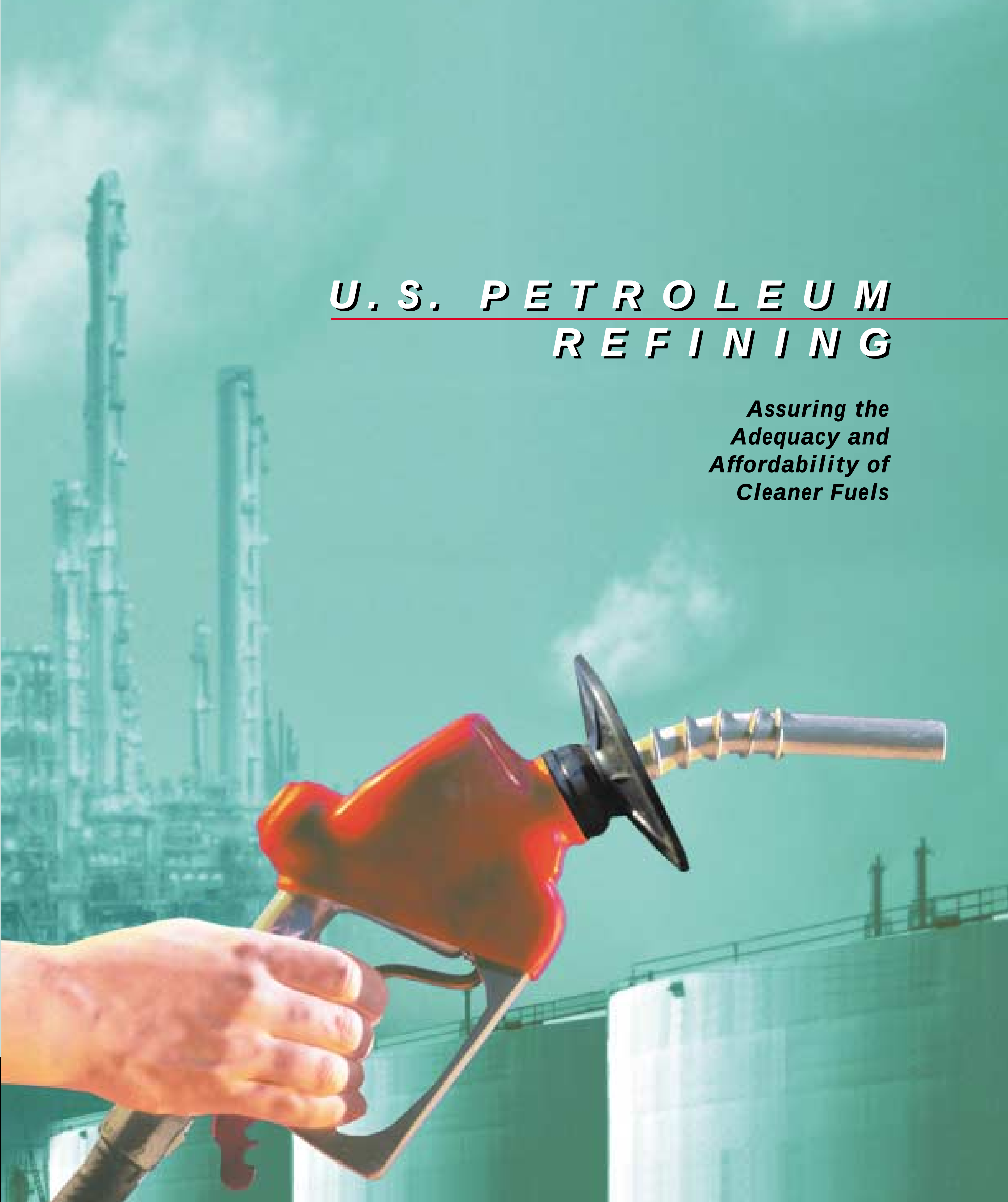
U.S. PETROLEUM REFINING

Assuring the Adequacy and Affordability of Cleaner Fuels



National Petroleum Council • June 2000

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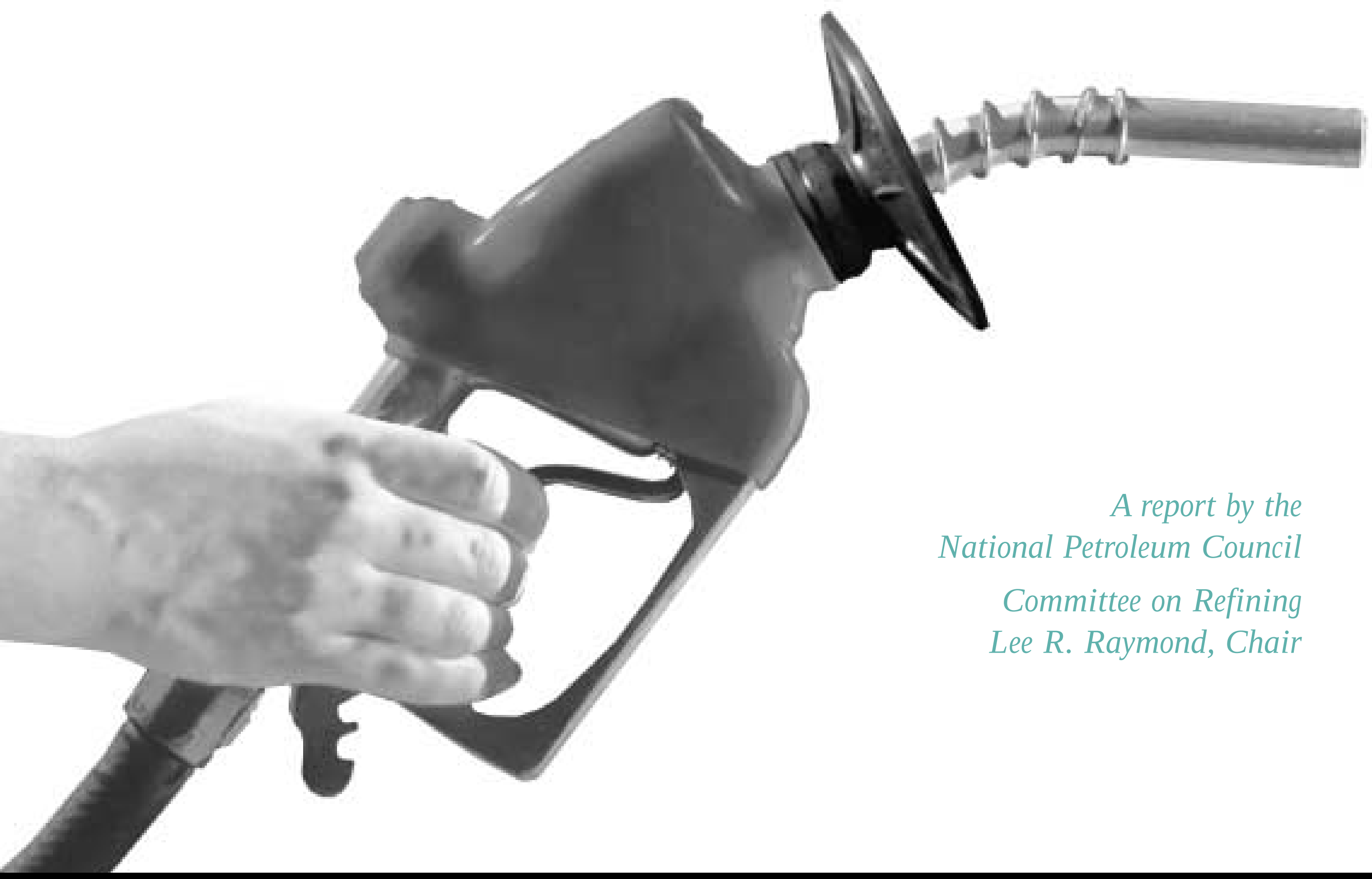

A report by the National Petroleum Council

Committee on Refining
Lee R. Raymond, Chair

National Petroleum Council • June 2000

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Table of Contents

Executive Summary

The Secretary of Energy requested that the National Petroleum Council (NPC) undertake a study of U.S. product deliverability and refinery viability, focused in the notional 2005 time frame. Of particular interest to the Secretary was the Council's assessment of government policies and actions that would affect both the petroleum product supply and the continuing viability of U.S. refineries. The complete text of Secretary Peña's request letter and Secretary Richardson's follow-up letter, as well as a description of the NPC, can be found in Appendix A.

