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**THE EFFECTS OF AIR POLLUTION REGULATIONS
ON THE U.S. REFINING INDUSTRY**

PREPARED FOR:

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EXECUTIVE SUMMARY

Numerous air pollution regulations affecting petroleum refineries recently have been promulgated, have been proposed, or are under consideration at the federal, state, and local level. As shown in Figure ES-1, all of these environmental regulations are intended to take effect over the relatively short time period from 1989 through 1995. In the aggregate these regulatory activities have significant implications for the U.S. refining industry and the Nation, including:

- Major investment requirements
- Changes in industry profitability
- Potential closure of some refineries
- Potential changes in crude oil or product import dependence.

At issue is whether the cumulative effect of these regulations could so adversely affect the U.S. refining industry that U.S. national security would be affected.

In addition to the regulations outlined in Figure ES-1, President Bush recently presented a major new plan to improve the nation's air quality. The aspects of the President's plan that could strongly affect U.S. refineries are summarized below.^{1/}

TWO KINDS OF REGULATIONS

Although all regulations typically require refiners to incur incremental costs, all regulations are not alike from the standpoint of industry impact. Regulations setting product quality specifications affect the U.S. refining industry very differently than regulations limiting refinery emissions of air pollutants.

- Stricter U.S. product specifications affect all refineries supplying the U.S. market and generally do not put U.S. refineries at a competitive disadvantage relative to foreign competitors.
- More stringent U.S. emission controls apply only to U.S. refineries and do put U.S. refineries at a disadvantage.

Since both types of regulations generally require incremental investment, both types may drive marginal refineries out of business. Usually refineries that are covering their variable costs but are not profitable continue to operate as long as significant investments are not required. When a significant investment is required to continue operation, these refineries may choose to close down.

^{1/} The President's Clean Air Plan was announced just prior to the completion of this analysis. Consequently, it is not covered in detail in this report. However, the key aspects of the President's plan that may affect U.S. refineries are summarized in this section of the report. Initial industry reaction to the President's plan is also noted.

FIGURE ES-1

**Time Line for Federal and State Petroleum
Refinery Air Quality Regulations**

FEDERAL PRODUCT QUALITY REGULATIONS

The principal federal air quality regulations affecting U.S. refineries in the near term are regulations on product quality:

- Promulgated and proposed EPA regulations require a reduction in gasoline Reid vapor pressure (RVP) in the summer.
- Anticipated EPA regulations will require a reduction in diesel fuel sulfur (and possibly aromatics) content.

The Phase I EPA regulations on gasoline RVP and some more stringent state regulations in the Northeast are already in effect. Phase II RVP regulations have been proposed by EPA and likely will be promulgated. Stricter limitations on diesel fuel sulfur content have been analyzed as part of a program to reduce particulate emissions from diesel-powered trucks and buses. An industry group, including the American Petroleum Institute and the National Petroleum Refiners Association, has submitted a consensus diesel fuel sulfur content proposal to EPA. EPA likely will adopt this proposal as a proposed regulation. As shown in Table ES-1, the costs associated with these regulations are substantial and likely will have to be incurred by 1992. Phase II RVP regulations and the low-sulfur diesel regulations together will require a very significant capital investment of \$5.7 billion.

In addition, President Bush's recently released Clean Air Plan has several aspects that will affect petroleum product quality. A major component of the President's plan provides for the use of alternative automotive fuels such as methanol, ethanol, and natural gas to reduce ozone causing volatile organic compounds. Under the President's Plan, one million alternative fuel motor vehicles will be required to be sold each year starting in 1995 in the nine cities with the most severe ozone problems. In addition, the Plan will require the use of gasoline blended with oxygenated fuels such as ethanol, methanol, ETBE or MTBE^{2/} in cities with the most serious winter carbon monoxide problems.

Energy related Impacts of Product Quality Regulations

The overall effect of the fuel specification changes is to increase the amount of processing required to supply the same amount of product. Once investments have been made, total U.S. crude requirements may increase by up to three percent in the summer or about one percent on an annual basis. Assuming that future imports will be about 50 percent of consumption, this increase in crude requirements could result in a two percent annual increase in petroleum imports.

The lack of surplus U.S gasoline production capacity at the moment has caused consultants and oil companies to predict that in the near-term summer gasoline imports could increase by five percent in the Northeast in response to the EPA Phase I and state RVP regulations already in effect. Since spare capacity is in short supply outside the U.S., however, it appears that price increases rather than increased gasoline imports are the principal effect of the recently

^{2/} ETBE stands for Ethyl Tertiary Butyl Ether, an ethanol derivative. MTBE stands for methyl Tertiary Butyl Ether a methanol derivative.

promulgated regulations. Investments in processing and additives production now underway should lead to lower prices within 1-2 years, albeit higher than before the regulations were implemented.

Economic Impacts of Product Quality Regulations

The current shortage of gasoline has occurred as a result of numerous market changes which have reduced gasoline supply, while the demand for gasoline continued to grow. World refinery capability to produce gasoline has fallen due to the lead phase-down regulations in Europe, the stricter RVP regulations in the U.S., the increase in demand for premium unleaded grades of gasoline, and the loss of Brent crude oil production, which has led to its replacement by heavier Middle Eastern crude oils. The net effect is shortages of gasoline, which are driving up the price of gasoline and increasing refinery profit margins for those refineries with significant gasoline yields. U.S. refineries have higher gasoline yields than refineries in other parts of the world and are the refineries most benefited by this development.

The total cost of the existing and proposed gasoline RVP standards are about 1.5 cents/gallon of gasoline, while the diesel fuel sulfur limits will cost about 3.1 cents/gallon of diesel fuel. If these costs could not be passed on to consumers, U.S. refinery profit margins could fall about 23 percent from current record levels. Unless refineries overinvest in processing equipment (and cause a surplus of capacity) over the next few years, however, Phase II RVP standards and limitations on sulfur in diesel fuel will tend to create shortages of these products and drive up prices.

The adverse economic effects of these regulations will be felt by consumers, natural gas processors, and possibly ethanol producers and small refineries. Consumers are already paying the price associated with the initial RVP regulations. This price currently far exceeds refining cost because of the combined effect of the RVP regulations, and other factors listed above, which have caused wholesale gasoline prices to rise by up to 20 cents per gallon since February 1989.

To meet the lower gasoline RVP regulations refiners must reduce the butane content in gasoline in the summer. Refiners are cutting back their purchases of butane from natural gas processors, which has created a surplus of butane and reduced butane prices. Longer term the combined Phase I and Phase II RVP regulations are expected to reduce natural gas processor revenues by up to 10 percent and create a permanent summer butane surplus and seasonal price cycle. National gas processors clearly will be adversely impacted by these regulations.

Ethanol producers may also be adversely impacted by the RVP regulations. Ethanol has a high RVP level, and its use to make gasohol is much more difficult when gasoline RVP limits are reduced. Currently, EPA is allowing gasohol RVP to be 1.0 psi higher than gasoline, and an increased exemption may be required once Phase II RVP regulations are in effect if the use of ethanol in gasoline is to be promoted.

Small refineries may be adversely affected by the Phase II RVP and diesel fuel standards because their per barrel costs of compliance could exceed the costs incurred by larger refineries by 35 percent or more. Consequently, their profits per barrel of crude refined will be lower, and if overall industry profitability is low, they may be forced out of business.

TABLE ES-1

Costs of Federal Initiatives to Regulate Petroleum Refineries

	<u>1989</u>	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>
RVP PHASE I							
Annual Cost (MM \$)	\$247	\$247	\$247	\$247	\$247	\$247	\$247
Annual Cost (cents/ gallon)	0.54	0.54	0.54	0.54	0.54	0.54	0.54
Capital Investment	\$0						
RVP PHASE II							
Annual Cost (MM \$)				\$405	\$405	\$405	\$405
Annual Cost (cents/ gallon)				0.94	0.94	0.94	0.94
Capital Investment				\$2,384			
DIESEL: REDUCED SULFUR							
Annual Cost (MM \$)				\$1,200	\$1,200	\$1,200	\$1,200
Annual Cost (cents/ gallon)				3.1	3.1	3.1	3.1
Capital Investment				\$3,300			
TOTAL: ALL PRO- GRAMS							
Annual Cost (MM \$)	\$247	\$247	\$247	\$1,852	\$1,852	\$1,852	\$1,852
Annual Cost (cents/ gallon)	0.54	0.54	0.54	4.58	4.58	4.58	4.58
Capital Investment	\$0	\$0	\$0	\$5,684	\$0	\$0	\$0

Source: See Table V-1.

Small refineries, however, have numerous alternatives to investment for responding to the tighter product specifications:

- Switch product output to products with less stringent characteristics
- Export products which no longer meet U.S. requirements
- Sell below-spec products to larger refineries as unfinished oils for further processing
- Reduce output to use available processing capacity more intensively.
- Add appropriate processing capacity to concentrate on specialty products.

Each refinery's capabilities and local options will determine how they respond and how seriously they are affected by the regulations.

The effects of the alternative fuels components of President Bush's Clean Air Plan on the U.S. petroleum refining industry have not been studied in detail. Oil industry trade associations believes that a large scale pilot program should be instituted to resolve uncertainties about the costs and health and safety effects of methanol use before proceeding with the President's Plan. The automotive industry believes that a pilot program for methanol use is also needed. In contrast, natural gas trade associations have praised the President's alternative fuels proposals.

EMISSION CONTROLS AND OTHER REGULATIONS

Controls on emissions from U.S. refineries are a more serious economic concern for U.S. refiners than tighter product specifications because they increase U.S. production costs relative to foreign refining costs. If U.S. product prices are significantly determined by the cost of imported foreign products, then increased U.S. production costs translate directly to reduced refining profits. If some marginal U.S. refining operations are reduced as a result, then product imports rise and crude imports decline.

The following federal emission controls will adversely affect U.S. refineries:

- **NSPS for Industrial Boilers:** New Source Performance Standards for industrial boiler emissions of NO_x, particulates and SO₂ have been tightened. The regulations apply to new, modified or reconstructed boilers.
- **VOC Controls:** Rules addressing the control of Volatile Organic Compound emissions from petroleum refinery waste water systems were published on November 23, 1988. These apply both to new systems and to the retrofit of existing systems.
- **Benzene Emissions:** Toxic emissions of benzene from Refinery storage tanks are being evaluated again with a view to tightening the

standards that have been in place since June 1984. EPA is expected to issue new rules on or about August 31, 1989.

The total cost of meeting these new federal regulations is small compared to the cost of the product quality regulations.

In addition, reducing air toxic emissions from stationary sources is a major component of President Bush's Clean Air Plan. The President's plan will give EPA authority to establish air toxic emission standards for industrial stationary sources based on the Best Available Control Technology (BACT). The Plan will also authorize EPA to establish control technology guidelines for volatile organic compound emissions from stationary sources. Two bills have been introduced in Congress this year that contain provisions similar to President Bush's Plan in terms of proposed steps to reduce hazardous air emissions from stationary sources, including petroleum refineries. The House bill (H.R. 4) would require technology-based regulations but requires that costs be taken into account. The Senate bill (S.816) requires that regulations be developed based on benefit/cost analysis. Included in the list of hazardous emissions likely to be controlled under the President's Plan and the two congressional bills are benzene, toluene, and xylene (BTX), which are aromatic compounds found in crude oil which become major gasoline components.

