PIRINC

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August 17, 2004

Dear PIRINC Readers;

PIRINC is releasing the enclosed report, *Refining Capacity – Challenges and Opportunities Facing the U.S. Industry*, prepared by Lawrence C. Kummins, Brent Yacobucci, and Larry B. Parker, energy policy specialists from the Congressional Research Service (CRS) of the Library of Congress.

US refiners are currently enjoying high margins thanks to both global and domestic factors. Within the US, refiners are running flat out in the face of strong demand. Moreover, strong demand elsewhere in the world, combined with the impact of more stringent US product specifications, has made it more expensive to shop the global market to fill the growing gap between domestic market requirements and domestic refining capacity. The EIA estimates that this year, net product imports will meet about 9% of US oil demand, up from 7% in 2000 and more than double the 4% share in 1995. Gasoline, including blending components, currently accounts for over 35% of total imports and about 10% of total US gasoline supplies.

Other things equal, the combination of favorable margins, strong demand extremely high utilization rates creates strong incentives to invest in additional capacity---provided such conditions are expected to continue, or at least not revert to those that have made refining a marginally profitable business for so many years.

In terms of national interest, there are certain advantages in having a high level of domestic refining capability. The US can be most confident that its domestic refiners will meet the increasingly stringent product specifications being implemented over the next several years. While conforming product has been available---at a price---from foreign refiners, in many cases these supplies are marginal to the refiners main markets and therefore not determining in their own investment decisions. Some product sources are dedicated to the US market but are subject to other influences, which could limit their ability to make the needed investments in a timely manner.

In requesting the National Petroleum Council to produce a quick study of the refining and distribution industry's ability to meet future demand, the Secretary of Energy has recognized the importance of adequate domestic refining capacity to the health of the U.S. economy. The Secretary has observed that "---constraints on refinery expansion coupled with an effective moratorium on new construction since 1976 have resulted in our dependence on a system running at an average 96% utilization rate for the summer of 2004." He states that this level "---provides little system capability to manage unexpected outages." As global economies and oil demand continue to grow, the Secretary believes that the U.S. will face increasing competition for product supply from beyond our own borders and that foreign supply is less certain that that provided by our own domestic refining and distribution system.

Over the past two decades the U.S. economy has been slowly insulating itself from oil price shocks. But while we have insulated ourselves, we are not immune. The sudden run up in oil prices is having a negative impact on the U.S. and the global economies. It has probably reduced second and third quarter GDP by 0.5% from what otherwise would have been the case.

For most of the past 20 years, there was widespread global spare crude oil productive capacity, widely distributed spare refining capacity, and significant discretionary product inventories. Today these three cushions or shock absorbers are greatly diminished. The loss of these cushions has made price volatility the "norm" in the oil sector and has created an asymmetric bias toward the upside. Without these cushions, price is the only variable left to clear markets

The "problems" in the energy sector have been two decades in the making and it will clearly take more than two weeks, two months, and even two years to correct
.
At a time of heightened political sensitivities regarding energy, it is particularly important to offer what is acknowledged to be a nonpartisan analysis of some of these concerns. For this purpose, PIRINC has asked three energy policy specialists, Lawrence C. Kummins, Brent Yacobucci, and Larry B. Parker, from the Congressional Research Service (CRS) of the Library of Congress to prepare this report. The mission of the CRS is to provide the U.S. Congress with objective, unbiased research and policy analysis on any issue of interest to Members of Congress, their staffs, or Congressional committees.

Overall, national interest considerations do not require "refinery independence." Nor is there a compelling case for heavy-handed government measures. There are, however, strong grounds for allowing market incentives to do their work and, in this regard, to remove unintended government roadblocks to this happening.

The views of the authors are not necessarily those of PIRINC. PIRINC believes, however, that the report makes an important contribution to the national energy policy dialogue.

*Larry Goldstein*

Lawrence Goldstein
President

# Refining Capacity - Challenges and Opportunities Facing the U.S. Industry[1]

Lawrence Kumins, Larry Parker, and Brent Yacobucci

## Introduction

The number and total capacity of U.S. refineries peaked in 1981. In the ensuing years, 171 units have been closed. The lost capacity from these units has been partially offset by expansions in the 153 remaining plants. Notwithstanding, enough capacity has been lost so that the nation cannot currently manufacture all of its fuel needs. As a result, imports of refined products have risen, gasoline being the most significant. Imported gasoline that meets U.S. specifications is not always available from foreign refineries in quantities desired, and this appears to be contributing to high pump prices currently experienced.

A number of factors have contributed to the decline in refining, low profitability being most important. Refining has been a boom or bust business during the past quarter century. Volatile profits at the refinery gate have generally produced returns averaging less than other investment areas in the petroleum industry, such as hydrocarbon production. The closure of smaller plants not benefiting from economies of scale has resulted. Another factor has been the decline in lower-48 state onshore oil production, leaving inland refineries without access to cost-competitive crude oil supplies. Since most imported crude is water-borne, coastal locations offer important transportation benefits. Many closed refineries did not have direct water access.

Integrated, multinational firms have a worldwide menu of investment opportunities to choose from, and many present higher return opportunities than domestic refining. As a result, no new domestic plants have been built for a number of years; very few closed refineries have been reopened. A number of integrated, multinational companies have merged, disposing of U.S. plants. A few specialty refining companies have acquired some of the more desirable of these facilities, but — at least through 2003 — profitability has been modest for these stand-alone refinery firms. And while the early quarters of 2004 have shown promising profitability, the industry as a whole is slow to invest in long-lived assets that might not be supported for their complete lifespan by this year’s financial results.

Beyond the changing supply conditions and unsatisfactory profitability, the refining industry has had to respond to an increasing range of regulatory issues that affect facility operations and profits. They range from product issues including gasoline composition and product liability, to operational issues, including the permissibility of rehabilitation and routine maintenance programs.

[1] The opinions expressed in this article are those of the authors and do not necessarily represent the opinions of the Congressional Research Service, the Library of Congress, or the Petroleum Industry Research Foundation.

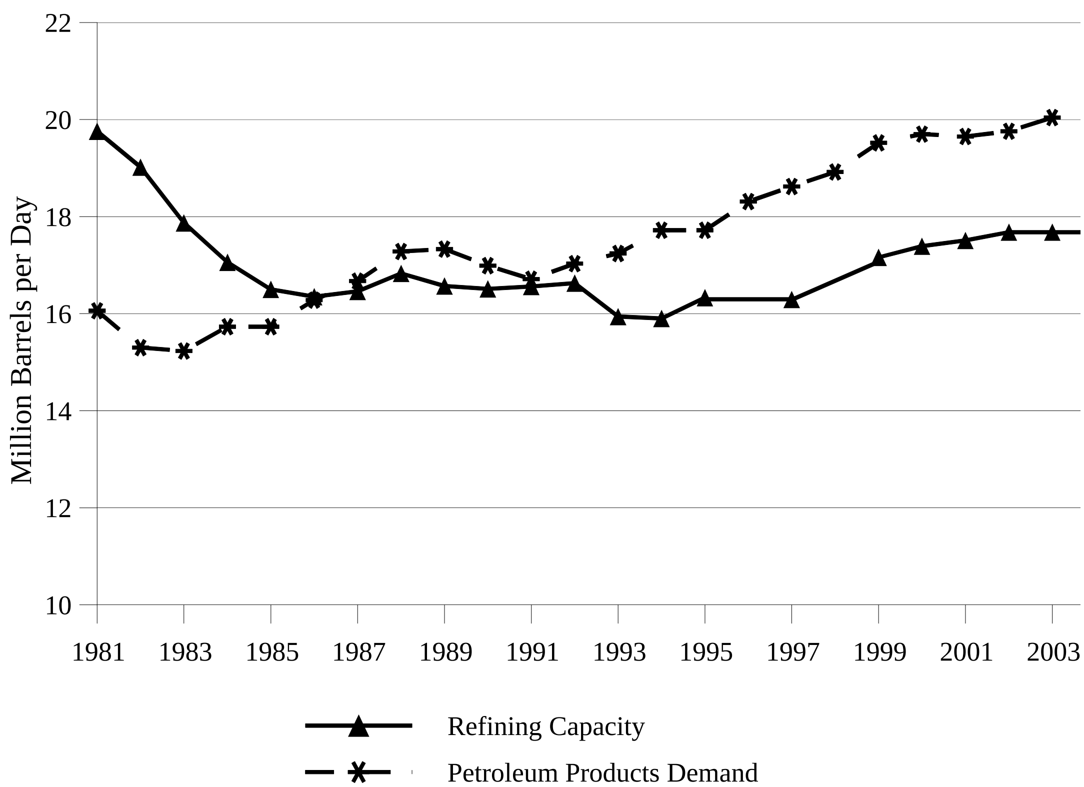
Recognizing the complexity of both the refining industry and the various levels of government regulating it, this paper specifically delineates salient trends in the industry and the representative business plans being adopted to respond to them; the burdens that federal, state, and local governments have placed on industry with respect to product specifications and liability; and the challenges that federal, state, and local government environmental permitting requirements place on industry decision-making with respect to capacity enhancement. From this discussion, some thoughts on potential approaches to refining policy are provided.