The NPC established a Committee on Refining, chaired by Lee R. Raymond, Chairman, President and Chief Executive Officer, Exxon Mobil Corporation. Mark J. Mazur, Special Assistant to the Administrator of the Energy Information Administration, U.S. Department of Energy, served as Government Cochair. The Committee established a Coordinating Subcommittee and four Task Groups: Technology, Producibility, Logistics, and Imports and Other Factors. Task Group members represented a broad cross section of stakeholders, including refiners, pipeline companies, engineering contractors, the Department of Energy (DOE), and the Environmental Protection Agency (EPA). The NPC commends the EPA for their constructive participation in this study. Rosters of the Committee, Subcommittee, and Task Groups are presented in Appendix B.

To respond to the Secretary's request, the NPC examined the potential impact of four possible changes to product specifications that might be mandated by government agencies:

- Reducing the sulfur content of gasoline to 30 parts per million (ppm) average
- Reducing the sulfur content of on-highway diesel fuel to 30 ppm average
- Eliminating MTBE from gasoline
- Reducing the driveability index (DI) of gasoline to 1,200°F.

These specific cases were chosen for examination of implementation impacts because they were representative of changes being discussed at the time the study commenced. The NPC did not examine the vehicle emissions effects or cost effectiveness of these changes.

The gasoline sulfur reduction case was examined first, and the diesel sulfur, MTBE, and DI impacts were then each examined in conjunction with a reduction in gasoline sulfur. The study included examination of such factors as process technology availability and readiness, refinery producibility, product delivery considerations, and facility implementation requirements and capabilities. The impacts on California refineries were not considered in this study.

Product quality regulatory development was underway as this study began, hence

[1] Mr. Mazur served as Director, Office of Policy, U.S. Department of Energy, during the study.

timeliness of results was essential. The study timeline was established to provide a report to the Secretary by June of 2000. There was considerable existing public domain material for the Task Groups to evaluate and analyze, including the NPC's 1993 refining study, *U.S. Petroleum Refining–Meeting Requirements for Cleaner Fuels and Refineries*, and several relevant studies and modeling done for and by the oil and auto industries and the federal and California governments. In addition to using existing studies, the NPC commissioned new modeling work to further examine the effects of eliminating MTBE and reducing DI.

On December 21, 1999, the EPA issued the "Tier 2 Rule," which requires a reduction in the sulfur content of most domestic gasoline to 30 ppm average in the 2004 to 2006 time frame. Special provisions for the Rocky Mountain area and for hardship cases allow a delay past 2006 for reaching 30 ppm sulfur in some gasoline. While the Tier 2 Rule contains some provisions that were not quantitatively examined in this study, such as credit systems and phase-in of caps and averages, the study basis provides a sound foundation for the findings and recommendations pertaining to the Tier 2 Rule.

On March 20, 2000, the EPA proposed Congressional and regulatory action to significantly reduce or eliminate the use of MTBE in gasoline, including replacement of the 1990 Clean Air Act oxygen content requirement for reformulated gasoline (RFG) with a renewable fuel content standard and maintenance of current air quality improvements. The MTBE elimination cases examined in this study provide insight into the potential range of costs and implications that could result from the EPA's proposal, depending upon the specifics of any final requirements.

On May 17, 2000, the EPA issued a Notice of Proposed Rulemaking (NPRM) for on-highway diesel fuel sulfur reduction requirements. The EPA proposed a 15 ppm sulfur maximum for all on-highway diesel beginning April 1, 2006, at the refinery gate or point of import. The EPA expects that a 15 ppm maximum will result in an average sulfur level of 7 to 10 ppm in diesel. The analysis performed for this study provides a basis for qualitative assessment of the issues that will be imposed by such a requirement.

Overview

The NPC concludes that the refining and distribution industry will be significantly challenged to meet the increasing domestic light petroleum product demand with the substantial changes in fuel quality specifications recently promulgated and currently being considered. The timing and size of the necessary refinery and distribution investments to reduce sulfur in gasoline and diesel, eliminate MTBE, and make other product specification changes such as reducing toxic emissions from vehicles are unprecedented in the petroleum industry. Large investments will be required at essentially all domestic refineries and many product terminals. It is imperative that the fuel specification changes and resulting required investment be appropriately sequenced with minimum overlap to mitigate the potential for major disruptions in supply and resulting significant price variations. Furthermore, regulatory agencies must streamline the environmental permitting process or significant implementation delays will result. With timely permits, proper sequencing of fuel quality changes with minimum overlap, and sufficient lead time to respond to each major specification change, the NPC believes that the domestic refining industry can be expected to satisfy product demand under the more stringent product specification requirements studied.

Each individual company will make its own business decisions to respond to more restrictive product specifications. Consequently, there may be supply imbalances in some regions during the early stages of implementing each major specification change. Such supply imbalances are likely to be short-lived but could result in localized price volatility as the industry adjusts to the new requirements. As additional, more stringent specifications are required, the longer term risk of occasional supply disturbances will also be increased because the additional refinery complexity necessary to meet more stringent product specifications will reduce refinery flexibility.

The product quality changes examined in this study will require increased investment and operating costs in refineries and the distribution system. The industry must ultimately recover its costs in the marketplace to remain financially viable and able to provide consumers with reliable product supplies. In the past, overall petroleum industry efficiency improvements have more than offset regulatory-driven cost increases. If the product specification changes studied are implemented over a short period of time, it is unlikely that near-term efficiency improvements will be sufficient to offset all of the cost increases resulting from the specification changes.

The number of domestic refineries has steadily decreased since World War II, with the exception of the period of price controls in the 1970s. The NPC expects that refinery shutdowns will likely continue to occur in the future, and investment requirements for regulated product quality changes could accelerate the near-term pace. Historically, capacity increases at remaining domestic refineries have more than offset lost capacity due to shutdowns, supplying increased domestic demand while net imports remain low.

Domestic investment to meet the Tier 2 Rule requirement for reducing gasoline sulfur to 30 ppm is estimated to be at least $8 billion in 1998 dollars, about twice the EPA's estimate. The availability of engineering, equipment manufacture, and construction resources is expected to be sufficient to meet the Tier 2 Rule requirements in the 2004 to 2006 time frame, provided that environmental permits can be acquired expeditiously. Engineering and construction resources will be stretched during the peak of this workload. Resources would be inadequate if other substantial construction demands occur concurrently, such as for another significant product specification change, an increase in stationary source emission control requirements, a cyclical peak in petrochemical industry construction activity, or a requirement for significant increase in fuel ethanol production.

The investment necessary to reduce on-highway diesel sulfur to 30 ppm average is estimated to be about $4 billion. Industry resources should be sufficient to allow implementing 30 ppm diesel in 2007 for model year 2008 vehicles without substantial risk of supply disturbances other than those normally associated with implementation of a new product specification program. If diesel sulfur reduction is required in 2006, implementation would overlap significantly with the Tier 2 Rule gasoline sulfur reduction. With this overlap, engineering and construction resources will likely be inadequate during peak periods, resulting in implementation delays, higher costs, and failure to meet the regulatory timelines.

Significantly more study is needed to evaluate technology options, refinery operations, and distribution system capabilities before quantitative conclusions can be reached about the cost and reliability of supplying gasoline and diesel with sulfur levels below 30 ppm. The cost to produce lower sulfur gasoline is expected to increase significantly as sulfur is reduced below 30 ppm.

A large step increase in diesel production cost is expected between the study basis of 30 ppm average sulfur and the EPA proposal of 15 ppm maximum, 7 to 10 ppm average. EPA has assumed that the proposed sulfur level can be reached with modification of existing diesel hydrotreating equipment at relatively low cost. The NPC concludes that significant investment in grassroots higher pressure hydrotreating will be required to supply the domestic on-highway diesel demand; modifications to existing hydrotreaters could achieve this low sulfur level but only on a substantially smaller volume of diesel than currently supplied.

The higher investment and operating cost for grassroots higher pressure hydrotreating and the significant schedule overlap with the Tier 2 Rule requirements will result in higher costs than EPA has proposed, shortages of implementation resources, and a significant risk of inadequate diesel supplies until the market reaches equilibrium. Furthermore, there is serious doubt about the ability of the existing distribution system to maintain the integrity of diesel with the sulfur level proposed by EPA.

The cost to implement EPA's recent proposal to significantly reduce or eliminate MTBE use will be highly dependent upon the specific requirements for any renewable fuel content standard and maintenance of air quality benefits. If a renewable content standard does not require an increase in volume or shift in geographic use of ethanol from today, the required refinery investment would be about $1.8 billion to replace lost octane and volume while preserving the current RFG air toxics reduction. If a renewable standard essentially requires meeting the current oxygen content requirement for RFG, total investment would be about $5 billion, including $3 billion to double ethanol production. If a renewable standard requires increasing ethanol to replace current MTBE use barrel-for-barrel, ethanol production would have to quadruple, necessitating about $10 billion of investment. Requiring MTBE elimination concurrent with gasoline sulfur reduction would severely strain permitting and construction resources to the extent that achieving compliance schedules and maintaining domestic producibility would be jeopardized. The strain and potential for adverse consequences would be substantially higher in a scenario where increased ethanol use is mandated.