The oil industry is particularly concerned about the potential compliance cost of these two bills and the air toxic provisions of the President's Clean Air Plan because they embody a move away from a risk-based regulatory strategy toward a best available technology control strategy. The current EPA cost estimate for the air toxic provision of President Bush's Clean Air Plan is \$2.0 billion per year. The petroleum industry estimates that these costs will be considerably higher. These costs would be incurred by U.S. petroleum refineries and other industrial stationary sources. The potential economic impacts of the House bill on U.S. refineries have been estimated at \$1.4 to \$14.3 billion. These are total capital costs and do not include operating and maintenance costs for the installed control equipment.

California Air Pollution Controls

A threat facing the U.S. refinery industry relates to the Plan developed by the South Coast Air Quality Management District (SCAQMD) to achieve ambient air quality standards in the California South Coast basin. The long term stated intent of SCAQMD is to eliminate petroleum refining in the region. The program to achieve this end includes draconian reductions in refinery emissions and residual fuel sulfur content (approaching zero discharge), taxes to make product shipment out of the region prohibitive, and taxes to force consumers to switch to "clean" fuels like (imported) methanol, LPG, and natural gas.

ECONOMIC IMPACT OF ALL REGULATIONS ON THE U.S. REFINING INDUSTRY

If all the proposed federal and state air quality regulations are implemented, the costs incurred by the U.S. refining industry will be very substantial, particularly in the 1992-93 time period. The total investment required to comply with federal product specifications alone has been estimated to be \$5.7 billion. This figure should be compared to the industry's normal total level of capital investment of \$2.6 billion annually. Stationary source emission and California regulations would significantly increase this amount. Investment cost estimates for the South Coast Air Quality Management District regulations and the proposed California Air Resources Board

(CARB) aromatics limitations on diesel fuel are not available. However, SCAQMD has estimated that the stationary source regulations alone will cost Southern California petroleum refineries from \$251 million to \$515 million per year. The cost of these regulations could be on the order of 3-6 cents/gallon of product refined, which exceeds typical U.S. refining industry profit margins.

The net effect of the federal, state, and local fuel quality regulations could be further industry restructuring. Because the major oil companies are larger and tend to be diversified, they are in a better position to make the investments required to comply with the proposed federal regulations than small, low complexity, and independent refineries. In addition, because of the advantages gained from economies of scale, the per barrel investment costs of the federal environmental regulations will be smaller for large refineries. Small refineries may find it more practical to close down rather than risk the considerable financial investment required to comply with the environmental regulations discussed in this report, but unless the refining industry overinvests in new capacity or the country enters a serious recession, refinery profit margins should be adequate to cover the cost of federal fuel quality^{3/} regulations. The situation in California, however, could be quite different.

South Coast Air Quality Management District Plan

If carried out, the California Air Resources Board product specifications and the South Coast Air Quality Management District plan would have a major impact on the West Coast petroleum market. The enormous investment program required to keep the refineries in business combined with the reduced market for SCAQMD refinery output would eliminate the potential financial returns from continued operation, and many refiners would close down.

Clearly, these refineries would tend to be the smaller ones, whose costs per barrel of output to comply with the regulations would be higher. South Coast refineries have 1.3 million barrels per day of capacity, which accounts for nine percent of total U.S. refining capacity. Closure of South Coast refineries would significantly affect U.S. petroleum supply patterns. The twenty percent of their output shipped to other parts of the West Coast would have to be replaced with product imports.

While the South Coast does have a very serious air pollution problem and petroleum refineries are the largest single contributor to stationary source emissions in this area, there is no evidence that the proposed SCAQMD plan is cost-effective or has an adequate benefit/cost ratio. In addition, this plan has national security implications because Northern California would become more dependent on product imports and Southern California would become dependent on imported methanol.

^{3/} The economic impact of proposed federal stationary source air emission legislation^S and regulations were not analyzed in detail for this report. They will be addressed separately in a subsequent report.

STER

I. INTRODUCTION

The U.S. refining industry is currently facing the prospect of compliance with numerous new and proposed air-pollution-control regulations. This report examines the potential impact of these environmental regulations on U.S. petroleum refineries.

TYPES OF REGULATIONS ANALYZED

The air pollution control regulations discussed in this report include stricter limits on the contaminants in petroleum fuels or their characteristics and limits on refinery air pollutant emissions. The regulatory initiatives currently under way can be categorized into three areas:

- Controls on gasoline characteristics, including most notably summer limits on gasoline volatility, as measured by Reid vapor pressure (RVP)
- Controls on diesel fuel characteristics, including principally sulfur content
- Other regulations, including principally:
 - proposed federal legislation and regulations aimed at refinery hazardous air pollutant emissions
 - controls on refinery emissions, refinery production, and petroleum product utilization in the California South Coast Air Quality Management District.

Federal Regulations

Figure I-1 shows the schedule for the development of these regulations. At the federal level, Phase I of the federal RVP regulations will become effective this summer. The Phase I limits will reduce summer gasoline volatility by 1.0 pounds per square inch (psi) in the coldest climates and by 0.5 psi in intermediate climates. The Phase I limits will not change gasoline volatility in the hottest climates. EPA has also proposed Phase II RVP limits to become effective in 1992. The Phase II RVP limits are designed to reduce gasoline volatility by an additional 2.5 psi.

EPA has also analyzed regulations that would limit the sulfur content of diesel fuel oil. These regulations will likely be proposed this year, but the limits will not become effective until 1992 or 1994. EPA is also considering limiting the aromatics content of diesel fuel, but, at present, regulations appear unlikely.

In addition to these limits on petroleum product specifications, several federal initiatives are underway to control emissions from petroleum refineries. EPA is expected to finalize a regulation limiting benzene emissions from petroleum refineries this summer. In addition, two bills have been

FIGURE I-1

**Time Line for Federal, State, and Local
Petroleum Environmental Regulations**

introduced in the Congress, one in the House of Representatives and one in the Senate, that will limit hazardous air pollutant emissions from stationary sources, including petroleum refineries.

State Regulations

The states have also proposed, and in some cases promulgated, regulations to control petroleum product specifications and limit refinery emissions. A group of Northeastern states (NESCAUM) has enacted regulations that accelerate the federal restrictions on gasoline volatility by imposing the proposed federal Phase II RVP standards this summer rather than in 1992.

The state of California has had restrictions on gasoline volatility as strict as the proposed Phase II federal standards since 1977. It has also proposed limits on the sulfur and aromatics content of diesel fuel that will be effective in 1993. California will also hold hearings this summer on proposed regulations aimed at reducing refinery benzene emissions.

At the local level, the most significant developments are occurring in southern California. The South Coast Air Quality Management District (SCAQMD) has proposed a three tiered program that goes beyond the federal regulations in terms of the restrictions placed on refinery emissions and fuel specifications. A stated goal of this plan is to eliminate petroleum refining in southern California. The SCAQMD plan includes tough limits on emissions from stationary sources, tougher restrictions on the level of contaminants in diesel and residual fuel, and a system of taxes and incentives aimed at reducing local consumption and the export of petroleum products.

OBJECTIVES OF THE REGULATIONS

These federal, state, and local initiatives have been undertaken in order to confront significant air quality problems. As shown in Figure I-2, the target pollutants are ozone, sulfur dioxide (SO₂), nitrogen oxide (NO_x), and particulates, with particular emphasis on ozone levels.^{4/}

The major thrust of the federal regulations is the control of volatile organic compound emissions (VOCs), which are precursors of ozone, and particulate emissions. Federal regulation of SO₂ and NO_x emissions have also been tightened, but NO_x emissions are not a major focus of federal regulations.

Like the federal restrictions, state regulations are aimed at ozone levels and particulates. Southern California regulations also target NO₂ emissions because this area is the only non-attainment area for NO_x in the country. There is also emphasis on SO₂ emissions in Southern California due to the particular pollution problems of the Los Angeles Basin.

ORGANIZATION OF THE REPORT

This report examines the potential impact of these new, proposed, and potential environmental regulations on U.S. petroleum refineries. The next chapter examines the federal, state, and local restrictions on gasoline specifications. This is followed by a discussion of the

^{4/} These are four of the six criteria air pollutants identified in the Clean Air Act. The other two pollutants are lead and carbon monoxide.

FIGURE I-2
Regulation of Specific Pollutants

proposed regulations limiting the sulfur and aromatics content of diesel fuel oil. The next chapter examines the other environmental regulations affecting U.S. petroleum refineries, including the three-tiered program of the South Coast Air Quality Management District and proposed federal legislation and regulations limiting hazardous emissions. The final chapter of the report examines the aggregate effect of all of these regulations on the U.S. refining industry.

This report was prepared by ICF Resources Incorporated (ICF) and ENSYS Energy and Systems, Inc. (ENSYs).

II. GASOLINE STANDARDS

This section is focused on the effects on the U.S. refinery industry of recent or proposed U.S. federal and state regulations to control gasoline emission characteristics. Federal and state gasoline controls are focused on many pollution problems, which have varying degrees of incidence in different geographic areas. These controls are targeted at reducing ambient levels of lead, ozone, particulates, carbon monoxide, NO_x, and hazardous air pollutants.

Over the last ten years, the thrust of federal regulations has been to reduce the amount of lead in gasoline. Today this process is largely complete. Leaded regular constitutes less than 20 percent of the U.S. gasoline market, and even this product contains very low levels of lead.

Recently, EPA's focus has shifted to the control of volatile hydrocarbon emissions from gasoline in an attempt to reduce ozone formation in the summer.^{5/} Concurrently, regulatory action in the states is focused on hydrocarbon emissions or on a variety of other pollution problems.

REID VAPOR PRESSURE REGULATIONS

In March 1987, EPA issued proposed regulations to control evaporative emissions from light-duty vehicles by requiring (1) on-board vehicle refueling controls (canisters containing charcoal)^{6/} and (2) reductions in gasoline volatility as measured by Reid vapor pressure (RVP).

In March of this year, EPA promulgated Phase I regulations requiring nationwide reductions in summer gasoline RVP. This rule is in effect and will apply to the (May 16 - September 15) 1989 summer gasoline season. A definitive EPA proposal for stricter Phase II standards to apply in 1992 is still pending and expected later this year. In addition, EPA's proposed final ruling for refueling canister controls is currently under review at OMB.

EPA's RVP regulations vary by state, but a representative set of existing, Phase I, and Phase II RVP standards is shown in Table II-1. Figure II-1 presents a map of the United States showing which states are in the three climate categories used by EPA for setting RVP standards. The limits for each state are presented in Appendix A.

Most states previously have limited gasoline RVP as part of their State Implementation Plans (SIPs) to achieve National Ambient Air Quality Standards. California has maintained its own separate RVP standard (9.0 psi) since 1977.

^{5/} Prior to EPA's Phase I RVP controls, no federal controls existed on gasoline volatility.

^{6/} These canisters represent a change from existing equipment which is designed to handle routine evaporation but not the surge that occurs during re-fueling.

TABLE II-1**Representative Summer Reid Vapor Pressure Limitations (RVP)**

<u>U.S. Regions</u>	<u>Typical Levels</u>	<u>EPA Regulations</u>	
		<u>Phase I</u>	<u>Phase II</u>
Class A (hottest)	9.0	9.0	7.0
Class B (intermediate)	10.0	9.5	7.8
Class C (coolest)	11.5	10.5	9.0

Recently, eight Northeastern States^{2/} (the NESCAUM group) have mandated sharp RVP cuts, corresponding to EPA's Phase II 1992 proposals, for immediate implementation this summer. These state regulations require formal EPA approval before they can be put into effect, but rapid approval is expected according to both EPA and NESCAUM representatives. These proposed changes have been driven by the high level of ambient ozone concentrations in those states last summer.