## Review of U.S. Petroleum Refining

### The Petroleum Refining Capacity Shortfall

**Figure 1** below shows U.S. demand for refined oil products has grown steadily since the mid-1980s. For the year 2003, oil product demand exceeded 20 million barrels per day (mbd), a record that likely will be surpassed in 2004, as petroleum demand has averaged 20.6 mbd for the first seven months. Over this timespan, 2 mbd of excess capacity has become a 2 mbd shortfall. The gap between product demand and domestic refining capacity indicates the need for imports, which have been increasing since the mid-1990s. At present, about 1 mbd of total product imports is gasoline, either as a finished product or as a blending component. On a net import basis, another 800,000 barrels per day of other products are currently imported. The product import situation suggests that a domestic refinery shortfall of nearly 2 million barrels per day exists.

Figure 1 U.S. Refining Capacity & Petroleum Product Demand, 1981-2003




**Source**: Refining Capacity: EIA, Petroleum Supply Annual 2002, Table 41. Petroleum Products Demand: EIA, Monthly Energy Review April 2004, Table 3.1a

The significance of depending on foreign refined products is a matter of perspective. International trade in products is a commercial fact of life, especially since some offshore refining capacity — especially in the Caribbean basin, where more is currently being added — specifically exists to serve U.S. markets. Additionally, other refineries around the world have been built to supply world markets, regardless of which country is the customer, on a strictly commercial basis. From one perspective, these imports could be viewed as similar to domestic supply, as long as U.S. product specifications are not so divergent that refiners outside the U.S. are unable or unwilling to manufacture products meeting these specifications. Components that can be imported and completed by U.S. firms might be similar. In theory, it should make little difference whether products are refined here or abroad.

But real world considerations, such as the off-shoring of U.S. manufacturing, higher transport costs for imported products (in contrast to crude oil), supply reliability issues, and availability of U.S. "spec" materials have bearing. These can impact supplies and prices, always a source of concern.

## Refinery Capacity Trends

Also shown on **Figure 1** is the trend in domestic refinery capacity, as measured by total barrels of distillation capacity. While an accurate way of measuring capacity, these data mask some underlying trends, especially the drop in the number of refineries from 324 in 1981 to the current 153.[i]

However, the most notable feature of the refining capacity trend is the decline in aggregate capacity from 1981 into the mid-1990s. The capacity of operable refineries fell from 18.6 mbd to 16.8 in 2002, a loss of 1.8 mbd. The 1981 to 2004 time frame includes a period of growth between 1995 and 2002, and more recently (2002 through 2004) a period where capacity was virtually unchanged.

The closure of 171 plants left many abandoned refinery sites. For the most part, they were inland refineries without access to water transportation. The closed sites housed small plants; almost all less than 100,000 barrels per day, with most being significantly smaller, the smallest being 1,400 barrels per day. While the closed sites theoretically offer an opportunity for revitalization, this has not taken place to date because would-be operators are seeking larger sites, with valuable refinery assets, water-transport access, and a number of other desirable attributes that seem to distinguish plants successfully sold from those simply shut down.

## Profiling The Top Three Domestic Refiners

The configuration of the top three domestic refiners' fleets, shown in **Table 1**, is illustrative of the industry's current profile. These firms hold capacity exceeding 6 million barrels per day, about 34% of the nation's total. Their fleets consist mostly of large plants, although each owns at least one small facility. ExxonMobil — the third-largest domestic refiner — owns the two largest refineries in the nation, and has by far the largest facility size average. The top two firms each have twice as many U.S. plants, but they average roughly half the size of ExxonMobil. Both ConocoPhillips and Valero gained their large market share through acquisition of other facilities. In the case of ConocoPhillips, it was by way of the merger of two formerly independent firms.

**Table 1. Top 3 U.S. Refining Companies–2004**

| Company | Total Cap. (Mil b/d) | Number of Refineries | Average Size (b/d) | Largest Plant (b/d) | Smallest Plant (b/d) |
|---|---|---|---|---|---|
| Conoco Phillips | 2.208 | 12 | 184,000 | 300,000 | 60,000 |
| Valero Energy | 1.993 | 13 | 153,000 | 340,000 | 27,000 |
| ExxonMobil | 1.808 | 6 | 301,000 | 523,000 | 58,000 |

**Sources:** Company web sites, Energy Information Administration, Petroleum Supply Annual, 2002. Table 40.

Valero grew into its current position as the nation's second largest refiner during the past decade by acquiring refineries from other companies, including those spun off under deals with the Federal Trade Commission to facilitate mergers. ConocoPhillips, for example, sold 4 refineries during 2002, with total capacity of about 500,000 barrels per day, to satisfy antitrust considerations.[ii] These sales were mandated to avoid excessive regional concentration of ownership. It is noteworthy that Valero is prohibited from acquiring any more California refineries for similar reasons.

## Refining Profitability — Two Case Studies

In an attempt to gain insight into the business fundamentals of refining, we examined Valero and ExxonMobil. These two firms are clearly successful in U.S. refining, each using a very different business model. Valero has become the second largest domestic refiner very quickly. Formed in 1980, it began acquiring refineries in 1981 and grew its U.S. refining steadily, reaching nearly 2 million barrels per day currently. In addition, it owns a refinery in Canada and another in Aruba. The newly acquired Aruba refinery is undergoing a substantial upgrade, and may well be a new source of gasoline supply later this year. The bulk of Valero's business is refining purchased crude oil, chiefly for the U.S. fuels market, and wholesaling the refined products.

In contrast, ExxonMobil is an extremely large firm with worldwide operations in all phases of the oil business. While the third largest participant in U.S. refining, it has not pursued growth in this part of its business. This may have to do with return on invested capital considerations, which make investing in projects other than domestic refining a greater priority. ExxonMobil also owns substantial foreign refining capacity, and can source products for the U.S. market from its own facilities abroad.

**Table 2** below shows Exxon's rate-of-return statistics for the firm as a whole and 2 broad lines of business — "upstream" and "downstream." This table also shows Valero's — which only has one line of business — operating return on capital.

**Table 2. Return on Investment 2001-03 — ExxonMobil and Valero**

| (1) Year | (2) Exxon-Whole Company RACE–% | (3)Exxon Production RACE–% | (4) Exxon Refining & Marketing RACE–% | (5) Valero Return on Capital from Operations–% |
|---|---|---|---|---|
| 2003 | 20.9 | 30.4 | 13.0 | 7.5 |
| 2002 | 13.5 | 22.3 | 5.0 | 3.6 |
| 2001 | 17.8 | 26.8 | 16.1 | 11.7 |

**Sources:** ExxonMobil data from company's *2003 Annual Report*, p. 33. Valero data from *Valero Energy Corporation* April 1, 2004, by Deutsche Bank Securities Inc., p. 2.