Automakers have proposed a reduction in gasoline Driveability Index (DI), a measure of gasoline volatility. Implementing a 50°F reduction in the refinery gate DI cap to 1,200°F could be very costly–refinery linear program (LP) modeling suggests an investment of as much as $11 billion. Improvements in testing and operational variability might reduce this investment cost. Refiners would likely seek variability improvements before making substantial refinery processing investments. However, the timing and magnitude of any potential variability improvement is uncertain, and if variability improvement is not achieved, a significant loss in domestic gasoline producibility could result from imposition of a more restrictive DI cap. Additional study of both cost and benefit is necessary before a change in DI specification is considered. Enforcement of a 1,200°F DI cap has been proposed at the retail station level. The cost for a DI cap at the retail station level would be much higher than for the same cap at the refinery gate, unless the downstream enforcement provisions fully recognize testing variability and nonlinear blending effects.

The existing petroleum product distribution system can be modified to deliver 30 ppm average sulfur gasoline and diesel. Operating costs will increase as product specifications become more stringent. The ability to combine, sequence, and ship batches of similar products together is a key contributor to the efficiency and reliability of the current distribution system. Unique, localized product specifications restrict this ability and will raise the cost and reduce the reliability of supplies to both the affected and surrounding areas.

The industry has significant concern about the ability of regulatory agencies to review and approve in time the significant number of environmental permits necessary to deliver the product quality changes examined in this study. Reducing gasoline and diesel sulfur will require new equipment at nearly every refinery and many product distribution terminals in the United States. The large number of permits needed in a short time frame may overwhelm the permitting resources available within the responsible government agencies. Furthermore, environmental justice is an area of increasing activity and concern. Courts may intervene in the permitting process on behalf of environmental justice claims, effectively removing control of the process from the regulatory agencies.

The industry's ability to acquire permits to expand capacity to meet growing demand is an additional concern. Domestic refinery expansion will be necessary to meet demand growth as well as to offset the production loss resulting from more stringent product quality requirements and possible refinery shutdowns. The EPA Enforcement Division has recently been challenging past interpretation of requirements for New Source Review (NSR). Reinterpretation of NSR rules will significantly hinder the industry's ability to continue its historical capacity expansion rate. Retroactive enforcement of a more stringent NSR interpretation that requires review and reissuance of past permits will add significantly to the total permitting requirement and slow the installation of new processing equipment necessary to meet required product quality changes.

Recommendations

The NPC provides the following recommendations to help ensure a reliable supply of light petroleum products to the U.S. consumer.

Regulatory Basis

Regulations should be based on sound science and thorough analysis of cost effectiveness. The EPA should consider all risks and costs necessary to provide the anticipated benefits. When performing regulatory analysis based on technologies that have not been commercially proven, the level of uncertainty surrounding costs and performance should receive careful evaluation and realistic assessment.

Regulatory Timing

Fuel quality changes and the necessary investment must be appropriately sequenced with minimum overlap. The Tier 2 Rule gasoline sulfur reduction and other product specification changes should not be mandated for implementation in the same time frame, otherwise permitting, engineering, and construction resource constraints will likely result in higher costs, inability to meet the mandated schedules, and product supply disturbances. The EPA's proposal to lower diesel sulfur should be changed to require introduction no earlier than mid-2007 rather than early 2006.

While not overlapping the implementation requirements, the EPA should finalize any timing and specifications for on- and off-highway diesel sulfur reduction and MTBE use in a timely manner. Potential efficiencies exist for providing support facilities common to these programs and gasoline sulfur reduction.

Regulations must provide adequate lead time for scoping, technical option evaluation, design, engineering, financing, permit acquisition, equipment procurement, field construction, and start-up. Four years is the minimum time necessary after finalization of requirements for implementation of significant industry investment. The required lead time can be longer as the magnitude of the investment increases.

Regulatory Certainty

Regulations should include certainty in scope, timing, and requirements, to allow the refining and distribution industry to make effective investment decisions. Regulations that introduce uncertainty into the outlook for required product qualities or product demands will increase the hesitancy of individual companies to invest. For example, the Tier 2 Rule includes an expectation that the EPA will develop a future provision dealing with gasoline sulfur cap flexibility during processing unit downtimes. Until the flexibility that such a provision might provide is known, refiners are unable to plan effectively for necessary facilities.

The EPA should clarify its position on individual state fuel requirements. Currently there is potential for state action that could undermine the Tier 2 Rule credit banking and trading provisions, and this potential creates uncertainty for investment planning.

Policymakers should recognize that policies or regulations favoring or promoting renewable or alternative fuels will tend to discourage investment to supply petroleum fuels.

Very Low Sulfur Gasoline and Diesel Requirements

Requirements for reducing gasoline or on-highway diesel sulfur below 30 ppm average should not be imposed until significantly more study can be completed to provide a basis for sound conclusions about the cost, benefit, producibility, and deliverability of products with very low sulfur levels. There is a significant risk of inadequate diesel supplies if the EPA's proposal for 15 ppm maximum sulfur on-highway diesel beginning April 1, 2006, is implemented.

Driveability Index

The current DI specification should not be changed until additional study can provide a sound basis for thorough analysis of the cost effectiveness and potential impacts on supply of any change. Refinery modeling predicts high cost to reduce average DI. While there may be potential to lower this cost by reducing testing and operational variability, this potential is not sufficiently understood to support sound regulatory analysis.

Environmental Permitting

The permitting process should be streamlined wherever possible, and state and local agencies should provide the necessary resources to process permits expeditiously. The EPA's plan outlined in the Tier 2 Rule preamble to define presumptive Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) will be a positive first step, provided that the presumptive definitions are reasonable and not excessively burdensome.

The EPA should be prepared to promptly address environmental justice claims that arise during the permitting process. The EPA should support state and local agency decisions where environmental justice issues have been addressed during the permitting process.

A portion of the emissions reduction resulting from use of lower sulfur fuels should be allowed as an offset to the stationary source emissions resulting from the new facilities required to produce the lower sulfur fuels. The EPA, state and local agencies, and industry members should work jointly to identify additional action steps to provide timely permitting while continuing progress toward meeting environmental goals.

The requirements for New Source Review should not be retroactively reinterpreted. The EPA Enforcement Division should recognize the validity of netting refinery-generated internal offsets against emissions from new facilities, as discussed in the Tier 2 Rule preamble. Any review of past application of NSR should be conducted in a manner that does not affect the ability to acquire new permits necessary to meet product demand and regulatory requirements.

Distribution System Flexibility

States and localities that are considering localized restrictive fuel requirements, such as lower sulfur and limitations on MTBE use, should recognize that these requirements will increase cost and reduce reliability of product supplies.

Enforcement requirements should be structured to provide necessary compliance assurance while maintaining the flexibility and capability of the distribution system. Primary enforcement should be directed at the refinery gate or point of production or import, and downstream compliance assurance should appropriately consider test tolerances and the nonlinearity of some quality blending to avoid imposing unnecessary additional production costs.