Controversy Over the RVP Regulations

EPA's March 1987 proposals for installation of onboard vehicle refueling controls (canisters) and for gasoline RVP reduction sparked considerable debate and controversy. The thrust of EPA's approach was to rely primarily on gasoline RVP reduction as the quickest means to reduce hydrocarbon evaporative emissions at all stages in the gasoline production and distribution chain and in doing so to bring summer RVP levels into line with the original volatility level proposed for vehicle canister certification (7.0-9.0 RVP in the summer, depending on the climate).

The Motor Vehicle Manufacturers' Association supported EPA. The American Petroleum Institute (API) accused EPA of grossly underestimating the cost of Phase II compliance and called for reliance on vehicle canisters at existing ASTM RVP standards. API also raised concerns over driveability and safety problems that would result from the Phase II standards, because during cold spells low RVP gasoline can cause starting problems.

^{2/} New York, New Jersey, Pennsylvania, Connecticut, Rhode Island, Massachusetts, Maine, Vermont. NESCAUM stands for North East States for Co-ordinated Air Use Management.

FIGURE II-1

Categorization of States by RVP Control Levels

API's argument was that, since on-board vehicle emissions account for the majority of total gasoline evaporative losses, overall emissions targets could be met at far lower net cost to the country by maintaining RVP at then current levels while requiring that "the size of the evaporative canister already required be increased as necessary to treat the revised certification fuel". Refining costs for RVP reduction would therefore be avoided. EPA appears to have rejected this argument in part because a canister designed to capture vapors from high RVP gasoline is impractical. (It would apparently take up about the same space as the vehicle engine.)

EPA is planning to formalize Phase II regulations by the third quarter of this year. While there is no disagreement over the basic technical feasibility of producing Phase II RVP gasoline, arguments may re-emerge over cost-effectiveness.

The action of NESCAUM to move directly to the Phase II RVP standards this summer is controversial because it requires processing which may not be feasible given the capacity in place worldwide to make gasoline.

ACTIONS REQUIRED TO COMPLY WITH THE PROPOSED STANDARDS

The EPA Phase I regulations require a 0.5-1.0 RVP reduction across much of the country. The NESCAUM regulations require a 2.5 RVP reduction in the eight Northeast states. EPA's Phase II proposals call for a similar 2.5 reduction nationwide. In terms of absolute RVP levels, Phase II proposals for 7.8 and 7.0 RVP summer gasoline in Class B and A regions reduce gasoline volatility to levels significantly below those at which gasoline has historically been produced in the U.S. or elsewhere.

U.S. gasoline today contains an average of seven percent butane, which is highly volatile (around 65 psi RVP). Volatility reduction can, therefore, be readily achieved by removing butane from the gasoline pool. Butane, however, is valued for its high octane, which at around 92.5 (R+M/2)^{8/} is equivalent to that of premium gasoline. The refining issues surrounding gasoline RVP reduction therefore relate to:

- How to replace the volume lost when butane is displaced from gasoline
- How to replace the (high) octane lost
- How to dispose of the displaced butane

There was a general consensus among EPA, refiners, and industry organizations, such as API and NPRA, that U.S. refiners could meet the Phase I 0.5-1.0 RVP reduction by utilizing limited spare capacity on the key gasoline units, the fluid catalytic cracker (FCC) and the catalytic reformer, each of which account for over 30 percent of the total components blended nationally

^{8/} Two different methods are used for measuring gasoline octane: the Research Octane Number method and the Motor Octane Number method. Industry practice in the U.S. is to use the average of these two methods. This is commonly signified as: "R+M/2".

into motor gasoline. They would be used to manufacture sufficient volumes of low-RVP, high-octane gasoline components to replace the displaced butane.

To move to EPA's proposed Phase II RVP levels, there is general agreement that capital investment is necessary to supply additional high-octane, low-RVP components. Based on Bonner and Moore's analysis, API estimated the capital investment required by refineries for compliance with the Phase II limits to be \$2.4 billion. Again there is broad concurrence that Phase II levels are technically achievable using proven processes and that investments are likely to be focused on:

- revamping FCC and catalytic reforming units to use new catalysts which provide higher product octane and/or yield. (A gain of 1-3 octane can be achieved at current gasoline yield levels).
- adding a variety of processes which polymerize (combine) butane and other light streams (e.g. CH_4) into heavier, high octane compounds, including oxygenates like MTBE.
- equipment to seasonally store butane and to permit its use as a refinery fuel.

Industry personnel are pointing to a significant role for the production of the oxygenate MTBE because it combines several beneficial qualities: very high octane (109), moderate RVP, reduction of particulates and other emissions, and non-aromaticity. Initially introduced in Europe to aid lead phase-out, MTBE is now the preferred oxygenate component in gasoline, and its worldwide supply is growing rapidly.

MTBE is produced from natural gas (methane) and butane and would absorb part of the butane displaced from gasoline by RVP reduction. Oxygenate production is a long term supply option because it requires investment by refiners or petrochemical companies in new process units.

EPA and industry references indicate that some proportion of displaced butane will be used as refinery fuel. Unless the equipment is already in place, this will require installation of simple facilities to vaporize the butane into the refinery fuel system. Alternatively, the displaced butane can be shipped to locations where there is summer demand (although these opportunities appear limited) and/or can be stored so that butane produced in the summer can be used in the winter.

REGULATORY IMPACTS OF RVP REGULATION

Implementation of the reduced RVP regulations will have these impacts:

- Increase investment and operating costs in U.S. refineries
- Increase use of crude oil
- Increase gasoline prices
- Discourage use of ethanol in gasoline
- Create a seasonal surplus butane problem

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Cost Impacts

In its Final Regulatory Impact Analysis (FRIA) statement, EPA estimated the total refining cost of the Phase I standard as \$247 million per year or 0.54 cents per gallon of gasoline based on \$22/bbl crude. EPA believes this direct cost to the Nation should be partially offset by consumers' savings due to reduced evaporative hydrocarbon emission losses from vehicle tanks worth \$54 million per year.

In the FRIA, EPA reconciled API's higher cost estimate with that of EPA, which was derived from detailed studies by Bonner and Moore. API's estimate of \$540 million per year in effect contained a lower base refining cost than EPA's but inter alia foresaw a longer period for supplying summer compliance gasoline (+\$150 million per year) and used higher baseline RVP levels (+\$103 million per year). Actual industry costs will hinge on these and other factors, such as the prevailing crude price. In any event, it appears Phase I compliance will impose a minor cost on the refining industry, unlikely to exceed one cent per gallon of gasoline. EPA claims its ruling is cost-effective in reducing volatile hydrocarbon emissions. At the Phase I level, this does not appear to be an issue.

In its August 1987 study for EPA, Bonner and Moore put the capital cost of meeting Phase II targets at \$2.4 billion, while estimates from Sobotka and API are nearer \$1 billion. The API estimates of \$1.1-1.2 billion were based on a combination of extensive refinery surveying and industry modeling. Both Bonner and Moore and API claim to have taken into account ancillary investments for butane fractionation, storage, etc. as well as primary facilities for chemically producing high quality gasoline components. Clearly there is disagreement about the anticipated investment level. The ICF and ENSYS view is that the B&M results probably represent the more credible cost estimate, in part because their study was a careful reassessment of earlier work and in part because of the history of cost underestimates in this area.

Bonner and Moore places the annual Phase II refining cost at \$405 million per year or 0.94 cents per gallon of summer gasoline. These costs are reported as sensitive to the price of refinery fuel.

Gasoline Supply and Price Impacts

The potential near-term gasoline market problems are the result of the unexpected 2.5 RVP reduction in the 8 Northeast states, the phase out of lead in European gasoline, the recent surge in U.S. demand for high-octane premium fuels, and the unexpected fall in North Sea (Brent) crude oil production.

According to industry publications, refiners such as Sun and Texaco are projecting an increase in gasoline cost of up to 8 cents per gallon and a 5 percent cutback in gasoline production. The cutback arises due to the Northeastern refiners' reduction in the use of butane in gasoline.

A recent study on the topic for EPA by Sobotka reported that East Coast refiners have little storage, limited butane shipping capability, and lack the equipment to put butane into refinery fuel. They are also unable to reduce their own production of butane since processing severity must be maintained to meet octane requirements. Sobotka claims the only option available is to

cut back on total crude throughput, hence the projected five percent shortfall in East Coast gasoline production (around 35,000 barrels per day).

Forty percent of East Coast gasoline demand historically has been supplied by East Coast refinery production, 25 percent from other regions of the U.S. (notably the U.S. Gulf) and 35 percent from imports (mainly from Europe, South America and the Caribbean).

The Sobotka study estimates that the East Coast shortfall can be met from additional U.S. Gulf production, as long as either imports are maintained or U.S. gasoline consumption growth is nearer one percent rather than two percent over summer 1988. Sobotka further estimates that under these conditions the associated gasoline price increases will be around 2-3 cents per gallon in the Northeast and around one cent per gallon elsewhere.

Sobotka, however, indicates uncertainty over whether 1989 summer imports will be forthcoming at the 1988 summer levels of over 500,000 barrels per day. Half the South American product traditionally has been boosted to U.S. octane specifications by addition of butane, a practice that is no longer possible. ICF sources indicate that, while the European industry can supply 9.0 RVP gasoline, most of the spare gasoline reforming capacity is required to meet the European gasoline requirements relating to lead phase-out. Europe could provide additional gasoline to the U.S. by processing more crude oil, but this activity is only financially attractive at a very high gasoline price because the other products concurrently produced would have to be sold with low margins or at a loss.

Sobotka did review the gasoline supply capability of the major U.S. refining regions but was unable to provide the overall assessment which would come from addressing the problem on a global basis. In addition, the unexpected recent production problems in the North Sea have reduced supplies of Brent crude, which is a particularly good feedstock for gasoline production.

Wholesale gasoline prices have already risen up to 20 cents/gallon since February 1989, in part in response to EPA Phase I plus NESCAUM rulings. Premium gasoline prices are particularly high. In theory, continuing price hikes, especially on premium gasoline (the product most affected) will cause consumers to switch to lower octane grades and/or reduce consumption. At lower octane levels refiners could reduce catalytic cracker and reformer operating severity and thus raise gasoline production. ICF and ENSYS believe that the Sobotka report understates how close the world refining industry is to its gasoline production limits and, thus, underestimates the likely price increase.

No limitations on gasoline supply are expected over the longer term since the refining industry will invest in the necessary capacity to provide additional low-RVP gasoline components. Fuel economy improvements and reduced evaporative losses resulting from lowered RVP will marginally reduce gasoline demand.

Crude Oil Imports

Gasoline RVP reduction will cause refiners to increase crude runs to generate the raw materials to replace all or part of the butane lost from gasoline. RVP reduction (especially to Phase II levels), and also diesel fuel quality improvement, will increase refinery fuel use as processing severity and refinery throughput increase. Drawing from industry sources, ICF and

ENSYS estimate around 150 Mb/d of butane will be displaced from summer gasoline to meet Phase I plus NESCAUM rules. At first sight this could be taken to imply a 150 Mb/d (three percent) summer increase in crude oil imports. However, absorption of displaced butane as ethylene cracker feedstock (displacing naphtha and gas oil feed) and as refinery or petrochemical fuel will back out both crude oil and natural gas. The net effect on crude oil use and imports depends on the proportion to which crude oil is backed out versus natural gas. The actual summer increase in crude imports is, however, likely to be as low as one percent.