With regard to ExxonMobil, column 2 shows return on investment figures based on the average amount of capital employed (RACE) in the company as a whole during the year. Column 3 shows the RACE in production, which is substantially higher during the past few years than the average rate of return in the rest of Exxon's business. In order to maximize returns on investment, management would presumably invest in production first because it generates the highest rate of return — to the extent that desirable projects were available. Downstream operations, whose returns are shown in column 4, where investment payoff is lowest, would be a lower funding priority.

The chips for 2004 have not yet been counted, but it should be a high rate of return year for both firms. Preliminary data from ExxonMobil's second quarter 2004 company financial report show U.S. downstream earnings more than doubled, rising from $419 million to $907 million year-over-year Certainly for this firm, the early 2004 showing of refining profitability was impressive, but of insufficient duration to offer more than an encouraging sign as to long-run profitability in U.S. refining.

Setting aside 2004's initial showing of high profits, company management at an integrated company like ExxonMobil might not choose to fund a profitable downstream investment because — although profitable — its rate of return would be lower than the existing corporate average and, as such, that project would reduce the historically higher overall rate of return earned on ExxonMobil's overall investment

In contrast to ExxonMobil's rate of return, Valero realizes much lower returns on its investment, which is essentially all in refining assets, its only business. Valero's rates of return might be representative of the refining business as an industry. **Figure 2** below, which has been scanned from the Deutsche Bank report on Valero, shows low rates of return for a number of refiners for a significant time period. It suggests that, historically, low rates of return might be the rule in refining. To the extent that Exxon might earn higher rates of return in downstream investments — which include refining — this could be due to in some part to the fact that its refineries are very large and have significant economies of scale.

**Figure 2. Rates of Return in US Refining, 1979-2003**

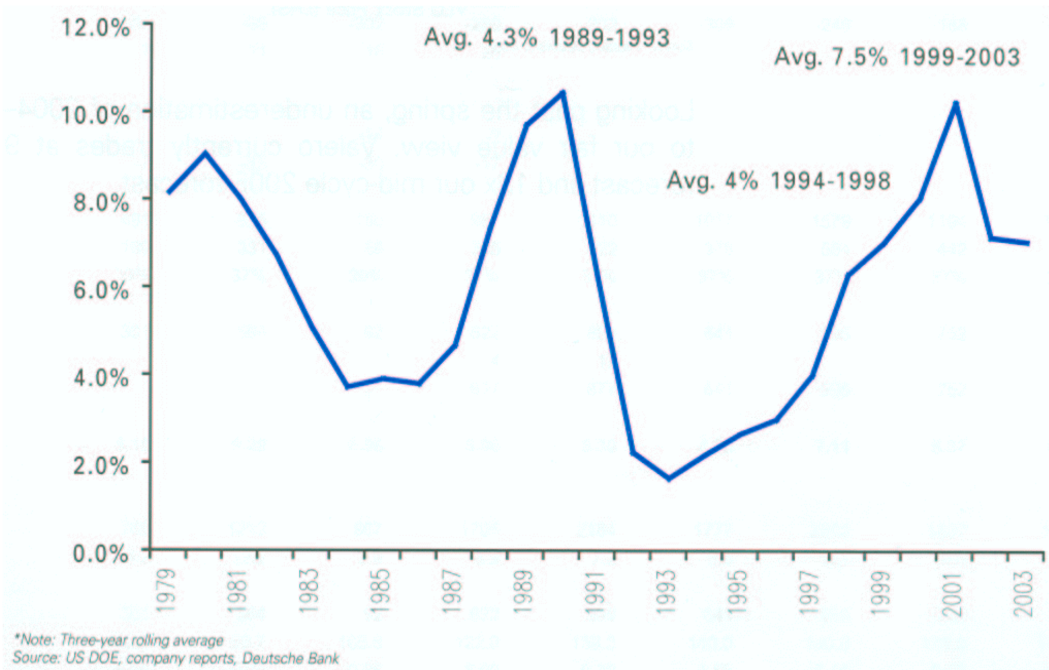



**Figure 2** data — which consists of a 3-year moving average of rates of return — illustrates the peaks and valleys in refinery profitability since 1979. When the total number of refineries reached its modern peak in 1981 at 324 facilities (and 18.6 mbd of capacity), falling oil demand had led to a utilization rate of only 69%, which adversely impacted profits. More refineries were closed, and product demand crossed over capacity, illustrating the need for refined product imports. This gap between supply and demand has expanded during the 1990s as **Figure 1** shows, and likely contributed to rising rates of return in more recent years. For the first part of 2004 — although complete data are certainly not yet available — it would appear that refinery profitability may well have peaked again.

Valero's second quarter 2004 corporate report also showed increases in profitability. The company as a whole earned 1,200 million in the second quarter, compared to $388 during the same period in 2003. In its June 21 - 24, 2004 Roadshow presentation[iii] for the investment community, Valero forecasts this year's earnings trend to translate into a return on investment of 11.6% for all of 2004 and 11.7% for 2005. These figures are high by historic, industry-wide measures. But at least for Valero, these results have been sufficient to encourage the firm to embark on a significant investment program for existing refinery upgrades.

Refinery profitability has a volatile history. This causes refinery investments to be seen as risky compared to other investment opportunities which offer higher and more stable and predictable returns. One profitable year does not necessarily change the long-term perception about profitability in refining, especially since long-lived capital equipment is generally involved.

**Interviews with Representatives of Refiners**

We met with representatives of two oil companies to discuss the refinery capacity shortfall and what criteria might be employed in considering acquiring or expanding an existing refinery. Both viewed the concept of a new, grassroots plant as completely beyond the scope of current thought about their business. But both were on the lookout for opportunities regarding existing refineries.

Among the criteria for such deals were:

- Valuable plant and equipment — both firms were interested in underlying asset value, in terms of useful site and/or plant components, which represent bargains.

- Facility size — there seemed to be a consensus that 100,000 barrels per day was a minimum size for economic scale. While both firms operate at least one (each) smaller plant, these facilities have some unique qualities, which offset small size.

- Water access — both asserted that they were only interested in coastal plants. This is understandable because of increasing crude oil imports, and declining lower-48 state onshore production; both trends ensure that an increasing amount of crude supply will be water-borne. Refiners need the flexibility of a waterside location to ensure a diversity of crude suppliers, and the ability to deal with a multiplicity of suppliers as relationships change over a plant's life. On the refinery output side, firms like cheap and easy-access product transport to U.S. consumers. In addition, there is a need to transport some products for which little domestic market exists. The nation exports about 1 mbd of refined petroleum products, half of which is petroleum coke (used in steel-making). Selling coke and other products, some of which do not meet U.S. specifications, is important for overall refinery economics. These products require ocean transportation to their natural markets.

Both firms expressed concern about the low historic rates of return in the refining business, and great caution regarding projects with below-average long-term rates of return. Clearly, the Valero attitude toward return is shaped by all the company's business opportunities having to do with refining, while ExxonMobil is faced with a full cross section of oil industry opportunities. Given limited funds for investment, Exxon is likely to choose the highest return investments, which may well be in parts of its business other than refining. As a firm, ExxonMobil seeks a greater return than Valero, and this clearly shows in the financial results of both companies and the way investors and lenders perceive them. For a firm such as Valero — which would likely have to borrow money or sell new shares of stock — low profitability in refining could inhibit capacity expansion.

### Enhancing the Rate of Return In Refining

Given the seeming public policy call for more domestic refining capability, are there policy tools that could be used to make investment in refining more attractive to private firms by raising the effective rate of return on capital? Policy makers have in the past used two measures to raise the return on capital to businesses needing encouragement; they are specifically targeted investment tax credits and accelerated depreciation of plant and equipment.

In this case, investment tax credits would allow refiners to effectively reduce the cost of a qualifying investment as it is made, and becomes a positive factor in the project's rate of return calculation. And by lowering investment cost, the investment tax credit could have the effect of reducing new cash financing needs. Such a measure could contribute to enhanced rate of return and lowered new capital requirements, although the amount of such benefits could vary significantly from firm to firm.