Findings

Product Deliverability

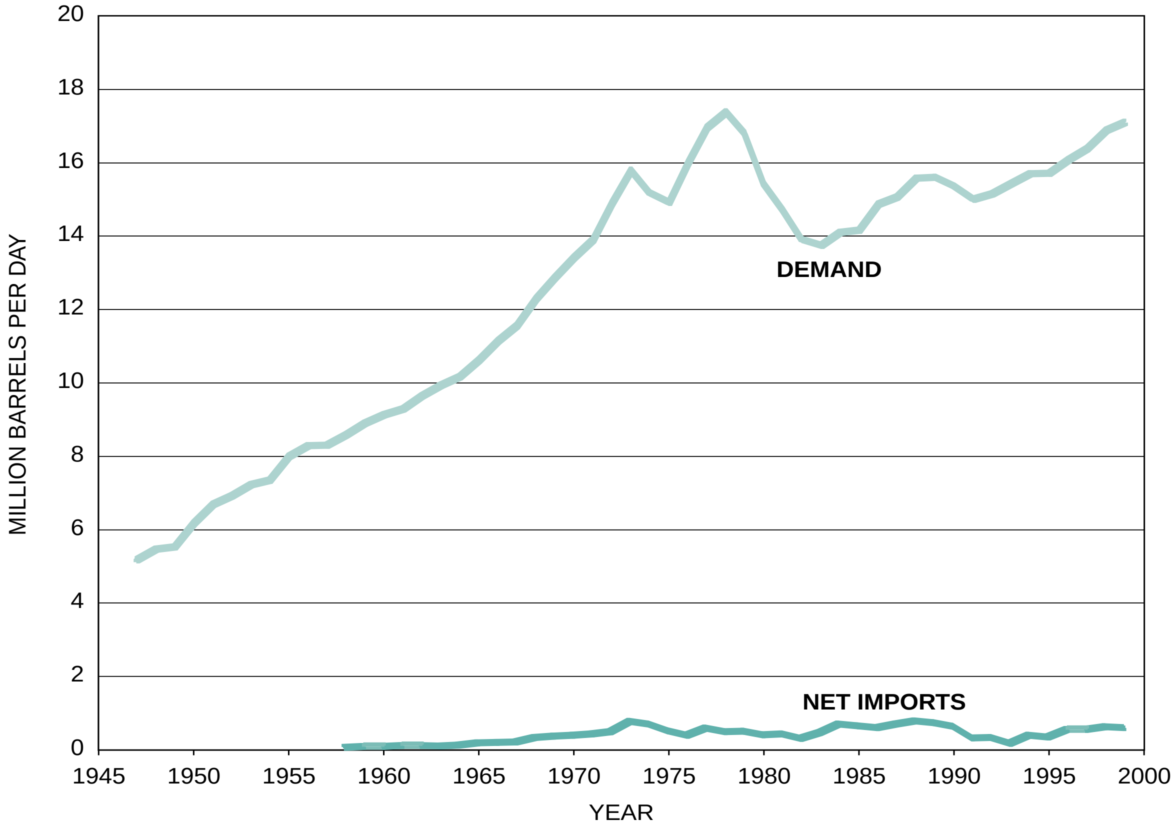
In the period from 1947 to 1999, domestic petroleum product demand grew over threefold, as shown in Figure 1, with domestic production increases meeting the vast majority of this increased demand. Imports of light petroleum products have increased slowly from a net negative in the early 1950s to a peak of about 7% of domestic demand in the late 1980s. Since then, annual net imports have varied from 2% to 6% of domestic product demand year to year. The domestic industry has a long history of investing substantial amounts of capital to provide a reliable and economic supply of petroleum products.

The DOE's Energy Information Administration (EIA) forecasts a continuing increase in domestic light product demand, averaging 1.9% per year between 1999 and 2005.[2] The refining and distribution industry will be significantly challenged to meet this increasing domestic light petroleum product demand with the substantial changes in fuel quality specifications recently promulgated and currently being considered. It is imperative that the fuel specification changes and resulting required investment be appropriately sequenced with minimum overlap to mitigate the potential for major disruptions in supply and resulting significant price variations. Furthermore, regulatory agencies must streamline the environmental permitting process to provide timely permits, or significant implementation delays will result. With timely permits, proper sequencing of fuel quality changes with minimum overlap, and sufficient lead time to respond to each major specification change, the NPC believes that the domestic refining industry can be expected to satisfy product demand under the more stringent product specification requirements studied.

However, the NPC cautions that there will be an increased likelihood of localized supply disturbances as product quality specifications are tightened, particularly during the initial implementation of new specifications. There are three reasons for this. First, each company will make its own investment decisions. Some companies may choose not to invest, while other companies may choose to invest in capacity additions as well as product quality changes. Since these decisions will be made independently, the result may be tight supply conditions in some regions during initial implementation. Consequently, there could be short-term localized supply disturbances and resulting price volatility during this period as industry adjusts to the new requirements.

[2] EIA 1999 Annual Energy Outlook Base Case.

Figure 1. U.S. Finished Petroleum Product Demand and Light Petroleum Product Net Imports



Source: Data from API Basic Petroleum Data Book and EIA.

Second, to achieve the product quality improvements studied, some portion of the industry is likely to employ technology that has not yet been fully demonstrated on a commercial basis. These developing technologies could yield lower costs, providing an incentive for refiners to consider them in spite of higher risk that they might not perform as expected. A higher incidence of initial performance below design should be expected when employing technologies with limited commercial experience.

Third, tighter product specifications place greater demands on additional pieces of refinery process equipment. An increasing amount of refinery equipment will become more critical to maintaining day-to-day producibility, and individual refinery producibility will be reduced more frequently than in the past, especially during upsets and turnarounds. As the frequency of individual refinery production loss increases with new demands on equipment, the industry's capability to provide alternative supplies and continue reliable delivery to customers may be reduced. This effect will be long term, and it may be particularly onerous during the initial implementation period.

Appropriate sequencing and sufficient lead time are necessary for orderly implementation of substantial product quality changes. The NPC examined the availability of resources for engineering, funding, equipment fabrication, and construction. The ability to acquire necessary permits to construct and operate new facilities was identified as a major potential obstacle to timely implementation, as was the availability of certain types of equipment, such as reciprocating compressors. The product quality changes examined in this study would require major equipment additions to virtually every domestic refinery and many product distribution terminals. The NPC has concerns that the large number of permit requests may overwhelm the resources available within government agencies responsible for issuing the permits. Furthermore, environmental justice is an area of increasing activity and concern. Courts may intervene in the permitting process on behalf of environmental justice or other claims, effectively removing control of the process from the regulatory agencies.

In addition to permits for equipment to produce the product specification changes contemplated, permits will also be required for additional capacity to meet the expected product demand increase. Recent EPA enforcement actions are attempting to retroactively change the interpretation of requirements for NSR permits. This reinterpretation could significantly hinder the industry's ability to continue its historical capacity expansion rate and acquire permits to meet new regulatory requirements, and retroactive reinterpretation could result in the loss of recent capacity additions.

Provided that a domestic environment conducive to investment exists, there is unlikely to be a significant shift in the economics of domestic versus foreign supplies in the study time frame. The European Union plans to implement gasoline and diesel sulfur requirements similar to the 30 ppm average sulfur levels examined in this study, in a time frame similar to that contemplated by the United States. Likewise, Canada plans to require 30 ppm sulfur gasoline by 2004. There may be some potential for Caribbean or South American refineries to minimize low sulfur product costs and gain competitive advantage by diverting some higher sulfur material to other dispositions, but this potential is not expected to be significant. Thus, the overall competitiveness of foreign refiners is not likely to change substantially with the reductions in domestic gasoline and diesel sulfur examined in this study, and international trade of these products is expected to remain viable. If the United States implements product specifications more stringent or earlier than Europe, import availability will likely be lower than historical levels.

In its December 1998 study *U.S. Petroleum Product Supply–Inventory Dynamics*, the NPC concluded that domestic light petroleum product inventories had been and were likely to continue a slow downward trend, primarily reflecting efficiency gains in gasoline terminalling operations. This inventory study further concluded that even at these lower inventory levels, the market balancing capability of the system had not appreciably changed, and absent additional regulatory constraints to capacity growth, operational flexibility, or import availability, the frequency or magnitude of significant upward retail price moves was not likely to increase. However, this current study has identified that the product specification changes examined will reduce operational capacity and flexibility, and permitting constraints may restrict the industry's ability to increase capacity. These new regulatory constraints will increase the likelihood of more frequent and possibly more severe supply disturbances and price volatility.