Phase II reductions will continue the trend to higher crude consumption and imports. The last Bonner and Moore study indicates an increase of about 300 Mb/d of crude oil requirements in the summer or about 100 Mb/d on an annual basis. This is an increase of two percent over current import levels of about 5.0 million b/d. With crude imports less than half of total U.S. petroleum consumption, this increase is less than one percent of total U.S. crude oil requirements.

Ethanol Market Impacts

The lead phase-out from gasoline in the U.S. and Europe created a market for high octane hydrocarbon additives (Lead increases gasoline octane.) The initial response was to use methanol and ethanol, but blending and distribution difficulties related to chemical incompatibility with normal gasoline curtailed their use. Today only ethanol is used in the U.S.A. Total ethanol use is around 55 thousand barrels per day (Mb/d), which is supplied by agricultural sources in the Midwest for "gasohol". This form of ethanol is a renewable fuel, but it is uneconomic without a continuing tax subsidy.

The absolute maximum concentration of oxygenates in gasoline is set by an EPA limit of 3.5 weight percent oxygen (3.7 wt. % for gasohol blends, which equates to around a 10.6% ethanol maximum). These limits are set at this level due to a tendency for NO_x emissions to increase above the 3.5% level and, therefore, are not expected to be relaxed.

Ethanol has high octane (113) but also high RVP (around 18 psi). RVP reduction requirements will discourage ethanol use. As part of the Phase I regulations, EPA has allowed a 1.0 RVP increase for gasoline containing ethanol (but not methanol). If the Nation is willing to accept the emissions penalty, the use of ethanol in the summer will remain feasible.

One industry source has projected that ethanol's comparatively high volatility could lead to its virtual elimination from gasoline under Phase II regulations. Further, that the most economic option to continue its use is to convert ethanol into a highly attractive oxygenate (ETBE) that is a sister compound to MTBE. The underlying issue is federal and state tax support for "renewable" ethanol which is due to expire in 1993.

Butane and Gas Market Impacts

The Natural Gas Processors Association (NGPA) has voiced concerns in the industry press over the loss of butane sales to refiners. In 1987, total U.S. butane production from natural gas liquids (NGL's) was 298 Mb/d, which closely matched refinery purchases. In the short term, butane projected to be displaced in the summer period from gasoline equates to roughly 40 percent of total U.S. production, but around 75 percent of normal-butane production since it is this type of butane that will be rejected. Refiners buy stable quantities of iso-butane as a

feedstock for production of high quality gasoline components. The NGPA has stated that "91 percent of the nation's small independent gas processors [will be] put out of business" and that there will be a regional butane problem since only Gulf Coast gas processors will be readily able to adapt to the RVP reductions.^{9/}

In its August 1987 report for EPA, Bonner and Moore estimated that 75-85 Mb/d of butane could be utilized as ethylene feedstock, backing out mainly naphtha and gas oil, which are also refinery products. Outside of this market, Bonner and Moore saw little other short term outlet for butane except as fuel. Since the summer price for both normal and iso-butane is likely to drop to its fuel value, the Phase I and NESCAUM rulings will seriously affect gas processing economics.

Over the long-term there is a consensus that the gas processing industry will have to invest in seasonal storage to alleviate the summer butane surplus. In the near term, much of the displacement will occur in PADD III, the region with the largest global concentration of complex refineries and petrochemical plants. ICF and ENSYS believe that 1) the summer butane surplus will cause the butane price to drop as it has in California and 2) the highly flexible U.S. petroleum industry will respond by finding ways to either seasonally store, ship out, or directly consume the surplus butane, thereby allowing overall NGLs and associated gas production to be maintained.

RVP reduction to Phase II levels will largely eliminate butane from U.S. gasoline in the summer. However, EPA and industry see possibly 40 percent of the displaced butane being used as feedstock for high octane, low RVP gasoline components (such as alkylate and MTBE). While these changes will partially alleviate butane suppliers' problems, Bonner and Moore project that long term a significant proportion of butane production will have to be used for fuel. Bonner and Moore estimate that gas processors will lose overall around 10 percent of their revenues. Displacement of butane and potentially naphtha into refinery fuel could lead to a decline in natural gas sales to refineries.

OTHER AIR-QUALITY-RELATED GASOLINE CONTROLS

Several western mountain states (notably Colorado, Arizona, New Mexico) have imposed rules mandating minimum winter-time oxygen content in gasoline (around two percent oxygen). The purpose is to ensure more complete combustion and thereby reduce particulate, carbon monoxide, and NO_x emissions. These rules are met by blending oxygenated hydrocarbons, generally ethanol or MTBE (methyl tertiary butyl ether) into the gasoline. EPA currently limits MTBE to an oxygen limit of two weight percent in unleaded gasoline. Therefore, regulations requiring on oxygen content over two percent, virtually mandate ethanol use.

Aromatics/Toxic Pollutants

While EPA's recent efforts to reduce gasoline emissions are directed toward meeting Clean Air Act criteria for pollutants, some attention has also been focused on the harmful health effects of benzene and other aromatics in gasoline. The Occupational Safety and Health Administration

^{9/} Oil and Gas Journal, "GPA: Gasoline RVP Reduction Could Jolt U.S. Gas Processing," December 14, 1987, p. 30.

(OSHA) has recently set tighter standards for workplace/stationary benzene emissions, but no current federal legislation exists or is proposed to control the benzene content in gasoline.

Aromatics are compounds which contain one or more six-carbon benzene rings. Formal EPA work on aromatics in gasoline appears limited to one Arthur D. Little study in 1978. Nonetheless, the proposed Air Toxics legislation and current developments in California may spark additional study. A proposal is expected to go before the California Air Resources Board (CARB) in 1989/90 requesting that benzene content in gasoline be halved. Benzene is a known carcinogen. The proposed Air Toxics legislation would focus on benzene and other aromatics, including toluene and xylene.

According to industry sources, the benzene concentration in the U.S. gasoline pool varies from 1 to 5 percent in individual gasolines but currently averages 1.5 percent. Benzene is currently extracted from catalytic reformer product for petrochemicals feedstock in some refineries. This practice could be extended to remove most benzene but (as with butane displacement) would require incremental refinery processing investment both to remove the benzene and to replace the lost product.

The 1978 Arthur D. Little Study estimated total U.S. investment for benzene removal at \$5.3 billion in 1977 dollars, or \$9.1 billion in 1987 dollars. This investment covered benzene removal from the two main sources only, namely FCC gasoline and catalytic reformer gasoline. It did not include the cost associated with replacing lost octane, lost gasoline volume, or disposal of benzene. The study also reviewed options for improving distribution facilities and found these to be more cost effective than refinery process investment.

The total aromatics content of gasoline far exceeds that of benzene and continues to grow as gasoline pool octane rises. In 1980 with U.S. clear pool octane at 83, the aromatics content was 22 volume percent. By 1988, the corresponding values were 88 octane and about 32 percent aromatics. With growing demand for premium and rising premium octane levels, some individual gasolines are reported to be approaching 50 percent aromatics.

EPA RVP regulation and the use of on-board refueling canisters should reduce benzene emissions. However those same regulations are likely to drive up the aromatics content in gasoline, depending on the extent to which refiners rely on cat cracking and reforming rather than production of alkylates and MTBE from butane. Direct restrictions on aromatics levels in gasoline would have a radical impact on the refining industry, requiring massive investment. Since the bulk of the aromatics in gasoline are produced from the two main gasoline plants, FCC and catalytic reformers, blanket aromatics reduction would radically affect refinery processing.

Table of contents **Clean Fuels Legislation**

RVP reduction, oxygenate requirements, and benzene controls all constitute incremental change to the established gasoline market and refining industry. More radical proposals also exist which would have the effect of displacing conventional gasoline with non-petroleum "clean fuels," notably ethanol, methanol, LPG, and compressed natural gas.

The Federal Alternative Motor Fuel Act came into effect in December 1988 with a funding authorization of \$47 million. This Act calls for research and demonstration of clean fuels

automobiles. A bill (HR-99) currently at the House committee stage seeks amendment of the Clean Air Act to mandate use of clean fuels, at least for fleet vehicles, in severe non-attainment areas, such as New York.

California's extreme difficulty in meeting the National Ambient Air Quality Standards (NAAQS) has led to regulatory efforts that could radically affect gasoline quality and consumption in the state. EPA reportedly has estimated that an 80-90 percent reduction in volatile organic compounds emissions is necessary to meet NAAQS for ozone in the South Coast region. The South Coast Air Quality Management District (SCAQMD) believes that mobile sources account for about 52 percent of reactive hydrocarbons and 72 percent of nitrogen oxides. A sweeping Air Quality Management Plan (AQMP) has been drawn up to bring the basin into compliance with federal and state standards.

SCAQMD and CARB proposals focus on a variety of measures to control gasoline-related emissions, including mandating winter oxygenate use, reducing aromatics levels, lowering RVP levels and mandating the use of methanol as a clean fuel. SCAQMD has ordered that M-85, an 85%/15% mix of gasoline and methanol, be used in all standby emergency vehicles. The California proposals are examined in more detail in Chapter IV.

CONCLUSIONS

There was a general consensus that Phase I RVP limits on gasoline could be met at relatively low cost. Nevertheless, the unexpected additional reduction in the RVP limit in the Northeastern states combined with lead phase-out in Europe and the rapid increase in high-octane gasoline demand has created a supply problem. Gasoline margins are likely to remain high through the summer of 1989. Longer term U.S. refiners will be able to provide gasoline at more normal margins through investment in more processing equipment and the use of oxygenate additives.

The RVP regulations will lead to permanent changes in the butane market. Butane will be virtually eliminated from gasoline in the summer under Phase II RVP regulations, and this will create a permanent summer butane surplus. In response, butane prices will follow a seasonal price cycle.

III. DIESEL FUEL STANDARDS

This section is focused on the effects on U.S. refineries of compliance with proposed or potential federal and state regulations to limit the sulfur and aromatics content of diesel fuel. The primary purpose of stricter federal sulfur and aromatics limits on diesel fuel is to reduce emissions of particulates and nitrogen oxides and to enable tail pipe pollution control equipment to function properly. Similar regulations in California are focused on control of sulfur dioxide and NO_x emissions.

FEDERAL REGULATIONS ON DIESEL FUEL

In March 1985, EPA issued the particulate emission standards for heavy-duty trucks and buses shown in Table III-1 to take effect in 1991 and 1994. Industry had commented that diesel fuel specifications would have to be tightened because sulfur and aromatics combustion products would otherwise adversely affect the exhaust treatment devices or the particulate traps manufacturers likely would install on vehicles to meet the standards. EPA indicated in the rule-making that they would examine whether use of the traps would require additional controls on diesel fuel.

TABLE III-1

**Particulate Emission Standards for Heavy Duty Trucks and Buses
(grams/brake horsepower-hour)**

	<u>Current</u>	<u>1991</u>	<u>1994</u>
Trucks	.6	.25	.10
Buses	.6	.10	.10

Diesel fuel has a sulfur content of about .28 percent sulfur and an aromatics content of 27-35 percent. In 1986 EPA made available a Sobotka report which examined the technical feasibility and cost of meeting a 0.05 percent sulfur limit and a 20 percent aromatics limit. These levels of control have been considered by industry as an informal EPA proposal.