Accelerated depreciation of refining capital assets would raise rates of return by reducing taxes and shifting net cash flows forward in time. This can be established by shortening the depreciation period — currently 10 years for most refining investment — or by changing the depreciation schedule to permit higher percentage write-offs in early years. It could reduce taxes in the near term, which can improve overall project rate of return. Like the investment tax credit, actual impact on return on investment would likely vary from firm to firm.

## Boutique Fuels Issues

### What Are Boutique Fuels?

The term "boutique fuels" refers to the various specialized gasoline formulations made to meet air quality standards or local preferences. Besides meeting standards for conventional fuel, refiners and marketers in a state may also have to meet requirements in different areas for one, two, or even three different formulations. Compared to conventional gasoline, other fuel specifications require greater investment by suppliers in refining equipment and storage capacity. In addition, some petroleum feedstocks may be unsuitable for the production of certain specifications. Therefore, raw material costs may be higher for the production of some boutique fuels than for conventional gasoline. Further, some blends requiring specific components such as ethanol can lead to increased transportation costs because these components cannot be transported through pipelines. However, a refinery tooled to meet specific local requirements may face limited competition from other refineries, potentially increasing profits.

The existing system has evolved in response to various federal air quality standards, and resulting state standards, local refiner decisions, and consumer choices. Further, many of the state formulations were designed to mitigate moderate air quality problems without requiring more stringent and more expensive measures. An attempt to group states under one regional or national standard, referred to as "harmonization," could lead to lower pump prices, as supplies become more fungible throughout a national system.

However, harmonization could also lead to higher pump prices for areas with less severe ozone problems, or higher emissions in areas with more severe problems. Further, refiners have stranded considerable costs in tooling facilities to meet specific local requirements.

## Fuel Specifications[iv]

The Clean Air Act requires the use of special fuels in areas that are in nonattainment of the National Ambient Air Quality Standards (NAAQS) for ozone or carbon monoxide. Federal reformulated gasoline (RFG) must be used in severe or extreme nonattainment areas for ground-level ozone. Other areas with less serious ozone problems may opt-in to the RFG program to help them attain or maintain compliance with the NAAQS. Areas that choose not to opt-in to the RFG program are permitted to adopt their own state specifications. Overall, about one-half of U.S. (summertime) gasoline is conventional, a little over one-fourth is federal RFG and the remainder localized variations.

**Conventional Gasoline.** Conventional gasoline is the fuel sold across most of the country. It is the least stringently regulated fuel, with a summertime limit on volatility,[v] a prohibition on the use of lead, and a limit on the level of manganese (a heavy metal). In summer months, conventional gasoline accounts for approximately 49% of U.S. gasoline consumption.[vi]

**Reformulated Gasoline (RFG).** In areas with major ozone problems, federal RFG is required. Other areas with less severe problems may also opt-in to the program. Currently, major metropolitan areas in 17 states and the District of Columbia use RFG.[vii] The program has several requirements, including a minimum oxygen content, a benzene cap, limits on nitrogen oxide and toxic emissions, and a cap on volatility. In the summer months, the volatility limits are more stringent than in the winter months, and are more stringent for southern areas than for northern areas.[viii] Federal RFG accounts for about 28% of summertime gasoline consumption.[ix]

**Low Volatility Conventional Gasoline.** The Environmental Protection Agency (EPA) requires that certain ozone non-attainment areas (that are not required to use RFG) use a lower volatility fuel in the summer months. Instead of the conventional fuel required across most of the country, Reid Vapor Pressure (RVP) — a measure of volatility --- is capped for these areas, which include parts of states in the South and West. Low-volatility gasoline accounts for about 7% of summertime gasoline consumption.[x]

**State Fuels.** In areas that have less serious ozone problems (in contrast to severe or extreme nonattainment areas), states may establish their own fuel standards as a strategy for mitigating emissions, if they choose not to opt-in to the RFG program. Most states require only a lower volatility; in all other ways the requirements are identical to conventional gasoline. However, some states go further and require a lower sulfur content (e.g. Georgia), or limit the use of certain additives (e.g. Texas).[xi] Further, Minnesota requires a minimum of 2% ethanol in all gasoline sold in the state. These various fuels account for about 12% of summer gasoline consumption.[xii]

**California Cleaner-Burning Gasoline (CBG).** In addition to giving states leeway on setting fuel standards, the Clean Air Act allows California to set its own standards, as long as those standards are at least as stringent as the federal standards. California requires the use of "Cleaner-Burning Gasoline" (CBG), with generally stricter requirements than those for federal RFG. Allowable sulfur and benzene content is lower, and performance standards are tighter for several pollutants. However, there is no oxygen standard for California CBG. In areas of the state where federal RFG is required, gasoline must meet all the standards for RFG as well as CBG.[xiii] Arizona and Nevada have comparable state programs. California CBG accounts for approximately 4.5% of summertime gasoline consumption.[xiv]

**Meeting Oxygen Standards**

In the past few years, the federal RFG oxygen requirement has led to major problems for states, localities, and fuel suppliers. There are two common ways to meet the oxygen requirements for RFG, methyl tertiary butyl ether (MTBE), and ethanol. MTBE — until recently the most widely used — is produced from natural gas or as a by-product of the petroleum refining process. Ethanol is an alcohol produced from agricultural products, mainly corn. While both have their advantages and disadvantages, groundwater contamination from MTBE has led to a push for its elimination. However, if MTBE were banned, RFG areas would need to use ethanol, unless the oxygen standard were eliminated.

Contaminated (underground) wells have been found in numerous states, especially in the Northeast and California.[xv] While most detected levels are not thought to be a health concern, even in low concentrations MTBE can make water noxious, with a smell and taste resembling turpentine to some. Because of concerns over contamination, an EPA Blue Ribbon Panel recommended a substantial reduction in the use of MTBE.[xvi]

Because MTBE finds it way into groundwater, 17 states have passed legislation or taken executive action to ban or limit its use, and there have been congressional proposals to ban the additive nationally as well. However, a ban on MTBE could have substantial effects on the gasoline supply. Approximately 62 million barrels of MTBE were produced in the United States in 2003, or about 2% to 3% of total gasoline consumption.[xvii]

Replacing the energy[xviii] lost from this production would require about 50 million barrels of gasoline per year, or about 76 million barrels of ethanol.[xix] To meet equivalent levels of demand, elimination of MTBE would likely require increases in petroleum production or imports, increases in refinery efficiency, and/or increases in ethanol production. Complicating this issue is the requirement that RFG contain oxygen. Unless the Clean Air Act is amended to eliminate the oxygen requirement, or provide waivers, the lost oxygen from MTBE must be replaced. In California, New York, and Connecticut, where state MTBE bans have taken effect, suppliers are delivering ethanol-blended RFG. However, there are concerns that gasoline prices, which are already high, could increase even more as nearby areas do not blend ethanol in their RFG, and it may be difficult to obtain MTBE-free RFG in the event of a supply disruption.[xx] However, with high crude oil prices, there is some indication that wholesale ethanol prices are below gasoline prices, taking taxes into account.

Ethanol-blended RFG differs in several ways from RFG with MTBE. Ethanol has a higher oxygen content per gallon than MTBE, meaning less ethanol must be used to meet the oxygen requirement. However, it is also more volatile than MTBE, contributing to more ozone formation. To counter the higher volatility of ethanol, the gasoline blendstock used in ethanol RFG must have a lower volatility. This low-volatility blendstock is more expensive than the blendstock for RFG with MTBE.

Because of concerns regarding the supply of ethanol, there is interest by some in requesting waivers from the oxygen requirement, or eliminating the oxygen requirement altogether. The EPA Blue Ribbon Panel recommended action to eliminate the oxygen standard, to provide gasoline suppliers with more flexibility in dealing with an MTBE ban.[xxi]

Environmentalists are concerned that eliminating the oxygen requirement would lead to further air quality problems. This is because oxygenates, in addition to improving combustion, displace other, more toxic blending agents such as benzene. Currently, most RFG producers are reducing toxic content and emissions substantially more than required. Environmentalists fear that an elimination of the oxygen standard would lead to the production of fuel that, while compliant with the RFG requirements, contains more toxic compounds than current RFG. This situation is referred to as “backsliding.”

