industry Capability to Manufacture Low Sulfur Diesel Fuels" NPRA Survey 1986.

Acronyms

ADL	Arthur D. Little, Inc.
ANS	Alaska North Slope Crude - Marginal Crude in Alaska
ARB/CARB	California Air Resources Board
API	American Petroleum Institute: degrees API is a widely used measure of gravity of crude oils
AP-42	Air Pollution 42 emissions factors
BACT	Best-Available Control Technology
BBL	One Barrel: a unit of volume equivalent to 42 US Gallons
B/D	Barrels per Day
BTU	British Thermal Units
BTX	Benzene, Toluene and Xylene (light aromatics)
C_3	Propane
C_4	Butane
Cet	Cetane index
CDU	Crude Distillation Unit
CEC	California Energy Commission
CEP	Car Efficiency Parameter
CO	Carbon Monoxide
CRU	Catalitic Reforming Unit
CS or cst	Centistokes: a measure of viscosity
EPA	United States Environmental Protection Agency
FCC or FCCU	Fluid Catalytic Cracking Unit
FOEB	Fuel Oil Equivalent Barrel (6.3 million BTU)

H_2	Hydrogen
HDA	Hydro-dearomatization unit
HCU	Hydrocracking unit
HDT	Hydrotreating unit
HGO	Heavy Atmospheric Gas Oil
HSFO	High Sulfur Fuel Oil
ISBL	Inside Battery Limits Process Unit Investment
LCO	Light Cycle Oil: middle distillate produced in the catalytic cracking process
LGO	Light Atmospheric Gas Oil
LP	Linear Programming
LPG	Liquefied Petroleum Gas
LSFO	Low Sulphur Fuel Oil
M	Thousand
MM	Million
MON	Motor Octane Number: a measure of the high speed performance of gasoline in the internal combustion engine
MTBE	Methyl Tertiary Butyl Ether: a high octane motor gasoline component
MOGD	Mobil Methanol to Gasoline and Diesel
MTG	Mobil Methanol to Gasoline process
MTO	Mobil Methanol to Olefins process
MVEG	Motor Vehicles Emission Group
NOX	Nitrogen Oxides
NPAH	Nitrated Polycyclic Aromatic Hydrocarbons
NPC	National Petroleum Council
NPRA	National Petroleum Refiners Association
PAH	Polycyclic Aromatic Hydrocarbons
PPM	Parts Per Million

PSI	Pounds per square inch
RFL	Refinery Fuel and Loss
RON	Research Octane Number: a measure of the low speed performance of gasoline in the internal combustion engine
(R+M)/2	Average of Research Octane plus Motor Octane
RVP	Reid Vapour Pressure: a measure of the volatility of gasoline
SCAQMD	South Coast Air Quality Management District
S	Sulfur
SOX	Sulfur Oxides
TBA	Tertiary Butyl Alcohol: a high octane motor gasoline component
TC	Thermal Cracking unit
TEL	Tetra Ethyl Lead: a gasoline additive for octane boosting
USGC	United States Gulf Coast
VBU	Visbreaking Unit
VDU	Vacuum Distillation Unit
VGO	Vacuum Gas Oil: a feedstock for cracking processes
VOC	Volatile Organic Compounds
VS	Viscosity