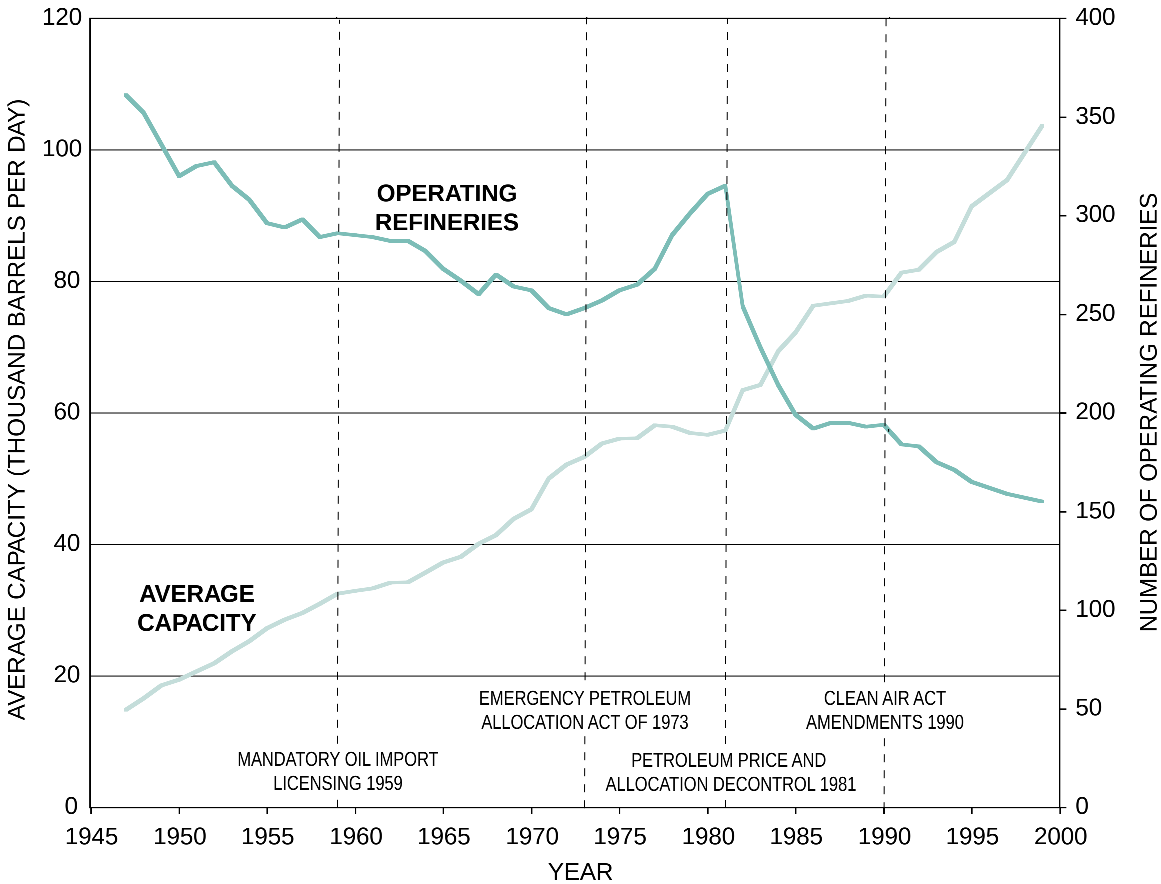
Refinery Viability

As illustrated in Figure 2, the number of domestic refineries has steadily decreased since World War II, with the exception of the period of price controls in the 1970s. Recent shutdown history has included a range of sizes, configurations, and geographies. The average refinery size has increased, but a broad range of refinery sizes continues to exist. The NPC expects that individual refinery shutdowns will likely continue to occur in the future.

The product quality changes examined in this study will require substantial investment at essentially all domestic refineries and many product distribution terminals. This investment would be in addition to the investment required for stationary source emission controls. Stationary source investment is anticipated to continue to be required at levels typical of 1990s spending throughout the time frame of this study, as numerous programs continue or are implemented. Should accelerated requirements for stationary source controls increase demands on capital funds and implementation resources, the industry's ability to fund and implement the product specification changes discussed in this report could be jeopardized.

The investment and operating cost on a per-gallon basis for product specification changes will likely vary among refineries. However, refineries facing higher costs as a result of new product specification changes will not necessarily be at risk of closure, since these refineries may be more competitive in the base than refineries facing lower costs for product specification changes. The NPC is unable to define a set of common characteristics such as size, configuration, location, or raw material

Figure 2. Average Capacity and Number of U.S. Operating Refineries



Source: Data from API Basic Petroleum Data Book and EIA.

slate that would identify a typical refinery candidate for shutdown. Some refinery owners may be either unwilling or unable to finance necessary investments. However, shutdown is not inevitable in such cases, since sale to another entity may be more attractive than incurring shutdown costs.

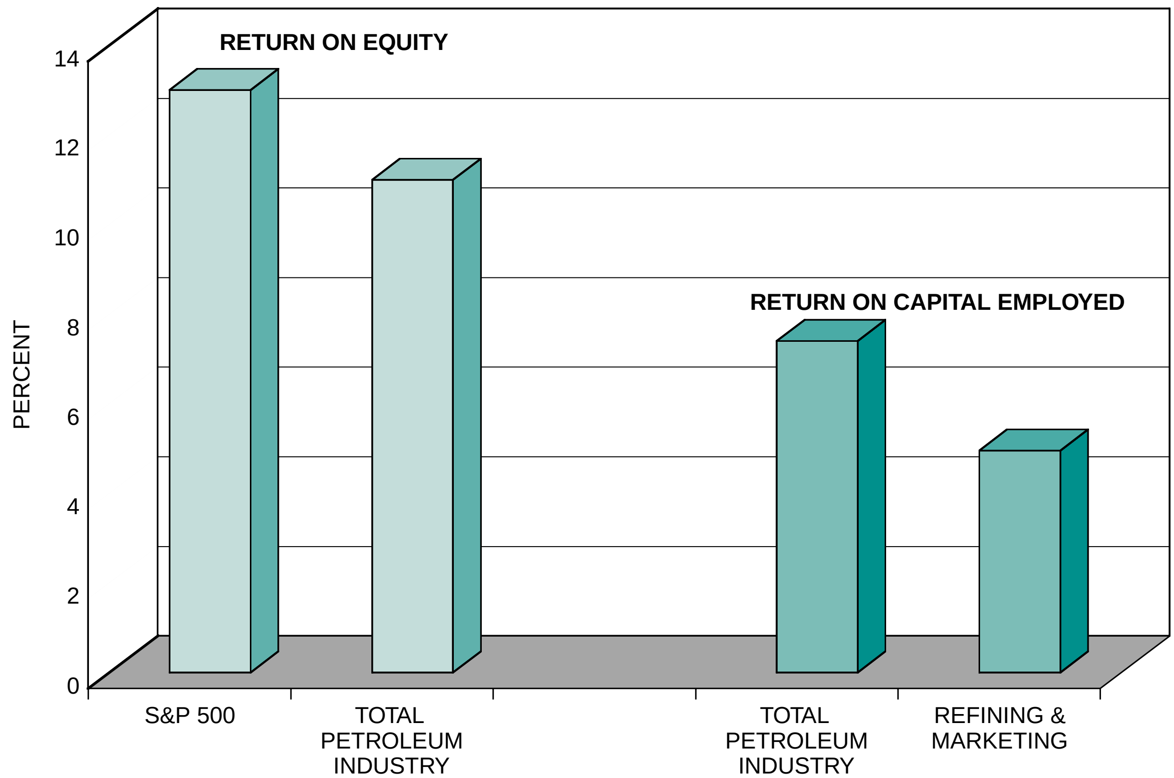
To retain the viability of the domestic industry in aggregate, the increased investment and operating costs to meet regulatory requirements must ultimately be recovered in the marketplace. The financial performance of U.S. refining and marketing has generally been below the performance of other industries. Figure 3 shows that the petroleum industry's return on equity has been below the performance of the S&P 500 average for the last two decades. The refining and marketing segment's 5% return on capital employed has been below the petroleum industry's return as a whole.

Gasoline Sulfur Reduction

The NPC estimates that reducing the sulfur content of domestic gasoline from today's level of about 340 ppm to an average of 30 ppm will require investment of at least $8 billion in 1998 dollars. This estimate excludes California, where industry has already invested about $4 billion to supply unique California gasoline including lower sulfur. Greater expenditures and consumption of implementation resources may occur if a significant number of refiners choose to implement fluid catalytic cracking (FCC) feed sulfur reduction in addition to FCC product desulfurization. Fluid catalytic cracking and other refinery processes are described in Appendix C.

The per-gallon cost increase to provide 30 ppm sulfur gasoline is estimated to be about 4.5 cents, which includes operating and capital

Figure 3. U.S. Refining and Marketing Return Comparison
1981-1998 Average



Source: Data from EIA's Financial Reporting System.

costs at refineries and in the product distribution system. A 10% after-tax rate of return was used to amortize the capital investment, assuming an economic life of 15 years. The components of this cost are shown in Table 1.