Opponents of the oxygen requirement counter that gasoline can be made that meets all of the performance requirements of RFG without the use of oxygenates. Their claim is bolstered by the fact that California CBG is as stringent, if not more stringent, than federal RFG, without the use of oxygenates.[xxii] However, the oxygen requirement for RFG creates additional demand for ethanol. Because of this, ethanol producers and corn growers are concerned that an elimination of the oxygen requirement associated with a ban on MTBE would lead to a drop in demand that could severely harm the ethanol industry. This would ultimately lead to lower corn prices and lower farm income, as well.

Ethanol is biodegradable, and relatively non-toxic, except at very high concentrations. Therefore, there are few concerns about ethanol itself contaminating groundwater. However, ethanol has shown the propensity to carry other toxic gasoline components, such as benzene, farther than they would have otherwise traveled. Although this issue has been little studied, ethanol-blended gasoline could potentially contribute to more water contamination than conventional gasoline.[xxiii]

**Renewable Fuels Standard.** To fill the void in ethanol demand left by an elimination of the oxygen requirement, there have been legislative proposals to develop a renewable fuels standard (RFS). A renewable fuel is one that can be produced from renewable resources. In general, renewable fuels are those that are produced from animal or vegetable matter. Ethanol is the most common renewable fuel; approximately 2.8 billion gallons (67 million barrels) were produced in 2003. The next most common renewable fuel is biodiesel, a synthetic diesel fuel made from vegetable oils (mainly soy) or recycled grease; less than 100 million gallons (2 million barrels) of biodiesel were produced in 2003.

Among the options considered in the 108th Congress, a renewable fuels standard would require that all motor fuel in the United States contain a certain percentage of renewable fuel, or require that a set amount of renewable fuel be sold in a given year. Legislative proposals in the 108th Congress generally would require the use of 5.0 billion gallons (120 million barrels) per year of renewable fuel by 2010 to 2015 time frame. This would mean nearly a doubling of renewable fuel use. And because ethanol is the most common renewable fuel, ethanol consumption would also double in all likelihood.

Supporters argue that a renewable fuels standard would foster agricultural production, promote domestic energy sources, and lead to cleaner air. Critics argue that it would raise gasoline prices and artificially inflate demand for ethanol. Further, critics argue that a renewable mandate would result in “corporate welfare” for a few large ethanol producers. They add that greater ethanol consumption would lead to reduced fuels excise tax receipts, and that a renewable standard would add one more layer of requirements to an already complex system.

**“Safe Harbor” Liability Protection.** Among the most controversial issues surrounding boutique fuels is the proposal to grant MTBE and renewable fuels a “safe harbor” from defective product litigation. It would protect anyone in the product chain, from manufacturers down to retailers, from liability for cleanup of MTBE and renewable fuels or for personal injury or property damage based on the nature of the product (a legal approach that has been successfully used in California to require refiners to shoulder liability for MTBE cleanup). In some legislative proposals, the safe harbor would be retroactive, eliminating lawsuits filed before a given date.

With liability for manufacturing and design defects ruled out, plaintiffs would be forced to demonstrate negligence in the handling of such fuels in these and any future cases, a more difficult legal standard to meet. As a result, drinking water suppliers widely oppose the safe harbor provision and have expressed concern that it could leave communities paying much of the cost for cleaning up contamination caused by fuels containing MTBE or ethanol. Manufacturers counter that the problem lies with leaking tanks, not with the fuels the tanks contain. They argue that a product liability safe harbor provision is reasonable, given that the fuels are used to meet federal fuel mandates.

## Harmonizing Gasoline Standards

Because of the complex nature of various gasoline standards, there is interest in harmonizing the standards. This would entail requiring one set of standards across a region (or even across the country). Potential scenarios include requiring that within an area, only one low volatility fuel could be used in addition to conventional gasoline and RFG. For example, currently, summer gasoline produced for the Charlotte, NC, area cannot be used in Norfolk, VA (RFG), or Atlanta, GA (low-volatility). However, fuel from either Norfolk or Atlanta could be shipped to Charlotte. Under one proposed harmonized system, while Norfolk would still use RFG, the standards for Charlotte and Atlanta would be identical. Another, more drastic, scenario would require that all fuel be conventional gasoline or RFG. Some of the key issues involved in harmonization would be production costs, consumer prices, production capacity, supply stability, and air quality.

**Production Cost.** Depending on the way standards are harmonized, production costs could increase dramatically. While fewer standards across the country would seem to benefit refiners, it could create a need for expensive refinery modifications to meet the harmonized standards. Because refiners made investments in tooling their plants to meet the local requirements, changes could be costly. However, a less drastic harmonization, where some of the low-volatility fuels were harmonized but not eliminated, could mitigate some of these difficulties.

**Production Capacity.** Most U.S. refiners are operating at or near capacity. Limited production capacity will always lead to higher price, especially if there is a disruption in production from a major refiner. Harmonization could potentially exacerbate this problem, depending on how it was implemented. New standards could lead to higher or lower supply levels. For example, very stringent volatility standards could require refiners to limit the use of some gasoline components. The loss of volume from cutting back on these components would require increased supply in the form of petroleum, ethanol, or other blending components.

**Supply Stability.** Because the main goal of harmonization would be to improve the fungibility of the system, supply disruptions might be reduced. Fewer standards make it more likely that product could be moved from one area of the country to another to meet local needs. However, it must be noted that supply disruptions can never be completely eliminated because there are many factors outside of fuel standards that play a role in supply adequacy. These include levels of crude oil supply, petroleum imports, refining capacity, seasonal fluctuations in demand, and weather patterns (which may influence demand for fuel).

**Air Quality.** A key concern in any discussion of harmonization is the effect on air quality. Many of these “boutique fuels” standards were created specifically to mitigate the unique air quality problems in a metropolitan area. The standards were devised as part of a State Implementation Plan (SIP) for ozone. SIPs are based on models showing that particular fuels requirements will lead to projected reductions in pollutant emissions. More stringent requirements, while more costly, lead to greater emissions reductions. Therefore, an effort has been made in the SIPs to balance air quality goals with producer and consumer concerns about cost.

Any harmonization would necessitate that certain state fuels be chosen over others. What must be resolved is the question of which standards should apply to all states in a region. The most stringent? The least stringent? Some compromise standard? Any standard less stringent than an SIP’s current standard would require the state to identify other emissions reductions. Any standard more stringent than a state’s current standard would likely lead to higher consumer prices.

**Other Issues.** In addition to the above concerns about harmonization, some other issues remain. One of these has to do with local marketing decisions and state requirements unrelated to air quality. If these factors are not addressed, the system could still remain quite complex. For example, Minnesota requires the use of ethanol across the state. Under harmonization, would states be allowed to set such a standard, or would they be precluded?

Another key issue is the role of MTBE. Several states have banned or limited the use of the additive. If MTBE is not banned nationwide, this could lead to even more complexity in the system, with some states allowing its use and others precluding it. Non-MTBE states would be unable to import fuel from MTBE states.

**Administration Action on Boutique Fuels**

As part of the Bush Administration's action on its National Energy Policy,[xxiv] EPA is currently studying the potential effects of harmonization. In a preliminary report, EPA studied various scenarios and attempted to analyze the effects of those scenarios. Recognizing that its study is the first step in a much longer process, EPA found that depending on the scenario, standards could be harmonized without major cost increases, increases in emissions, or reductions in gasoline supply. The study states that even though some of the harmonized areas have not faced supply disruptions in the past, harmonization could reduce the potential for future disruptions.[xxv] More drastic measures (such as requiring RFG across the country), the study finds, would lead to more supply stability, but could lead to much higher prices and major reductions in gasoline production capacity.