The Industry Group Proposal

In response, a group of industries (referred to hereafter as The Industry Group), including the American Petroleum Institute (API), the National Petroleum Refiners Association (NPRA), the Engine Manufacturers Association (EMA), and the National Council of Farmers Cooperatives (NCFC) have put together an alternative proposal to meet truck particulate standards. The Industry Group contends that engine re-design is the preferred means for reducing particulate emissions. While no suitable engines currently exist, The Industry Group claims that the 1991 particulates standard of .25 grams/brake horsepower-hour (g/b hp-hr) can and will be met by engine re-design. No cost estimates for engine design and retooling were included in this proposal.

Since engines must be over-designed to ensure they will meet standards, a .16 g/b hp-hr sulfur-free design target has been set for 1991 engines. Since the sulfur present in diesel fuel only contributes 0.07 g/b hp-hr to particulate emissions, The Industry Group argues that, between 1991 and 1993, emissions from new diesel engines will at worst marginally exceed the 1991 truck standard (.25).

To meet the 1994 standard (.10) they argue that both further engine re-design and tail-pipe particulate traps are essential. Sulfur must be largely removed to eliminate associated particulate emissions and to prevent damage to particulate traps. The Industry Group believes its proposal will provide a stable platform for long-term engine design specifications and avoid the refining difficulties associated with supplying diesel fuel at an interim sulfur standard.

The Industry Group also pointed to test data which indicated that a reduction in diesel aromatics content from 35% to 25% would reduce particulate emissions by a nominal 0.01-0.02 g/b hp-hr. Their view was that aromatics reduction was largely ineffective and, because of its high refining cost, not cost-effective. They did argue, however, that it was important that the refining industry control fuel aromatics content at current levels and that a cetane index set to a minimum of 40 would be adequate because cetane correlates closely with aromatics content. ICF and ENSYS observe that there is an inconsistency in the industry argument. The current national average diesel cetane index is over 45. A reduction in the index to 40 could permit a significantly higher aromatics content of roughly 40 percent, compared to current levels of 27 to 35 percent.

EPA reportedly is close to issuing a Notice of Proposed Rule-Making (NPRM) to reduce the diesel fuel sulfur content to 0.05 percent in 1994, but apparently no aromatics limit will be proposed at this time. It appears that the EPA strategy will be to accept The Industry Group proposal.

ACTIONS REQUIRED TO COMPLY WITH THE PROPOSED STANDARDS

Analysis performed to date confirms that refiners could not currently meet diesel fuel requirements if sulfur limits were lowered. Two strategies could be followed to meet the 0.05 percent sulfur standard:

- Add desulfurization capacity and reduce the content of all distillates, including No. 2 fuel oil, to 0.05 percent sulfur. This strategy is consistent with current industry practice, which does not generally segregate diesel fuel and No. 2 fuel oil.
- Add desulfurization capacity to reduce diesel fuel sulfur content, and set up a segregated supply system which treats higher sulfur content No. 2 fuel oil as a separate product. Under this approach, No. 2 fuel oil sulfur content could rise from the 0.28 percent average today toward the 0.5 percent ASTM limit.

In practice, some combination of the two strategies likely will be adopted. Segregation of product should be worthwhile in areas like the Northeast where No. 2 fuel oil is used in larger quantities

and where distillate is imported.^{10/} The SCAQMD has dealt with the potential deterioration in No. 2 fuel quality in California by proposing the same 0.05 percent limit for No. 2 fuel oil.

Meeting the combined sulfur and aromatics limits examined by Sobotka would be far more difficult and costly. Analysis performed by ENSYS indicates that virtually no diesel fuel could be reliably produced at these limits today. Two approaches are available to meet the combined low-sulfur, low-aromatics standards:

- The most direct and most expensive option is to install deep hydro-treating to desulfurize and to convert aromatics to non-aromatics. This approach also requires significant investment in hydrogen plants and sulfur recovery.
- The second option is to conventionally desulfurize distillate stocks and use solvent extraction to remove aromatics from the distillate pool. Overall investment would be lower than for deep hydrotreating. However, the extracted aromatics would have to be dumped into No. 2 or residual (No. 6) fuel oil. The quality of No. 6 and probably No. 2 would deteriorate. U.S. production of residual fuel would increase unless additional residual fuel processing equipment also were installed.

Under either option the segregation of diesel fuel from No. 2 fuel oil would reduce refinery capital and operating costs but lead to poorer quality No. 2 fuel than is produced today. The problem with the aromatics segregation options is that they will tend to increase the soot (particulates) emitted in the combustion of No. 2 fuel oil and residual fuel. Truck particulate emissions would decline, but particulate and NO_x emissions from stationary sources would undoubtedly increase. However, if newly developed additives are eventually proved successful, they could reduce particulate emissions while allowing present aromatics levels to be maintained.

Currently, the principal limit on aromatics content in diesel fuel is the cetane index. The ASTM minimum specification is 40, which is significantly below the 45.6 average in fuel produced today. Consequently, the aromatics content of diesel could increase in the future in the absence of limitations. Refinery operational changes to meet gasoline RVP limitations could lead to higher aromatics content in diesel fuel.

REGULATORY IMPACTS

Implementation of the 0.05 percent sulfur limitation on diesel fuel with or without the aromatics limitation could have these impacts:

- Increase investment and operating cost in U.S. refineries

^{10/} The East Coast is the only region where there is significant diesel fuel and No. 2 fuel oil segregation.

- Increase investment and operating cost in the U.S. product distribution system
- Increase fuel prices
- Cause adverse impacts on small refiners.

The NPRA has estimated that the reduction of the sulfur content of all distillates to 0.05 percent sulfur would require \$3.3 billion in investment costs and would increase annualized refining costs by \$1.2 billion per year. The analysis performed by ENSYS supports this estimate. This estimate is the upper bound on the potential cost because segregated fuel distribution could be pursued if it turned out to be a lower cost option. If a separate diesel and No. 2 fuel oil distribution system were set up, refining costs would decline and distribution (and storage) costs would increase.

Since 0.05 percent sulfur diesel cannot be easily produced, this fuel would initially be scarce and would command a premium price. If refiners invested in sufficient desulfurization equipment to lower all U.S. distillate output to 0.05 percent, distillate prices would have to increase by 3.1 cents/gallon to cover all costs.

Nevertheless, the availability of imported No. 2 fuel oil at lower prices would tend to create a separate price structure for large lots of diesel fuel and No. 2 fuel oil. As a result, diesel fuel prices would undoubtedly rise more than No. 2 fuel oil prices in major markets. NPRA estimates that diesel fuel prices would rise by 7.7 cents/gallon if all distillates were desulfurized and all the costs were allocated to the diesel fuel. The most likely outcome of the diesel sulfur limitation is a diesel fuel price increase between 3.1 and 7.7 cents per gallon.

Impact of Sulfur and Aromatics Limitations

Implementation of the 0.05 percent sulfur limitation and the 20 percent aromatics limitation would greatly increase the required investment and operating costs to produce diesel fuel. NPRA estimates that without fuel segregation capital expenditures would rise to \$6.6 billion and annualized costs to \$2.4 billion. Again, the ENSYS analysis supports these estimates. As discussed above, diesel fuel and No. 2 fuel oil segregation could potentially reduce these costs. Sobotka's estimates using the solvent extraction approach were about 50 percent lower.

The fuel price impacts associated with the low sulfur and low aromatics standards would follow the same pattern as with low sulfur fuel standards alone, except the price increases with aromatics reduction would be about double the levels described above. Diesel fuel prices likely would increase between 6.2 and 15.5 cents per gallon.

SMALL REFINER IMPACTS

Although estimates of the magnitude vary, most studies indicate that small refineries will be adversely affected by the regulations. A recent Sobotka and Company Inc. (draft) report estimated the effect of the proposed diesel fuel regulations on small refineries to be similar to those of the entire industry for reducing sulfur content alone, but significantly higher (25 to 50 percent higher) for reducing both sulfur and aromatics content. An NPRA report found that for the 30-100 thousand barrel per day refinery size class, the increased cost (per gallon of diesel fuel

product) of desulfurization was reported at 35 percent higher than the national average, and the cost of both desulfurization and dearomatization was 16 percent higher. In contrast, for the 0-30 thousand barrel per day class, the corresponding cost increases were found to be 325 percent and 230 percent.

The NPRA estimates appear reasonable since the smaller refineries are more likely to be tight on desulfurization capacity and hydrogen-deficient. The larger refineries are more likely to have extensive hydrogen generation facilities in place, beyond the hydrogen supplied by catalytic reforming, and are more likely to have excess desulfurization capacity. The NPRA findings, however, narrow the small refinery cost increment for both desulfurization and dearomatization, indicating that all classes of refineries must invest to meet the proposed diesel level aromatics limitation. ENSYS found in their recent work for EIA/ORNL, that the smaller refineries tend to have distillate blends which are lower in aromatics content, tending to give them some offsetting advantage when compared to the larger refineries.

CALIFORNIA REGULATIONS

The 0.05 percent sulfur limitation for diesel fuel is already in effect in the South Coast Air Quality basin and in Ventura county in California and will be extended to the entire state by 1993. In addition, the SCAQMD has promulgated a rule requiring that No. 2 fuel oil also meet the 0.05 percent sulfur limitation by 1993.

In November 1988, California also issued proposed regulations on diesel fuel aromatics content to reduce NO_x emissions from diesel-powered vehicles. These regulations will go into effect in 1993. The South Coast basin is the only area which still has an ambient NO₂ air quality problem. Large refiners will be required to meet a 10 percent limit and small refiners a 20 percent limit on aromatics content unless they can show by September 1989 that the NO_x emissions standards can be met using diesel fuel oil additives.

Regulatory Issues

The regulatory issues are as follows:

- Would reductions in NO_x emissions from trucks and buses cause an increase in ozone concentrations?
- Are aromatics limits a cost-effective way to reduce NO_x?

The Western Petroleum Supply Association (WPSA) has argued that reducing NO_x emissions from trucks and buses in California could lead to higher ambient ozone levels. Using an EPA model, they have shown that this could happen. EPA staff agree that this outcome could be consistent with their model, but that the exact atmospheric chemistry is not known and might not behave like the model. WPSA has argued that California should concentrate on ozone reduction and delay NO_x control strategies.

A further issue relates to the general utility of reducing aromatics to reduce NO_x. WPSA has argued that other control approaches would be more cost-effective for reducing NO_x. Such approaches could include raising the cetane specification or including additives in the diesel fuel.

Certainly, refinery processing to achieve 10% aromatics content would be extremely expensive, costing at least twice as much as the cost of achieving 20% aromatics content.

Diesel engine tests are underway at the Southwest Research Institute to examine the effectiveness of additives. Data is to be presented to CARB by September 1989 at which point a final decision as to how to meet NO_x emissions standards will be made. Indications so far from refiners are that the available additives will not permit the achievement of the standards by September.

No cost estimates have been developed for the cost of reducing the aromatics content of diesel fuel in California to 10 percent, but the incremental cost to move from 20 percent to 10 percent should be at least comparable to the cost of reducing aromatics content from today's level to 20 percent in response to possible federal regulations.

CONCLUSIONS

The desirability of reducing the diesel fuel sulfur content to 0.05 percent sulfur is not being seriously debated, even though it will cause the U.S. refining industry to incur considerable cost. Since this specification cannot currently be met, prices of low-sulfur diesel will undoubtedly rise, and price increases should enable refineries to cover their incremental costs.