These investment and per-gallon cost increases are approximately twice the EPA's estimates provided in the Tier 2 Rule. EPA based its cost estimate on wide-scale use of technology that has little or no commercial experience. The NPC believes that the risks incumbent in the use of undemonstrated technology will cause many refiners to choose more developed processes. The NPC's estimate is based on technologies that, while not fully proven, have at least some commercial experience. The NPC also believes that EPA underestimated the cost associated with building gasoline desulfurization units with technology that has little or no commercial experience, and underestimated the costs for ancillary and support facilities associated with the desulfurization units. Table 2 shows the individual factors that reconcile the $8 billion investment estimate by NPC to the $4 billion March 1999 estimate by MathPro, which is similar in magnitude

TABLE 1

COST OF REDUCING GASOLINE SULFUR TO 30 PPM AVERAGE
(Costs in 1998 Dollars)

Investment Cost:	**$8 Billion**
Per-Gallon Cost Increase:	
Operating Cost	3.1 ¢/gallon
Capital Cost	1.3 ¢/gallon
Subtotal	4.4 ¢/gallon
Fuel Economy Penalty	0.1 ¢/gallon
Total	4.5 ¢/gallon

TABLE 2

INVESTMENT COST FOR 30 PPM GASOLINE
Comparison to MathPro's Estimate

	$ Billion
MathPro March 1999 Study for API 50% OCTGAIN 220, 50% CDTECH	**3.9***
Adjustments:	
Investment Factor Adjustments	+1.6
Include PADD IV, WA, OR	+0.8
Scaling factor based on FCC gasoline rate vs. crude oil rate	+0.8
Likely use of demonstrated technology by some refineries vs. developing	+0.7
Gasoline capacity growth	+0.2
Convert $96 to $98	+0.2
	Total of $8.2 Billion
NPC Investment Estimate	**$8 Billion**

*The EPA Tier 2 Rule estimate is $3.7 billion when adjusted to a similar geography and inflation basis.

and basis to the EPA's $4 billion estimate in the Tier 2 Rule.

Projections of future refining costs are always uncertain. New technologies may provide unexpected efficiencies, and other technology promises may fail to materialize. The NPC investment and cost estimates reflect the collective experiences and best judgment of experts from refining, petroleum process research, and engineering/construction companies.

The Tier 2 Rule provides for a phase-in of the lower sulfur requirements for most gasoline over the 2004 to 2006 period. Assuming timely acquisition of environmental permits, the availability of engineering, equipment manufacture, and construction resources is generally expected to be sufficient to allow industry to meet the Tier 2 Rule gasoline requirements. Engineering and construction resources will be taxed during the peak workload periods and will be inadequate if other substantial demands occur concurrently, such as for another significant product specification change, an increase in stationary source emission control requirements, a cyclical increase in petrochemical industry construction activity, or a requirement for significant increase in fuel ethanol production. Had the regulations required full production of 30 ppm sulfur gasoline by 2004, implementation resource constraints would have limited industry's ability to comply.

The expected $8 billion investment spread over the years 2001 through 2005 is equivalent to about half of the domestic refining industry's recent capital spending level, shown in Figure 4. The industry should be capable of funding this $8 billion investment in the time frame required by the Tier 2 Rule, although at the expense of other investments whose benefits will then be delayed or lost. While the industry as a whole should be capable of funding this investment, each individual company will make its own investment decisions, and some may choose not to invest.

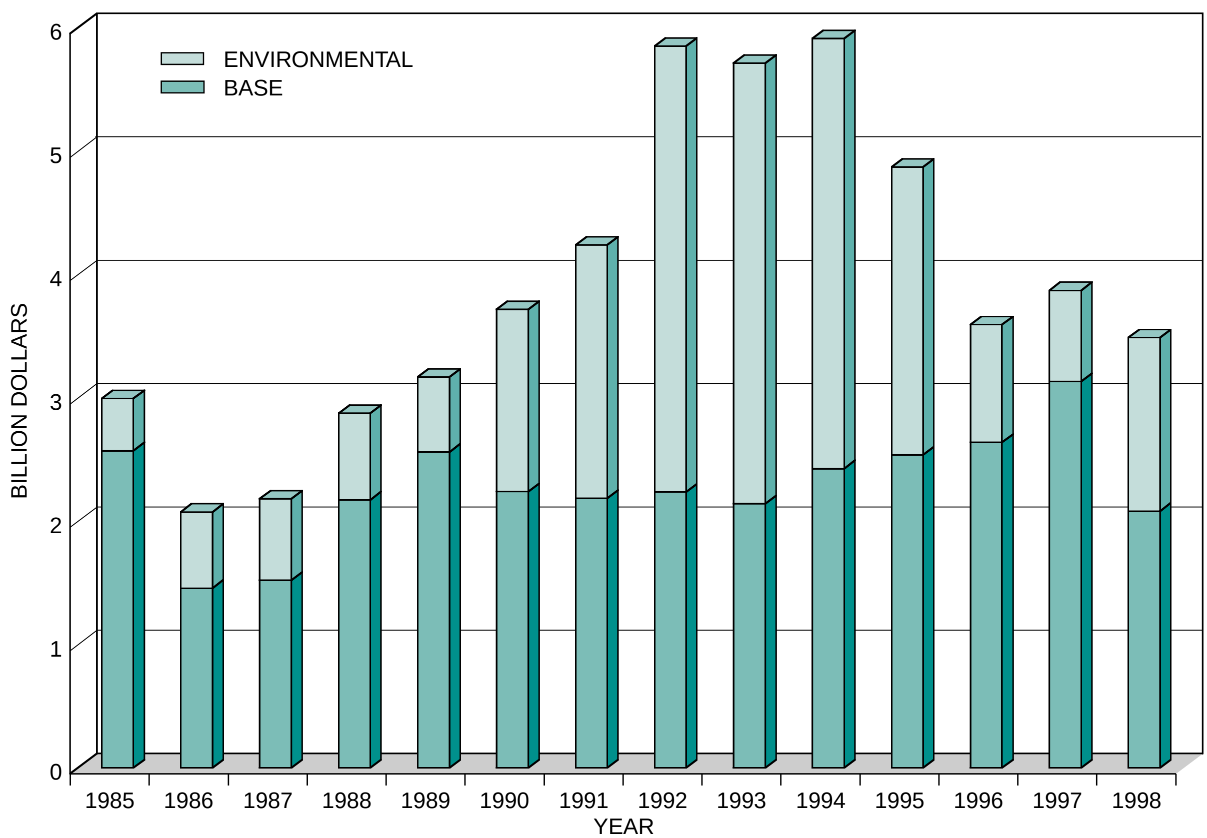
Desulfurization equipment will have to be installed at nearly every domestic refinery to reduce gasoline sulfur to 30 ppm. A mix of technologies is expected to be employed, ranging from commercially demonstrated caustic treating to one of several near-commercial selective desulfurization processes. Individual refiners will make technology choices based on a number of factors including hydrogen availability, octane requirements, and their tolerance of risk associated with installing technology with limited commercial experience.

Most of the technologies reflected in this cost estimate have limited commercial experience. A higher incidence of initial operating problems and performance below design should be expected with these processes.

Distribution of lower sulfur gasoline will require additional facilities at about 400 product distribution terminals and additional operating cost for interface handling and quality assurance at essentially all 1,300 domestic product terminals. These costs are included in the investment and per-gallon costs above. Typical distribution operations are described in Appendix D.

The NPC also examined the potential to reduce gasoline sulfur to levels below 30 ppm. While demonstrated refining processes exist to produce very low sulfur gasoline levels, the costs are expected to increase dramatically with each increment of sulfur reduction. The high-sulfur FCC gasoline streams anticipated to be treated to achieve 30 ppm sulfur gasoline would have to be treated much more severely to reduce sulfur further. At these higher severities,

Figure 4. Historical U.S. Refining and Marketing Investments



Source: Data for Total from *Oil & Gas Journal.*
Data for Environmental from API Reported Refining & Marketing Capital Investments 1990-1998; and Pre-1990 estimate from Department of Commerce.

costs for hydrogen production, octane loss, and yield loss will increase dramatically, and most technologies would be operating beyond the range of demonstrated experience. Additionally, many other refinery gasoline streams that will not require desulfurization to achieve 30 ppm sulfur average will require treatment to reduce gasoline sulfur below 30 ppm. All domestic refineries will require additional desulfurization facilities to reduce gasoline sulfur below 30 ppm, increasing investment requirements and operating cost.

In addition to substantially higher refinery processing costs, the total costs associated with producing and delivering very low sulfur fuels will likely be higher than indicated by current analysis techniques using LP models of a typical refinery. These models represent average refinery operations and do not include the effects of daily variations in refinery processing that will affect the production of very low sulfur fuels. Also, these models only examine refinery processing unit operations; they do not consider the significant and costly changes that will be required for blending, handling, and distributing very low sulfur fuels in refineries, pipelines, terminals, trucks, and retail stations. Further study with models of expanded capability would be needed to provide reliable estimates of the cost to reduce gasoline sulfur below 30 ppm.