**Congressional Action**

Because of the federal and state issues involved with boutique fuels, there has been considerable interest in the topic. Legislation has been introduced in the 108th Congress to reduce the use of MTBE or ban it entirely, as well as bills to grant liability protection for MTBE. Further there have been proposals to eliminate the RFG oxygen requirement and/or establish a renewable fuels standard. In addition, there have been bills to harmonize requirements, or to require the Administration to further study the effects of harmonization. None of these proposals has yet been signed into law. But with constituent concerns over high gasoline prices, Congress will likely continue to discuss these issues.

## Permitting Issues

**What is NSR?**

The Clean Air Act (CAA) requires a preconstruction review of, and a permit for, almost any modification of an air polluting source or any major new source. Assuming that a state has an EPA-approved State Implementation Plan (SIP), which spells out the state's strategy for complying with National Ambient Air Quality Standards (NAAQS), regulatory approval to construct the new source or modify the existing source must come from the appropriate state agency. To receive this "Permit to Construct," the applicant must show that the proposed source or modification will not result in, or exacerbate, violation of a NAAQS, either locally or downwind. In addition, applicants must show that their proposal will not result in local or downwind excedences of increments of increased air pollution allowed under Prevention of Significant Deterioration (PSD) regulations in areas complying with NAAQS. It is this preconstruction review process that is called New Source Review (NSR).[xxvi]

The NSR process is triggered for any new source that potentially could emit 100 tons annually (or less in some areas) of any criteria air pollutant, and by any modification that will cause a significant increase in annual emissions (regulatorily defined as 40 tons for $SO_2$ and NOx[xxvii]). The specific NSR requirements for affected sources depend on whether the sources involved are subject to the PSD or the non-attainment provisions.[xxviii] If covered by PSD, the source is required to install Best Available Control Technology (BACT), which is determined on a case-by-case basis, and which cannot be less stringent than the federally determined New Source Performance Standard (NSPS) for that pollutant. If covered by non-attainment provisions, the source is required to install Lowest Achievable Emission Rate (LAER) and obtain applicable offsets for that particular area.[xxix] Like BACT, LAER must not be less stringent than the federal NSPS.

**What is the Source of Debate?**

In 1998, the Clinton Administration launched its Petroleum Refinery Initiative — a multi-faceted approach to review the petroleum refining industry's compliance with the CAA.[xxx] The initiative extended CAA provisions beyond NSR to include three others: (1) NSPS, (2) Leak Detection and Repair Requirements (LDAR), and (3) Benzene National Emissions Standards for Hazardous Air Pollutants (BWON). Since March 2000, EPA has entered into 11 global settlements covering 42 refineries and 40% of U.S. domestic refining capacity.

An example of this enforcement action involves the settlement between the Justice Department (for EPA) and a consortium consisting of Equilon Enterprises LLC, Motiva Enterprises and Deer Park Refining Limited Partnership. Owners of nine refineries,[xxxi] the Justice Department complaint found violations of several CAA provisions, including NSR, NSPS, LDAR, and BWON.[xxxii] A civil judicial settlement was announced March 21, 2001, and included a $9.5 million civil penalty.[xxxiii]

According to EPA, the settlement will cost the consortium about $400 million over eight years and result emissions of nitrogen oxides by 8,000 tons annually and sulfur dioxide by 49,550 tons annually. Much of the expense involves controlling pollutants resulting from Fluid Catalytic Cracking Unit (FCCU) operations. For example, eight refineries are required to install and operate a combination of new control technology and to optimize the performance of existing control technology for controlling FCCU related pollutants.[xxxiv] For sulfur dioxide control, this includes installing and operating wet gas scrubbers at five refiners while optimizing performance of existing scrubbers at two other refineries. For nitrogen oxide control, this includes installing and operating selective catalyst reduction (SCR) at one refinery and two selective non-catalyst reduction (SCR) at two refineries, and the aggressive use of catalysts at five other refineries. In addition, other measures were required to respond to NSR, NSPS, LDAR and BWON complaints. These measures include reducing emissions from heaters and boilers; preventing sulfurous gas flaring from sulfur recovery units; controlling fugitive emissions of volatile organic compounds by implementing an enhanced program for identifying and repairing leaking valves and pumps; and, implementing an enhanced program for ensuring compliance with benzene waste management practices.

The ninth facility, the 66,000 barrel per day refinery at Bakersfield CA, was cited for excessive flaring of sulfurous gases from sulfur recovery units, and required to remedy the situation. Because Bakersfield does not have a FCCU, it was not required to install control technologies to reduce emissions associated with FCCU operations.[xxxv] In addition, the refinery avoided any additional controls with respect to benzene, contending its emissions were below the 10 mega-gram per year threshold for such controls.[xxxvi] The consent degree does require that sampling of such emissions be increased at the facility.

**What has EPA Done to Assist Refiners?**

The Clinton Administration's enforcement initiative raised questions within the Bush Administration. In May 2001, Vice President Cheney's energy task force called on the Justice Department to review the legality of NSR-related lawsuits initiated by the Clinton administration.[xxxvii] In January 2002, the Justice Department found the lawsuits to be supported in law and fact.[xxxviii] In addition, the energy task force asked EPA to review the impact of NSR on new utility and refinery generation capacity, energy efficiency, and environmental protection. In June 2002, EPA reported to the President that: (1) NSR had not significantly impeded investment in new power plants or refineries; (2) NSR had impeded projects at existing facilities that would maintain and improve reliability, efficiency and safety; and, (3) NSR does result in significant environmental and public health benefits.[xxxix] Based on its findings, EPA recommended several revisions to NSR.[xl] There were two parts to the recommendations. The first consisted of four recommendations that would complete the 1996 Clinton Administration's rulemaking process. The second consisted of a recommendation to propose a regulation to clarify the definition of "routine maintenance," and its policy on debottlenecking and aggregation.[xli]

EPA finalized the first part of its recommendations in December 2002.[xlii] The final rule's provisions fall into four categories based on EPA's earlier recommendations,[xliii] and which the EPA believes complete the rulemaking process begun under the Clinton Administration in 1996[xliv]: (1) Plantwide Applicability Limits (PALs); (2) Clean Unit Exclusion; (3) Pollution Control and Prevention Projects; and (4) Emissions Calculation Test Methodology. **Table 3** briefly summarizes the major differences between the Clinton Administration's proposed rule; EPA's 2002 direct final rule; and pre-2002 regulations. EPA's final rule provides a detailed discussion of what it proposed in 1996 and what it finalized in November.[xlv]

Of these modifications to NSR, it is the PALs provision that is probably the most significant for refiners. Considered a "welcome component" of NSR reform, PALs were praised by the National Petrochemical and Refiners Association (NPRA), which stated that PALs "will provide industry with the certainty and flexibility necessary to plan future projects, manage their current emissions and reduce emissions sooner."[xlvi] Basically, if a plant owner decides to establish a plantwide emissions cap based on actual emissions (any 24-month period over the past 10 years), the owner can make changes without obtaining a major NSR permit (provided the changes do not result in the facility's emissions exceeding the PAL). The PAL is analogous to an emissions "bubble" where emissions from the facility are treated as a whole, not on a smokestack-by-smokestack basis.