The industry is challenging the desirability of reducing diesel fuel aromatics content for the purpose of reducing particulates and NO_x emissions. Engine redesign and the use of fuel additives potentially offer a lower cost route to meet the same objectives. EPA appears to be oriented toward this strategy. In contrast, the CARB strategy to control truck emissions through diesel fuel aromatics limits is less cost-effective, but is a more certain, faster approach to meet ambient air quality goals if refineries decide to make the necessary investments to provide this fuel.

IV. OTHER REGULATIONS

In this section we focus on the existing and proposed federal and state air pollution regulations which affect U.S. refiners other than gasoline and diesel fuel specifications.

FEDERAL REFINERY EMISSION REGULATIONS

There has been recent federal regulatory activity over stationary source emissions that has and will affect the refinery industry:

- New Source Performance Standards for industrial boiler emissions of NO_x, Particulates, and SO₂ have been tightened. NO_x emissions were set at 0.30 or 0.40 lbs/MMBtu, depending on the size of the boiler in November 1986. SO₂ emissions were set at 0.30 lbs/MMBtu in December 1987. The regulations apply to new, modified, or reconstructed boilers.
- Rules addressing the control of VOC emissions from petroleum refinery waste water systems were published on November 23, 1988. These apply both to new systems and to the retrofit of existing systems.
- Toxic emissions of benzene from refinery storage tanks are being evaluated again with a view to tightening the standards that have been in place since June 1984. EPA is expected to issue new rules on August 31, 1989.

In addition to the existing and proposed federal regulations outlined above, two bills have been introduced in congress this year to increase the control of hazardous emissions from stationary sources including petroleum refineries. In the House of Representatives, Congressman Dingell introduced a bill, H.R.4, which was referred to the Committee on Energy and Commerce. In the Senate, Senator Durenberger introduced a bill, S. 816, entitled the Toxics Release Prevention Act of 1989. The Senate bill was referred to the Committee on Environment and Public Works. Both bills are still awaiting committee action.

If passed, the House bill on hazardous emissions from stationary sources would authorize the EPA Administrator to establish technology-based industrial emissions standards for a large number of hazardous air pollutants. Included in this list are benzene, toluene, and xylene (BTX), three aromatic compounds found in crude oil which are major gasoline components. The existing legislation authorizes risk-related regulations for hazardous air pollutants. Since EPA has proposed few regulations using this approach, the proposed House bill would require regulations irrespective of risk if they could be met at reasonable cost.

The Senate bill would amend the Clean Air Act in a less drastic fashion. The EPA Administrator's authority to regulate hazardous emissions from stationary sources, including petroleum refineries, would be strengthened, but cost/benefit analysis would be part of each regulation's development process.

STATE REGULATIONS AFFECTING REFINERIES

Section 7401 of the Clean Air Act specifically states that the prevention and control of air pollution at its source is the primary responsibility of the States and of local governments. In addition, States must develop State Implementation Plans to achieve the National Ambient Air Quality Standards. Therefore, the States are charged with the responsibility of enforcing federal standards and also have the option of instituting more stringent standards on a state-wide or regional basis.

On the state level much of the recent activity is taking place in California, specifically in the South Coast Region. As Figure IV-1, Figure IV-2, and Figure IV-3 show, Southern California is one of the major non-attainment areas in the country for compliance with ozone, particulates, and NO_x standards, and this is the driving force behind the regulatory activity in that state.

In its efforts to achieve these standards, The South Coast Air Quality Management District (SCAQMD) adopted a new Air Quality Management Plan on April 20, 1989. The overall plan still has to receive approval from both the California Air Resources Board (CARB) and EPA, but SCAQMD has the authority to issue rules under the Plan as it pertains to stationary emissions.

Generally, the thrust of the Plan falls into three categories: refinery emissions controls, fuel use specifications and other more general regulations. Under Tier I control measures, which are to be in place by 1993, the following regulations apply to petroleum refineries:

Refinery Emissions Controls

- Emissions of SO₂ from FCC units are to be cut from 132 lbs./Mbbls of feedstock to 13.2 lbs./Mbbls.
- Emissions of SO₂ are to be cut by reducing the sulfur limit of refinery gaseous fuels from 800 ppm to 100 ppm.
- To reduce NO_x emissions, the standard of allowed NO_x emissions from large boilers (>40 MMBtu/hr) at refineries is to be reduced to 0.14 lb./MMBtu by 1992 and 0.03 lb./MMBtu by 1995. [Amended Rule No. 1109 adopted August 5, 1988.]
- To reduce NO_x emissions from small boilers SCAQMD proposed Rule No. 1146 which limits emission levels to 40 ppm (0.05 lbs./MMBtu). Units ≥ 10 MMBtu/hr must meet this level by March 1991 while units ≥ 5 MMBtu/hr must meet this level by March 1992. [Rule No. 1146 Adopted September 9, 1988, Amended January 6, 1989].
- Emissions of reactive organic gases (ROG) are to be reduced by covering refinery oil/waste water separators and by replacing old valves with new leakless equipment.

FIGURE IV-1

Trends in Ambient Ozone Concentration

FIGURE IV-2

Trends in Ambient Suspended Particulate Concentration

FIGURE IV-3

Trends in Ambient Nitrogen Dioxide Concentration

- Emissions of particulates are to be controlled by installing either electrostatic precipitators or baghouse filters in refinery process heaters and by using electrostatic precipitators to limit emissions from the regeneration of FCC catalysts.

Fuel Specifications

- All No. 2 fuel oil used in the South Coast Basin is to be limited to a sulfur content of 0.05 percent.
- The sulfur content of residual (No. 6) fuel oil used by Electric Utilities is to be reduced from 0.25 percent to 0.10 percent. The fuel used by industry is to be reduced from 0.50 percent to 0.25 percent sulfur.
- A limit of 10 percent maximum aromatics in diesel fuel has been proposed for large refineries (20% for small refineries).

Other Regulations

- Fleet operators of public or commercial vehicle fleets greater than 15 vehicles will be required to purchase only vehicles capable of operating on alternate "clean fuels," i.e., methanol, propane, compressed natural gas, fuel cells, and electricity. This is authorized

by Senate Bill 151 in the California Legislature. The goal is to have up to 30 percent of the fleet operating on clean fuels by 2000. [Proposed Rule 1601 to be adopted early 1989.]

- If proposed Rules 1109, 1134, 1135 and 1146, all of which limit NO_x emissions from various boilers and heaters to 0.03 lbs./MMBtu, are not adopted or if new technology is developed that results in the standards being met, SCAQMD proposes eliminating the use of fuel oil and solid fossil fuels under all conditions. Substitutes will be natural gas, electricity, and alternate fuels. The phase out would begin in 1992 with an annual 33 percent reduction per year.
- Emission charges i.e., taxes, are proposed on conventional motor vehicle fuels (gasoline and diesel) to raise prices to parity with alternative clean fuels. Currently, the SCAQMD does not have the authority to levy emission charges but is working to obtain the authority.

In addition to the above proposals, under Tier II (which is to be implemented by 1998) SCAQMD requires that:

- 40 percent of the passenger vehicle fleet use alternative fuels.
- 70 percent of freight vehicles use alternative fuels.
- All buses be electrified or use alternative fuels.
- Export taxes be levied after 1993 on the approximately 20 percent of petroleum products produced that are exported from Southern California either overseas or to other parts of the U.S.

REGULATORY ISSUES

The API and other oil industry trade associations are concerned about the new legislation introduced in Congress to regulate hazardous emissions from stationary sources. But, at present, no extensive analysis of these bills has been done. Consequently, the regulatory issues associated with stationary emissions controls and other regulations are largely centered around the activity in Southern California. The principal issues raised are whether the proposed SCAQMD plan is cost-effective and whether the benefits exceed the costs.

Southern California is the main non-attainment area for criteria air pollutants in the U.S., and the only non-attainment area for NO₂. Nevertheless, the desirability of the proposed level of emission control with its attendant massive economic and social disruptions has not been fully examined. The impact is compounded by the very short time period in which controls are to be implemented.

There has been considerable criticism of the benefit/cost ratio of the SCAQMD Plan and of the benefit/cost ratio SCAQMD is claiming for its program. The District issued a draft

Environmental Impact Report (EIR) at the same time the draft Plan was issued. Estimates of \$3.9 billion per year in costs and \$9.6 billion per year in benefits were provided. The SCAQMD Plan contains 160 control measures, 120 of which are to be implemented under Tier I, 37 under Tier II and the remainder under Tier III. Of the 160 control measures 58 have estimates of costs and benefits, 85 have benefits but no cost estimates, while 17 have neither costs nor benefits estimates attached to them. This has resulted in severe criticism of SCAQMD and considerable doubt about the benefit/cost ratio of the plan. As an example, the National Economic Research Associates estimate costs to be \$14.8 billion per year, with benefits only totaling \$2.6 billion per year. Indicative of the disagreement is a bill in the California Legislature to require cost and economic impact studies on all environmental control rules.

Much of the SCAQMD Plan depends on greatly expanded use of alternative fuels, particularly methanol. Since methanol is toxic and the use of it as a vehicle fuel produces emissions of formaldehyde, a known carcinogen, its widespread use could pose problems. The SCAQMD Plan assumes that methanol will be produced and electricity generated outside the South Coast Basin, raising the issue of the desirability of high regional reliance on energy imports and the fairness of exporting pollution outside the region.

ACTIONS REQUIRED TO COMPLY WITH THE SCAQMD PLAN

The California South Coast basin contains 15 refineries with a combined capacity of over 1.3 million b/d, corresponding to nine percent of total U.S. capacity. Of these 15 refineries, eight are small refineries (under 50 MB/d).

The proposed regulations would cut plant atmospheric emissions of pollutants by factors of six to ten. At this time ENSYS and ICF have not ascertained that compliance is technically feasible using proven technology. Similarly, technology presently in limited use would have to be applied in order to achieve a 10 percent aromatics level in diesel fuel. The refiners would need to invest in a combination of distillate desulfurization, distillate aromatics removal, residual desulfurization and upgrading units in order to comply with tightened product quality specifications.

ICF and ENSYS estimate that the combined capital cost of process and environmental facilities could be in excess of \$1 billion. In addition, operating costs would rise. SCAQMD has estimated the annual costs of complying with the emissions regulations alone at \$251-515 million per year. The increased costs may be of the order of 3 to 6 cents per gallon across all products. Some of the smaller refineries may not be able to sustain the added financial burden and may elect to close if overall refinery margins fall below current levels.

Regulatory Impacts

The regulatory impacts of the SCAQMD Plan would be substantial, if it were fully implemented.

- Substantial investments would be required of refineries in the SCAQMD to (i) meet emission controls, and (ii) meet distillate and residual fuel oil sulfur specifications.

- Demand for products from SCAQMD refineries would be substantially reduced on a local level. Export taxes would also make regional and international exports uneconomic.
- The initial impact will be to create refinery overcapacity as product demand declines, and thus reduce refinery margins in the South Coast Basin.
- As a result of overcapacity and declining margins, some refineries likely would be forced to close. This is the SCAQMD's expressed purpose in setting the very demanding regulations. Ultimately, if the Plan is fully implemented all refineries in the SCAQMD may close or relocate. Given the underlying thrust of the plan, refineries may hesitate to make the necessary investments to meet short term controls and some could close in the near term.
- Residual fuel oil would be eliminated as an electric utility fuel, forcing an increased reliance on natural gas, or increased demands on the electric grid system.
- Impacts would be felt outside the immediate SCAQMD due to existing substantial intra-regional movements of petroleum products.
- Product imports, into the rest of the West Coast, either from foreign sources or the U.S. Gulf Coast, would increase to compensate for the loss or declining volume of products from the SCAQMD refineries. Based on 1987 data, West Coast product imports would have to increase by roughly 200 Mb/d. This raises strategic questions about increased reliance of one region on product imports.
- These shifts in product supply sources would raise product and crude transportation costs substantially. In the long-run, production costs from West Coast refiners would be significantly higher. If demand for crude oil as feedstock declines among the SCAQMD refineries, or is eliminated, substantially more West Coast crude oil would begin appearing in the Gulf Coast.