Diesel Sulfur Reduction

The NPC estimates that reducing the sulfur content of domestic on-highway diesel from today's level of about 350 ppm to an average of 30 ppm will require investment of about $4 billion in 1998 dollars. The per-gallon cost increase of providing 30 ppm on-highway diesel is estimated to be about 5.8 cents per gallon, as shown in Table 3. A 10% after-tax rate of return was used to amortize the capital investment, assuming an economic life of 15 years. No additional costs are anticipated for the distribution system provided that the distribution investments for low sulfur gasoline precede low sulfur diesel implementation. On-highway diesel sulfur levels in California average about 140 ppm; consequently, some additional investment will also be required in California to reduce on-highway diesel to 30 ppm sulfur average.

TABLE 3

COST OF REDUCING ON-HIGHWAY DIESEL SULFUR TO 30 PPM AVERAGE
(Costs in 1998 Dollars)

Investment Cost:	**$4 Billion**
Per-Gallon Cost Increase:	
Operating Cost	2.1 ¢/gallon
Capital Cost	3.2 ¢/gallon
Subtotal	5.3 ¢/gallon
Fuel Economy Penalty	0.5 ¢/gallon
Total	5.8 ¢/gallon

Achieving 30 ppm average on-highway diesel sulfur will require investment in most but not all domestic refineries. Today, about 20% of domestic refineries do not produce on-highway diesel. On-highway diesel constitutes about 65% of the total domestic diesel and heating oil production. Refineries choosing to produce 30 ppm sulfur on-highway diesel are expected to modify existing hydrotreating units where feasible rather than build grassroots units. These modifications will be very extensive and require significant increases of up to four times in reactor volumes. The investment estimate includes modifications to existing diesel hydrotreaters in about 90 refineries.

If diesel sulfur reduction is required in 2006, implementation would overlap significantly with the Tier 2 Rule gasoline sulfur reduction, and engineering and construction resources will likely be inadequate, resulting in implementation delays, higher costs, and failure to meet the regulatory timelines. Overlapping implementation would further strain the ability of state and local agencies to issue construction and operating permits for the required facilities in time to meet the Tier 2 Rule requirements. The combined investment of $12 billion for gasoline and diesel sulfur reduction should be spread over at least seven years by requiring diesel sulfur reduction to 30 ppm average no earlier than 2007 for model year 2008 vehicles, to avoid substantially increased risk of supply disturbances.

There are potential economies to be gained by coordinating the expansions required in support systems such as utilities, hydrogen production, and sulfur recovery for gasoline and diesel sulfur removal. These economies can be achieved by clarifying the expectation for the eventual lowering of diesel sulfur in time for refiners to plan and preinvest during gasoline sulfur reduction investments.

The NPC also qualitatively studied reducing on-highway diesel sulfur to less than 30 ppm average. The EPA has recently proposed reducing on-highway diesel sulfur to 15 ppm maximum, about 7 to 10 ppm average, on a schedule that overlaps directly with Tier 2 gasoline sulfur reduction. The EPA estimated increased production and delivery cost of 4.4 cents per gallon. The NPC concludes that costs will be significantly higher, resource availability will constrain the industry's ability to implement required facilities in time to meet the requirements, and a significant risk of inadequate supplies will result.

The on-highway diesel demand in the United States is supplied with a combination of straight run (uncracked) and cracked stocks. Straight run diesel should generally be treatable to levels below 30 ppm sulfur by substantial modifications to typical existing diesel hydrotreating units. These modifications would include large increases in reactor volume and addition of hydrogen recycle and scrubbing facilities, and not all units will be practical to modify. Treating straight run stocks alone will be insufficient to supply the on-highway diesel volume in the United States; a significant amount of cracked material must be included in on-highway diesel supplies, especially in areas that lack a heating oil outlet for cracked stocks.

As the EPA recognizes in the diesel NPRM, removing the sulfur from cracked diesel stock is significantly more difficult than removing the sulfur from straight run stocks. NPC concludes that many existing diesel hydrotreaters will be impractical to modify sufficiently to reduce the sulfur of cracked diesel stocks to the EPA's proposed level of 15 ppm maximum, 7 to 10 ppm average. New grassroots higher pressure hydrotreating will be required in many U.S. refineries. The significantly higher investment and operating cost for this higher pressure hydrotreating have not been adequately reflected in the EPA's diesel NPRM cost estimate.

New grassroots higher pressure hydrotreating would require additional hydrogen compression and new thick-walled pressure vessels. The worldwide manufacturing capability for reciprocating compressors and thick-walled pressure vessels is limited to a handful of suppliers and could be a significant constraint on the industry's ability to provide adequate supplies of on-highway diesel with less than 30 ppm average sulfur.

Grassroots higher pressure hydrotreating would entail substantially higher investment and operating costs than modifications to existing hydrotreating. Many refiners will face a choice of investing in new higher pressure, high-cost hydrotreating to produce current on-highway diesel volumes or making lower cost modifications to existing hydrotreating to produce a reduced volume of on-highway diesel from available straight-run stocks. If enough refiners choose the lower cost option, supplies of on-highway diesel will initially be inadequate. Additional investment to correct a domestic producibility shortfall could take several years to implement.

Should off-highway diesel sulfur also be lowered, costs are likely to be substantially higher than other studies have concluded. Off-highway diesel is not currently desulfurized and typically contains large quantities of cracked materials that are particularly difficult to desulfurize to low levels. In some areas of the country, a single product is sold for both off-highway diesel and home heating oil. Reducing the sulfur level of off-highway diesel would require higher costs to segregate or desulfurize home heating oil as well.

The inadequacies of current modeling techniques for assessing the costs to provide very low sulfur fuels, discussed in the "Gasoline Sulfur Reduction" section earlier in this chapter, also apply to diesel.

Reducing MTBE in Gasoline

In 1998, approximately 300 thousand barrels per day (MB/D) of MTBE and other ethers were blended into gasoline, representing about three volume percent in the total gasoline pool. The majority of MTBE is used in gasoline to provide the oxygen content required by law in reformulated and oxygenated gasoline. While providing oxygen and volume, MTBE also has high octane, low aromatics and olefin content, and good distillation properties.

There are numerous scenarios under which MTBE use in gasoline could be reduced. The NPC examined cases where MTBE use is discontinued and the oxygen requirement is either eliminated or retained. California already has a requirement to end MTBE use by the end of 2002; California costs were not included in this analysis.

In a case where MTBE use is eliminated and the oxygen requirement is removed, the industry investment is estimated to be about $1.4 billion in 1998 dollars. This investment is necessary to replace the lost volume and octane from MTBE. The per-gallon cost increase to produce RFG in this scenario is about 2.4 cents for PADDs I and III, including operating costs and a 10% capital recovery. The per-gallon cost increase for PADD II oxygenated gasoline is lower, reflecting the lower use of MTBE and higher use of ethanol already present in PADD II. The components of this cost are shown in Table 4.

Ethanol use in domestic gasoline was about 95 MB/D in 1998. About half of this ethanol was used to provide legislatively mandated oxygen content, the other half was used as an economic gasoline blendstock. Provided that the existing excise tax exemption and credits remain in place, the NPC would expect this use to continue even with the oxygen requirement eliminated.

In a case where MTBE use is eliminated and the oxygen content requirement is retained, substantial additional ethanol blending is necessary to meet the oxygen requirement. Annual ethanol production would have to increase from the 1998 level of 95 MB/D to 200 MB/D to provide just the minimum amount of ethanol necessary to meet the oxygen requirement in

TABLE 4

COST OF ELIMINATING MTBE FROM GASOLINE
(Costs in 1998 Dollars)

	Oxygen Requirement Eliminated		Oxygen Requirement Retained	
Investment Cost:				
Refining and Distribution	$1.4 billion		$1.5 billion	
Ethanol Production Capacity	- 0 -		$3 billion	
	PADDs I & III	**PADD II**	**PADDs I & III**	**PADD II**
Per-Gallon Cost Increase:				
Operating Cost	1.8 ¢/gallon	0.9 ¢/gallon	3.4 ¢/gallon	1.5 ¢/gallon
Capital Cost	0.9 ¢/gallon	0.7 ¢/gallon	1.0 ¢/gallon	0.8 ¢/gallon
Fuel Economy Penalty	-0.3 ¢/gallon	-0.7 ¢/gallon	-0.2 ¢/gallon	-0.7 ¢/gallon
Total	**2.4 ¢/gallon**	**0.9 ¢/gallon**	**4.2 ¢/gallon**	**1.6 ¢/gallon**

Notes: An ethanol cost increase of 10 cents per gallon would increase the costs above by 0.6 cents per gallon in the Oxygen Mandate Retained case.

Capital charge is for a 10% real after-tax return, assuming an economic life of 15 years.