Discussions with individual refiners found agreement with NPRA's position that PALs are an important reform to the NSR process with respect to their operations, and significantly reduced their regulatory and permitting burden. However, not everybody agrees with industry and EPA that PALs will result in emissions reductions sooner. A General Accounting Office (GAO) survey of state officials indicates that over half believe that PALs will increase emissions – a concern also expressed by environmental groups.[xlvii]

**Table 3: Summary of Major Differences**

| Provision | Pre-2002 Regulation | 1996 Clinton Proposed Rule | 2002 EPA Final Rule |
|---|---|---|---|
| Plantwide Applicability Limits | none | Voluntary emission cap based on most recent 2-yr. average plus a reasonable operating margin that is less than the trigger for NSR review. PALs may be adjusted to reflect any new requirements | Emission cap based on any consecutive 24-month period over the past 10 years and valid for 10 years |
| Clean Unit Exclusion | none | If unit meets a BACT or LAER limit set in the last 10 years, NSR would not be triggered by changes unless unit increases hourly potential emissions | If unit meets a BACT or LAER limit set since 1990, or Maximum Achievable Control Technology (MACT), Reasonably Available Control Technology (RACT) or under-took pollution prevention efforts, it would be excluded from NSR for 10-15 years |
| Pollution Control and Prevention Projects (P2 projects) | none | Excludes P2 projects from NSR unless emission increase would contribute to violation of NAAQS, PSD, or air quality related values in a Class I area. Permitting authority responsible for air quality determination | Excludes P2 projects from NSR unless emission increase would contribute to violation of NAAQS, PSD or air quality related values in a Class I area. EPA will provide a list of presumptively eligible technologies |
| Emissions Calculation Test Methodology (baseline and test changes) | Actual to potential test for all industrial sources except electric utilities which have an actual to future actual test based on a facility's emissions over 24 consecutive months within the most recent five-year period | Proposed options ranging from applying the actual to future actual test to only electric utilities or to all industrial sources, or eliminating it | Applies the utility's actual to future actual test to all industrial sources based on a facility's emissions over two consecutive months within the most recent ten-year period |

### What Could EPA Do to Further Assist Refiners?

**Debottlenecking.** Some of the improvement in refinery capacity at existing units over the past decade has come from debottlenecking. Refineries have many integrated components. If an owner increases the efficiency of one component, it may affect the operation of other components, either upstream or downstream. If those effects include emissions increases at those unmodified units, the owner may have compliance problems, depending on whether the associated emissions increases put the affected, but unmodified component over its permitted level. In any case, regulatory review and intervention is likely.

EPA's 2002 recommendations to the President recognized this possibility. Its sixth recommendation suggested the following response to the debottlenecking issue:

> Through notice and comment rulemaking, EPA will clarify that, when calculating actual emissions associated with a physical change or change in the method of operation, sources generally should look only at the unit undergoing the change. Emissions from units "upstream" or "downstream" of the unit being changed should be considered only when the permitted emissions limit of the upstream or downstream unit would be exceeded or increased as a result of the change.[xlviii]

EPA has not proposed a debottlenecking reform yet. It is possible that EPA feels the PALs provision is sufficient, or the actual drafting is more difficult than anticipated when the recommendation was made. In any case, an EPA initiative on the debottlenecking issue might improve the permitting situation for existing refineries. However, it is likely that the controversy over the environmental effects of NSR reforms noted above would extend into any debottlenecking rulemaking proceedings.

**Routine Maintenance.** Fundamental to the debate on NSR enforcement with respect to existing facilities is the notion of "routine maintenance." In promulgating implementing regulations, EPA exempted certain activities from the definition of physical or operational change. Among those activities exempted was: "maintenance, repair, and replacement which the Administrator determines to be routine for a source category...."[xlix] In addition, increases in production rates that do not involve capital expenditures do not constitute a modification. Responding to this situation, industries began to spread out their rehabilitation efforts in an attempt to make them fit into their routine maintenance schedules.[l] By spreading out rehabilitation efforts and integrating them into facilities' operation and maintenance schedules, the distinction between "modification" and "routine maintenance" is effectively blurred, and arguably, eliminated.

Rehabilitation programs are common in the refinery industry. The issue is whether this activity violates the modification definition of NSR. If "routine maintenance" is defined in terms of "average industry maintenance practice" at the time of the 1970 or 1977 Clean Air Act Amendments, then a strong case can be made that it is — major components are being replaced or upgraded that would not have been under average industry maintenance practices of that time. Yet, if "routine maintenance" is interpreted to mean industry practices currently, then one can argue that rehabilitation has become routine over the past 20 years, and thus does not represent a modification.

On August 27, 2003, the EPA issued a final rule[li] on clarifying the definition of routine maintenance under NSR. Focused on existing sources, the final rule exempts industrial facilities from undergoing NSR for replacing safety, reliability, and efficiency rated components with new, functionally equivalent equipment if the cost of the replacement components is under 20% of the replacement value of the facility's process unit.[lii] If the replacement activity exceeds this threshold, a case-by-case determination will be made as to whether the plant undergoes NSR. Essentially, the final rule permits owners of existing units to maintain and operate their units at their basic design parameters (defined in terms of maximum heat input and fuel consumption specifications) without having to undergo NSR. As stated in the rule: "By not imposing a time limitation [on permissible replacement activities], the ERP [Equipment Replacement Provision] allows replacement activities to be driven by consideration of economic efficiency rather than artificial regulatory constraints."[liii]

The rule is highly controversial. Critics see the new regulation as permanently "grandfathering" older, more polluting facilities from ever having to meet the clean air standards required of newer plants. In October 2003, 12 states and several major cities petitioned the D.C. Circuit Court of Appeals to review the rule.[liv] In December 2003, a three-judge panel of the D.C. Circuit Court of Appeals issued a summary order blocking implementation of the rule until it can make a final determination. The Court accepted the states' argument that they would suffer irreparable harm if the rule were implemented and that the states also showed a "likelihood of success" when the case goes to trial.[lv]

The refinery industry would like to see the routine maintenance rule unblocked. The NPRA position is that the current routine maintenance provisions are "broken and adversely affect the industry's need to maintain safe, efficient and reliable operations while fulfilling its commitment to continued environmental improvement."[lvi]

The focus of controversy with respect to the routine maintenance rule was coal-fired electric power plants. Among the possible options is a narrow congressional amendment allowing the new EPA rule on routine maintenance to go through only for refineries. However, given the controversy over the environmental effects of the reforms noted previously, this may not be possible.

## Conclusion

U.S. refining capacity has not kept up with increasing demand for petroleum products. Some see the decline as reflecting fundamental trends in refining and the globalization of product trading. This view holds that the U.S. refining capacity situation is the inevitable result of a global market for petroleum products, as well as the decline in domestic crude production.

Economic fatalism of this sort seems too simplistic. Those concerned about the adequacy of U.S. refining capacity point to parameters that governments could change, were a concerted and comprehensive refining policy to be formulated. They see environmental policies that fracture the gasoline market and adversely affect efforts aimed at modernizing of physical plant. Additional concerns exist about other factors that could impact profitability, such as MTBE lawsuits. These factors may be restricting refining investment decisions.

Through this lens, changes in regulatory practices and legislative action are seen as effective tools to improve the outlook for refining. Some seek remedies by changing environmentally related regulation. Indeed, environmental impacts are one of the all-encompassing contexts that the industry must operate in. Environmental impacts occur in the front-end of business with the supply of crude, siting of new facilities, the operational end of the business with air pollutants and effluents, and the production-end of the business with product specifications and liability.

The complexity of the environmental aspects of the refining business is reflected in the complexity of the government-industry interactions. Despite the focus on changing federal rules and regulations, much environmental regulation occurs at the state and local levels. A change in federal rules does not necessary translate into changes at the state and local levels, and certainly not uniformly. The successful blockage of EPA's proposed routine maintenance rule was initiated by 12 states and several major cities. Likewise, the proliferation of boutique fuels and MTBE lawsuits are mostly the result of state and local decisions, not edicts of the federal government. Attempts to streamline governmental decision-making with respect to environmental impact is far more complex than simply changing some federal rule. States and local communities need to see that the advantages industry is claiming as a result of such actions will lead to important improvements in the nation's petroleum products situation.

Such promises are not easily made. Like government, the industry is not homogeneous. Individual companies have different business plans and different investment opportunities. Some companies, like Valero, focus on domestic refining, especially upgrading existing refineries. Improvements in the regulatory climate may provide significant encouragement of its core business. Others firms, like Exxon, have more global interests, which include construction and operation of refineries abroad. Improvements in the U.S. regulatory climate will have to compete with the regulatory and economic climate of other countries for its investment dollar.

To make it attractive for U.S. refiners to expand, clear and durable policy is critical. If the policy goal is really focused on reviving and expanding domestic refining capacity, the focus must be long-term, and — given the realities discussed in this paper — more complex. Meeting the economic and regulatory challenge of rehabilitating existing domestic facilities — not to mention constructing new ones — would require a comprehensive approach to refining policy that involves the multiple layers of government implementing refining policy, and the differing interests within the refining industry itself. The federal government would have to be a forum for sifting through the economic, environmental, and regulatory realities of the refining business and synthesizing fruitful possibilities in a world where there are no silver bullets and few short-term solutions.