CONCLUSIONS

The federal regulations currently proposed or in effect to limit refinery emissions are not particularly costly. The hazardous air pollutant regulations associated with proposed federal legislation could potentially be very costly, but no specific regulations have been proposed so far.

The regulations proposed to improve ambient air quality in California, if allowed to stand, will have a tremendous adverse impact on refiners in California. While the South Coast basin clearly has a problem attaining ambient air quality standards, the elimination of the refining industry and the substitution of other energy sources for petroleum appears to have huge costs which may far exceed the benefits.

V. ECONOMIC AND STRUCTURAL IMPACTS

This chapter provides an assessment of the economic impacts of the promulgated, proposed, and potential federal and state regulations on the U.S. refining industry. The effects of the California environmental plans are addressed.

INVESTMENT TO MEET FEDERAL REGULATIONS

Estimates from EPA contractor studies and from the National Petroleum Refinery Association indicate that Phase I and II federal RVP reductions combined with diesel sulfur reduction will place an additional investment burden of \$5.7 billion on the U.S. refinery industry in the period 1990 through 1993. Table V-1 shows these costs and the costs of potential diesel aromatics limitations. The total investment could be even higher if overseas refineries do not invest to meet U.S. product quality specifications and U.S. refiners are forced to meet the product demand currently met by product imports.

U.S. refining investment averaged \$2.6 billion per year over the 1972 to 1988 period with a 1981 peak of \$5.1 billion. RVP plus sulfur related investments will move investment levels toward their historical peak but should be manageable in the time frame provided RVP Phase II and diesel sulfur standards are finalized by the end of this year. However, given the current status of these regulations and necessary lead times for investment, implementation of Phase II standards may have to be set for summer season 1993 rather than 1992.

EPA is not currently contemplating the imposition of limits on aromatics content in diesel fuel. Implementing diesel aromatics reduction in addition to the other regulations could increase the investment burden by a further \$3.3 billion. The standard would also take the industry down a different investment path relative to implementing diesel sulfur reductions alone, (namely deep hydro-treating rather than hydro-desulfurization). At the refinery level, implementing low aromatics diesel standards would interact negatively with the move to lower gasoline RVP.

In addition, since widespread familiarity with the process technology for aromatics reduction does not exist today among refiners and engineering companies, the industry would need more time to make the necessary investments, possibly six years. The date for adoption of a 0.05% sulfur plus 20% aromatics standard would therefore have to be nearer 1996.

As no specific regulations have been defined the proposed air toxics legislation, no cost estimates for this legislation are available. These costs potentially could be quite significant.

PROFITABILITY AND PRICE EFFECTS OF FEDERAL REGULATIONS

Phase I and II RVP reduction combined with diesel sulfur reduction will increase annual refiner costs by \$1.9 billion per year. This is equivalent to 0.74 cents per gallon across total U.S. refined product production. The same costs allocated specifically to the products that are the subject of the regulations equate to 1.5 cents per gallon on gasoline and 3.1 cents per gallon on diesel (including No. 2).

TABLE V-1

Costs of Four Federal Initiatives to Regulate Petroleum Refineries

	<u>1989</u>	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>
RVP PHASE I							
Annual Cost (MM \$) ¹	\$247	\$247	\$247	\$247	\$247	\$247	\$247
Annual Cost (cents/ gallon) ¹	0.54	0.54	0.54	0.54	0.54	0.54	0.54
Capital Investment	\$0						
RVP PHASE II							
Annual Cost (MM \$) ²				\$405	\$405	\$405	\$405
Annual Cost (cents/ gallon) ⁷				0.94	0.94	0.94	0.94
Capital Investment ³				\$2,384			
DIESEL: REDUCED SULFUR							
Annual Cost (MM \$) ⁴				\$1,200	\$1,200	\$1,200	\$1,200
Annual Cost (cents/ gallon) ^{4,6}				3.1	3.1	3.1	3.1
Capital Investment ⁴				\$3,300			
TOTAL: THREE PROGRAMS							
Annual Cost (MM \$)	\$247	\$247	\$247	\$1,852	\$1,852	\$1,852	\$1,852
Annual Cost (cents/ gallon)	0.54	0.54	0.54	4.58	4.58	4.58	4.58
Capital Investment	\$0	\$0	\$0	\$5,684	\$0	\$0	\$0
DIESEL: REDUCED AROMATICS							
Annual Cost (MM \$) ^{4,6}				\$1,200	\$1,200	\$1,200	\$1,200
Annual Cost (cents/ gallon) ^{4,5,6}				3.1	3.1	3.1	3.1
Capital Investment ^{4,5,6}				\$3,300			
TOTAL: FOUR PROGRAMS							
Annual Cost (MM \$)	\$247	\$247	\$247	\$3,052	\$3,052	\$3,052	\$3,052
Annual Cost (cents/ gallon)	0.54	0.54	0.54	7.68	7.68	7.68	7.68
Capital Investment	\$0	\$0	\$0	\$8,984	\$0	\$0	\$0

TABLE V-1 (continued)

Costs of Federal Initiatives to Regulate Petroleum Refineries

SOURCES

1. EPA, Final Regulatory Impact Analysis, January 19, 1989, p. 409.
2. API, comments on EPA Draft Regulatory Impact Analysis, February 5, 1988, p. A-2.
3. API, comments on EPA Draft Regulatory Impact Analysis, February 5, 1988, p. A-3.
4. NRPA, Survey, 1986.
5. These are incremental costs assuming reduced sulfur costs of distillate are also implemented.
6. Cents per gallon estimates are based on the assumption that costs are recovered over the entire Diesel and No. 2 Distillate pool.
7. Based on refinery gasoline production derived from B&M, "Assessment of Impacts on the Refining and Natural Gas Liquids Industries of Summer Gasoline Vapor Pressure Control," January 15, 1987.

Prices of all petroleum products together with basic petrochemicals, crude oil, natural gas, and NGLs will be affected in some measure as the industry shifts towards a new market equilibrium. The price differential between low and high sulfur crudes will widen, because of the increased premium for low sulfur diesel fuel. Global as well as U.S. prices will be affected.

As shown in Figure V-1, refiner margins have historically varied considerably and consequently are difficult to predict. Current margins are near record levels due in the main to gasoline market tightness. In the immediate short term, refiners should easily be able to pass on the costs of Phase I RVP reduction to consumers. Depending on how close the industry comes this summer to its physical gasoline productivity limits, very high gasoline prices are possible. NYMEX futures prices indicate continuing high refinery margins through the summer driving season and a decline by the end of the year.

Future refiner profitability will hinge on their continued ability to pass on the costs of environmental regulations to the consumer. RVP reduction will tend to maintain a tight gasoline market, especially since European lead phase-out will continue in parallel with implementation of the U.S. Phase I and II regulations. This points to sustained margins and profitability unless refiners over-invest in gasoline process capacity or consumers reverse current trends toward higher octane. Both of these developments appear unlikely.

Refiners may have more difficulty in fully recovering the costs of diesel fuel sulfur reduction. Unless regulations are imposed to requiring 0.05% sulfur in No. 2 fuel oil, refiners may have difficulty obtaining a premium for low sulfur No.2 fuel oil even if they have to produce it because of the limited capability that exists to segregate diesel fuel and No. 2 fuel oil in the U.S. distribution system. At the same time some importers may be able to sell No. 2 fuel oil comparatively cheaply at the "old" higher sulfur level.

As a measure of the downside risk, refiner cash operating margins would decline by 23 percent from present record levels if refiners were unable to pass on to end-users any of the costs of the federal regulations. Again this appears very unlikely. Overall the combined gasoline RVP and diesel sulfur regulations seem likely to have a positive net impact on refiner profitability.

The effect of possible regulations under proposed air toxics legislation would be quite different. Emission control regulations apply only to U.S. refineries and generally their costs cannot be as easily passed on to consumers. Adverse impacts on refiner profitability are a likely result.

POTENTIAL IMPACT OF FEDERAL REGULATIONS ON INDUSTRY STRUCTURE

Refiners will be required to make large capital expenditures in order to comply with the proposed federal Phase II RVP regulation and the potential diesel fuel sulfur and aromatics content regulations. The major oil companies tend to be integrated and diversified with investments in other energy and non-energy markets. Consequently, the major oil companies have greater financial resources and are in a better position to make the investments required to comply with the federal regulations than small, low complexity, or independent refineries. Moreover, because of the economies of scale, the per barrel investment costs of the federal environmental regulations will be smaller for large refineries. For example, on a per barrel basis, the investment

FIGURE V-1
U.S. Refinery Cash Operating Margins

Sources: April, 1984-January, 1989 - Oil and Gas Journal Data Base.

 February, 1989-April, 1989 - Estimated from Spot Crude Oil and Petroleum Product
 Prices as reported By Platt's Oilgram Price Report.

 May, 1989-December, 1989 - Estimated from New York Mercantile Exchange
 (NYMEX) Crude Oil and Petroleum Product Futures Prices.

required to make low RVP gasoline may be three times as large for a simple refinery than for a complex refinery.^{11/}

Rather than incur the capital costs required to make compliance gasoline and diesel fuel, small/simple refineries have the following operational options they can pursue:

- Shift production away from gasoline and diesel fuel to alternative finished products such as JP4 and No. 2 fuel oil.
- Purchase high quality blending stocks from other refineries
- Sell the below-compliance-grade gasoline and/or distillate portion of the refined product as an unfinished oil feedstock to other more complex refineries.

The ability of simple refineries to switch from gasoline and diesel fuel to other products may be limited. Purchasing high quality blending stocks is only an option for gasoline. Supplies of high octane gasoline blending stocks may be available. But there will be little very low sulfur blending stock available to make compliance diesel fuel. In addition, purchasing high quality blending stock will only be an option for those simple refineries located near large refining centers such as the Gulf Coast. The cost of transporting blending feedstock to isolated remote simple refineries may be prohibitive.

Similarly, only those simple refineries located near large refining centers may be able to recover the variable costs of production by selling below-compliance grade gasoline and/or distillate as a feedstock to refineries or petrochemical plants. The netback price^{12/} for such sales from isolated refineries may be well below cost, depending on the relative tightness of the market tightness and transportation costs. The net effect of these regulations could be:

- Appreciable industry restructuring with possible closure of small regional refineries
- Increased trading of intermediate products
- Shifts in finished product supply patterns
- Product prices in some rural areas well above national average prices

ECONOMIC IMPACTS OF THE CALIFORNIA ENVIRONMENTAL REGULATIONS

As discussed in Section III of this report, there is a broad range of California regulatory initiatives that in total will go far beyond the federal environmental regulations in terms of their

^{11/} Based on work performed by ENSYS for EIA.