Maintaining current toxic emissions performance would increase investment by $0.4 billion and PADDs I and III per-gallon cost by 0.8 cents.

the U.S. including California. The investment necessary to expand ethanol production would be about $3 billion. The additional ethanol would replace some but not all of the volume and octane lost by removing MTBE, and refinery investment would be lower than in the no-oxygen-requirement case. However, modifications would be required at about 225 truck-loading terminals to receive and blend ethanol into gasoline before delivery to retail stations. Refinery and terminal investment is estimated to be about $1.5 billion, for a total investment requirement of $4.5 billion for this case. Lost revenue to the Highway Trust Fund due to increased ethanol subsidies would be at least $1 billion per year.

The per-gallon cost increase for RFG with the oxygen content requirement retained is about 4.2 cents in PADDs I and III and is highly dependent on the cost of ethanol. The NPC used a previous ethanol cost estimate developed by the Department of Energy and did not independently assess the likely ethanol cost. The components of this per-gallon cost are also shown in Table 4.

Due to MTBE's favorable blending properties, eliminating MTBE would increase the toxics emissions from gasoline, but not to a level exceeding RFG standards. If current toxics emissions performance is required to be maintained while MTBE is eliminated, an additional investment of $0.4 billion would be required and the per-gallon costs noted above would increase by about 0.8 cent in PADDs I and III.

The cost to implement EPA's recent proposal to significantly reduce or eliminate MTBE will be highly dependent upon the specific requirements for any renewable fuel content standard and maintenance of current air quality benefits. If a renewable content standard does not require an increase in volume or a shift in geographic use of ethanol from today, the required refinery investment would be about $1.8 billion to replace lost octane and volume while preserving the current RFG air toxics reduction. If a renewable standard essentially requires meeting the current oxygen content mandate for RFG, total investment would be about $5 billion. Required refinery investment would be about $1.7 billion, and an additional $0.2 billion of investment would be necessary to provide facilities for blending ethanol into gasoline at about 225 terminals. Current ethanol production would have to double, requiring an additional $3 billion investment. If a renewable content standard requires increasing ethanol to replace current MTBE use barrel-for-barrel, ethanol production would have to quadruple, necessitating about $10 billion investment.

While the petroleum industry investment for eliminating MTBE is smaller than the investment required for gasoline sulfur reduction, the burden is concentrated on PADD I and III refineries. The NPC recommends that elimination of MTBE and reduction of gasoline sulfur not be implemented concurrently. The volume and octane loss associated with eliminating MTBE would exacerbate the volume and octane loss imposed by reducing gasoline sulfur. The concurrent investment to eliminate MTBE and reduce gasoline sulfur would significantly strain the permitting and construction resources, especially in any case where additional ethanol capacity and terminal blending modifications are required.

Lowering the Driveability Index of Gasoline

Driveability index is a measure of gasoline's volatility, or tendency to vaporize. A lower number indicates a greater tendency to vaporize. Other measures of gasoline vaporization have been used by industry for many years. A maximum DI specification of 1,250°F at the refinery gate was adopted in October 1998 by the American Society for Testing and Materials (ASTM), an organization widely recognized for setting standards for petroleum products. As specified by ASTM, DI is the sum of 1.5 times T10 plus 3 times T50 plus T90, where T10, T50, and T90 are the temperatures at which 10%, 50%, and 90% of gasoline evaporates.

Automakers have recently called for a maximum DI specification of 1,200°F enforced at the retail station. Enforcement of a DI specification at retail stations instead of at the refinery gate poses several significant challenges for the petroleum industry. First, the test methods used to determine DI can vary 50 degrees between different tests of the same batch of gasoline. To assure that a gasoline shipment would not test above 1,200°F after release from the refinery, it would have to test at 1,150°F or less before leaving the refinery. While it may be possible to improve the test method precision, the extent and timing of possible improvement has not been determined. Second, gasoline blending is not linear with respect to DI–two different gasoline batches each testing at 1,200°F DI may combine to form a batch which tests above or below 1,200°F. The extent of this nonlinear blending is not currently well defined. Because gasoline batches are routinely mixed in the distribution system and in the tankage at retail stations, this nonlinear commingling effect must be defined before the cost to meet a retail specification can be assessed.

Reducing average DI can be accomplished in several ways: by directing higher DI gasoline components to other heavier products such as jet fuel or diesel, by cracking of higher DI material to lower DI blendstocks, or by increasing production of lower volatility blendstocks. Directing higher DI material to other products would reduce gasoline production. Cracking of higher DI blendstocks or increasing production of lower DI blendstocks would increase refinery investment and operating costs.

The NPC examined the cost of DI reduction using a notional refinery model for PADDs I and III. Modeling predicts that a 50°F reduction in the refinery gate cap from 1,250°F to 1,200°F could require as much as $11 billion investment. There is currently a large 100°F testing and operational variability tolerance necessary between the refinery gate cap and the refinery average DI, as shown in Table 5. Reducing this variability could lower the cost of a reduction in the current 1,250°F DI cap. However, the NPC is unable to predict the likely magnitude or timing of any potential testing or operational improvements. Additional study to understand the potential for reducing testing and operational variability and additional modeling of production cost should be undertaken before any DI specification change is required.

Extending the compliance point for DI from the refinery gate to the retail station would add costs as downstream entities would require compliance margins to account for downstream test variability and nonlinear blending effects.

Reducing or eliminating MTBE would result in additional costs to maintain or reduce DI, since MTBE has low DI blending characteristics. Eliminating MTBE would increase the average DI of the typical PADD I and III refinery by about 20°.

Distribution and Testing

During the 1990s, the operation of the petroleum product distribution system migrated

TABLE 5

DRIVEABILITY INDEX REDUCTION COST

Current Refinery Gate DI Cap	1,250°F
Refinery Gate DI Cap after 50° Reduction	1,200°F
Required Tolerances – Refinery Gate Cap to Refinery Average DI	
Measurement Variability	50°
Operational Variability	25-50°
Blending Variability	~25°
Total Variability	**~100°**
Required Refinery Average DI for 50° DI Reduction	1,100°F
Cost Increase, cents per gallon	7
Investment Cost, Billions of 1998$	11

Source: Data from MathPro study for the NPC (see Appendix K).

toward fungible pipelines and terminal blending of midgrade and oxygenated gasoline. This trend helped minimize the investment needed to meet the additional segregation and compliance requirements of the reformulated and oxygenated gasoline and low sulfur diesel programs of the 1990s. The NPC assessed costs of product quality changes for this study assuming that enforcement would not place additional encumbrances on the fungibility of the distribution system.

Localized requirements for unique fuels are emerging, such as Atlanta's specifications for low sulfur and low volatility fuels, and proposals for localized restrictions on MTBE use. Unique localized fuel specifications will raise the cost and reduce the reliability of supplies by limiting the number of possible suppliers and by interfering with the system's ability to redirect supplies from one area to cover unexpected shortfalls in another area.

In the diesel NPRM, the EPA requests comments on potential lower sulfur diesel phase-in approaches. Any phase-in would require another fuel segregation in addition to the existing low sulfur on-highway diesel and the off-highway diesel/home heating oil segregations. There would be substantial incentive to minimize investment in facilities to handle the additional segregation, since the economic life of any phase-in facilities would be short. Many refineries and terminals would likely choose to handle only two of the three grades of diesel, potentially reducing supply reliability of all three grades. Retail stations could be faced with significant and short-lived investment in tanks and dispensers to handle a new grade. If initial volumes of a new grade are small, distribution through the existing pipeline system may be very costly, resulting in distribution mostly by truck from producing refineries to retail. The delivery cost could be 10 cents per gallon or more for areas distant from producing refineries or major supply points.

There is serious doubt about whether the existing distribution system can maintain the integrity of ultra-low sulfur gasoline and diesel as long as significantly higher sulfur products continue to be shipped in the same systems. Off-highway diesel, jet fuel, and heating oil with a maximum sulfur content of 5,000 ppm sulfur would create a sulfur ratio of 333:1 against a shipment of ultra-low sulfur diesel with the 15 ppm maximum proposed by EPA. This is 33 times larger than today's maximum sulfur ratio of 10:1. There are numerous sources of small volumes of contaminants in the distribution system that are not significant at today's sulfur ratios but could be unmanageable at higher ratios.

Technology for testing of 30 ppm gasoline and diesel sulfur levels is currently available for use in controlled environments such as refinery and product inspection laboratories, but it is not presently suitable for field use. The NPC believes that field testing methods suitable for 30 ppm gasoline and diesel will become available in time at a reasonable cost to support field compliance activities, and the costs in this study include the NPC's estimate for field testing equipment. It is unlikely that any field test equipment would be available for measuring sulfur levels substantially below 30 ppm in the near future. This would likely cause delays and increase the cost of delivering products to the marketplace should sulfur levels below 30 ppm be mandated.