**Endnotes**

i.Annual Energy Review 2002. Table 5.9.
ii.Petroleum Supply Annual, 2002. Table 49.
iii.available on the company web site at www.valero.com
iv.Most boutique fuel specifications apply in the summer months. This discussion is limited to those fuels. While there are also winter-only formulations, these have a much smaller effect on U.S. gasoline supply.
v.Volatility is the propensity for a chemical to evaporate. The measurement of volatility is Reid Vapor Pressure (RVP), and is usually expressed in pounds per square inch.
vi.U.S. Environmental Protection Agency (EPA), Office of Transportation and Air Quality (OTAQ), *Staff White Paper: Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements.* October, 2001.
vii.With the designation of new nonattainment areas under revised ozone standards, this number may increase.
viii.Heat is a catalyst for the reactions that produce ozone. That is why ozone tends to be more serious in the summer months. Therefore, in warmer areas, and during warmer times, ozone-forming emissions are more tightly controlled.
ix.EPA, OTAQ, op. cit.
x.Ibid. Low-volatility gasoline actually accounts for about 19% of gasoline consumption, but much of this is a result of state, not federal requirements. See the section below on "State Fuels."
xi.MTBE is used to add oxygen, boost octane, and extend gasoline stocks. However, there are concerns about its use. These concerns will be discussed below, in the section on "Meeting Oxygen Standards."
xii.EPA, OTAQ, op. cit.
xiii.For example, while federal RFG requires a minimum oxygen content, California CBG does not.
xiv.EPA, OTAQ, op. cit.
xv.Because MTBE can travel farther than, and separately from, other components of gasoline, groundwater can be contaminated with MTBE even if other gasoline components are not detected in the water.
xvi.EPA Blue Ribbon Panel on Oxygenates in Gasoline, *Achieving Clean Air and Clean Water*. September 15, 1999. p. 86.
xvii.U.S. Department of Energy, Energy Information Administration, *Monthly Oxygenate Telephone Report.* January 2004.
xviii.MTBE has a higher energy content (btu/gallon) than ethanol, a lower energy content than gasoline. To equal the energy content in one gallon of MTBE, roughly 0.8 gallons of gasoline are needed, as compared to 1.2 gallons of ethanol.
xix.MTBE has a higher energy content (i.e. there is more energy per gallon) than ethanol. Therefore a greater volume of ethanol is necessary to supply the same amount of energy. Gasoline has a higher energy content than MTBE, so less volume is needed.
xx."DOE Says Resupplying NY and CT Gasoline Markets Will Be Difficult," *Energy Washington.* May 14, 2004.
xxi.EPA Blue Ribbon Panel on Oxygenates in Gasoline, op. cit.

xxii.Al Jessel, Chevron Products Company, *Testimony before the House Science Committee Subcommittee on Energy an d Environment.* September 20, 1999.
xxiii.Susan E. Powers, David Rice, Brendan Dooher, and Pedro J. J. Alvarez, "Will Ethanol-Blended Gasoline Affect Groundwater Quality?," *Environmental Science and Technology*. January 1, 2001. p. 24A.
xxiv.National Energy Policy Development Group, *National Energy Policy.* May 2001.
xxv.EPA, OTAQ, *Staff White Paper.* p. 47.
xxvi. Some restrict the term "NSR" to the review process in a non-attainment area only; the review process in an attainment area being called "PSD pre-construction review". This paper will use the term to indicate both. In addition, new and modified sources must meet New Source Performance Standards (NSPS).
xxvii. 40 CFR 52.24
xxviii. It should be noted that a source can be affected by the PSD requirements for one pollutant, and by the non-attainment requirements for another pollutant.
xxix. For details on these provisions and their requirements, see *Clean Air Act, Part C – Prevention of Significant Deterioration of Air Quality, sections 160-169; and, Part D – Plan Requirements for Nonattainment Areas, sections 171-178.*
xxx.For more information on the Petroleum Refinery Initiative, see: www.epa.gov/Compliance/civil/programs/caa/oil/index.html
xxxi.Equilon is part of a consortium with Motiva Enterprises and Deer Park Refining Limited Partnership (Shell) operating 9 refineries. All nine refineries were found in violation of CAA provisions.
xxxii.*U.S. v. Motiva Enterprises LLC, Equilon Enterprises LLC, and Deer Park Refining Limited Partnership.* Compliant filed June 18, 2000, United States District Court, Southern District of Texas.
xxxiii.For details on the case, including the compliant and consent decree, see: www.epa.gov/compliance/resources/cases/civil/caa/equilon.html
xxxiv.One refinery, the 152,000 barrel per day facility at Delaware City, DE has a Fluid Coking Unit.
xxxv. FCCU is a process that "cracks" petroleum products through use of a powered catalyst suspended in a moving stream of oil vapor.
xxxvi.For the 10 mega-gram exemption, see: 40 CFR 61.342(b).
xxxvii.*Report of the National Energy Policy Development Group*, May 2001 (Chapter 7, p. 14)
xxxviii.United States Department of Justice, *Office of Legal Policy*, *New Source Review: An Analysis of the Consistency of Enforcement Actions with the Clean Air Act and Implementing Regulations*, January 2002, p. vi.
xxxix.U.S. Environmental Protection Agency, *New Source Review: Report to the President* (June 2002) p. 1.
xl.U.S. Environmental Protection Agency, *New Source Review: Report to the President* (June 2002).
xli.U.S. Environmental Protection Agency, *New Source Review: Recommendations* (June 2002), pp. 1-6.
xlii.67 *Federal Register* 80185-80314 (December 31, 2002).
xliii.Some documents released by EPA refer to five "improvements" because they include in the Emissions Calculation Test Methodology category two improvements: (1) baseline change; and (2) test change.

xliv.61 *Federal Register* 142 (July 23, 1996), pp. 38250-38344.
xlv.67 *Federal Register* 80185-80314 (December 31, 2002). An internet version is available at: http://www.epa.gov/nsr/nsrfinal.pdf
xlvi.See NPRA website at: www.npra.org
xlvii.General Accounting Office, *Clean Air Act: Key Stakeholders" Views on Revisions to the New Source Review Program*, GAO-04-274 (February 2004), p. 15.
xlviii.U.S. Environmental Protection Agency, *New Source Review: Recommendations* (June 2002), p. 6.
xlix.40 CFR 60.14(e)(1)
l. As observed by Robert Smock, Editor, "Power Plant Life Extension Trend Takes New Directions," *Power Engineering* (February 1989) with respect to power plants: "There are signs that many utilities will not use the term "life extension" to describe their spending on old power plants, even though extended life is one of the major goals of the spending program. The reason for the aversion to the term lies in the 1970 Clean Air Act. That federal law requires all power plants constructed after August, 1971 to restrict emissions of air pollutants such as sulfur dioxide. Plants built prior to 1971 are exempt, which includes most of the early candidates for life extensions. The problem is that the law also says that grandfathered plants can lose their exemption if they are "modified" or "reconstructed" in a major way and emission of proscribed pollutants are increased." (p. 21)
li.Environmental Protection Agency, *Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion*, Final Rule, p. 37 Available at: [http://www.epa.gov/nsr/ERP_merged_8-27bh.pdf].
lii.For a coal-fired power plant, a process unit is basically everything from the coal-handling equipment to the smokestack with the exception of pollution control equipment.
liii.EPA, *Final Rule*, p. 37.
liv.The 12 states were: Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Mexico, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and Wisconsin. Major cities include New York City, Washington D.C., and San Francisco. Docket No. 03-1380, filed October 27, 2003 (D.C. Circuit Court of Appeals).
lv.*New York v. EPA*, No. 03-1380 (D.C. Cir. December 24, 2003).
lvi.NPRA, *NPRA NSR Talking Points*, available at www.npra.org