^{12/} Netback prices refer to destination selling price less transportation costs from the source to the destination point.

impact on California refineries. In particular, as described in detail in Chapter IV, the South Coast Air Quality Management District has proposed a three-tiered plan that would affect petroleum refineries in Southern California in the following ways:

- Impose strict emission controls on stationary sources including petroleum refineries
- Impose limits on the sulfur content of residual and distillate fuel oil
- Force reductions in local demand for petroleum products through:
 - emission taxes that raise the cost of petroleum products to parity with alternative fuels such as methanol
 - stationary source emission standards that will largely eliminate fuel oil as a boiler fuel
- Impose a tax on all petroleum products exported from southern California to other parts of the state, to other states, or to foreign countries.

As shown in Table V-2, SCAQMD estimates indicate that the cost of the stationary source environmental regulations that affect petroleum refineries in Southern California will range from 251 to 515 million dollars per year. The per gallon cost of these stationary source regulations would range from 1.6 to 3.2 cents per gallon.^{13/} ICF and ENSYS estimate that the cost of these regulations could be double this amount.

The estimates for the stationary source regulations alone indicate that the California environmental plans could have a substantial cost impact on in-state refineries. Although not quantified by the California regulatory bodies, the refinery costs for meeting the fuel specifications for residual fuel, distillate fuel, and diesel fuel limitations will also be significant.

In order to keep operating, California refineries will be forced to incur these additional costs at the same time demand for their products will be declining as a result of the forced reductions imposed by the SCAQMD. Revenues from the export of petroleum products to northern California, other states, or foreign countries will also be cut due to the export taxes proposed by SCAQMD. Added to these regulatory burdens will be the likely increase in crude oil acquisition costs as a result of the decline in Alaska North Slope crude oil production.^{14/}

^{13/} Based on total refinery capacity in Southern California of 1.3 mmbd and a capacity utilization of 79 percent. Refinery capacity and utilization data for Southern California were taken from the U.S. DOE, "Petroleum Supply Annual 1987." The 79 percent capacity utilization was the utilization rate for all West Coast refineries in 1987.

^{14/} EIA estimates that Alaska North Slope production will have declined to 1.29 mmbd by 1995. EIA, "Annual Energy Outlook 1989, p. 51.

TABLE V-2

Costs of SCAQMD Proposed Stationary Source Emission Limits for
Southern California Refineries

PROPOSED EMISSION CONTROL	COST (Millions/Year)
Replacement or Covering of Petroleum Sumps, Pits, and Process Heaters and Wastewater Separators	\$2.4
Control of SO _x Emissions from Fluid Catalytic Cracking Units	\$115 - \$288
Control of Emissions from Gas Fired Petroleum Refinery	\$10.1
Improvement of Existing Emission Control Equipment on Fluid Catalytic Cracking Units	\$11.8
Control of Emission Leaks from Valves, Pumps & Compressors	\$62.4
Control of Emissions from Petroleum Refinery Heaters & Boilers	\$50 - \$140
TOTAL COSTS	<u>\$251 - \$515</u>

Source: South Coast Air Quality Management District, "Draft Air Quality Management Plan:
1988 Revision," June 1988.

In addition to these SCAQMD initiatives, the California Air Resources Board (CARB) has developed proposed regulations that if enacted would go beyond the potential 20 percent federal specifications for the aromatics content of diesel fuel, lowering it to 10 percent for large refineries.

The ultimate impact of these regulatory initiatives on California refineries will be very significant if they are fully implemented. Some refineries would close down rather than incur the added compliance costs in the face of an uncertain regulatory environment and potential declines in petroleum product demand. A significant loss of California refinery capacity could also have profound impacts on petroleum markets in other U.S. regions. West Coast product imports in the regions outside the South Coast clearly would increase.

CONCLUSION

If all the proposed and possible federal and state air quality regulations are implemented, the costs incurred by the U.S. refining industry will be very substantial, particularly in the 1992-93 time period. If all the proposed and possible federal regulations are implemented, the total investment required would be over \$9 billion. This figure should be compared to the industry's normal total level of capital investment of \$2.6 billion annually. Some industry restructuring could result.

In addition, at least part of the California refining industry would shut down in response to the SCAQMD plan. As South Coast refineries have 1.3 million barrels per day of capacity, their loss would significantly affect U.S. petroleum supply patterns. The twenty percent of their output shipped to other parts of the West Coast would have to be replaced with product imports.

APPENDIX A

SUMMARY OF FEDERAL AND STATE REGULATIONS

This appendix is a summary of regulations regarding the composition of motor vehicle fuels and other refinery products. Major areas addressed include:

- Federal volatility regulations (RVP limits) for gasoline and alcohol blended fuels
- Individual state regulations for gasoline and alcohol blends including potential differences between state and federal requirements
- State programs mandating oxygenated fuels
- Regulation of diesel sulfur and aromatics

Summary of Gasoline Volatility Regulations

Federal Volatility Regulations (40 CFR Part 80)

Background

Current federal regulation seek to control volatile organic compound (VOC) emissions by reducing the volatility of gasoline as measured by average Reid Vapor Pressure (RVP). On March 22 of this year, the EPA released a final rule on Phase I of a two-phase reduction in summertime commercial gasoline volatility. Depending on the area of the country and the month, gasoline RVP must be 10.5 psi, or 9.5 psi, or 9.0 psi beginning in the summer of 1989.

RVP limits impact refineries by limiting the amount of butane that can be added to gasoline and requiring the use of more expensive additives to maintain octane levels. More stringent Phase II limits may require capital investment by refineries as well as additional storage capacity for butane. Methyl tertiary butyl ether (MTBE), is one possible substitute to replace butane as well as alcohol blends such as ethanol and methanol.

Highlights

- Gasoline volatility must be reduced nationwide (except for Hawaii and Alaska) according to a system developed by the American Society for Testing and Materials (ASTM). Table 1 indicates the month-by-month RVP limits.
- Standards apply only in the summer from May 16 - September 15.
- In-field sampling and testing will be the RVP enforcement mechanism. Compliance will be monitored at all points in the distribution network.

- The regulation provides for an interim 1 psi allowance in RVP for ethanol blends of approximately 10% by volume or "gasohol" but not for methanol blends.
- Phase II of the regulations (about 1992) would further decrease the required RVP by 2.5 psi. Additional allowances for blended fuels (other than gasohol) will be considered.

STATE VOLATILITY REGULATIONS

A majority of states have regulations that limit RVP. Table 1 also compares existing state limits to the federal limits. Some summary points follow:

Summary

- Of the 49 states with federal standards (48 contiguous states plus D.C.), 36 have separate state regulations for RVP.
- All states that have programs apply the limits statewide; some states, such as Illinois, Maryland, Nevada apply different limits in different parts of the state.

Federal Preemption Of State Limits

- States generally have RVP limits for all months in the year (generally based on the ASTM system). Federal limits would preempt state limits only during summer months.
- Of the 49 states with federal standards, 15 have more stringent RVP requirements than the Phase I federal limits. States with more stringent limits include California, Colorado, Idaho, Montana, North Dakota, South Dakota, and Wyoming as well as the Northeast States (e.g., Connecticut, Maine, Massachusetts, New Jersey, New Hampshire, New York, Rhode Island, Vermont).^{15/}
- Northeast States For Coordinated Air Use Management (NESCAUM) expects that the Northeast States will be permitted to maintain standards stricter than EPA. The states must obtain approval for their amended state implementation plans (SIP) in order to preempt the federal standard. Approval is expected for these states by June 1 1989.
- California's RVP limit applies to all air quality basins in the state, although the applicable summer season varies. For example, San

^{15/} New Jersey is expected to adopt the RVP limit of other Northeast States but has not completed the approval process.

Francisco and San Diego limits apply from May to October, while the South Coast Air Basin limits apply from April through October. California currently has approval under its SIP to apply more stringent limits.

- The remaining states exceed the Phase I federal limits. Most states must reduce KVP by about .5-1.0 psi to meet the federal standard.

Alcohol Blends

- According to a report prepared for EPA, thirteen states provide some form of allowance or exemption for alcohol blended fuels, particularly gasohol. These would include Indiana (.5 psi for gasohol) and Missouri (1.0) psi for gasohol). North Dakota requires only the gasoline portion of the fuel to meet RVP limits.

Monitoring

- The number of inspections resulting from testing of fuel varies from state to state, ranging from Delaware which had a total of five tests over a two-year period to Florida which ran 12,000 tests for RVP.
- Some states, such as Florida and Wisconsin, focus on terminals or pipelines for inspections while other states, such as Maryland, North Carolina, Utah, and Virginia, focus on service stations.

Oxygenated/Alcohol Blended Fuels

Individual states, primarily to address non-attainment problems for carbon monoxide, standards in the winter have devised programs mandating the minimum oxygen content of fuels. State programs include:

Colorado

- The Air Quality Control Commissions of Colorado has a mandatory blended fuel program for the "Front Range" region of the state. The program originally required an oxygen content of 1.5% but increased the requirement to 2% as of 1989. The limit applies annually from November 1 - March 1. Possible changes to the regulation are currently under review including reducing the number of months (to January 31 vs March 1) and increasing the oxygen content to 2.5%. To date, oxygen requirements are met primarily by blending MTBE with gasoline. The program began in 1988.

Arizona

- A requirement of 2.63% oxygen by weight applies from September 30 - March 30 for the Maricopa County of Arizona. Maricopa County includes the urban areas surrounding Phoenix and Tucson. Higher oxygen content levels can be required from January - March if ethanol blends are capturing less than 10% of the market. Possible future changes to the regulation include lowering the required alcohol content of the fuel to allow suppliers to meet oxygen content with lower alcohol blends. The program is effective as of 1989.

Nevada

- Nevada requires all fuel sold November 1 - February 15 in Clark and Washoe Counties to have a minimum oxygen content of 2.5% and 2.0% respectively. These counties include the cities of Las Vegas, Boulder City and Reno. The program is effective as of 1989.

New Mexico

- Albuquerque, New Mexico will mandate use of fuels having average oxygen content of at least 1.8 wt % from October 1 - March 31. The program begins fall 1989.

REGULATION FOR DIESEL FUEL

Preliminary Federal Efforts

- EPA has focused relatively little attention on the regulation of sulfur and aromatics in diesel. Sources at EPA expect preliminary regulations as of the Summer of 1989. The proposed limit for sulfur content is expected to be .05 percent. A decision on aromatics has not yet been reached.

California

- California is the only state identified that currently regulates sulfur and aromatics. Use of aromatic hydrocarbons leads to increased emissions of particulate matter and oxides of nitrogen from diesel engines. Emissions of sulfur dioxide are a function of the sulfur content of fuel. The sulfur content of diesel fuel is higher than that of gasoline.
- California currently regulates the sulfur content of motor vehicle diesel fuel in the South Coast Air Basin and Ventura County to 500 ppm (0.05% diesel fuel).

- As of October 1988, California proposes to further regulate both sulfur content and aromatics hydrocarbon content. The State proposes a statewide limit of 500 parts per million for all vehicle diesel fuel. The proposed aromatics hydrocarbon content limits are 10 volume percent for large refiners and 20 volume percent for small refiners.

MISCELLANEOUS

New York

- New York limits the RVP of commercial gasoline as discussed above.
- Oil products burned by stationary sources have limits for sulfur content.

California

- Specifications adopted by the California Air Resources Board (CARB) for gasoline include volatility limits, bromine number limits (degree of unsaturation), lead content, manganese content, and sulfur content.
- For lead in gasoline, the permitted standard is .8 grams per gallon for gasoline other than high octane gasoline and 1.4 grams per gallon for leaded high octane gasoline as of September 1984. Unlike sulfur restrictions for diesel and unleaded gasoline, the standard for lead content is not a flat limit. Offsetting of high lead product with lower lead content products is permitted.
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